

SB

305

(FILE 2)

SFIN

FILE

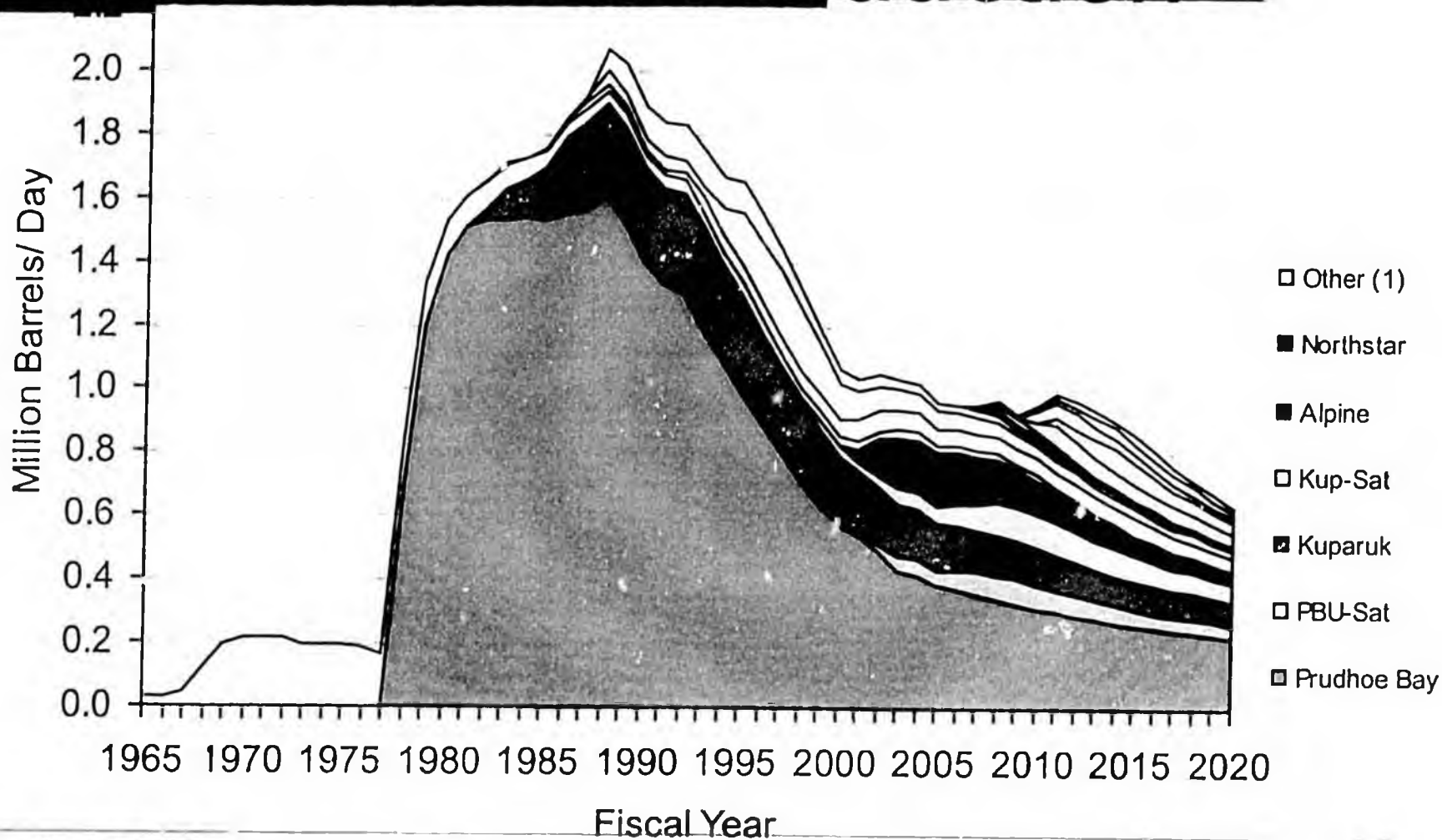
Petroleum Profits Tax (PPT)

CS for SB 305 (RES) Overview

Alaska Department of Revenue
Before the Senate Finance Committee
March 31, 2006

Robynn J. Wilson, CPA, Director, TAX Division, DOR
Dan E. Dickinson, CPA

Alaska Oil Production



Source: Fall 2005 Revenue Sources Book; Alaska Department of Revenue, Tax Division
 (1) Cook Inlet, Duck Island, Milne Point, Greater Point McIntyre, Liberty, Known On & Offshore, Fiord and N-PRA.

The Governor's 3 Big Ideas

- The current Production Tax system is broken.
- We need to use the tax system to encourage investment
- We ought to get a fair share of tax revenues when prices are high, especially if reinvestment is low

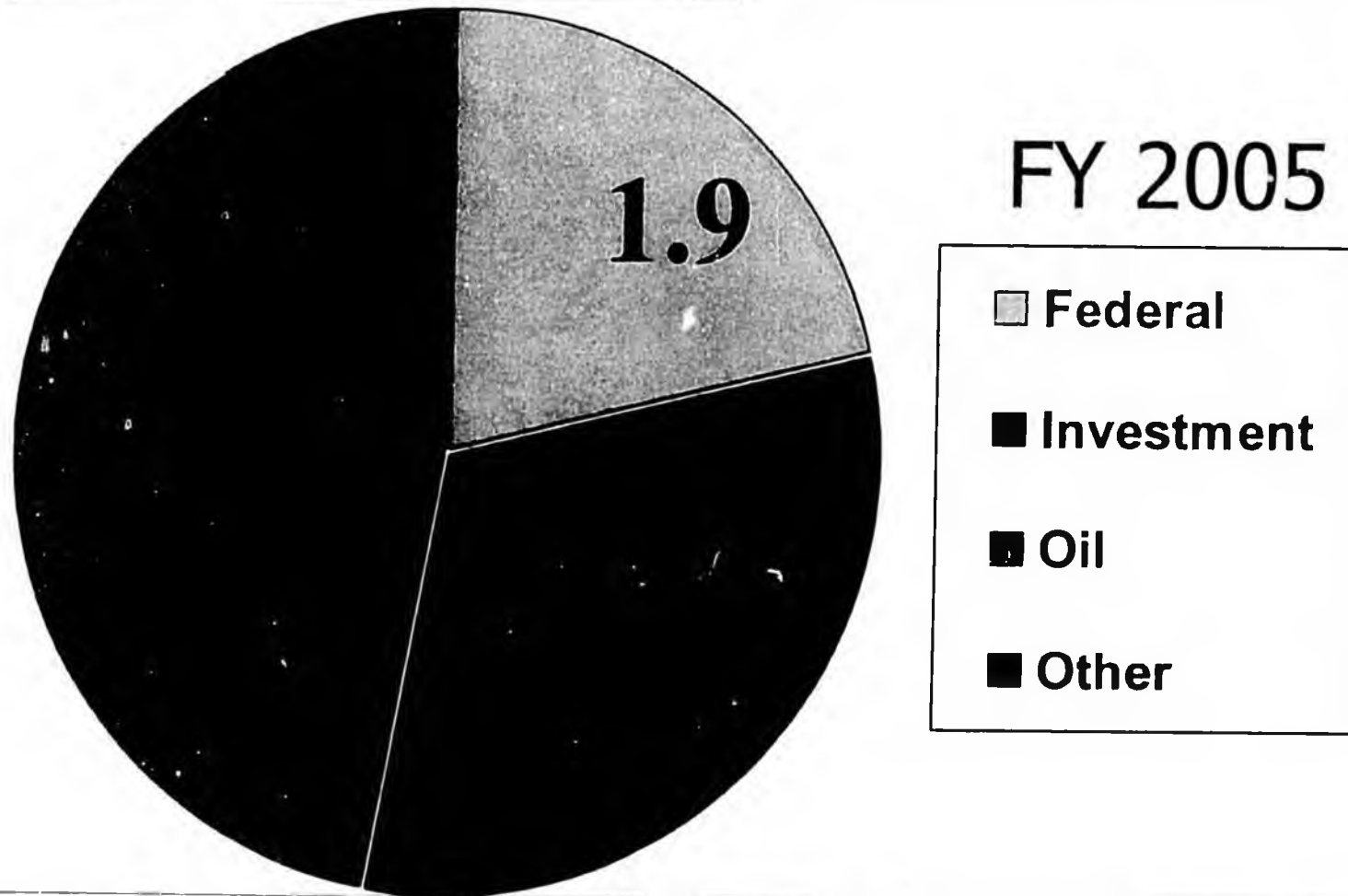
The Governor's 3 Big Ideas

- The current Production Tax system is broken. *The CS also replaces it.*
- We need to use the tax system to encourage investment. *The CS has incentives for investment*
- We ought to get a fair share of tax revenues when prices are high, especially if reinvestment is low. The CS pushes the tax rate to 25%, maintains credit rate of 20%

The Governor's 3 Big Ideas

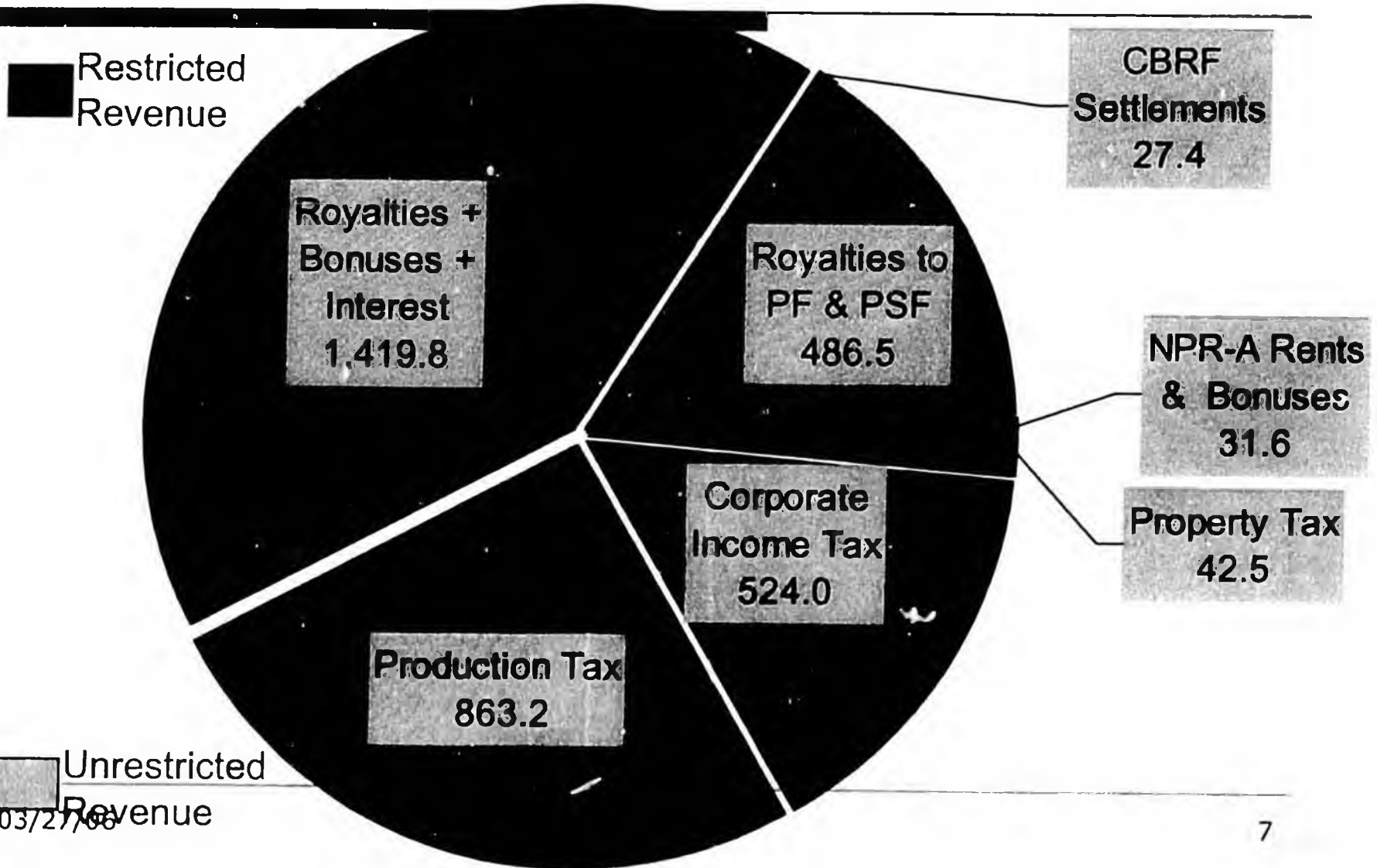
- Idea one: The Production Current Tax System is broken
 - We are not getting the investment we need – could the structure of the Production Tax be to blame
 - We are not getting a fair share of revenues when Prices are high and investment is low

Unrestricted & Restricted Revenue \$ Billion



FY 2005 Petroleum Revenue

\$ Million



03/27/05

1. Destination Value at Market (2005)

	Volume Millions barrels	\$ per barrel	\$ Million
Destination Value at Market	330	\$43.43	\$14,332
Less Tankering & Pipelines	<u>330</u>	<u>\$ 4.51</u>	<u>(\$1,488)</u>
Gross Value at Point of Production	330	\$38.92	\$12,844
Less Upstream Costs			
Operating:		\$ 3.33	
Capital:		<u>\$ 3.18</u>	
Total	330	\$ 9 6.52	(\$2,150)
Net Value at Point of Production	330	\$32.40	\$ 10,694

08/10/06

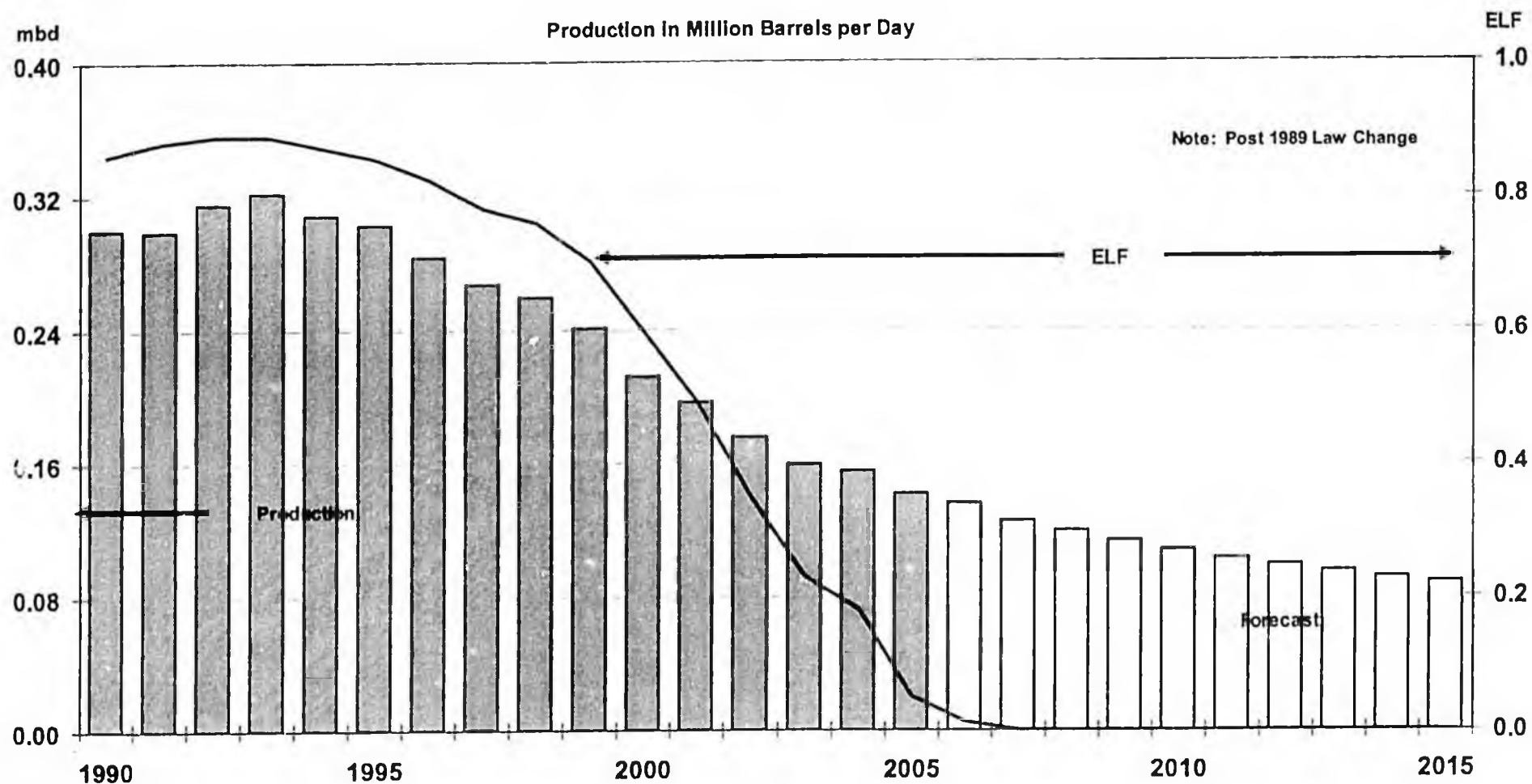
2. Current Production Tax

	\$ in Billion
Gross Value at Point of Production	\$12,844
1- Royalty Rate	0.875
Value Net of Royalty	<u>\$11,238</u>
Tax Rate	0.15
ELF Rate	0.55
Tax	\$ 927

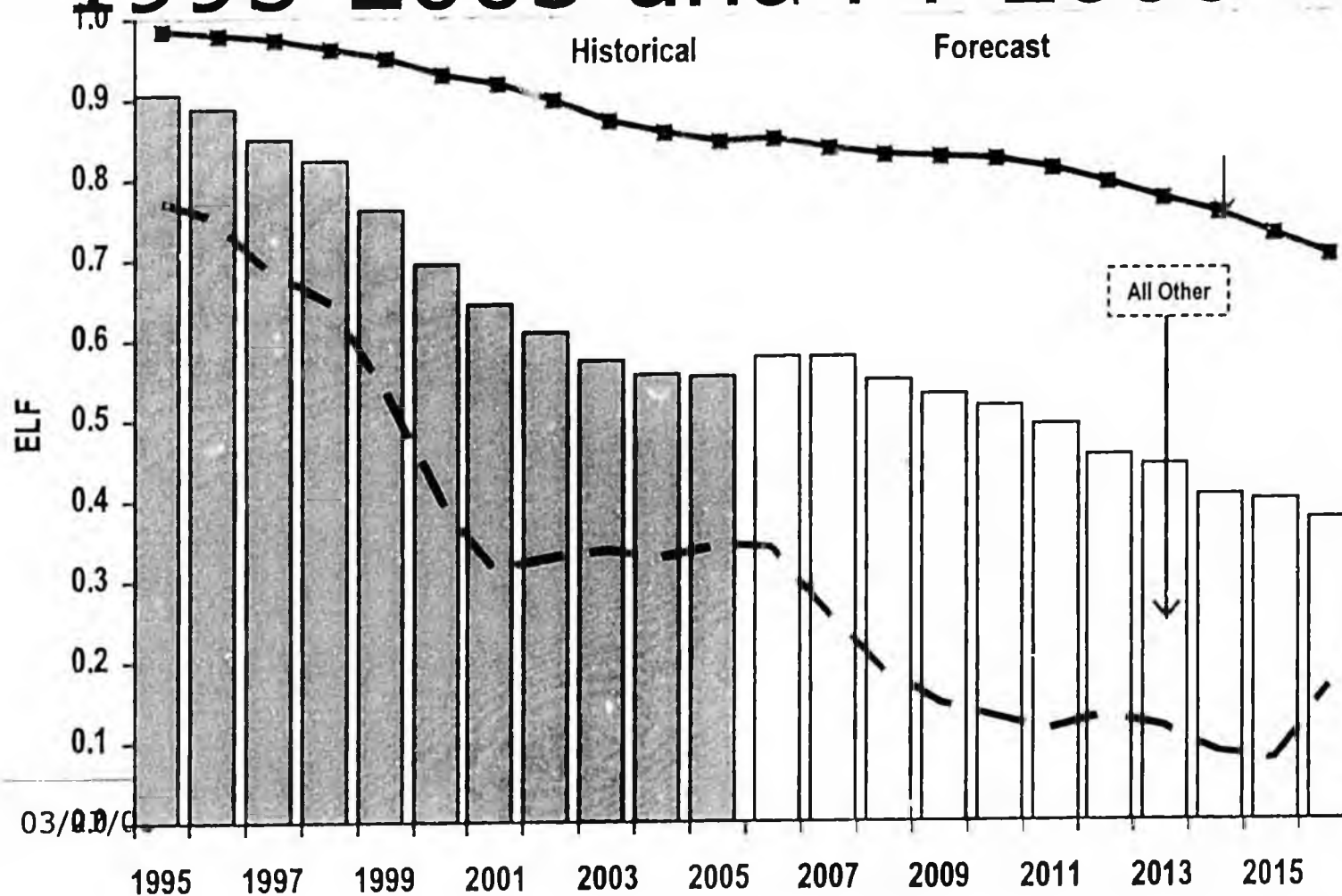
Implicit Cost

	\$ in Billion
Production Tax Net of Royalty	\$11,238
Less Implicit Cost from Proxy	(\$ 5,057)
	\$ 6,181
Tax Rate	0.15
Proposed Production Tax	\$ 927

Kuparuk Crude Oil Production & ELF



Economic Limit Factor, FY 1995-2005 and FY 2006-2016



The Governor's 3 Big Ideas

- Idea Two: We need to use the Tax system to encourage investment
- Investment leads to more production
- More production leads to more revenue
- Four ways the bill recognizes investment

Governor's Bill: 4 ways of encouraging investment

- Net vs gross – all investment is a deduction
- 20% credits for capital investments
- Up to a \$73 million Annual Allowance
- Recognition of Transition Investment Expenditures

CS: 4 ways of encouraging investment

- Net vs gross – all investment is a deduction *cs preserves*
- 20% credits for capital investments
cs preserves
- Up to a \$73 million annual allowance
CS has a a tax-free allowance based on production
- Recognition of Transition Investment Expenditures
CS changes this from a deduction to a credit with a requirement for current investment

Tax Based on Net Profits

- Governor's bill provided a tax based on Net Profits
- CS maintains this approach

Gross vs. Net

Current Tax on Gross

Value at wellhead \$50.00

Times: tax rate 15%

Tax before ELF \$7.50

PPT on Net

Value at wellhead \$50.00

Less:

Lease op exps (12.50)

Net taxable \$37.50

Times: tax rate 20%

Tax before
credits \$7.50

Tax Base

Gross value at point of production

Determining value under current system

West coast value

\$



Gross Value under PPT

Dept. of Revenue can allow a producer to elect the use of:

- Royalty value
- DOR formula that estimates a value at a specific location such as point of delivery into a common carrier pipeline

Tax Based on Net Profits

Gross value at point of production

Less: Lease expenditures

- ♦ operating costs
- ♦ capital expenditures
- ♦ allowance for overhead

Equals: Net Profits

Non-deductible expenses

- Depreciation
- Royalty payments
- Taxes based on net income
- Interest & financing charges
- Lease acquisition costs
- Other costs

Governor's Bill: Credits to Encourage Investment

- **20%** of qualified capital expenditures

- May be taken on:
 - ♦ Exploration costs
 - ♦ Capital costs **incurred on lease**

- Credits are transferable

CS: Credits to Encourage Investment

- CS maintains credits
- Credits may not be taken on:
 - Abandonment costs

Friendly to New Investors

- Ability to monetize credits
- Ability to monetize losses
- Base allowance
 - Governor's bill: \$73M deduction
 - CS: converts this to tax-free allowance based on production:
$$(5000 - .2 \times [ADP - 5000]) / ADP$$

ADP = average daily production
sunsets in 2013

CS: 5,000 bbl plan

		percentage
Daily	PPT tax-free	of net income
Production	production	tax-free
5,000	5000	100%
6,000	4800	80%
7,000	4600	66%
8,000	4400	55%
9,000	4200	47%
10,000	4000	40%
15,000	3000	20%
20,000	2000	10%
25,000	1000	4%
30,000	0	0%

03/27/06

Transition Provision

- Governor's bill allowed deductions for recent capital expenditures
 - Last five years' capital expenditures
 - Allowed over ~~5~~⁶ years
 - Allowable on when price of oil exceeded \$40

Transition Provisions in CS

- CS maintains 5 year look-back
- Allows recoupment of \$1 for every \$2 currently invested
- Removes oil price test
- Changes from a deduction to a credit

The Governor's 3 Big Ideas

- Idea Three: We ought to get a fair share of tax revenues when prices are high, especially if reinvestment is low
- With high prices we are not getting a fair share
- We should be treated as fairly as other jurisdictions while remaining competitive with them for investment

Fair Tax Rate

Governor's bill: 20%

Fair Tax Rate

Governor's bill: 20%

CS pushes tax rate to 25% and adds progressive feature

Progressivity Surcharge

- Oil surcharge applies when oil price (ANS West Coast) exceeds \$40/bbl

$(ANS_{wc} - \$40) \times .0015$

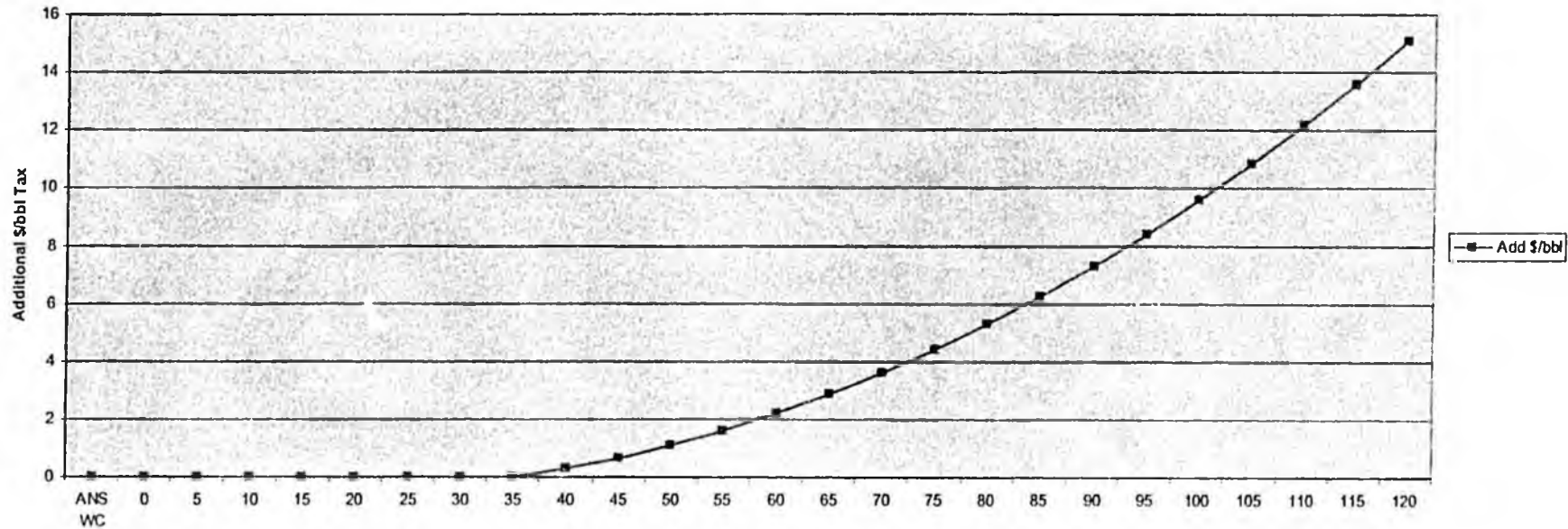
$\times ANS\ PV\ \text{"wellhead"} \times \text{taxable barrels of oil}$

Different definition for gross value at point of production

- Deductible from PPT

CS: Progressivity Feature

House Resource Progressivity Feature



Governor's bill provided a fair tax rate

	Governor's Bill
ANS West Coast Price:	\$ 70.00
Downstream Transportation	(7.00)
<i>Wellhead Value (gross)</i>	<u>63.00</u>
Upstream Production Costs	(7.00)
<i>Production Tax Value (net)</i>	<u>56.00</u>
	20%
	<u>11.20</u>
Percentage Gross	17.8%
Percentage Net	20.0%

CS: How Does Progressivity Feature Work?

Senate Resources CS

	PPT	Progressivity Factor
ANS Wellhead (PV)		63.50
ANS wc	70.00	
Downstream Transportation	(7.00)	4.5%
<i>Wellhead Value (gross)</i>	<u>63.00</u>	
Progressivity		<u>4.5%</u>
Progressivity Amount	(2.90)	2.90
Upstream Production Costs	<u>(7.00)</u>	
<i>Production Tax Value (net)</i>	<u>53.10</u>	

CS: How Does Progressivity Feature Work? (Cont.)

Senate Resources CS

~~PPT~~ Progressivity Total

	PPT	Progressivity	Total
<i>Production Tax Value (net)</i>	53.10		56.00
PPT Rate	25%		
Total Tax	13.29	2.86	16.15
Percentage Gross	25.0%		28.8%
Percentage Net	21.1%		25.6%

Governor's Bill: Other Provisions

- Monthly return filing
- 90% payment safe harbor
- Yearly true-up on 3/31

CS: Other Provisions

- Monthly return filing
CS maintains
- 90% payment safe harbor
CS increases this to 95%
- Yearly true-up on 3/31
CS changes this to quarterly true-up

Other Provisions in CS

spill fee increases total fee 1¢ to 6¢

--suspended fee (AS 43.55.201)

--2 cents changed to 1 cent

--non-suspended fee (AS 43.55.300)

--3 cents changed to 5 cents

No Longer Creditable as in Governor's Bill

Other Provisions in CS

- Existing Private royalty oil tax rate set at 5%, 1.5% in Cook Inlet

- Bill sets no tax rate on new private royalty lease production

- Effective date changed from 7/1/06 to 4/1/06

THE
FOLLOWING
DOCUMENT(S)
ARE
POOR
ORIGINAL
COPIES

PPT: A Tax for Alaska's Future



PPT REVENUE STUDIES

Presentation to
Senate Finance

Alaska Department of Revenue
Tax Division
March 31, 2006

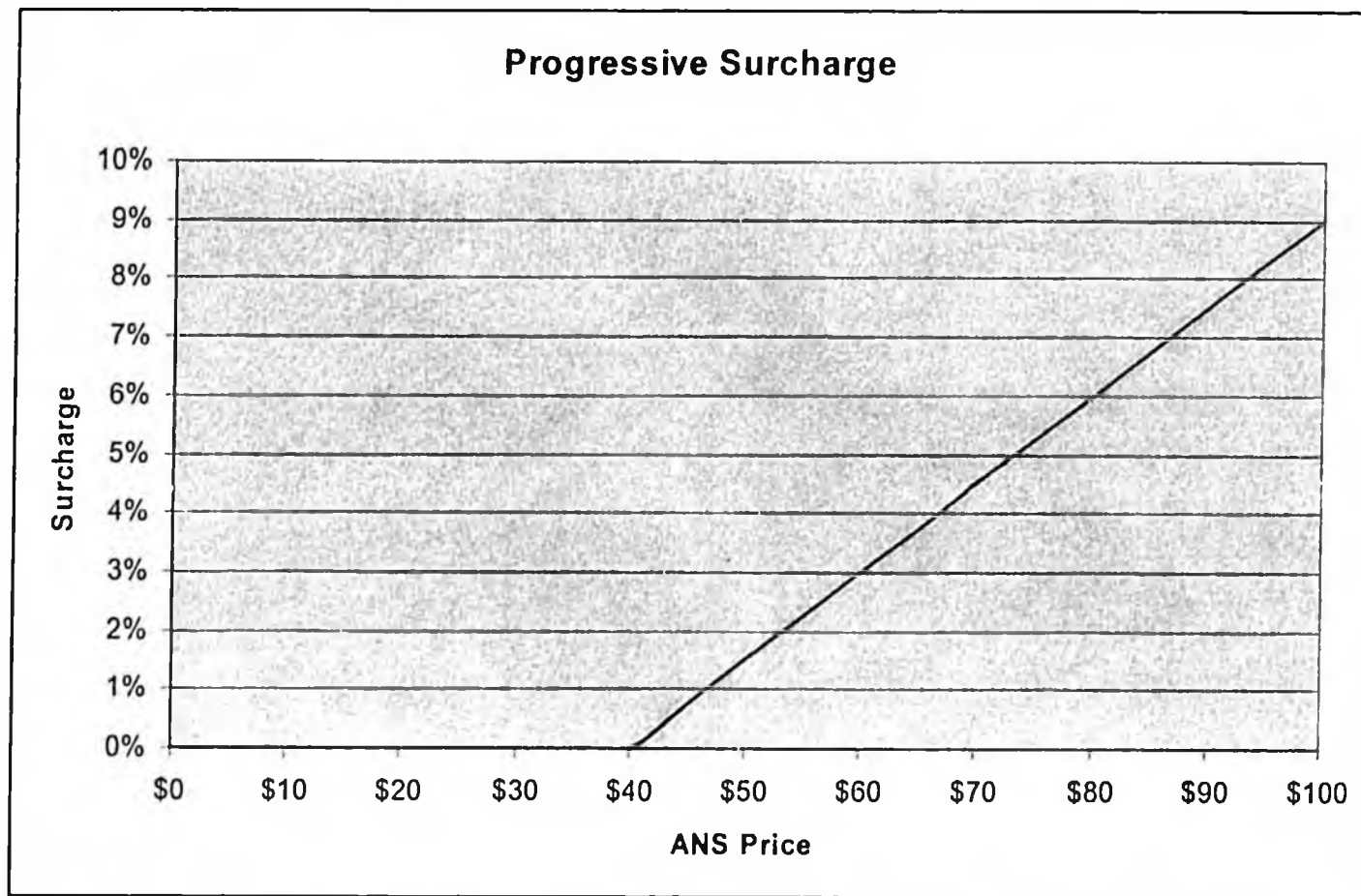
OVERVIEW

- Description of tax
- Description of model
- Long-term cumulative revenues
- Annual revenues
- Effective tax rate
- State take
- Cook Inlet

Progressive Surcharge

- $0.2\% \times (1 - \text{tax rate})$ of difference between ANS and \$40
- Applies to wellhead value
- Deductible for PPT calculation

FIGURE 1



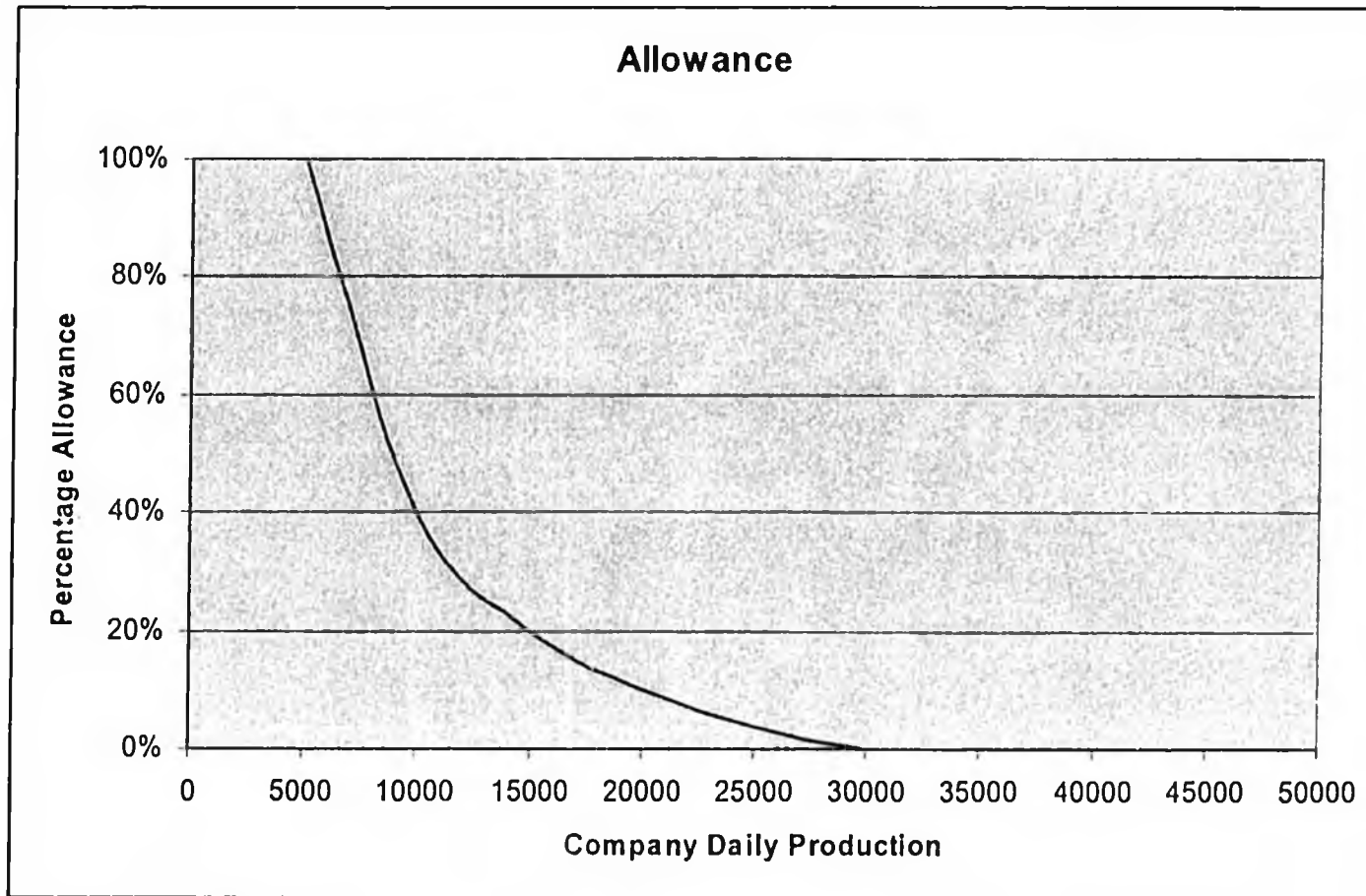
Assist Small Companies & Attract New Investors

- Small Investors
 - Bigger appetite for smaller targets
 - New targets
 - Diversity
 - Less risk averse
- New Investors
 - ANWR, NPRA

Small & New Investors Mechanisms

- Selling credits
- Converting losses to credits
- Big NPV boost
- Standard allowance
 - $(5,000 - 0.2 \times [ADP - 5,000]) / ADP$
 - Where ADP is average daily production for company
 - Expires after 2013

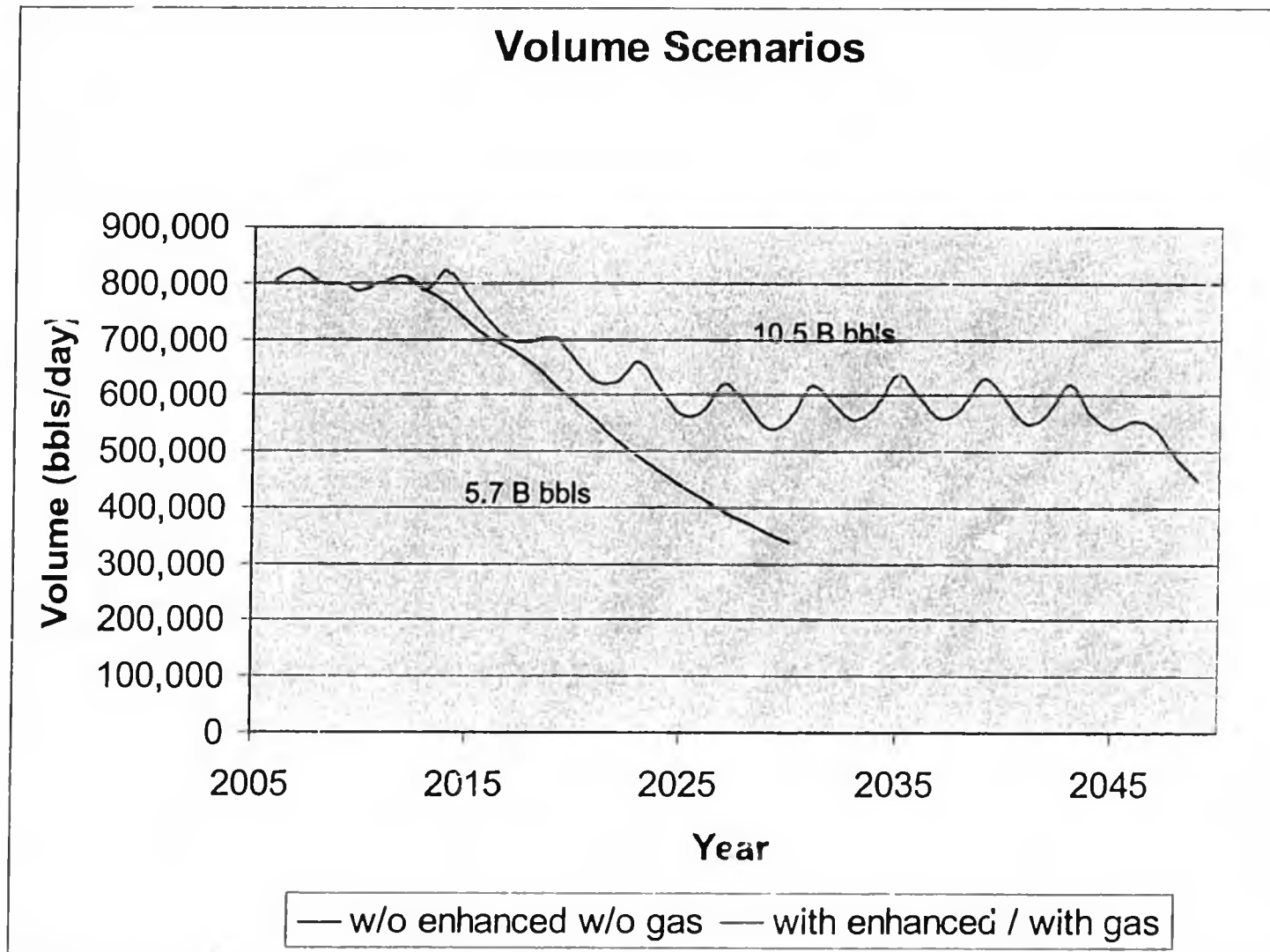
FIGURE 2



Volume Scenarios

- No enhanced volumes / No gasline
 - Totals 5.7 billion barrels through 2030
 - Including 0.6 billion barrels of heavy oil
 - No additional heavy oil at prices under \$30
- Gasline and enhanced volumes
 - Totals 10.5 billion barrels through 2050
 - Includes additional 3.1 billion barrels conventional
 - 700 million barrels net stemming from gasline
 - Including additional 1.7 billion barrels heavy oil
 - No additional heavy oil at prices under \$30

FIGURE 3



Costs and Prices

- Costs
 - \$100 mm/yr exploration through 2040
 - \$1/bbl on-going capital on all barrels
 - \$3.50/bbl developmental capital on 2/3 of existing conventional oil
 - \$8/bbl developmental capital on 2/3 of existing heavy oil
 - \$3.50/bbl developmental capital on new conventional oil
 - \$8/bbl developmental capital on new heavy oil
 - \$3/bbl operating costs on conventional oil
 - \$5/bbl operating costs on heavy oil
- Costs, prices, and revenues are all real \$2005 dollars
- Heavy oil discounted 8% for quality
- 2.5% of production subject to small company allowance (5,000 b/d)
- 70% of transition expenditures realized (2 for 1) as 20% credit
 - Costs \$100 mm/year over 7 years

Feedback Effects Not Modeled

- Production depends on investment
 - More investment with incentives
 - Credits are incentive
- More investment with higher prices
- Less investment with higher taxes
- Investment driven by competitive international opportunities ... which are always evolving

Cumulative Revenues

- Without enhanced volumes / without gasline (through 2030)
- With enhanced volumes / with gasline (through 2050)
 - Does not include gasline severance taxes
 - Includes gasline costs

FIGURE 4

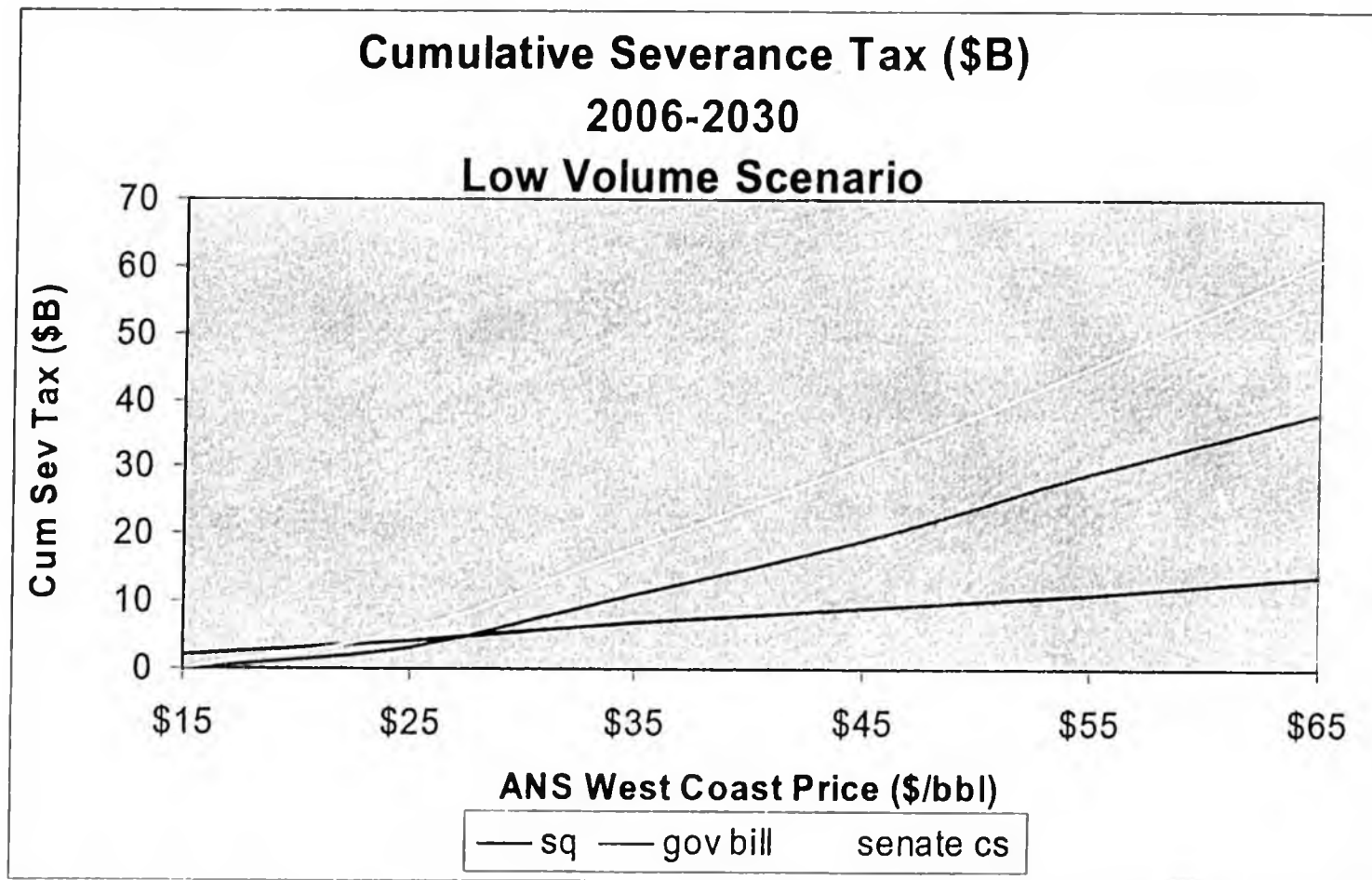
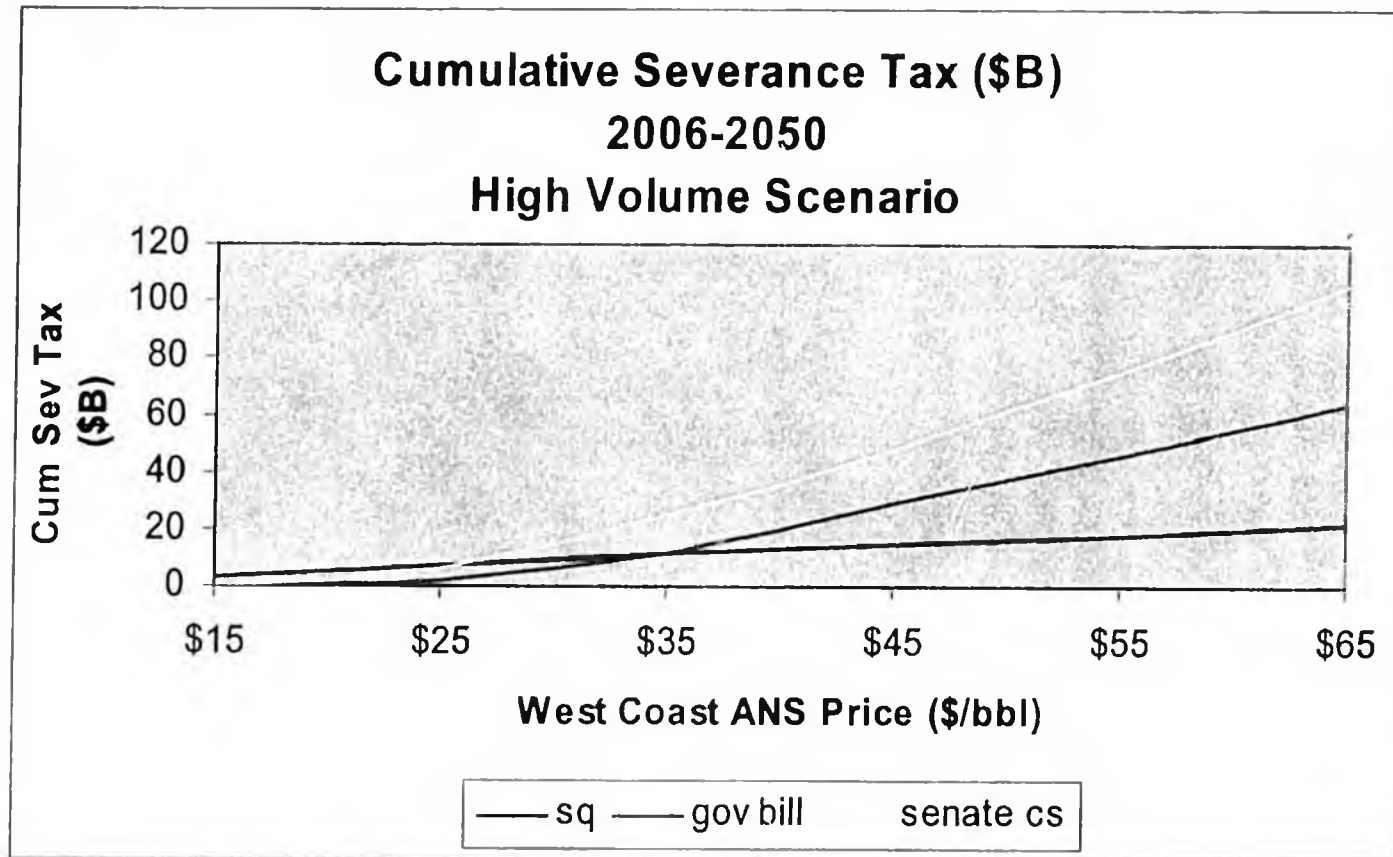


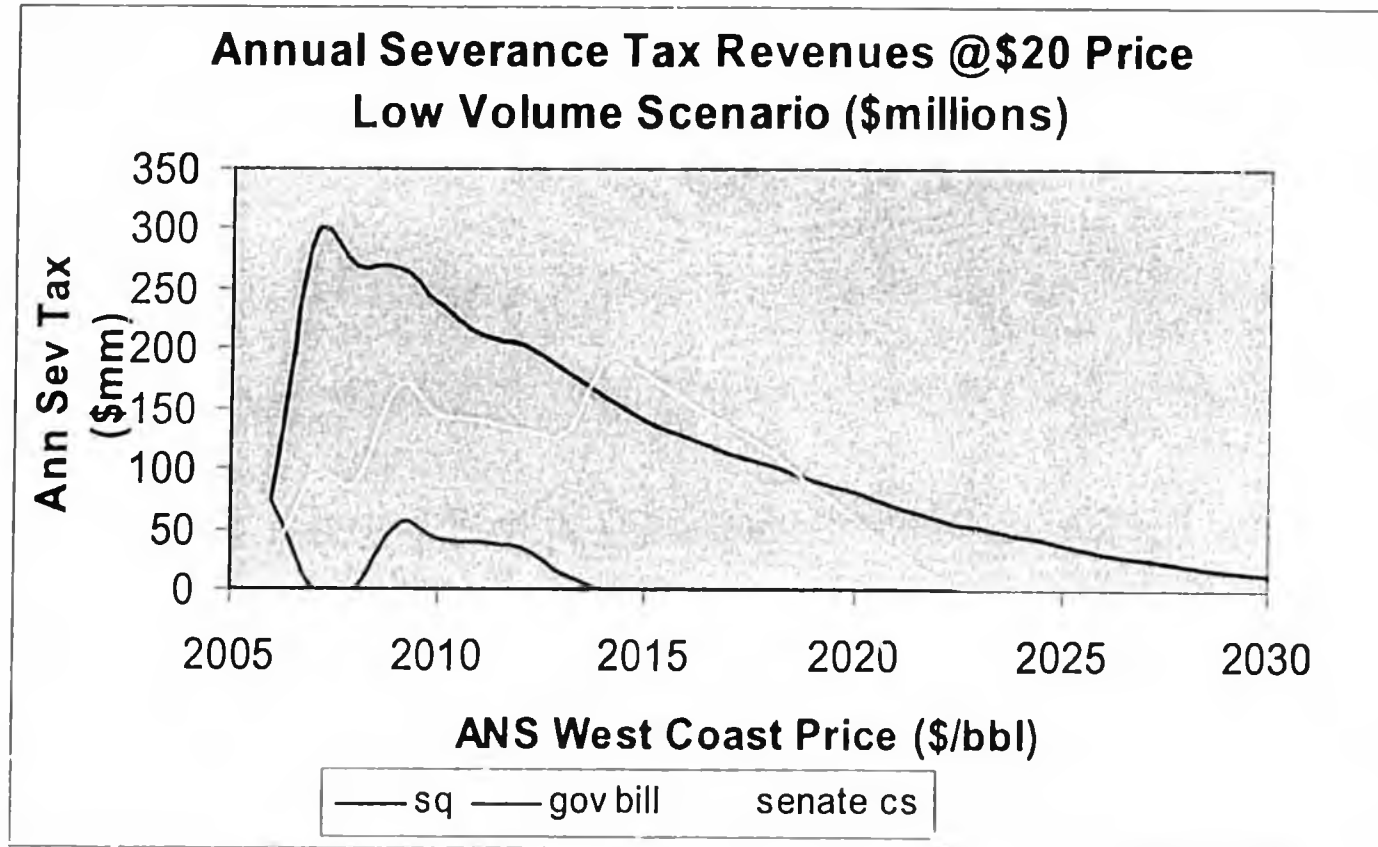
Figure 5



Annual Revenues

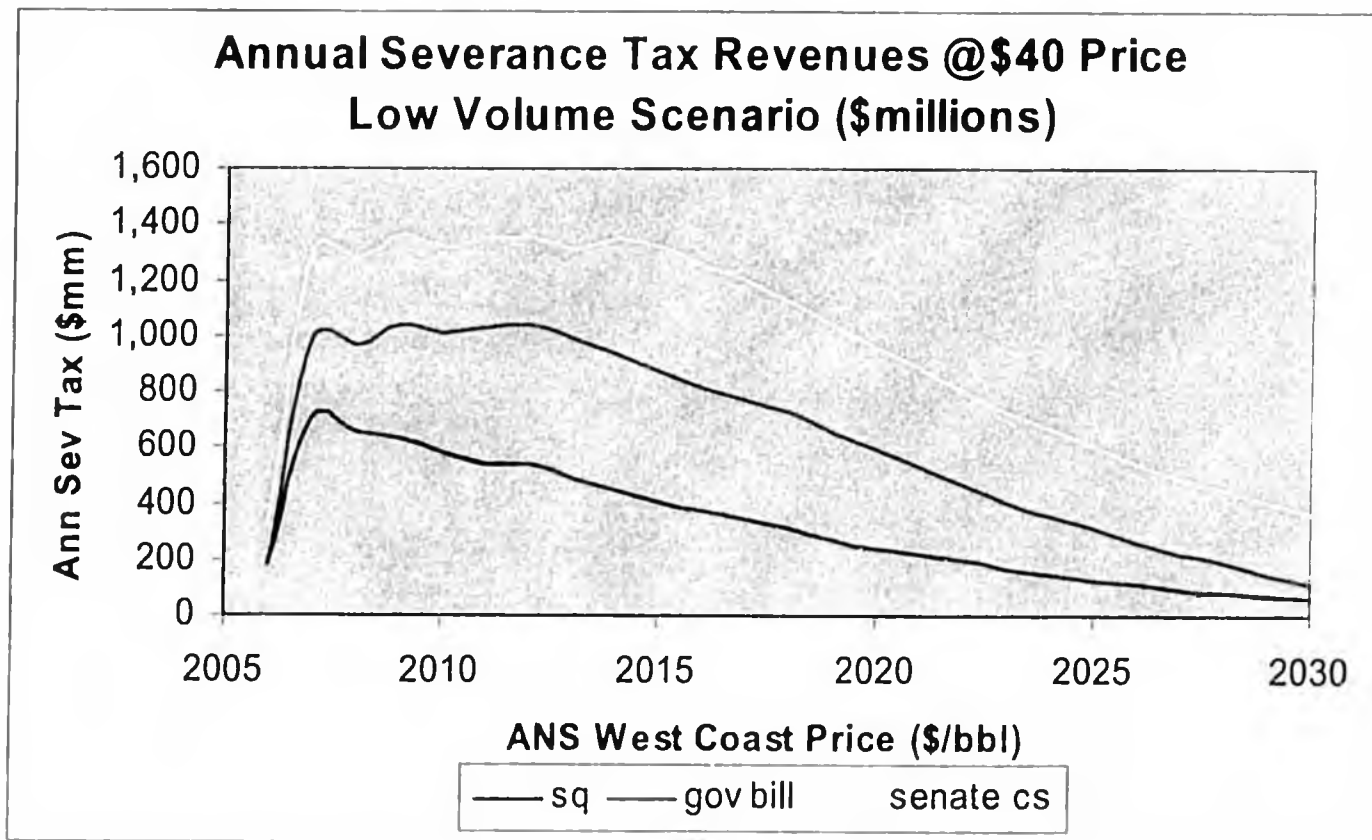
- Without enhanced volumes / without gasline (through 2030)
 - \$20
 - \$40
 - \$60
- With gasline / with enhanced volumes (through 2050) (does not include gasline severance taxes; includes gasline costs)
 - \$20
 - \$40
 - \$60

Figure 6



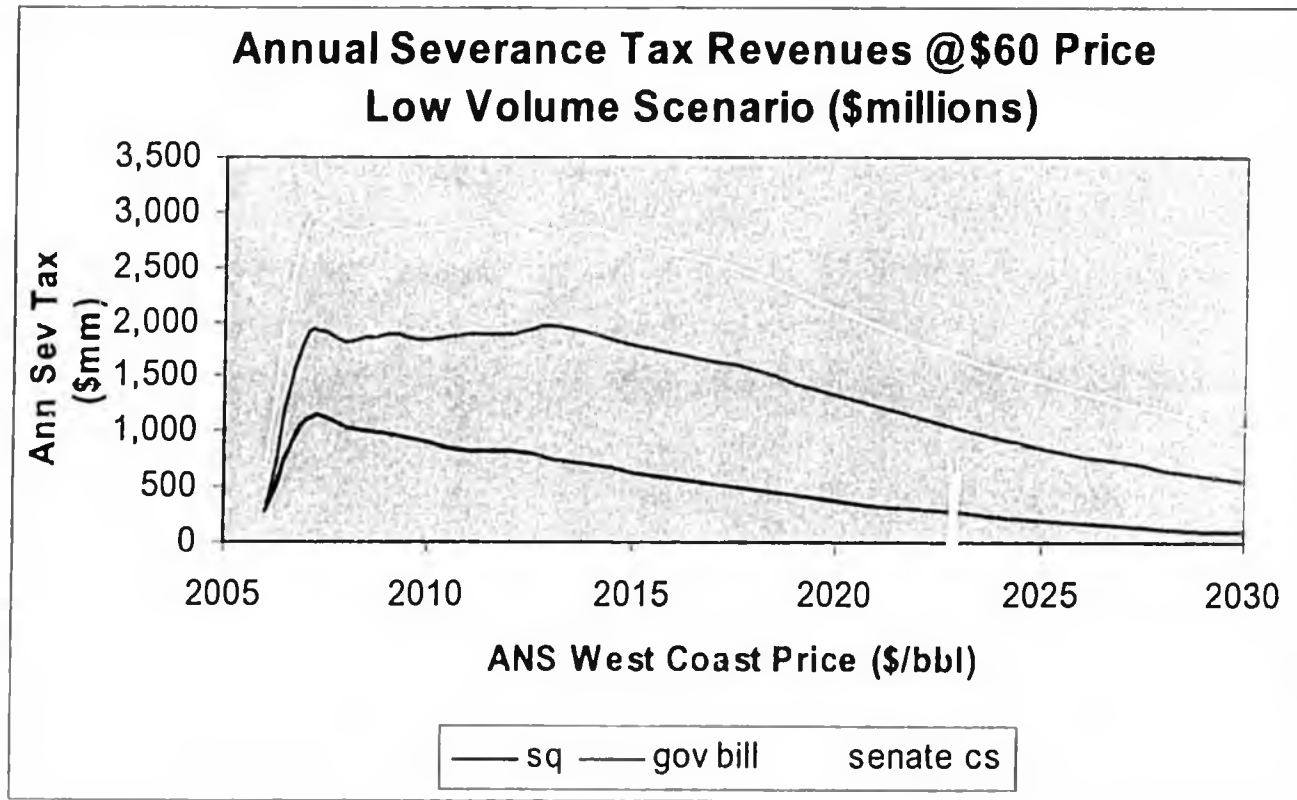
Average annual revenues \$40 million less than status quo (both proposals)
Note: Status quo averages \$116 million annually

Figure 7



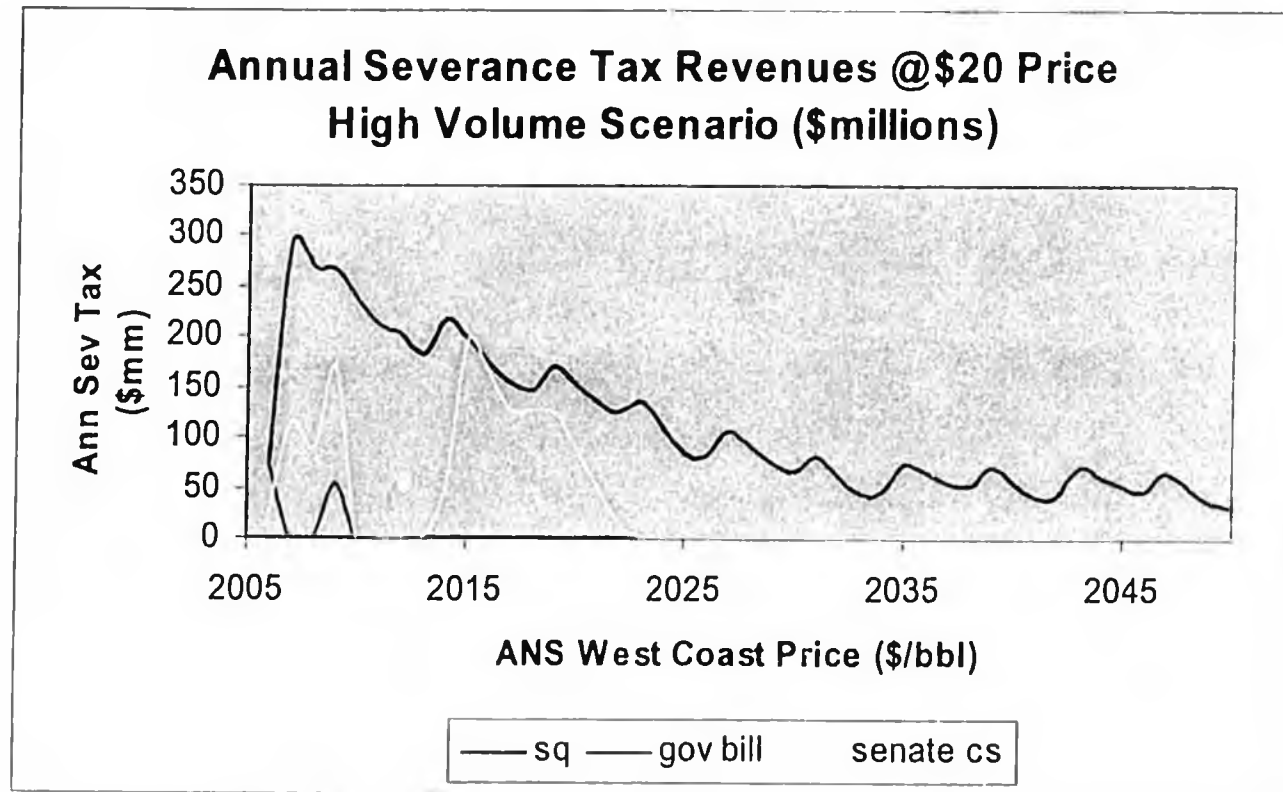
Senate CS has average annual revenues \$600 million more than status quo
and \$300 more than Governor's bill

Figure 8



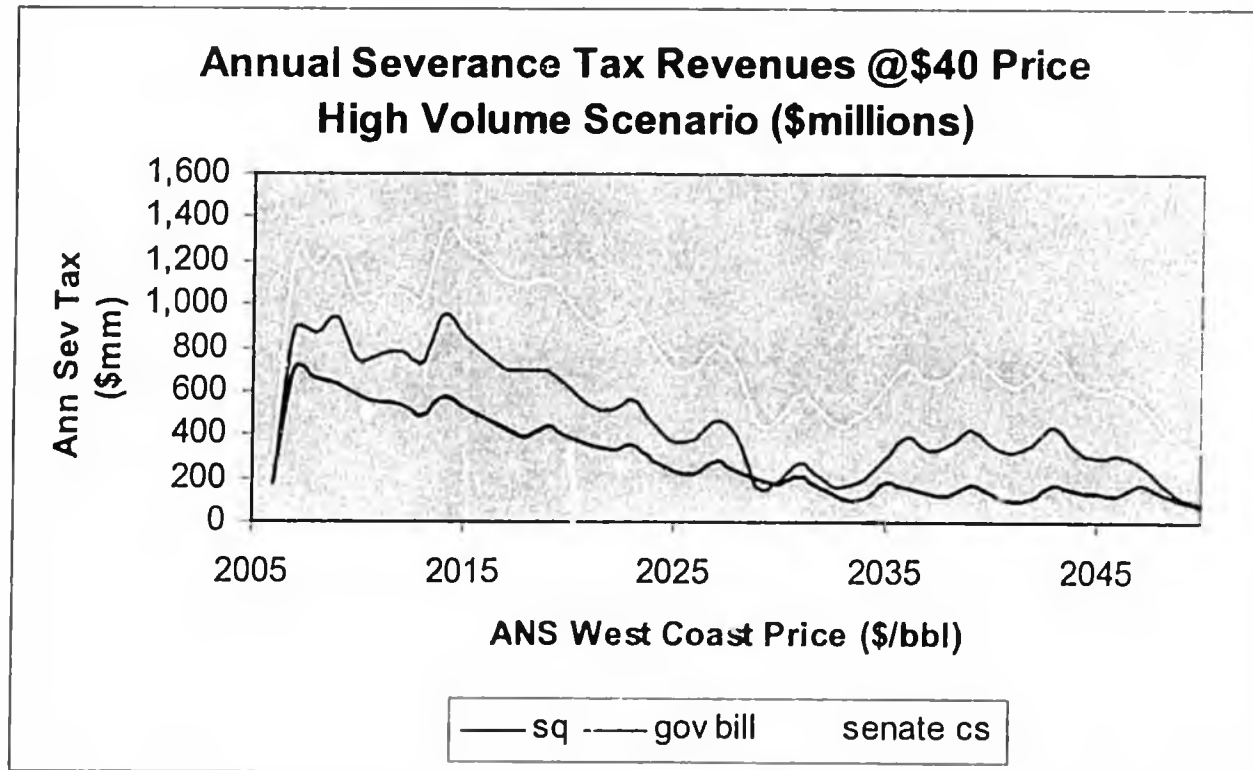
Senate CS has average annual revenues \$1.6 billion more than status quo and \$800 million more than Governor's bill. Annual progressive surcharge \$200-\$400 Note this is equivalent to State gasoline revenues at \$6.00/mmbtu Chicago price without the gasoline.

Figure 9



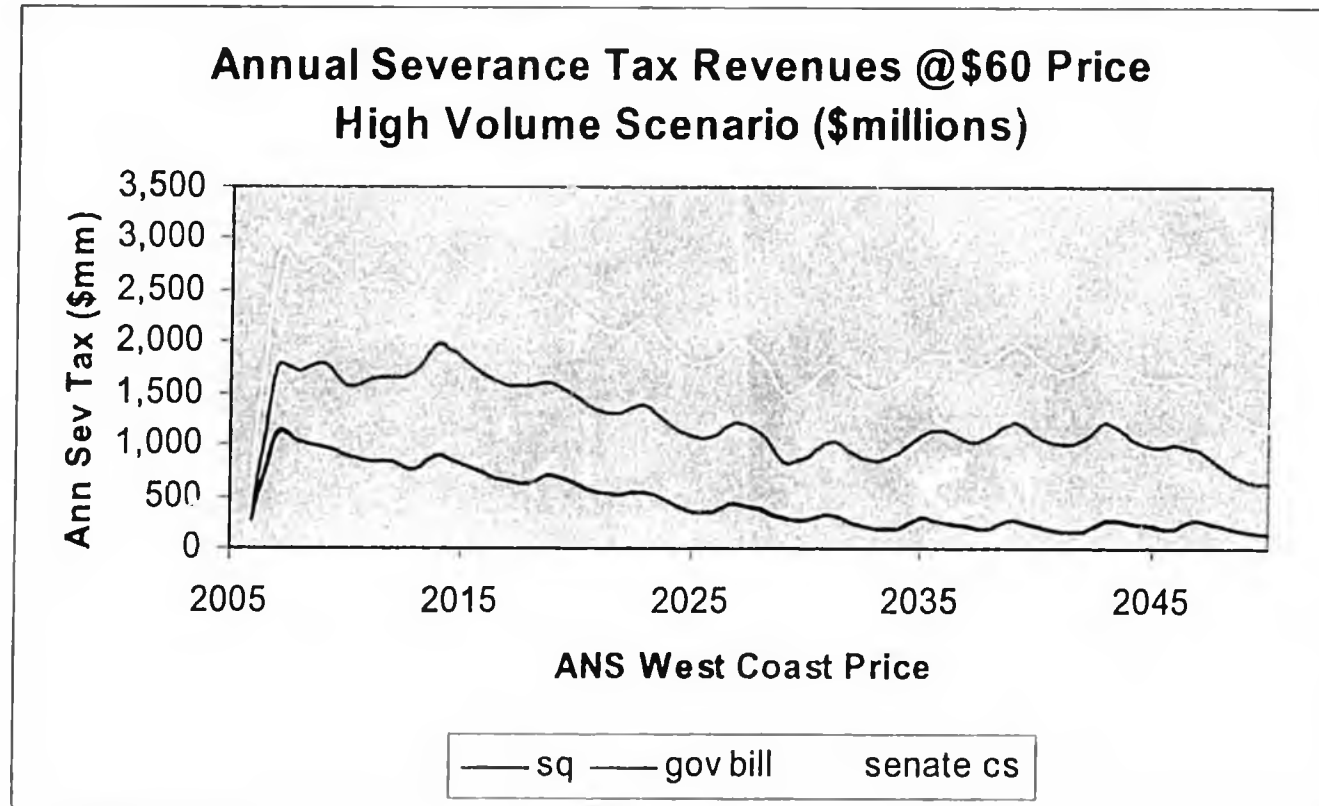
Average annual revenues \$80 million less than status quo (both proposals)
Note: Status quo averages \$112 million annually

Figure 10



Senate CS has average annual revenues \$500 million more than status quo and \$300 more than Governor's bill

Figure 11



Senate CS has average annual revenues \$1.5 billion more than status quo and \$800 million more than Governor's bill. Annual progressive surcharge \$200-\$400 mm.

Effective Tax Rate

- Severance Tax / (Wellhead less Royalty)
 - Without enhanced volumes / without gasline
 - With enhanced volumes / with gasline

FIGURE 12

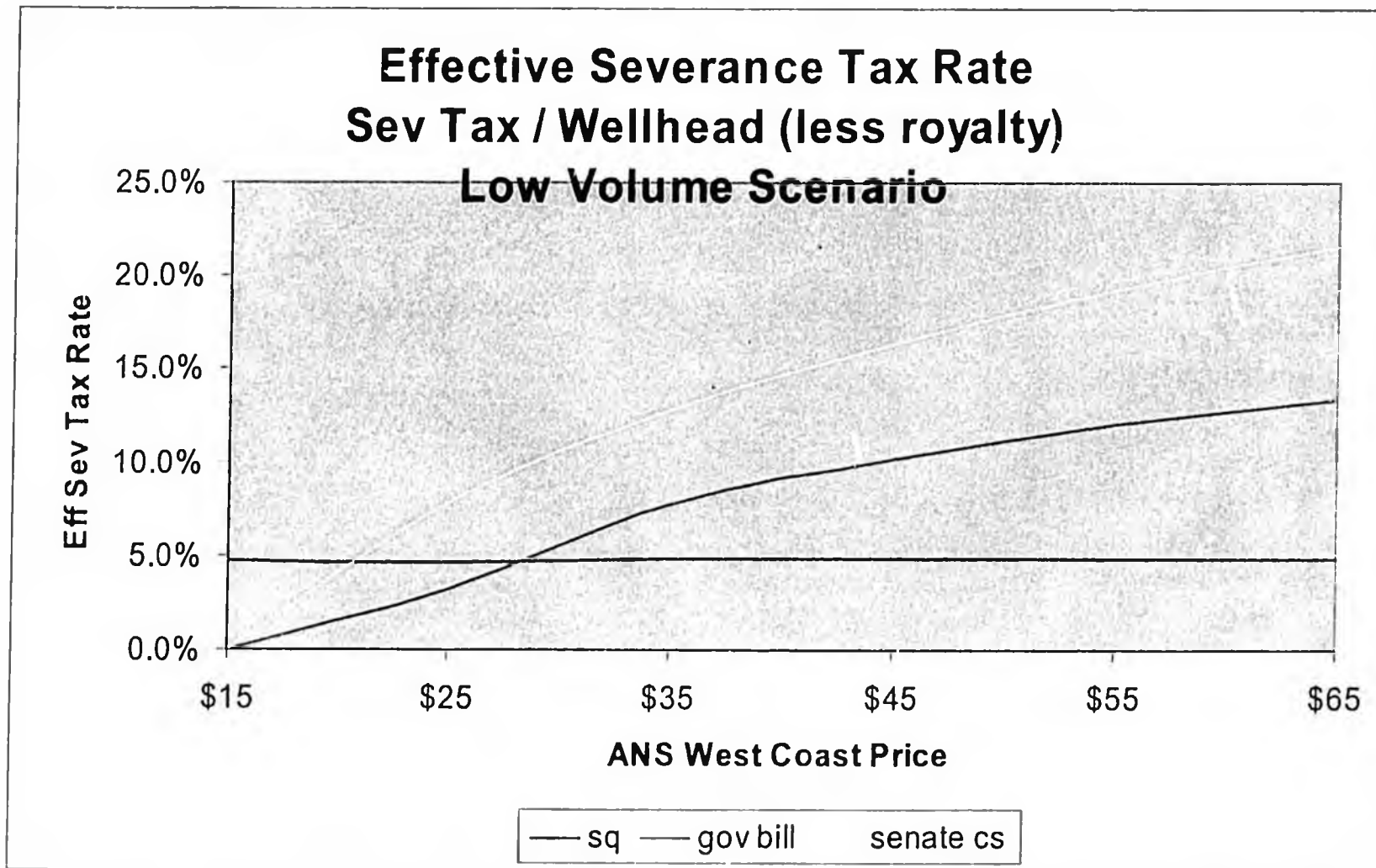
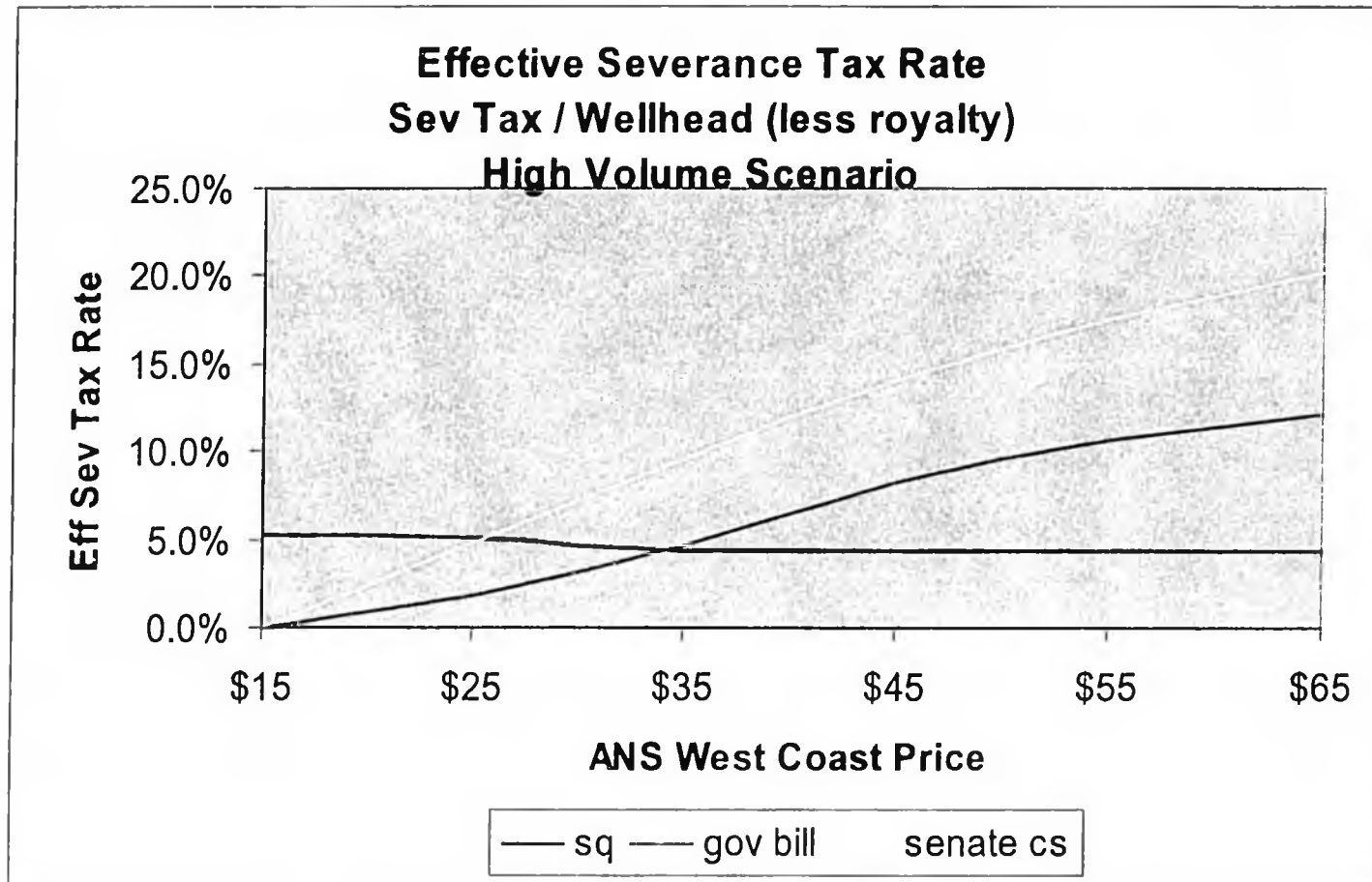


FIGURE 13



State Take

State Revenues / Economic Rent

FIGURE 14

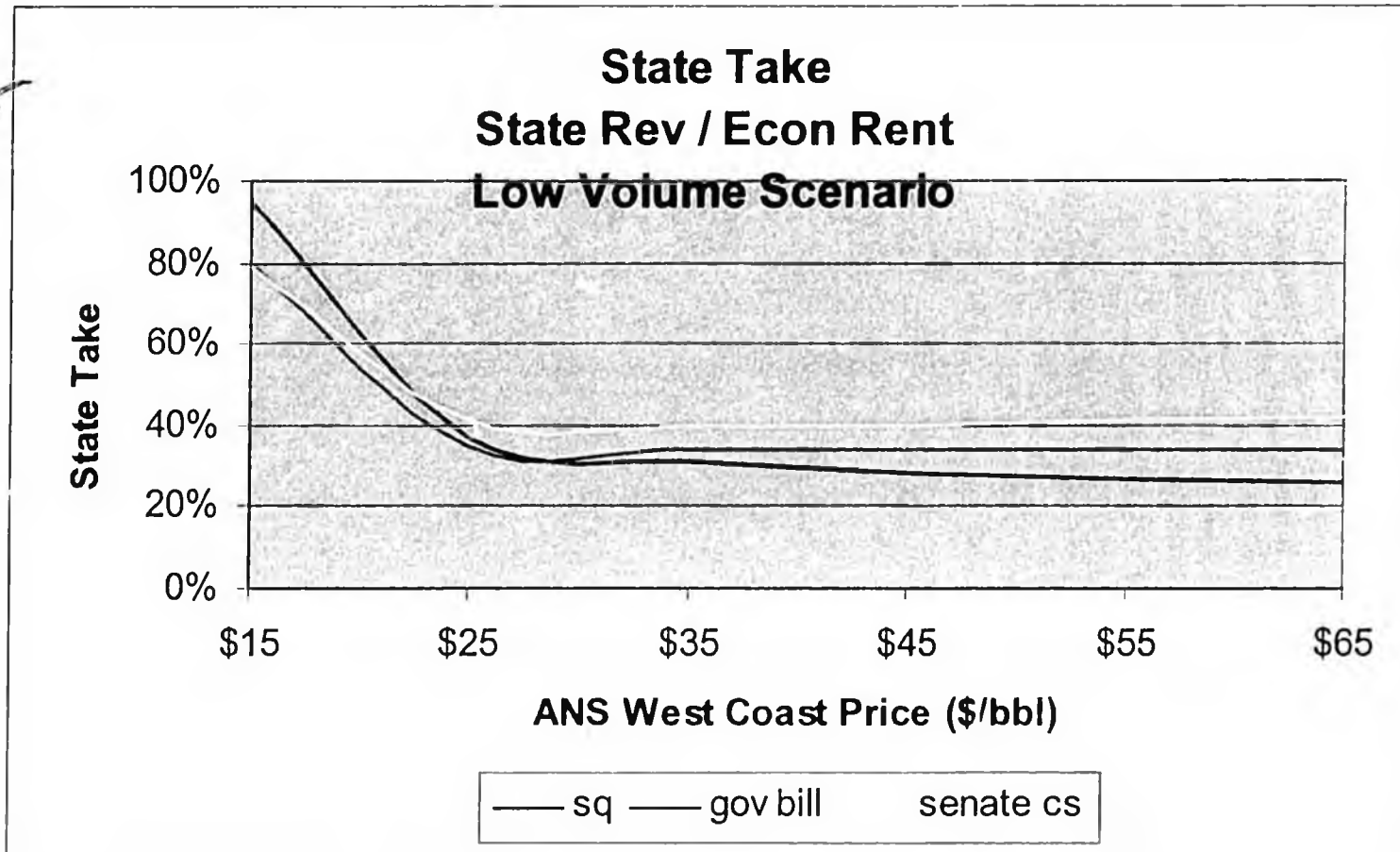


FIGURE 15

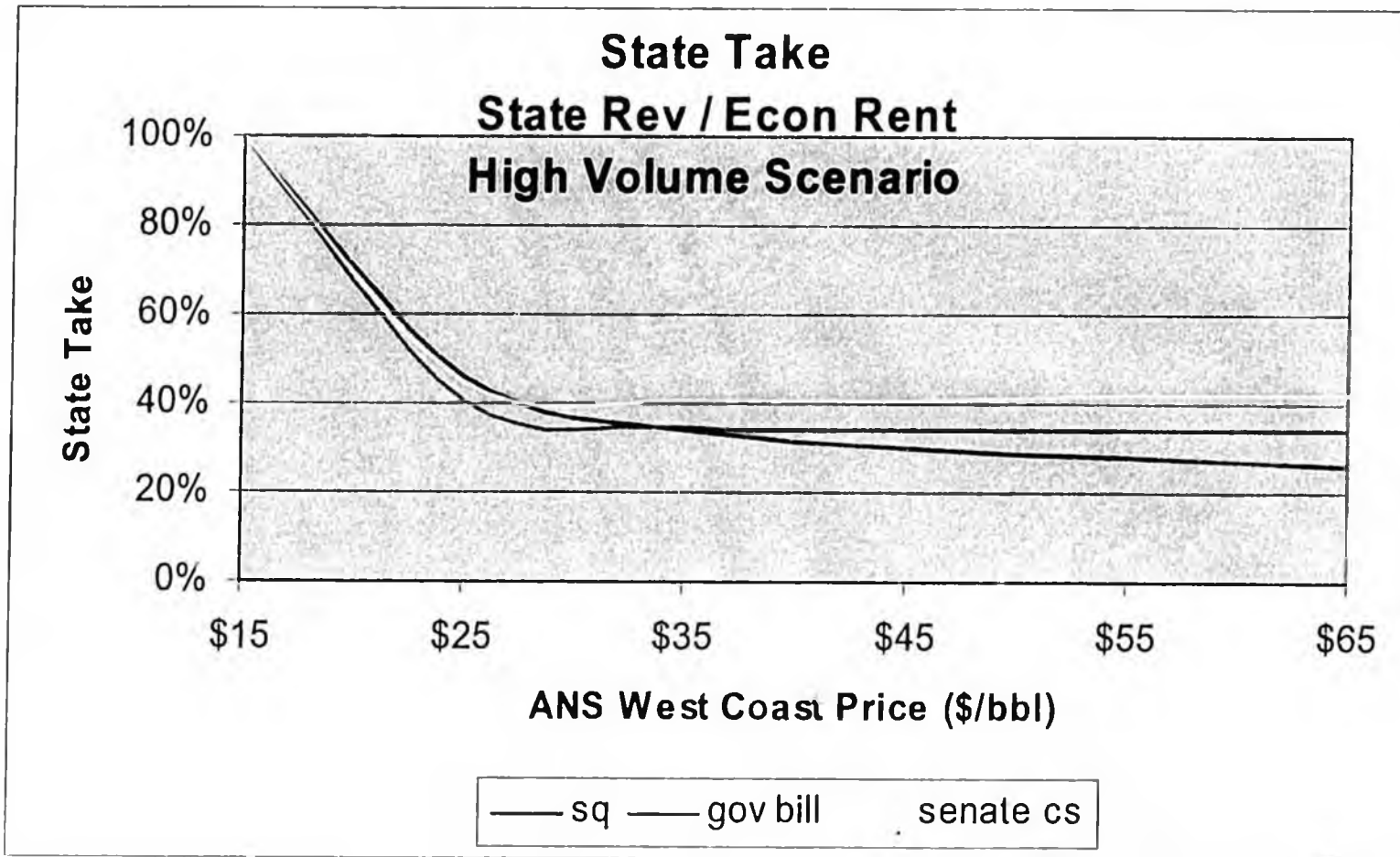
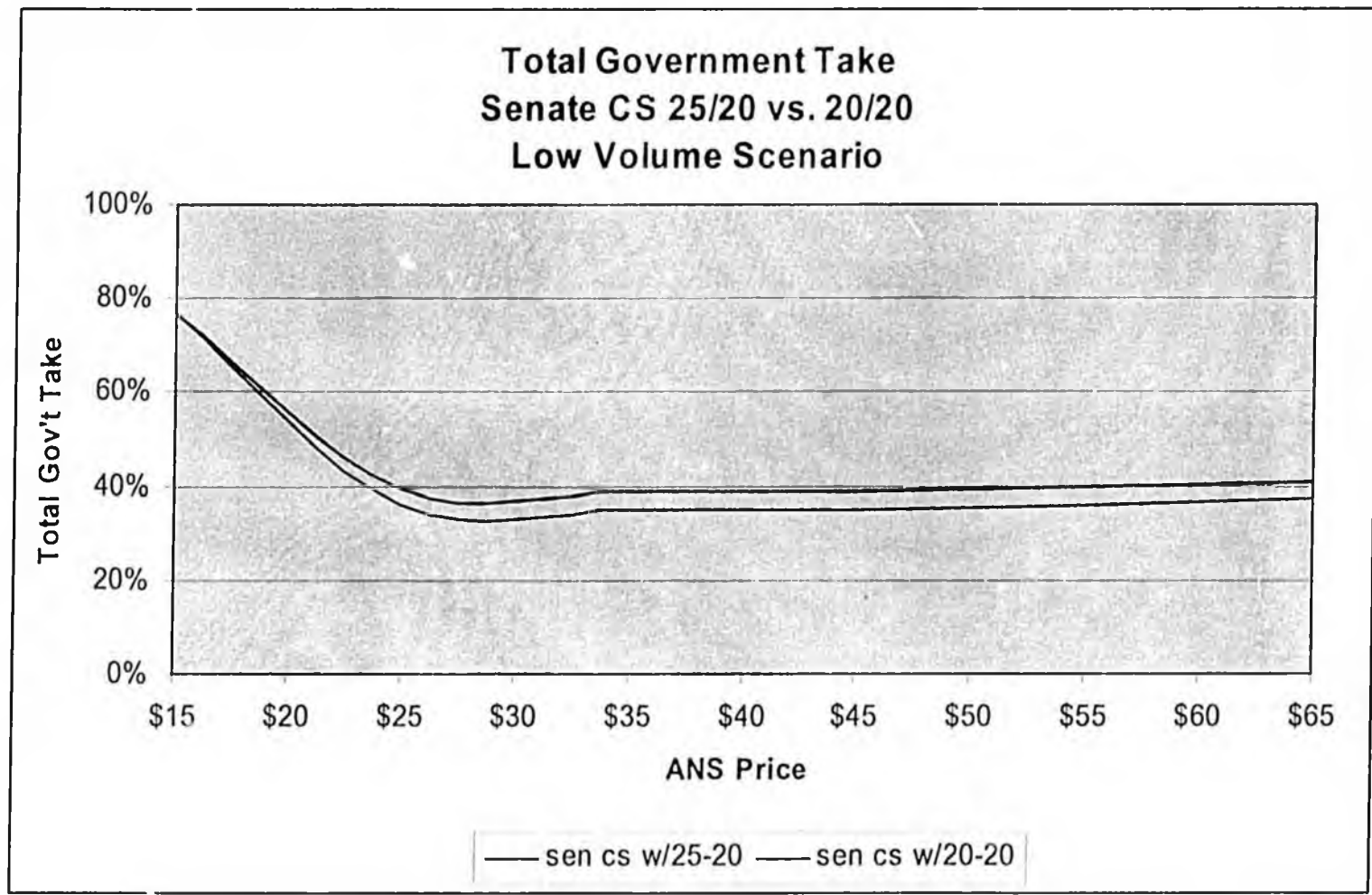


Figure 16



For "PPT Revenue Studies"
handout of 3/31/06

Cook Inlet

COOK INLET			
	Oil	Gas	Barrels of oil
	barrels/day	mcf/day	Equivalent
Aurora	0	9,260	1,543
Chevron/Unocal	7,885	116,755	27,344
ExxonMobil	1,111	0	1,111
Forest	6,891	108	6,909
Marathon	157	165,288	27,705
ML&P	0	15,431	2,572
ConocoPhillips	0	167,650	27,942
XTOE Energy	3,283	92	3,298
TOTAL	19,327	474,584	98,424

Cook Inlet Gas

- Cook Inlet is 80% gas on a BOE basis
- Industry is evolving
 - Decreased production?
 - Higher prices?
 - Increased investment?
- PPT impact on oil taxes not significant
- Gas taxes on existing fields may increase at higher prices
- New fields may see lower taxes/higher npv

GAS ELF

$$1 - (3000 / \text{Average Well Productivity})$$

Example: 10,000 mcf/well/day

$$\text{ELF} = 0.70$$

6,000 mcf/well/day

$$\text{ELF} = 0.50$$

COOK INLET GAS FIELDS

Field	MCF/day	Avg Elf
BELUGA RIVER	155,740	0.751
BEAVER CREEK	17,554	0.088
CANNERY LOOP	40,636	0.601
GRANITE POINT	208	0.000
HAPPY VALLEY	5,083	0.170
IVAN RIVER	4,348	0.000
KALOA FIELD	3,269	0.424
KENAI UNIT	60,907	0.001
LEWIS RIVER	1,042	0.000
LONE CREEK	4,240	0.358
MIDDLE GROUND SHOAL	61	0.000
MOQUAWKIE	5,188	0.354
NORTH COOK INLET	108,421	0.648
NICOLAI CREEK	1,593	0.000
NINILCHIK	30,783	0.373
NORTH TRADING BAY UNIT	587	0.000
PRETTY CREEK	1,967	0.000
REDOUBT SHOALS	2	0.559
STERLING GAS FIELD	2,094	0.278
TRADING BAY UNIT	146,343	0.474
SWANSON RIVER	10,539	0.000
WOLF LAKE	163	0.000
	600,768	0.500

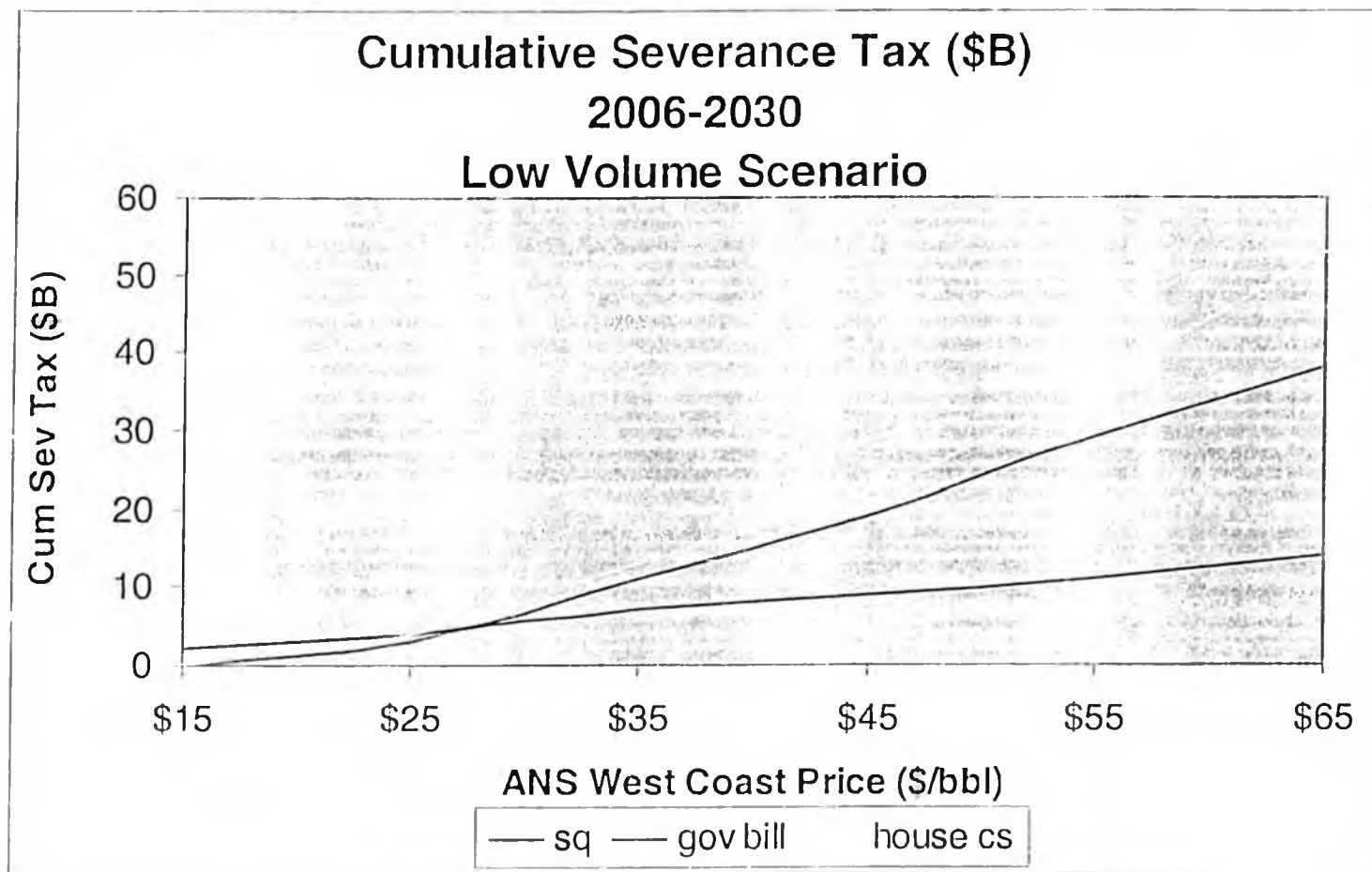
Gas ELF

- A 0.50 ELF implies 6,000 mcf/well/day
- Therefore, 3,000 mcf/well/day is tax-free
- The revenue from tax-free gas is supposed to recover operating costs
- Operating costs for Cook Inlet gas is estimated to be 50 cents
- Therefore operating costs are \$3,000/well/day
- Henry Hub prices are over \$7/mcf
- The revenue from the 3,000 tax-free mcf/well/day is worth \$21,000
- This is 7X more than it should be recovering

Cook Inlet Gas Tax

- We estimate crossover point at about \$3/mcf on existing fields
- At \$4/mcf increase of \$35 million annually on existing fields
- Out of \$1 billion gross revenues annually
- Decrease as production goes down
- New production may see reduced taxes

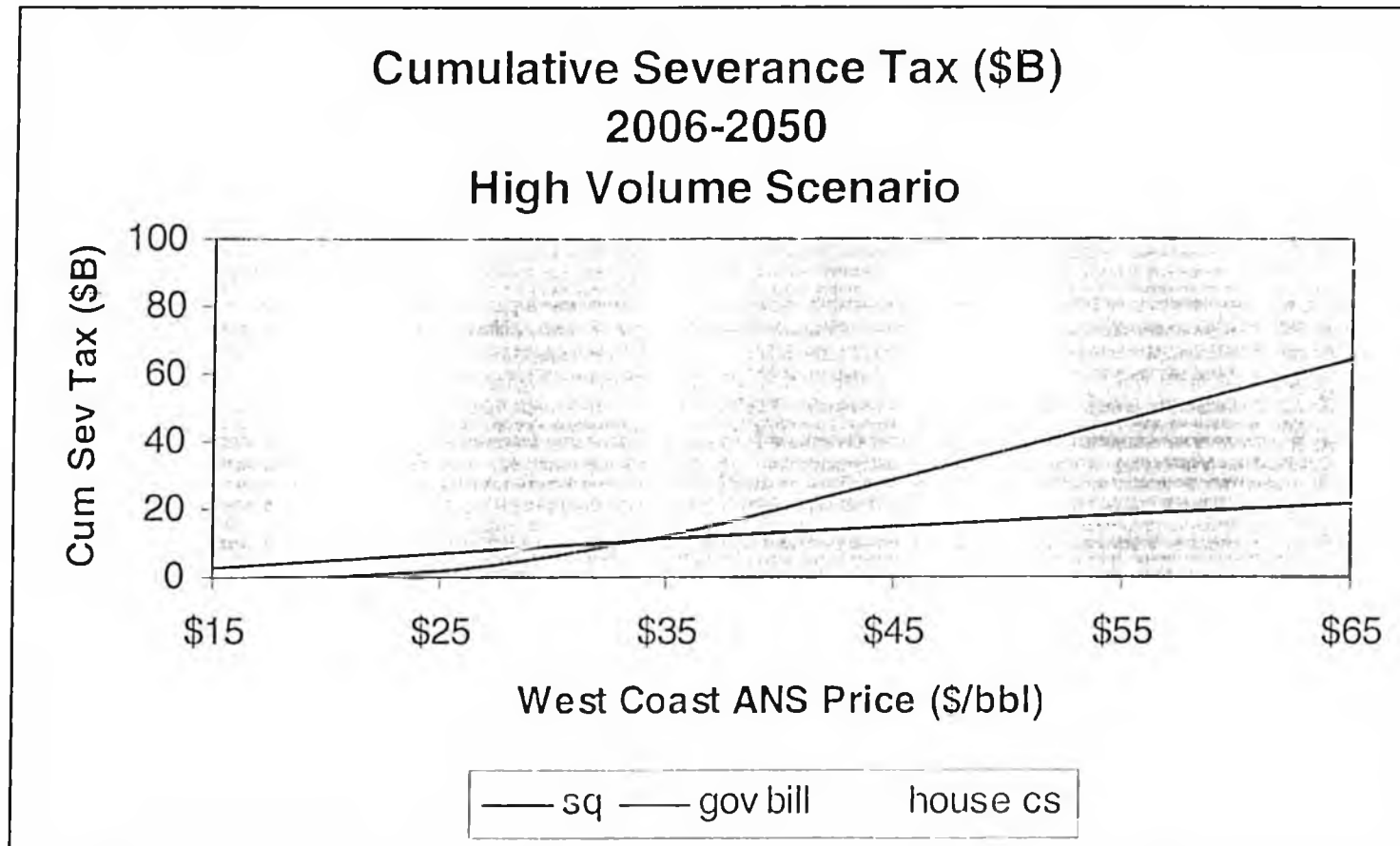
FIGURE 4



Provided 4/1/06
by Dan Dickinson
to address Sen Wilken request

9:21:37AM 4/1/06

Figure 6



074 c

Navigating CSSB 305 (RES) (With the Differences from SB 305 Highlighted)

Before the Senate Finance
Committee
April 1, 2006

Robert E. Mintz, Department of Law
Dan E. Dickinson, C.P.A.

SB 305, Section 35
CSSB 305, Section 32

**New production tax provisions apply to oil
and gas produced on or after:**

(SB 305)

April 1, 2006 (CSSB 305)

SB 305, Section 5

AS 43.55.011(a)

There is levied upon the producer . . . a tax
for all produced . . .

The tax is equal to of the,
. . . under AS 43.55.160.

CSSB 305, Section 5

AS 43.55.011(e)

There is levied upon the producer . . . a tax
for all produced . . .
[except for] a lessor's royalty interest. . . .
The tax is equal to 25 of the
production tax . . . under AS 43.55.160.

CSSB 305, Section 5 (cont.)

AS 43.55.011(f)

There is levied upon the producer . . . a tax for all oil and gas produced each month . . . the ownership or right to which constitutes a lessor's royalty interest The tax is equal to five percent of the gross value at the point of production [for existing leases]

- BUT . . .

5
CSSB 305, Section 6 (cont.)

AS 43.55.011(f) (cont.)

The tax is equal to 1.5 percent of the gross value at the point of production [for existing *COOK INLET BASIN* leases]

- AND . . .

CSSB 305, Section 6 (cont.)

AS 43.55.011(f) (cont.)

The commissioner shall recommend to the legislature the rate of tax [for FUTURE leases]

CSSB 305, Section 6 (cont.)

AS 43.55.011(g) – (h)

[When West Coast ANS is above \$40/Bbl]
there is levied upon the producer of oil a tax
... equal to

(West Coast ANS – 40) * .2% *

(ANS Prevailing Value) * 75% *

(amount of oil production)

So . . .

The has a production tax: 20 %
of net value.

The CS has three production tax components:

- (1) 25% of net value (now called "production tax value") *except* for lessor royalty share
- (2) 5% or 1.5% of gross value for lessor royalty share
- (3) A progressive-rate tax on prevailing value of *oil* only, including lessor royalty share

SB 305, Section 21

AS 43.55.160(a)

... is the total of the
of ... oil and gas ...
from in the state, less
... as ... and
... 1/72 of ...

CSSB 305, Section 22

AS 43.55.160(a)

production tax

... is the total of the

of ...

oil and gas ... from
the state,

in

less

... as

SB 305, Section 31
CSSB 305, Section 28

AS 43.55.900(7) .

“gross value at the point of production”
means

for⁷ , the value . . . at the . . . meter . . . in .

..
for . . . the value . . . where . . . metered

[. . .]

SB 305, Section 19
CSSB 305, Section 20

AS 43.55.150(a)

... gross value at the point of production is
calculated using the reasonable

...

SB 305, Section 20

AS 43.55.150(d)

... the department ... gross value
[to be calculated based upon] ... a

... [or]

a formula ... that uses ... [
] royalty ... valuation [or]

another

a value

CSSB 305, Section 21

AS 43.55.150(d)

if the commissioner completes a detailed fiscal analysis and determines . . . the long-term fiscal interests of the state [would be served] . . . the department . . . gross value [to be calculated based upon

] royalty . . . valuation [or] another .

a value

SB 305, Section 21

AS 43.55.160(c)

... lease expenditures ... are the costs
of the point of production ... on
or after ... that are the
costs of
oil or gas ...
in the state.

CSSB 305, Section 22

AS 43.55.160(c)

... lease expenditures ... are the costs
of the point of production ... on
or after April 1, 2006 ... that are the
costs of
oil or gas ...
in the state.

Section 21/22

AS 43.55.160(c) (continued)

In determining . . . [. . .] costs . . . the department shall give substantial weight . . . to typical . . . as to [billable] costs . . . under . . . and [. . .].

CSSB 305, Section 22

AS 43.55.160(n)(2)

CS adds a definition of “ordinary and necessary” to make clear that Internal Revenue Code meaning is adopted.

Section 21/22

§AS 43.55.160(d) provides specific examples of, and exclusions from, “direct costs”

CSSB 305 has several improvements recommended by the Administration: e.g.,

- (d)(1)(A) and (d)(2)(A), clarifying treatment of capitalized expenditures
- (d)(2)(L), ensuring that conservation surcharges are not deductible

CSSB 305, Section 22 (cont.)

CSSB 305 has several additional exclusions:

- (d)(2)(M) Costs of dismantlement, removal, restoration, etc., re: previous oil or gas production
- (d)(2)(N) Costs above fair market value, in non-arm's length transactions
- (d)(2)(O) Costs to acquire a company

SB 305, Section 21

AS 43.55.160(e)

[Lease expenditures must be by the producer for (1) another's use of a production facility; (2) reimbursement, e.g. field costs paid by state, that offset lease expenditures; and (3) sale of assets acquired through lease expenditures or of non-taxable oil or gas used in lease operations.]

CSSB 305, Section 22

AS 43.55.160(e)

[Lease expenditures must be by the producer for (1) another's use of – or for managing -- a production facility; (2) reimbursement, e.g. field costs paid by state, that offset lease expenditures; and (3) sale – or removal from the state – of assets acquired through lease expenditures or of non-taxable oil or gas used in lease operations.]

CSSB 305, Section 22

AS 43.55.160(a), (b)(2), and (e)

At the Administration's recommendation, the CS addresses potential timing mismatches between lease expenditures and adjustments, ensuring that the tax effect of an adjustment will be recognized even if a producer or explorer has no production, or has low lease expenditures, when an adjustment payment is received.

CSSB 305, Section 22

AS 43.55.160(k) and (l)

For purposes of (1) excluding from lease expenditures costs that exceed fair market value, and (2) determining the amount of an adjustment to lease expenditures due to the sale of an asset, standard = “a producer dealing at arm’s length with an uncontrolled entity”; and IRS rules may be adopted.

SB 305, Section 21

AS 43.55.160(g)

... transitional investment expenditures are ...
[incurred
] ... less ... [proceeds from] the
... acquired ... as a result of [those] capital
expenditures

[This provision is *not* in the CS; instead CS provides for a tax credit for some transitional investment expenditures.]

SB 305, Section 21

AS 43.55.160(i)

... a producer that is ... may reduce the
net value by ... [T]he
total of the allowances ... during the calendar year
does . . . An unused
allowance ... may

[This provision is *not* in the CS; instead CS provides for an allowance that depends on the average daily oil and gas production.]

CSSB 305, Section 22

AS 43.55.160(g)

... a producer that is under 55,000 BOE/day ... and produces
by ... equal to the

following fraction of the production tax value:

$(5,000 - 0.2 * [\text{average daily production} - 5,000]) \div$
average daily production

CSSB 305, Section 22

AS 43.55.160(h) – producer's qualification for an allowance - ability to qualify expires in 2013

This is an anti-splitting provision to prevent abuse of the *per producer* allowance under AS 43.55.160(g).

It is essentially the same anti-splitting provision that is in sec. 21 of the original bill, for the \$73 million *per producer* allowance.

SB 305, Section 7
CSSB 305, Section 7

AS 43.55.020(a)

... the tax levied under AS 43.55.011,
applied under this chapter, is due

... the tax levied under AS 43.55.011(e) . . .
applied under this chapter, is
due

SB 305, Section 12
CSSB 305, Section 13

AS 43.55.024(a)

... a producer ... that incurs a
... may ... elect ... to
take a ... in the amount of
of that expenditure.

CSSB 305, Section 13 (cont.)

~~AS~~ 43.55.024(h)(2)

“qualified capital expenditure” does not include

an expenditure incurred . . . for . . . an extended period of disuse, dismantlement, removal . . . or abandonment . . . or for the restoration of a lease, field, [etc.]

HB 305 Section 12 (cont.)

AS 43.55.024(b)

A producer may elect to take a

... of ... of a carried-forward

[which is the amount of a previous year's
that were

because they would have reduced the net value
of the oil and gas below zero].

CSHB 305 Section 13 (cont.)

AS 43.55.024(b)

A producer . . . may elect to take a
. . . of 25 . . . of a carried-forward
[which is the amount of a previous year's
that were
because they would have reduced the
production tax value of the oil and gas below
zero].

Section 12/13 (cont.)

AS 43.55.024(d) – (f)

A producer entitled to a tax credit may apply to the Dep't of Revenue for a

. Once issued, a certificate may be used for its face value, but a transferee may not apply a certificate to reduce its tax liability by more than during a calendar year.

CSSB 305, Section 13 (cont.)

AS 43.55.024(i) – nontransferable credit for transitional investment expenditures

... transitional investment expenditures [TIE] are
... [incurred 4
4 ,] ... less ... [proceeds from]
the ... acquired ... as a result
of [those] capital expenditures

CSSB 305, Section 13 (cont.)

AS 43.55.024(i) (cont.)

- a producer may . . . take a tax credit . . . of 20 percent of the producer's [TIE] but only [up to] one-half of the producer's qualified capital expenditures . . . during the month
- credits are non-transferable
- credit provision expires April 1, 2013

SB 305, Sections 22-29
CSSB 305, Sections 23-26

Original bill allowed a to be taken for.
conservation surcharge payments; CS does
not.

CS reduces sec. 201 surcharge from \$.02 to
\$.01 per barrel and increases sec. 300
surcharge from \$.03 to \$.05 per barrel.

SB 305, Section 7

of production tax, net of
credits, is due

The remainder is due of the next
calendar year.

CSSB 305, Sections 7, 12

AS 43.55.020(e) and (f)

- 95 percent of principal production tax (AS 43.55.011(e)), net of credits, due each month. Remaining portion due at end of next calendar quarter.
- 100 percent of tax on lessor royalty interest (AS 43.55.011(f)) due each month.
- Bill does not specify payment of progressive-rate oil tax (AS 43.55.011(g)).

SB 305, Section 9

• • CSSB 305, Section 9

[P]roducer may deduct [from royalty] the amount of the tax paid on taxable royalty oil and gas . . .

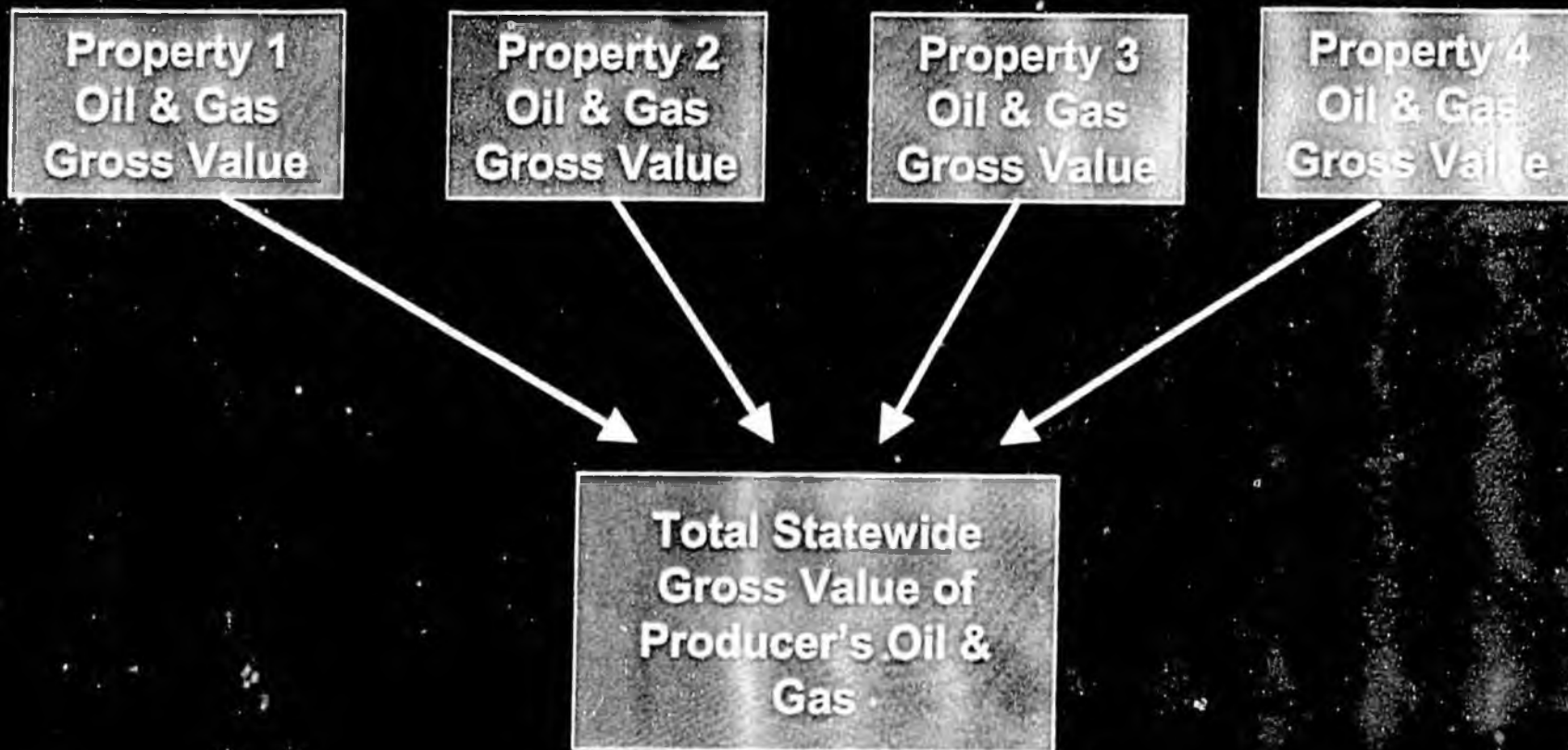
- Original bill provides a default formula for allocating the 20% tax on net value to royalty share.
- CS provides a slightly different formula for allocating the 25% tax on net value (“production tax value”) to *non-lessor* royalty share.

STEPS IN TAX CALCULATION

Under CSSB 305 (RES)

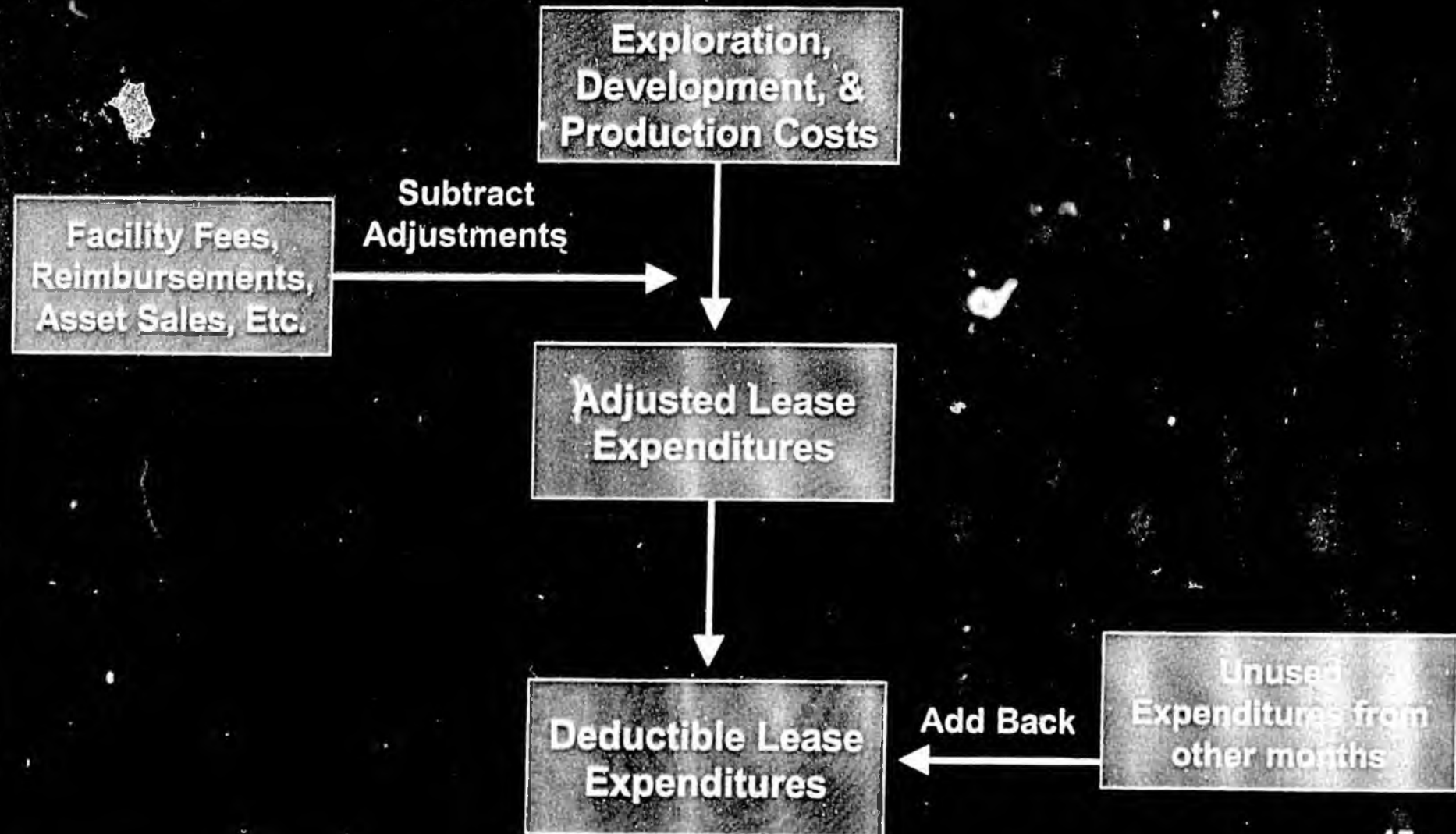
GROSS VALUE OF OIL AND GAS

AS 43.55.150, AS 43.55.900



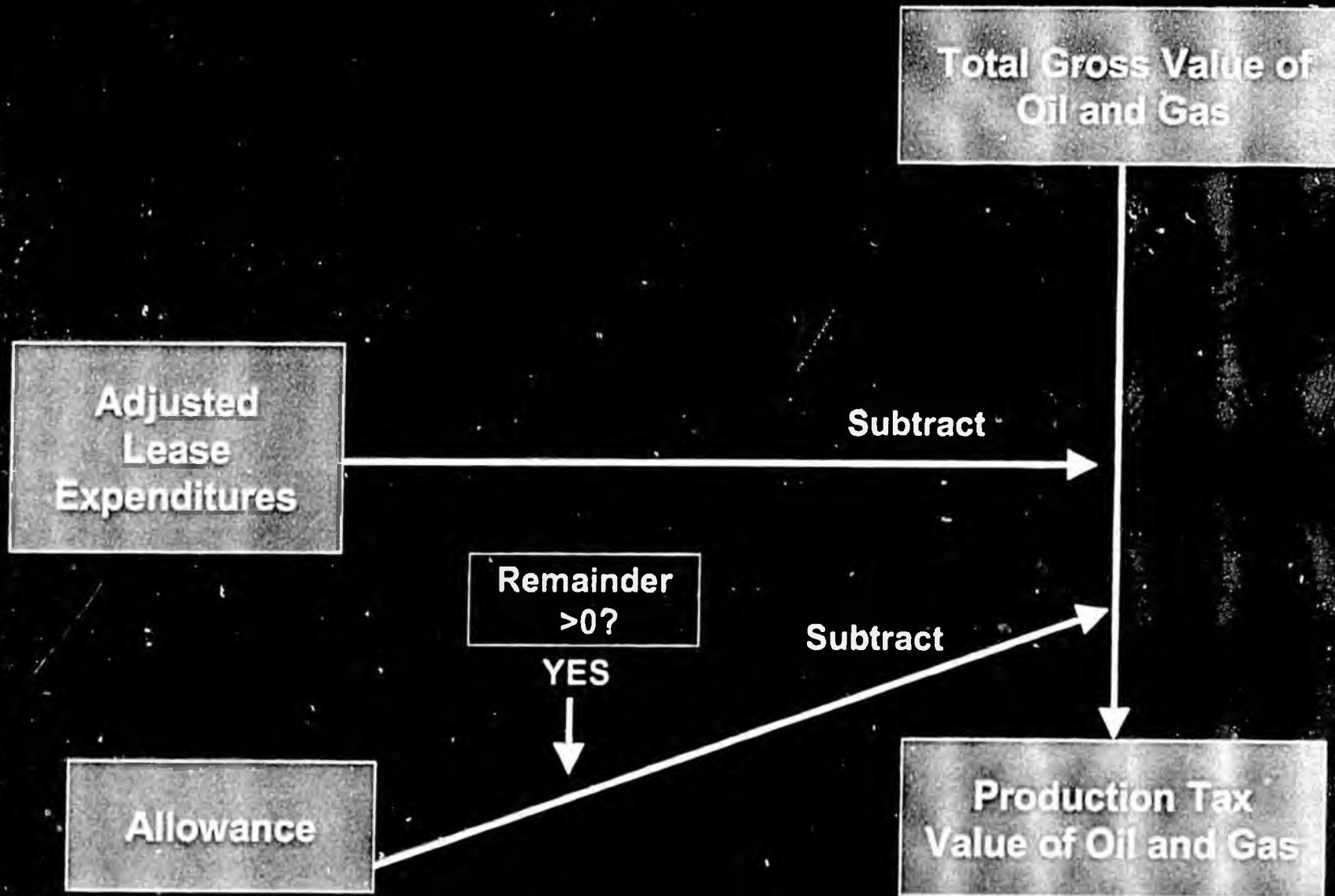
LEASE EXPENDITURES

AS 43.55.160(b) – (e)



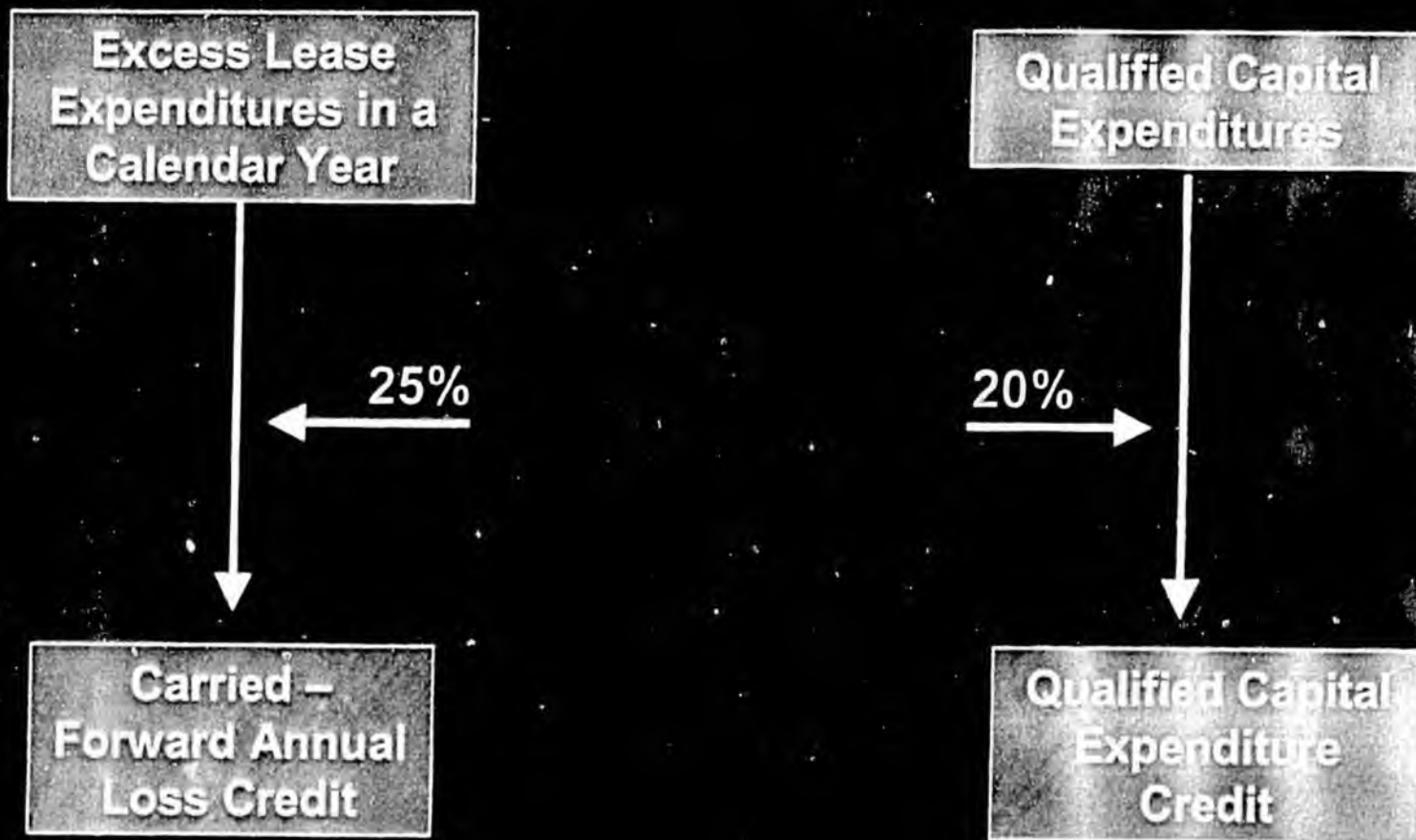
PRODUCTION TAX VALUE

AS 43.55.160 (a) and (g)

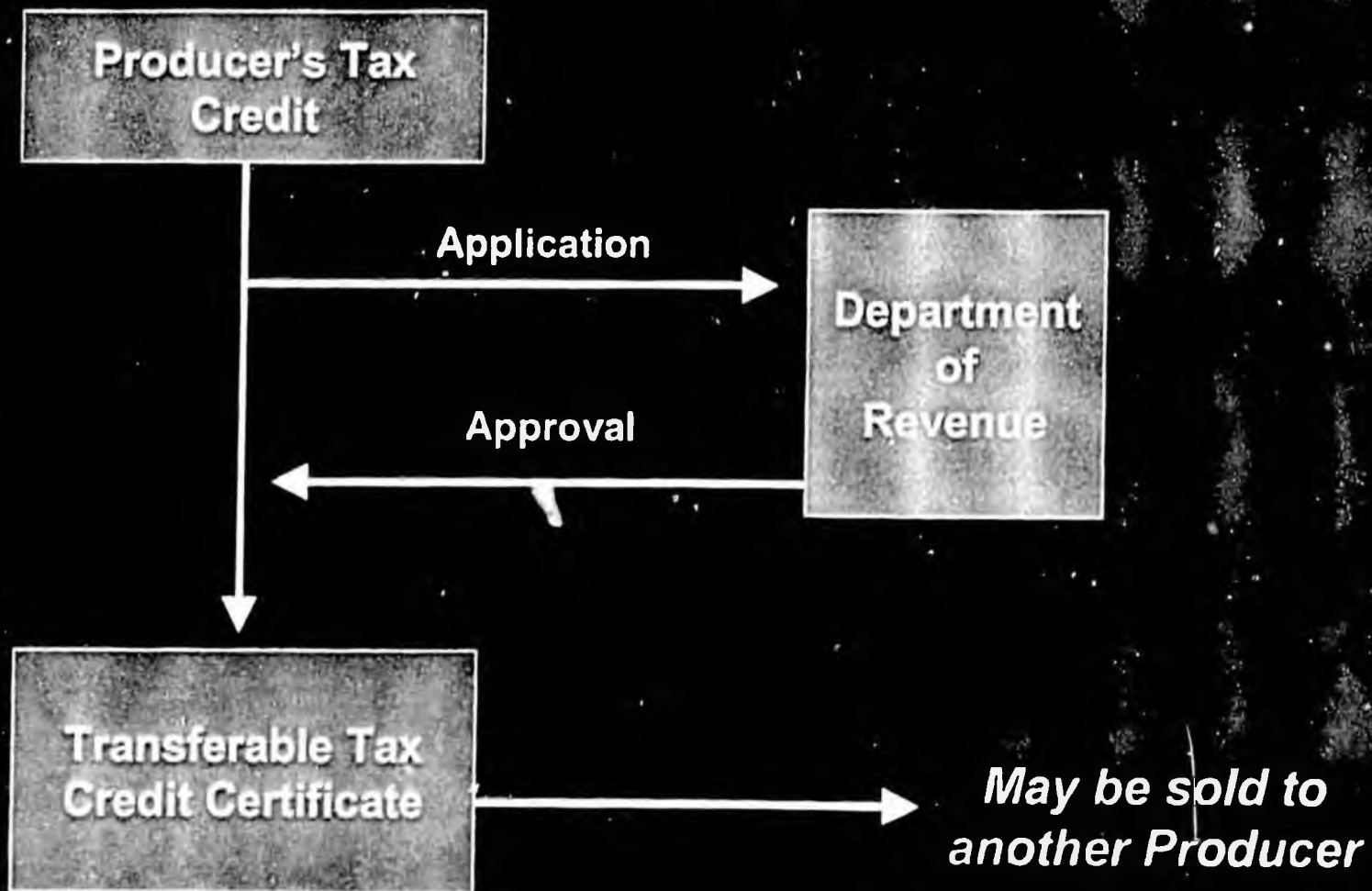


SEC. 024 TRANSFERABLE TAX CREDITS

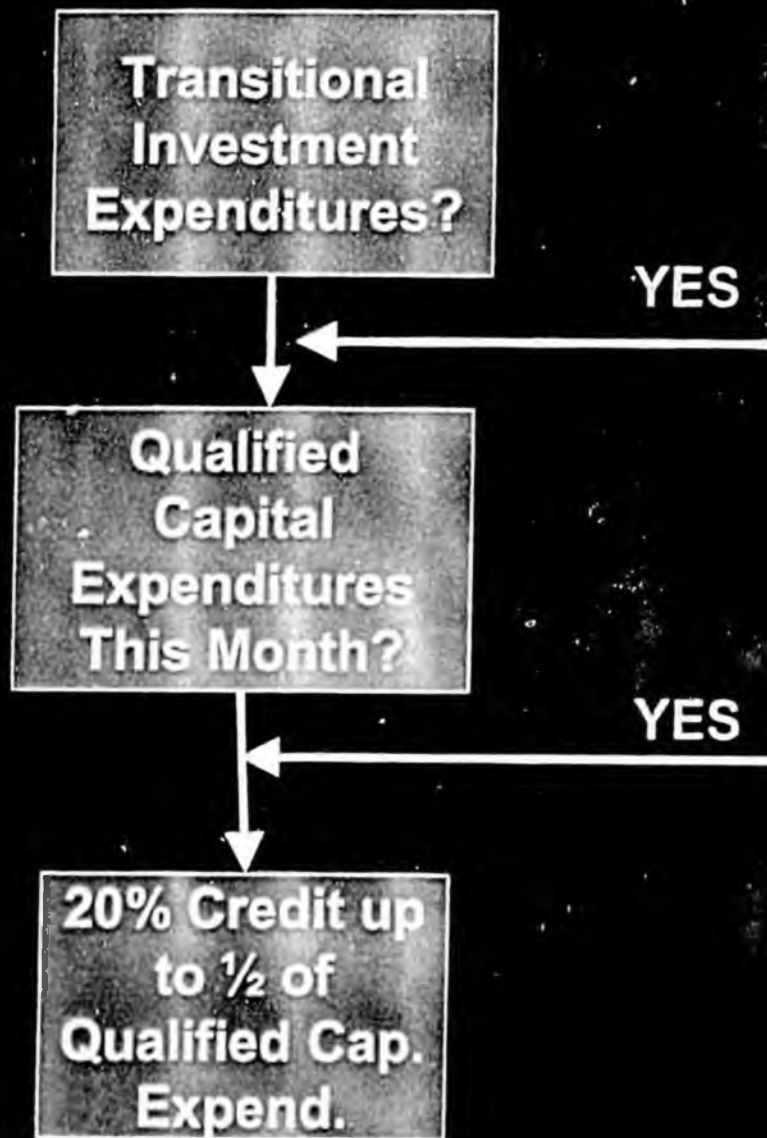
AS 43.55.024 (a) and (b)



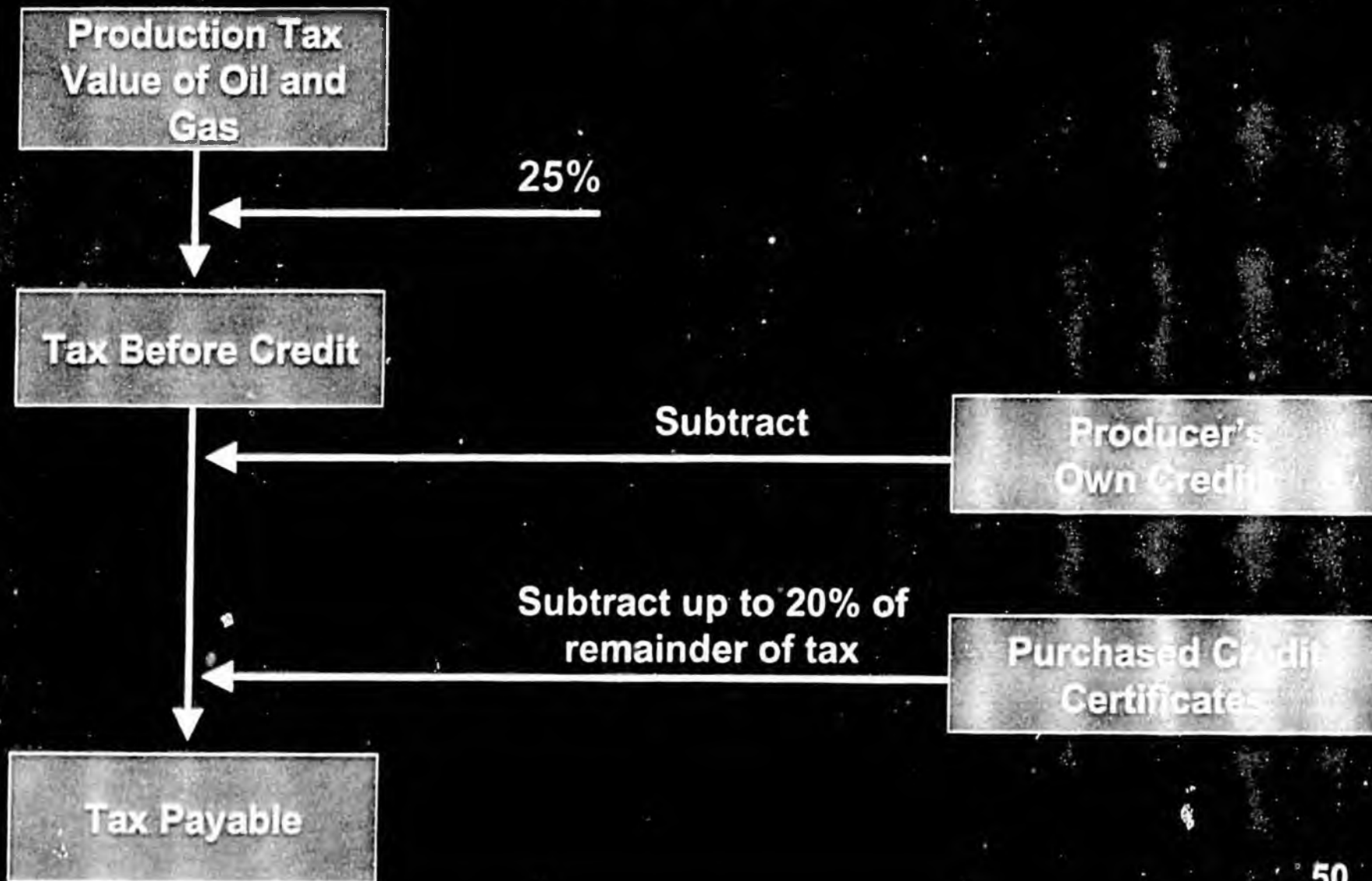
TRANSFERABLE TAX CREDIT CERTIFICATES - AS 43.55.024 (d)-(f)



TIE CREDIT 43.55.024(i)



TAX CALCULATION: AS 43.55.011(e), 43.55.024



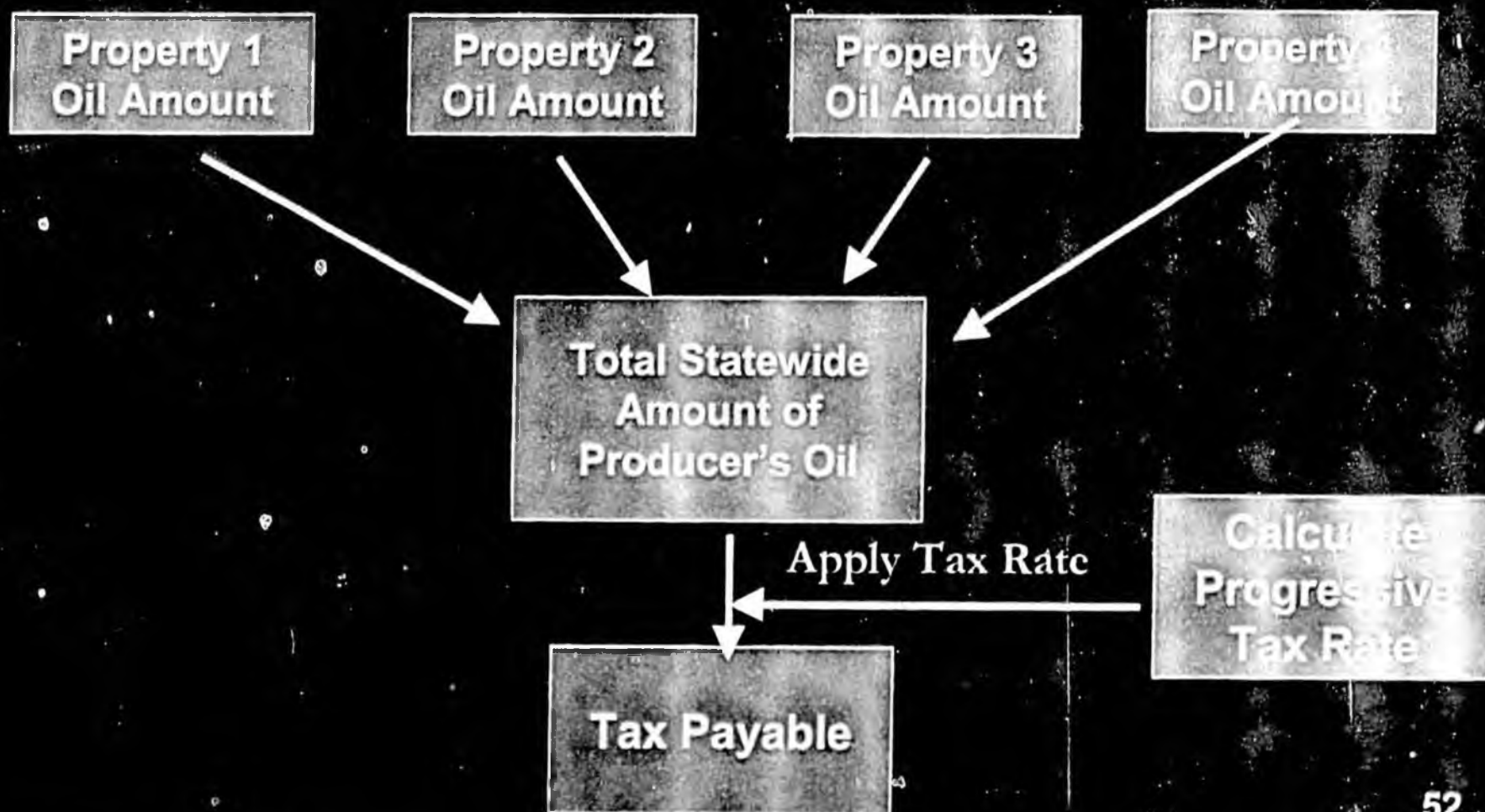
TAX CALCULATION: AS 43.55.011(f)

Gross Value at Point of
Production of Lessor's
Royalty Share of Oil and
Gas

Multiply by 1.5 % (Cook Inlet) or 5%

Tax Payable

TAX CALCULATION: AS 43.55.011(g)



TAX PAYMENT

AS 43.55.020(e)

Tax Payable on Oil and Gas
Produced in a Month

95%

Remainder

Remaining Tax for
Other Months in
Calendar Quarter

Payment Due at
End of Next Month

Payment Due End of
Next Calendar Quarter

TAX PAYMENT AS 43.55.020(f)

Tax Payable on Oil and Gas
Produced in a Month

- 100%



Total Due at End of
Next Month

PPT: Comparing the Options

Presentation to the Senate Finance
Committee

April 3, 2006

Robynn J. Wilson, CPA, Tax Director

Dan Dickinson, CPA, Consultant

Effective Dates & payments

- ◆ Governor's bill
 - Effective 7/1/06

- ◆ House CS & Senate CS
 - Effective 4/1/06

Effective Dates & payments

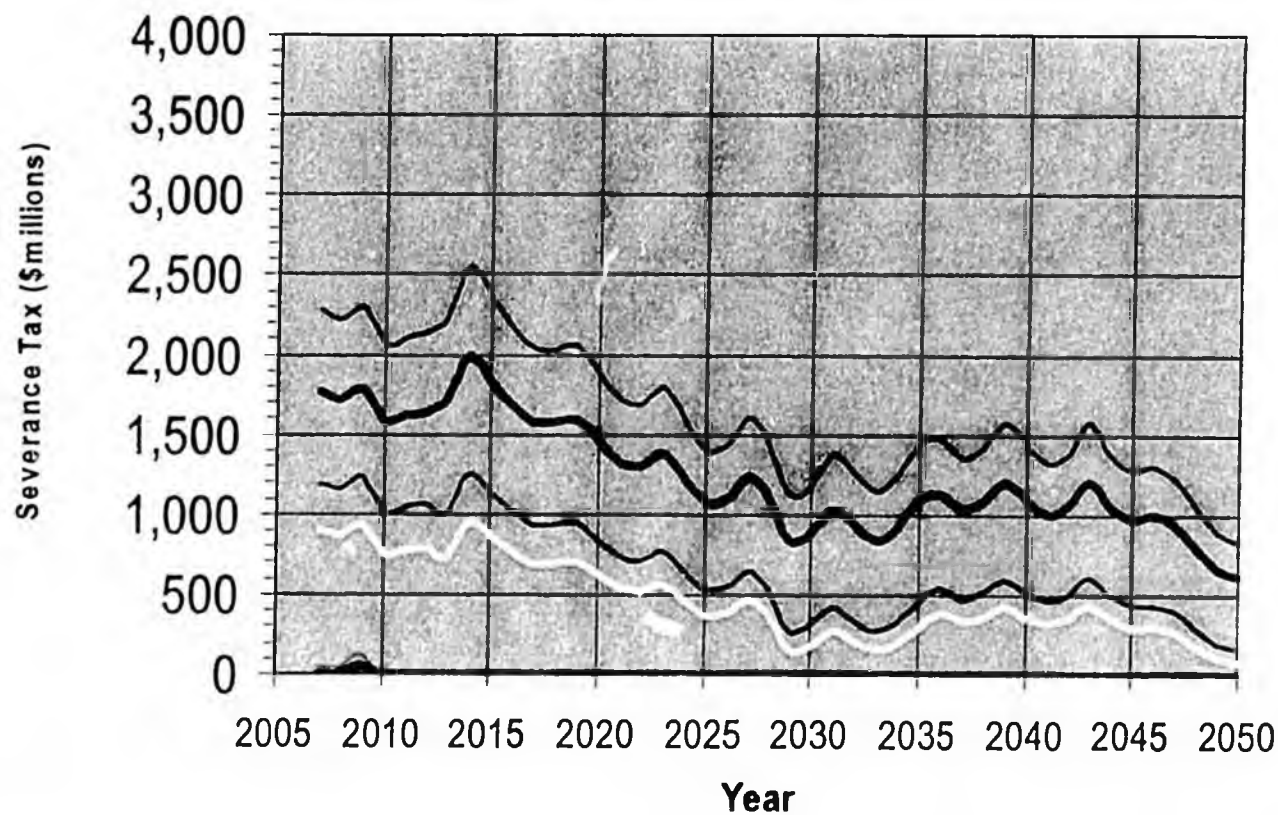
◆ Governor's bill

- Effective 7/1/06

◆ House CS & Senate CS

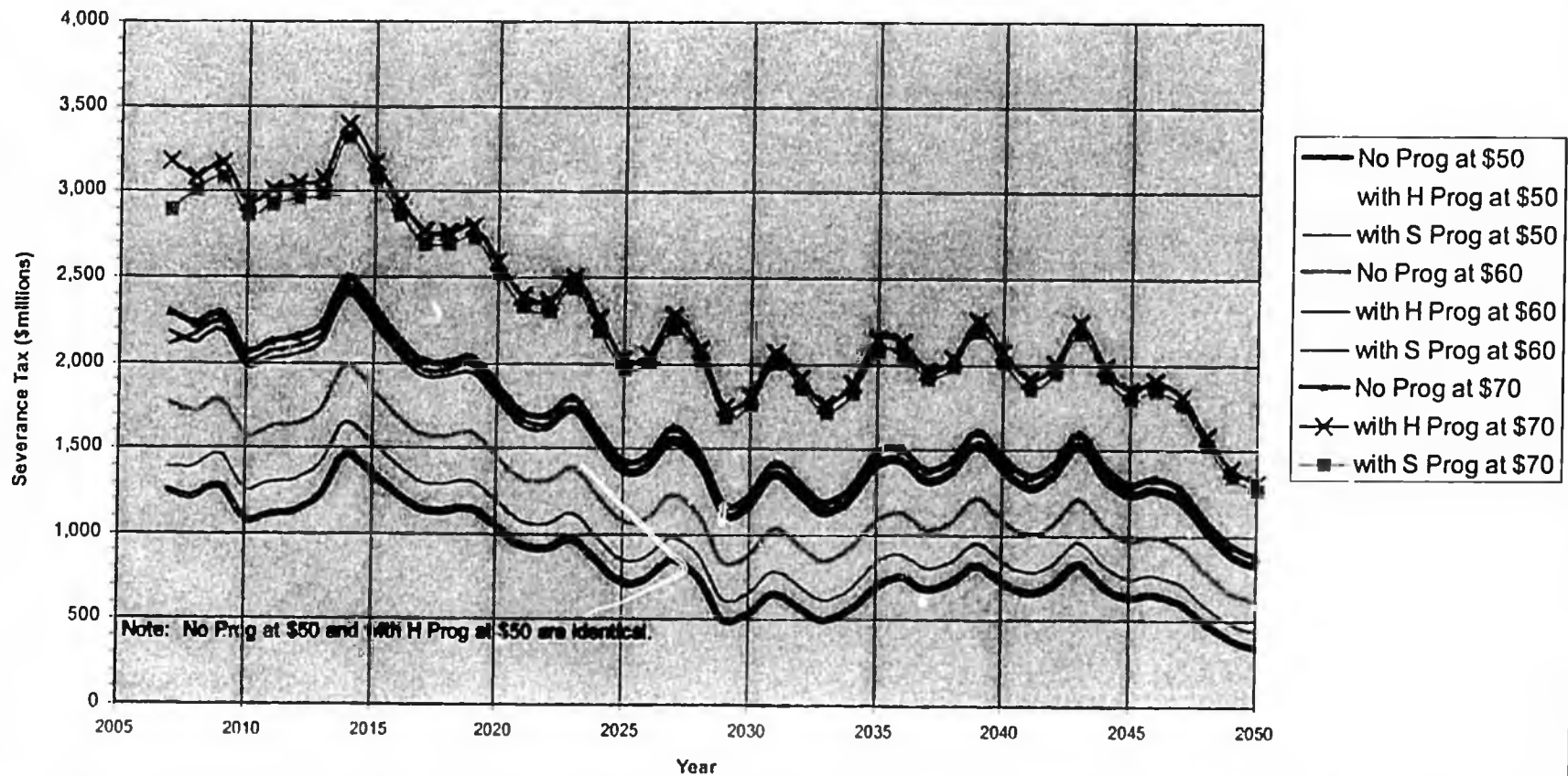
- Effective 4/1/06
- 6 mo. payment on ELF system, 7th mo. true-up

Tax Rate
Annual Oil Severance Tax (Millions of 2005 Dollars)
High Volume Scenario, \$20, \$40, and \$60 per bbl
Governor's PPT at 20/20 and 25/20

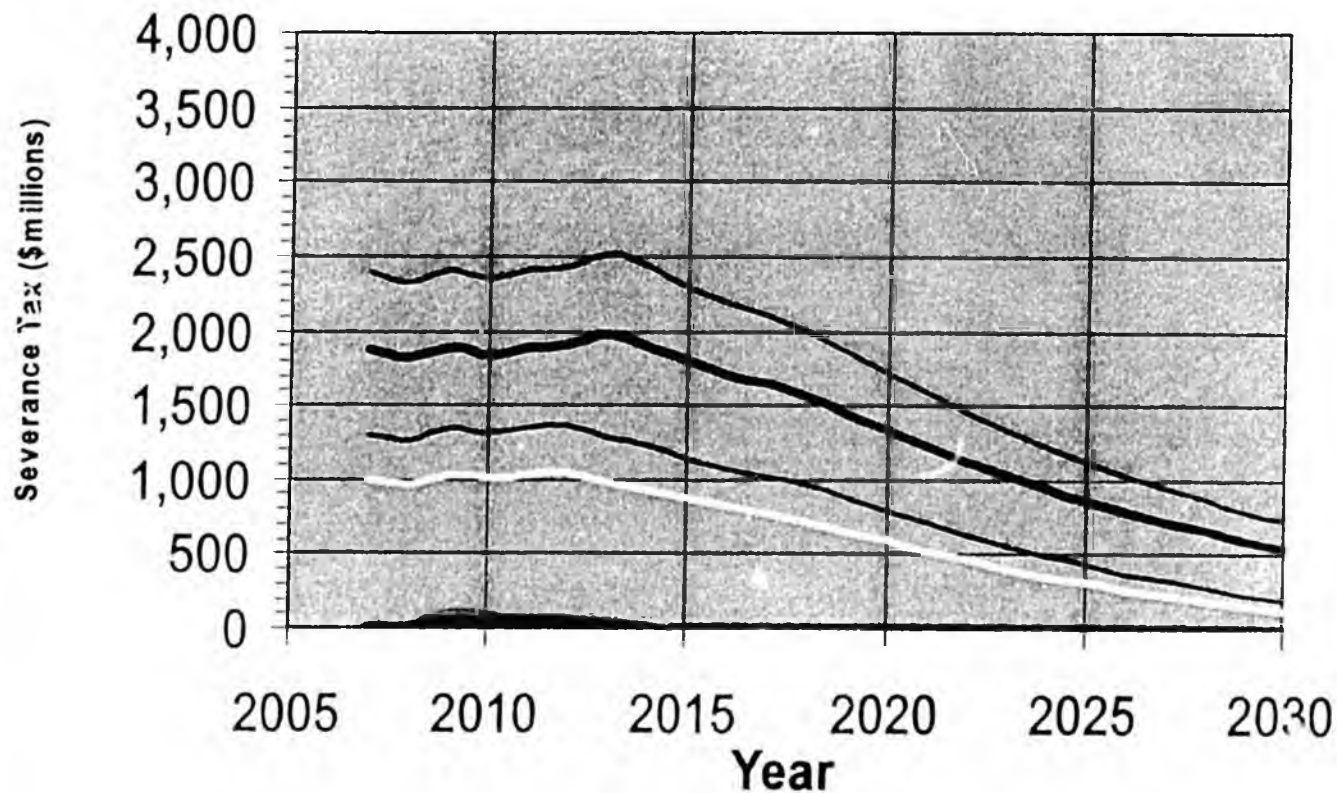


— 20/20 at \$20 20/20 at \$40 — 20/20 at \$60 — 25/20 at \$20 — 25/20 at \$40 — 25/20 at \$60

Effect of Progressivity
Annual Oil Severance Tax (Millions of 2005 Dollars)
High Volume Scenario, \$50, \$60, and \$70 per bbl
Governor's Bill as Written, with House Progressivity, and with Senate Progressivity



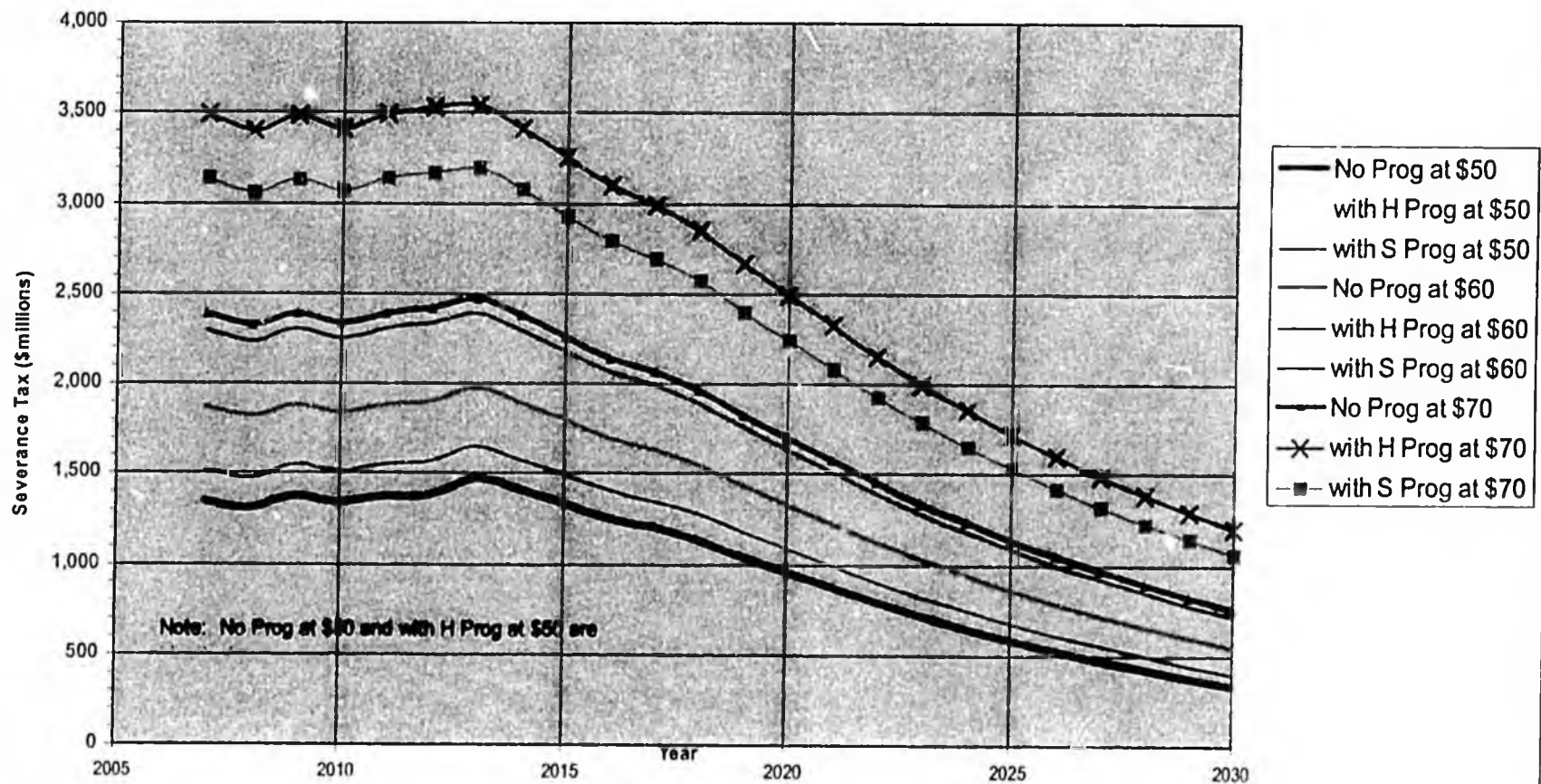
Tax Rate
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, \$20, \$40, and \$60 per bbl
Governor's PPT at 20/20 and 25/20



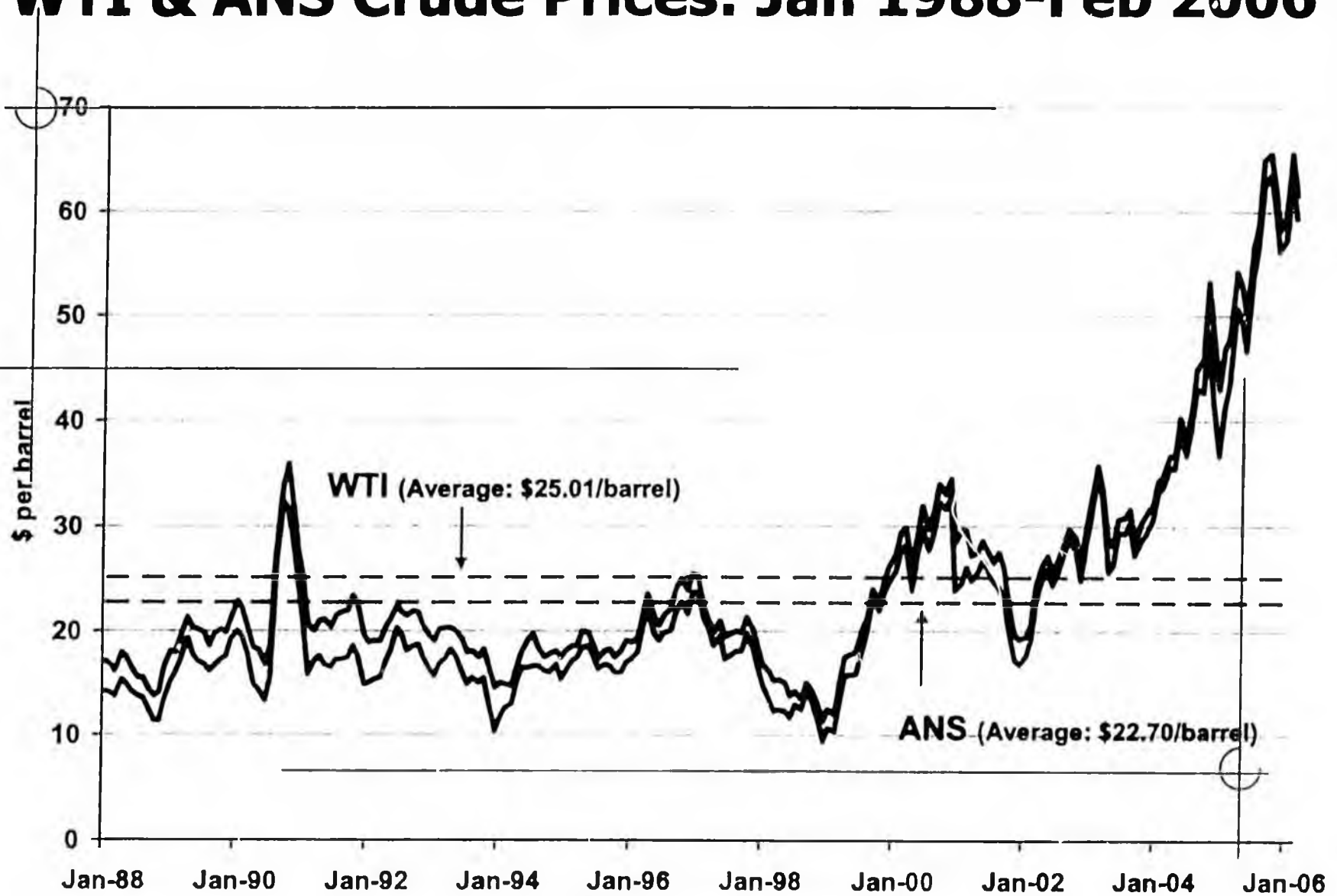
20/20 at \$20
 20/20 at \$40
 20/20 at \$60
 25/20 at \$20
 25/20 at \$40
 25/20 at \$60

Effect of Progressivity

Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, \$50, \$60, and \$70 per bbl
Governor's Bill as Written, with House Progressivity, and with Senate Progressivity

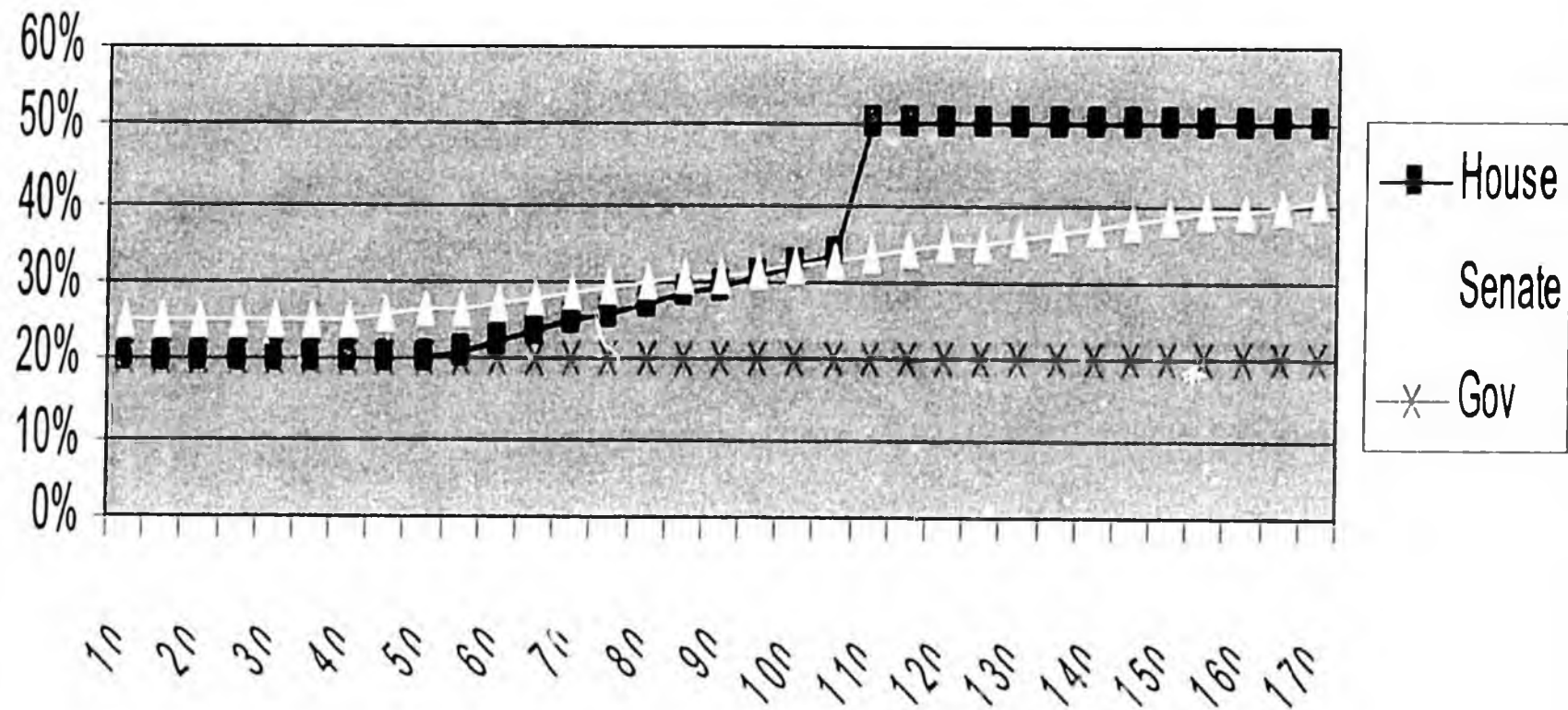


WTI & ANS Crude Prices: Jan 1988-Feb 2006

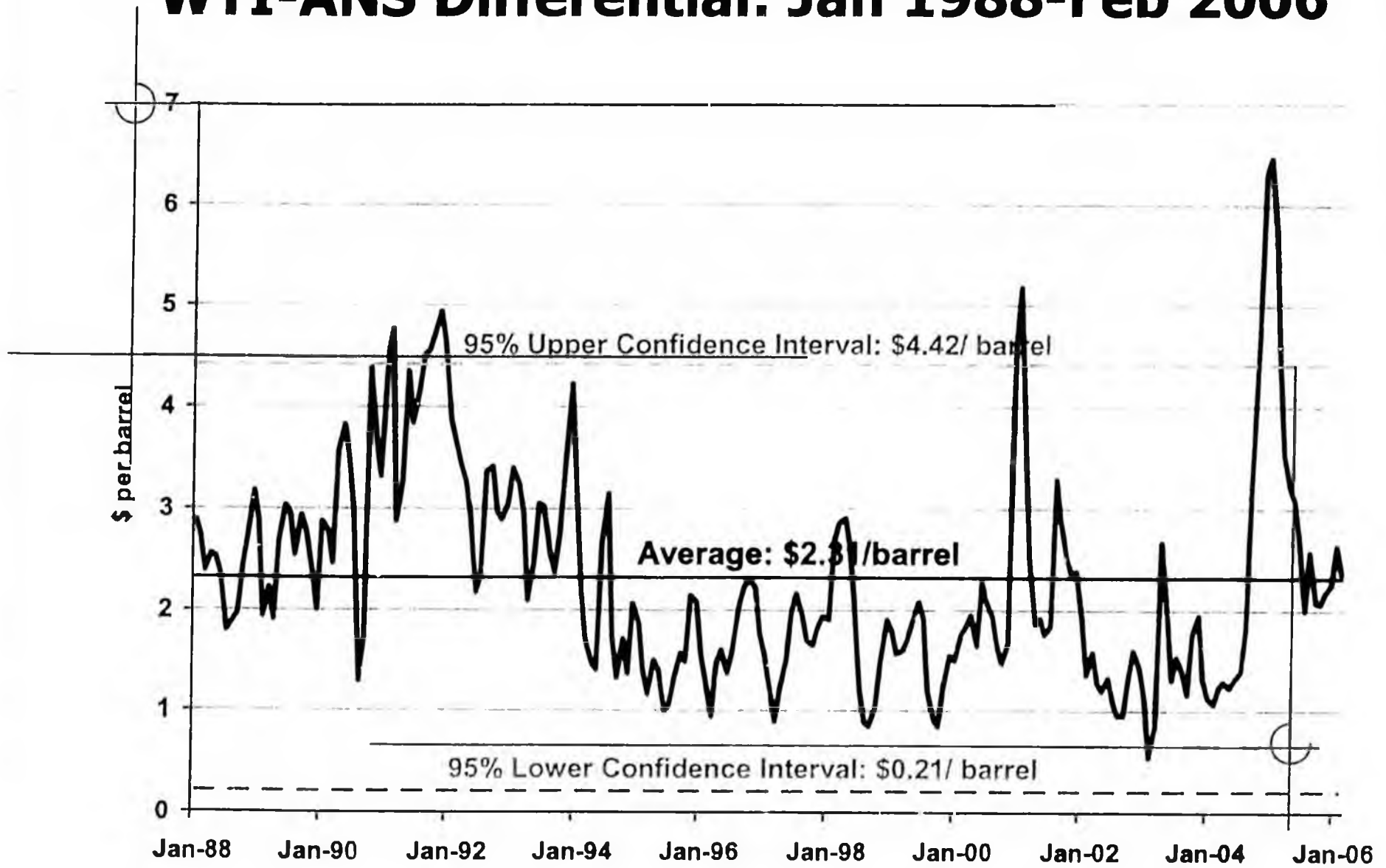


4/3/2006

Schematic Comparison of Tax on Gross Prior to netting out costs at various (INCLUDING VERY HIGH !!!) Oil Prices



WTI-ANS Differential: Jan 1988-Feb 2006



4/3/2006

Transition Provision

◆ Governor's bill

- 5 year lookback, deductible over 6 years

◆ House CS

- 3 months of capex and opex

◆ Senate CS

- 5 year lookback, 2 for 1 recoupment

Transition Treatment

◆ Governor's bill

- Allowable deduction if oil > \$40/bbl

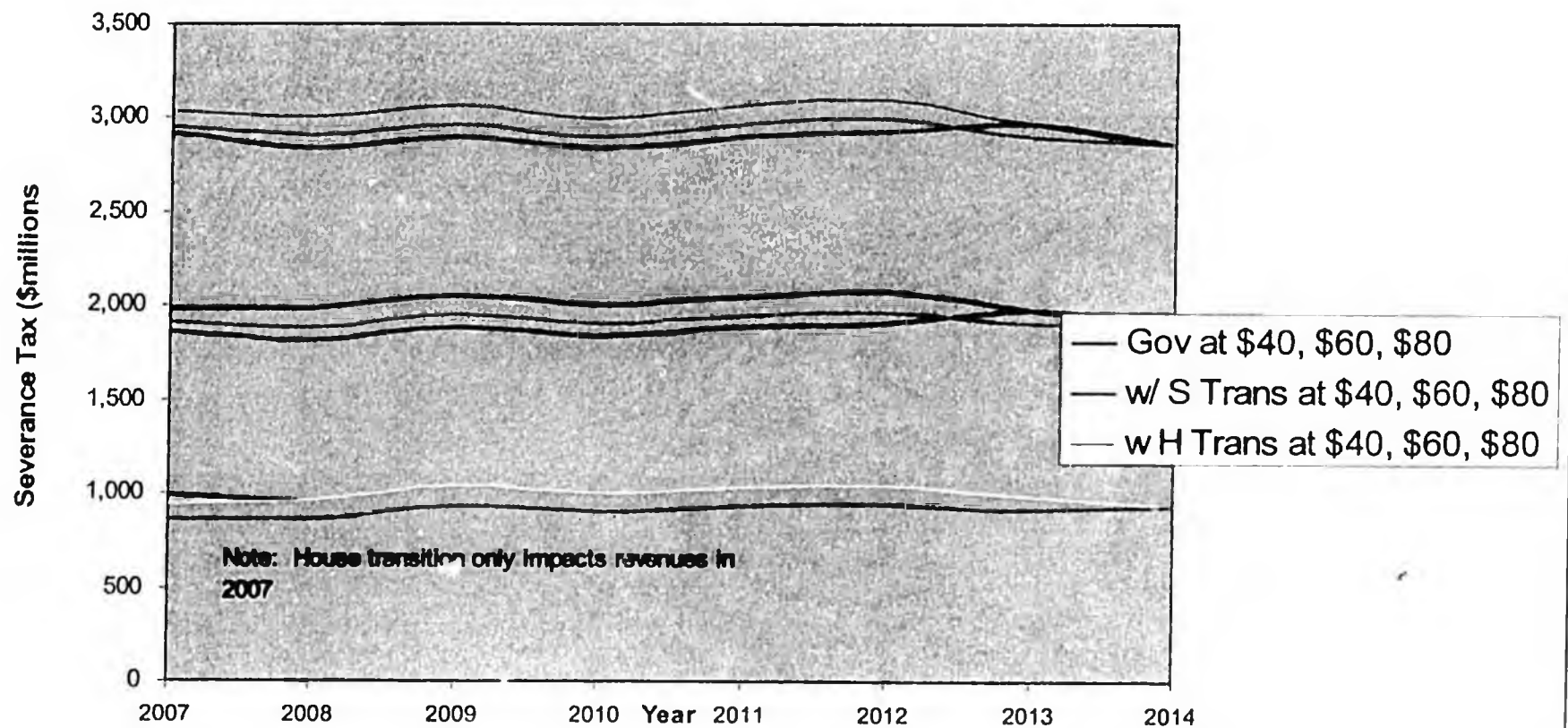
◆ House CS

- Deduction over 9 months
- No oil price test

◆ Senate CS

- Credit—no oil price test
- Sunsets 3/31/2013

Transition Provision
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, \$40, \$60, and \$80 per bbl
Governor's Bill, with House Transition, and with Senate Transition



Base Allowance

◆ Governor's bill

- Up to \$73M standard deduction

◆ House CS

- Up to \$12M credit (= \$60M deduction)

◆ Senate CS

- 5000 barrel plan

Base Allowance Sunset

- ◆ Governor's bill

- No sunset

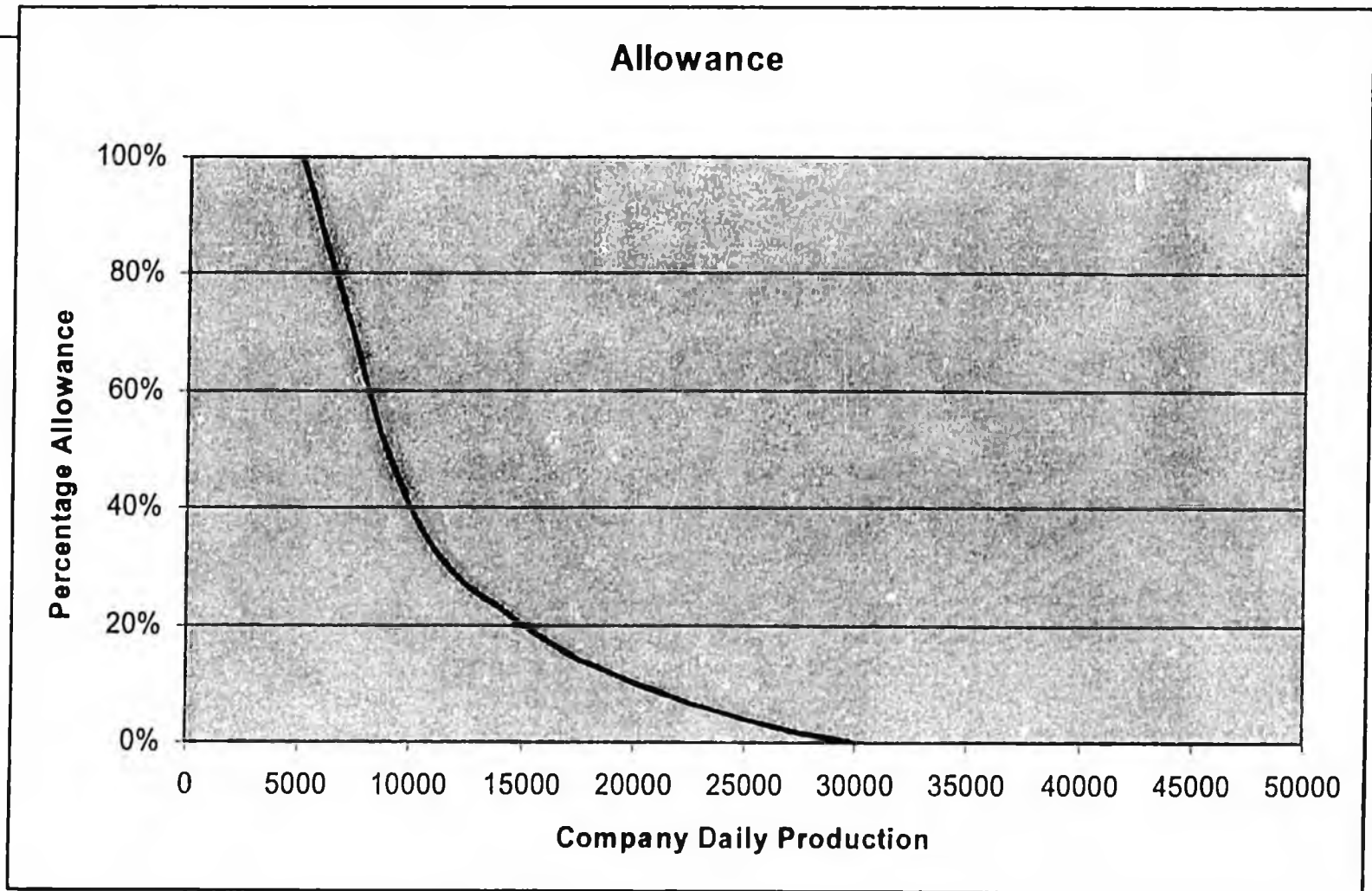
- ◆ House CS

- Sunsets 3/31/2016

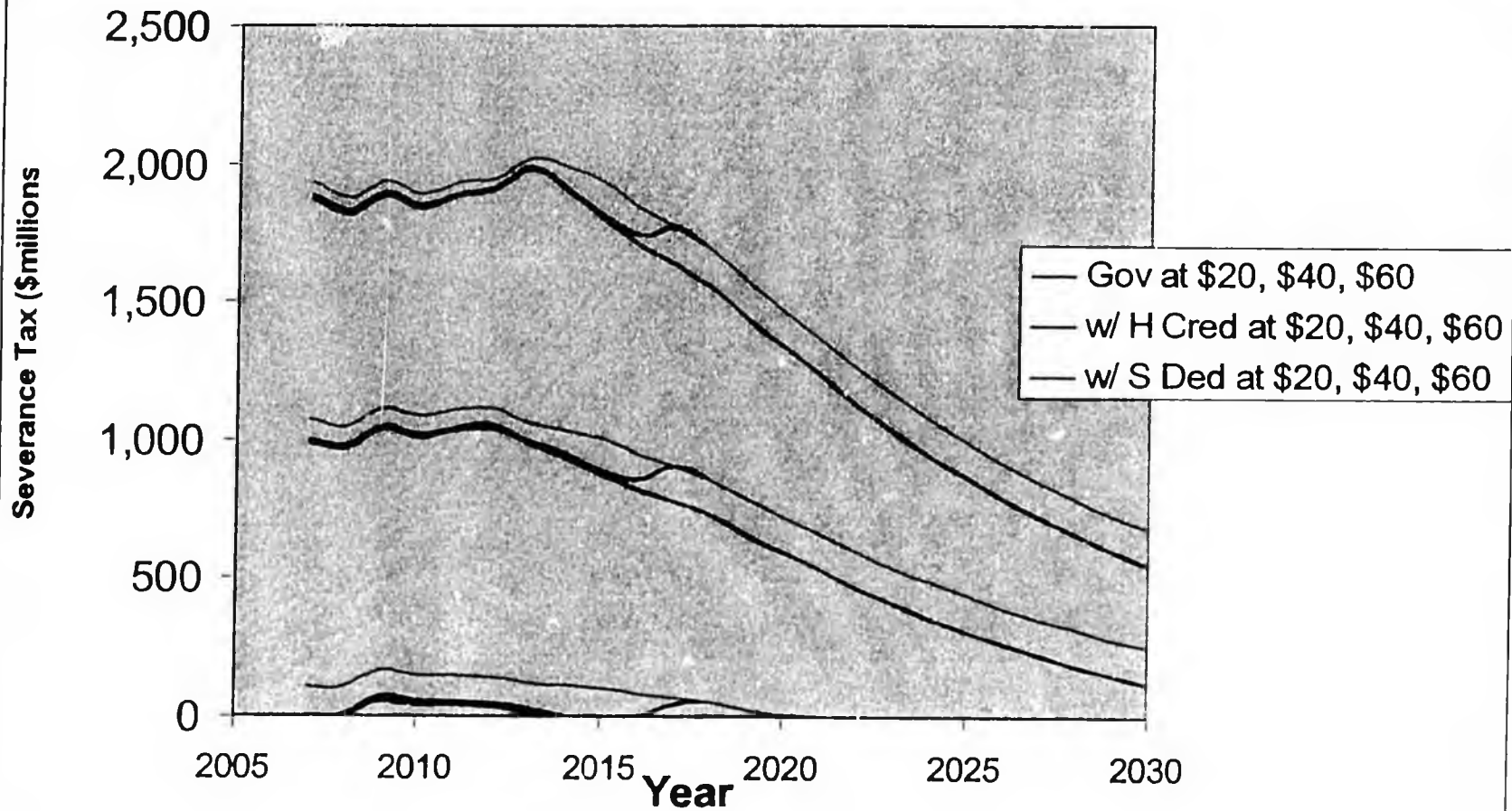
- ◆ Senate CS

- Sunsets 12/31/2013

Illustration of base allowance at various production levels



Base Allowance, or Credit
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, \$20, \$40, and \$60 per bbl
Governor's Bill as Written, with House Credit, and with Senate Deduction Provisions



Payment Safe Harbor

◆ Governor's bill

- 90% with annual true-up
- No interest if 90% test met

◆ House CS

- 90% with annual true-up
- Interest due on true-up amount
- Penalty if 90% not met

◆ Senate CS

- 95% with quarterly true-up
- No interest if 95% test met

Spill Surcharges

AS 43.55.201, AS 43.55.300

◆ Governor's bill

- No change to total 5 cents
- No change to split (2/3)

◆ House CS

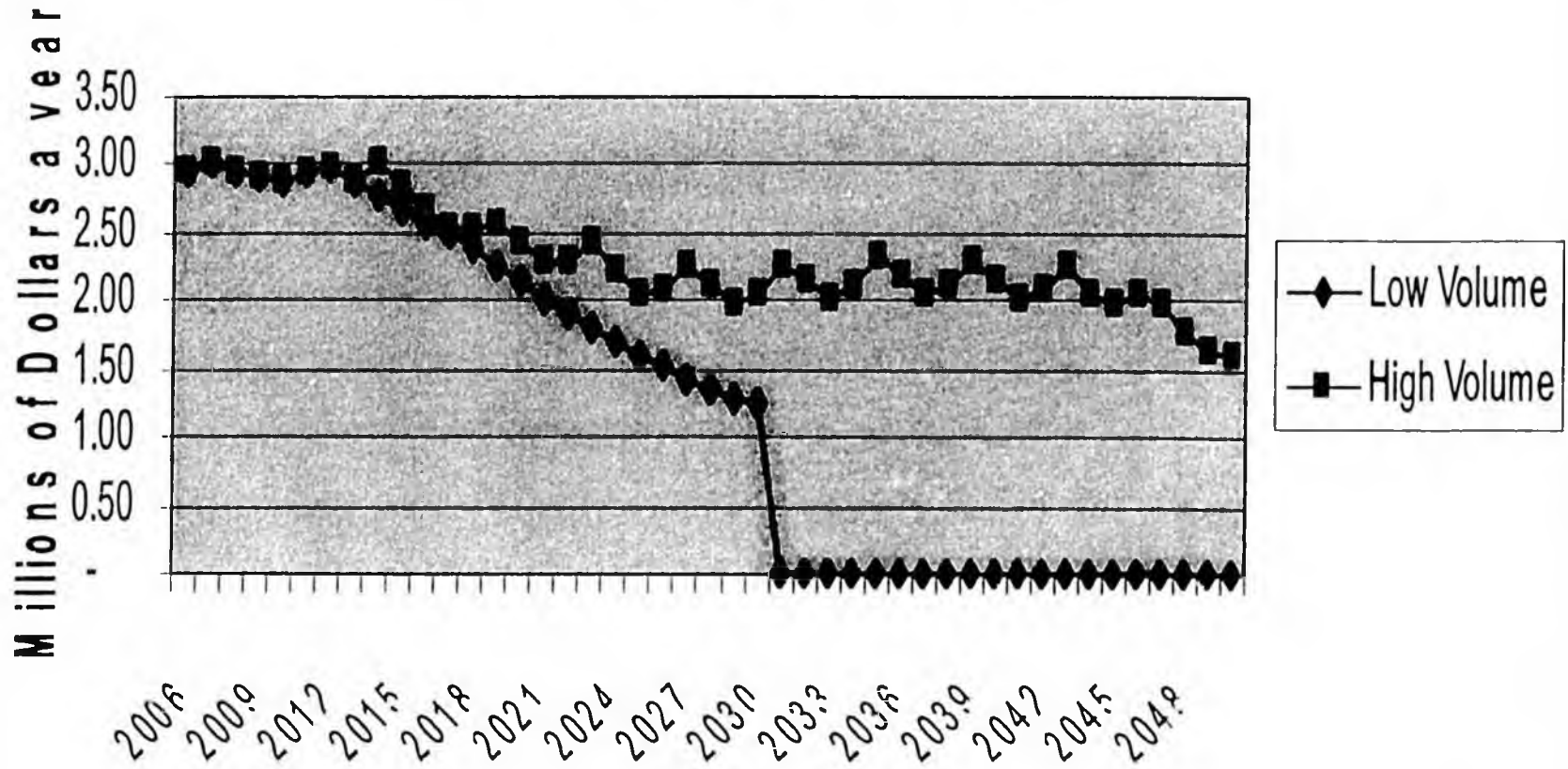
- No change to total 5 cents
- Changes split to 1/4

◆ Senate CS

- Increases total to 6 cents
- Changes split to 1/5

Spill Fees

Effect of 1 penny times Oil Volume



Other differences

- ◆ Credits refundable?
 - Up to \$10M in House CS only
- ◆ Abandonment
 - Governor's bill: no specific provision
 - House CS: No credit available
 - Senate CS: No credit available for old production
- ◆ Catastrophic oil spill expenses not deductible under House CS
- ◆ SB 185 credits: extended 10 years in House CS

Private Royalties

- ◆ State and federal royalty interests are tax free so a producer typically pays tax on 7/8ths of its production from these leases.
- ◆ Private royalty interests are not tax free, so producer typically pays tax on 8/8ths of its production from these leases.

Private Royalties

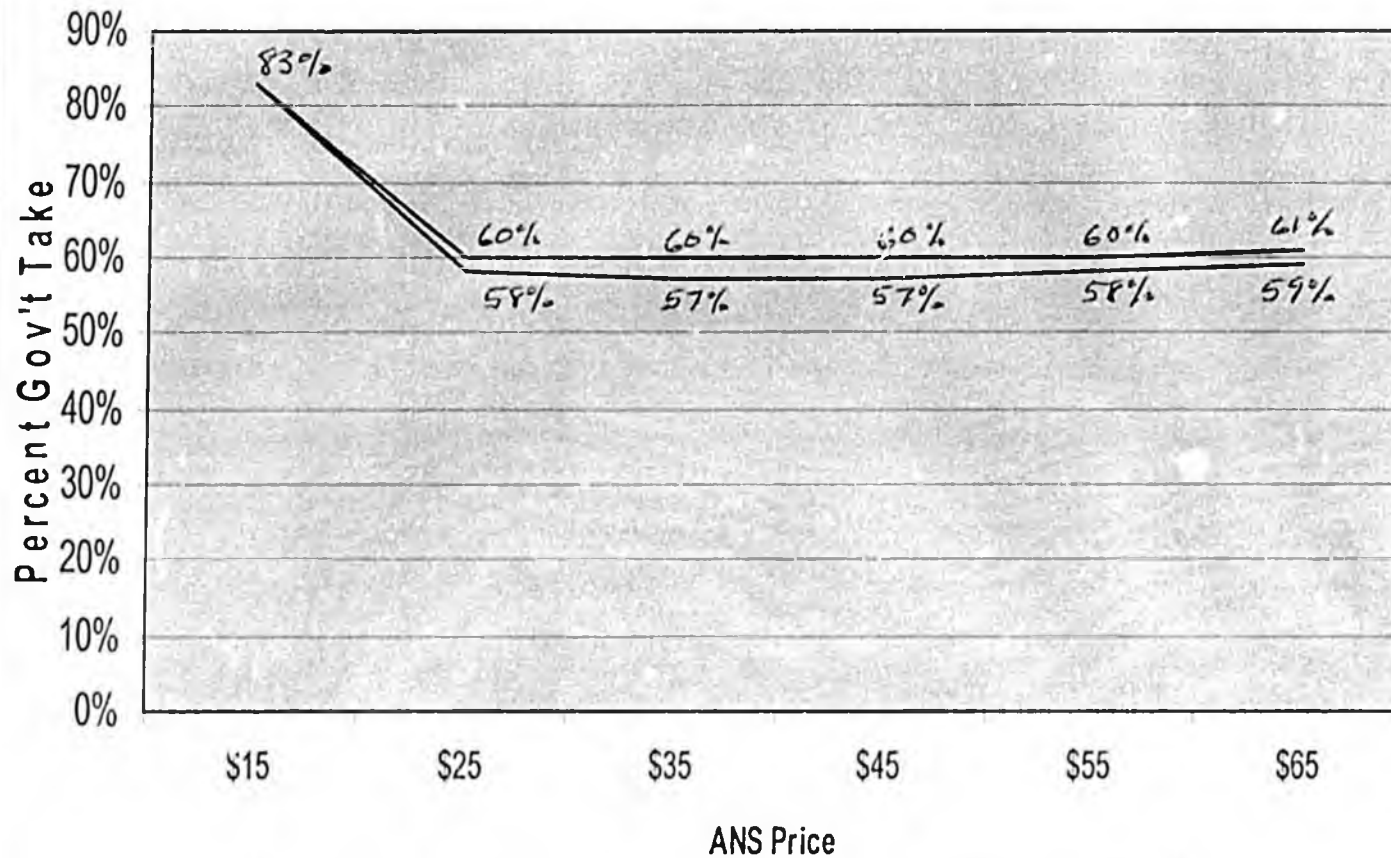
- ◆ Existing law authorizes producer to pass production on to royalty owner
 - Royalty owner bears no responsibility as a tax payer.
 - More difficult to calculate under PPT
- ◆ CS establishes new tax rate on existing private royalty leases, (excludes private lessor's royalty interests from PPT)

Private Royalties - Settlement

- New Formula for Settlement in Gov's Bill:
 - ◆ Total tax paid by producer/Total non-royalty bbls * Private royalty bbls

- New Formula for Settlement in CS:
 - ◆ Total tax paid by producer/total gross value at the point of production * Private royalty bbls

Total Government Take, Senate CS at 25/20 and 20/20, Low Volume Scenario



— Senate CS with 25/20
— Senate CS with 20/20

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 Corrected info on
 4/1/06 handout
 distributed by C. Nienhuis
 por

SLIDE 6

Tax Rate - Governor's Bill with 20/20 and with 25/20, Low Volume						
FY	20/20 at \$20	20/20 at \$40	20/20 at \$60	25/20 at \$20	25/20 at \$40	25/20 at \$60
2007	0	988	1,868	43	1290	2390
2008	0	964	1,816	41	1260	2324
2009	51	1,036	1,882	124	1350	2407
2010	42	1,006	1,835	99	1312	2348
2011	40	1,030	1,880	96	1342	2404
2012	35	1,040	1,901	90	1354	2431
2013	13	982	1,974	61	1282	2522
2014	0	932	1,894	34	1219	2421
2015	0	872	1,795	8	1143	2296
2016	0	815	1,700	0	1071	2178
2017	0	774	1,634	0	1019	2094
2018	0	724	1,552	0	956	1991
2019	0	654	1,436	0	868	1846
2020	0	590	1,330	0	788	1713
2021	0	528	1,228	0	710	1584
2022	0	465	1,123	0	630	1453
2023	0	408	1,028	0	558	1333
2024	0	356	941	0	492	1223
2025	0	307	860	0	431	1122
2026	0	263	787	0	376	1030
2027	0	223	720	0	325	946
2028	0	185	657	0	277	867
2029	0	150	599	0	233	794
2030	0	118	546	0	193	727
Totals	180	15,413	32,984	597	20,480	42,445

SLIDE 7

Progressivity: Annual Revenues, Governor's bill with No Progressivity, with House Progressivity, and with Senate Progressivity, Low Volume									
FY	No Prog at \$50	with H Prog at \$50	with S Prog at \$50	No Prog at \$60	with H Prog at \$60	with S Prog at \$60	No Prog at \$70	with H Prog at \$70	with S Prog at \$70
2007	1,345	1,345	1517	1,868	2,375	2,290	2391	3493	3142
2008	1,307	1,307	1475	1,816	2,312	2,229	2325	3402	3059
2009	1,376	1,376	1550	1,882	2,391	2,306	2389	3488	3138
2010	1,337	1,337	1508	1,835	2,335	2,251	2333	3413	3069
2011	1,372	1,372	1546	1,880	2,389	2,304	2388	3489	3138
2012	1,387	1,387	1562	1,901	2,415	2,329	2415	3526	3173
2013	1,478	1,478	1647	1,974	2,469	2,387	2471	3542	3201
2014	1,413	1,413	1576	1,894	2,373	2,293	2375	3412	3082
2015	1,333	1,333	1490	1,795	2,253	2,177	2256	3249	2933
2016	1,257	1,257	1407	1,700	2,139	2,066	2143	3094	2792
2017	1,204	1,204	1349	1,634	2,060	1,989	2064	2986	2693
2018	1,138	1,138	1277	1,552	1,961	1,892	1965	2852	2570
2019	1,045	1,045	1176	1,436	1,822	1,757	1827	2663	2397
2020	960	960	1084	1,330	1,694	1,633	1700	2489	2238
2021	878	878	995	1,228	1,571	1,514	1578	2323	2086
2022	794	794	903	1,123	1,445	1,391	1452	2150	1928
2023	718	718	821	1,028	1,330	1,280	1338	1994	1785
2024	648	648	745	941	1,225	1,177	1233	1850	1654
2025	584	584	674	860	1,128	1,083	1136	1718	1533
2026	525	525	611	787	1,039	997	1048	1598	1423
2027	471	471	552	720	958	918	968	1487	1322
2028	421	421	498	657	883	845	893	1385	1228
2029	374	374	447	599	813	777	823	1289	1141
2030	332	332	401	546	749	715	760	1203	1062
Totals	23,699	23,699	26,811	32,984	42,127	40,603	42,270	62,096	55,788

SLIDE 13

Transition: Governor's Bill as Written, with House Transition, and with Senate Transition, Low Volume									
FY	Gov at \$40	with H Trans at \$40	with S Trans at \$40	Gov at \$60	with H Trans at \$60	with S Trans at \$60	Gov at \$80	with H Trans at \$80	with S Trans at \$80
2007	988	938	863	1868	1985	1910	2914	3031	2956
2008	964	964	864	1816	1982	1882	2833	3000	2900
2009	1,036	1,036	936	1882	2049	1949	2895	3061	2961
2010	1,006	1,006	906	1835	2002	1902	2831	2997	2897
2011	1,030	1,030	930	1880	2046	1946	2896	3062	2962
2012	1,040	1,040	940	1901	2068	1968	2929	3096	2996
2013	982	982	907	1974	1974	1899	2967	2967	2892
2014	932	932	932	1894	1894	1894	2856	2856	2856
2015	872	872	872	1795	1795	1795	2717	2717	2717
2016	815	815	815	1700	1700	1700	2585	2585	2585
2017	774	774	774	1634	1634	1634	2494	2494	2494
2018	724	724	724	1552	1552	1552	2379	2379	2379
2019	654	654	654	1436	1436	1436	2218	2218	2218
2020	590	590	590	1330	1330	1330	2070	2070	2070
2021	528	528	528	1228	1228	1228	1928	1928	1928
2022	465	465	465	1123	1123	1123	1781	1781	1781
2023	408	408	408	1028	1028	1028	1648	1648	1648
2024	356	356	356	941	941	941	1526	1526	1526
2025	307	307	307	860	860	860	1413	1413	1413
2026	263	263	263	787	787	787	1310	1310	1310
2027	223	223	223	720	720	720	1216	1216	1216
2028	185	185	185	657	657	657	1129	1129	1129
2029	150	150	150	599	599	599	1047	1047	1047
2030	118	118	118	546	546	546	974	974	974
2007-2014	7,980	7,930	7,280	15,050	16,000	15,350	23,120	24,070	23,420

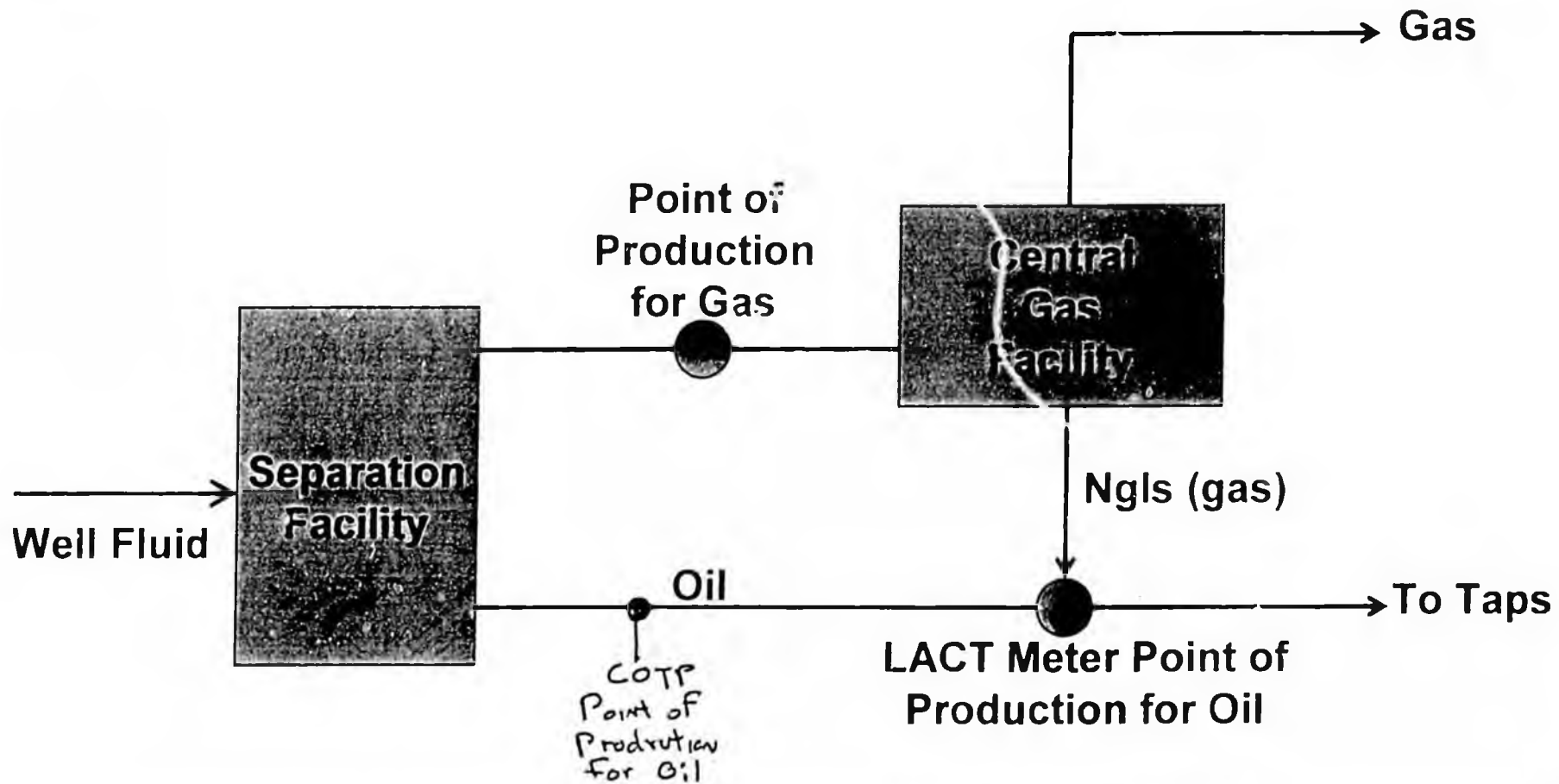
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SLIDE 17

Base Allowance or Credit, Governor's Bill as Written, with House Credit, and with Senate Credit, Low Volume									
FY	Gov at \$20	with H Cred at \$20	with S Ded at \$20	Gov at \$40	with H Cred at \$40	with S Ded at \$40	Gov at \$60	with H Cred at \$60	with S Ded at \$60
2007	0	8	109	988	1000	1074	1868	1879	1926
2008	0	7	108	964	976	1049	1816	1827	1873
2009	53	73	172	1036	1048	1117	1882	1894	1935
2010	42	53	152	1006	1018	1086	1835	1847	1886
2011	40	51	149	1030	1042	1107	1880	1891	1926
2012	35	46	144	1040	1051	1114	1901	1912	1944
2013	13	24	122	982	994	1058	1974	1986	2018
2014	7	3	112	932	943	1035	1894	1905	1981
2015	0	0	103	872	884	1004	1795	1806	1926
2016	0	0	83	815	856	946	1700	1741	1831
2017	0	43	68	774	905	905	1634	1765	1765
2018	0	52	52	724	855	855	1552	1683	1683
2019	0	30	30	654	786	786	1436	1568	1568
2020	0	10	10	590	721	721	1330	1461	1461
2021	0	0	0	528	660	660	1228	1359	1359
2022	0	0	0	465	597	597	1123	1255	1255
2023	0	0	0	408	540	540	1028	1160	1160
2024	0	0	0	356	487	487	941	1072	1072
2025	0	0	0	307	439	439	860	991	991
2026	0	0	0	263	395	395	787	918	918
2027	0	0	0	223	354	354	720	851	851
2028	0	0	0	185	317	317	657	789	789
2029	0	0	0	150	281	281	599	730	730
2030	0	0	0	118	250	250	546	677	677
Totals	182	400	1,413	15,413	17,396	18,176	32,984	34,968	35,526

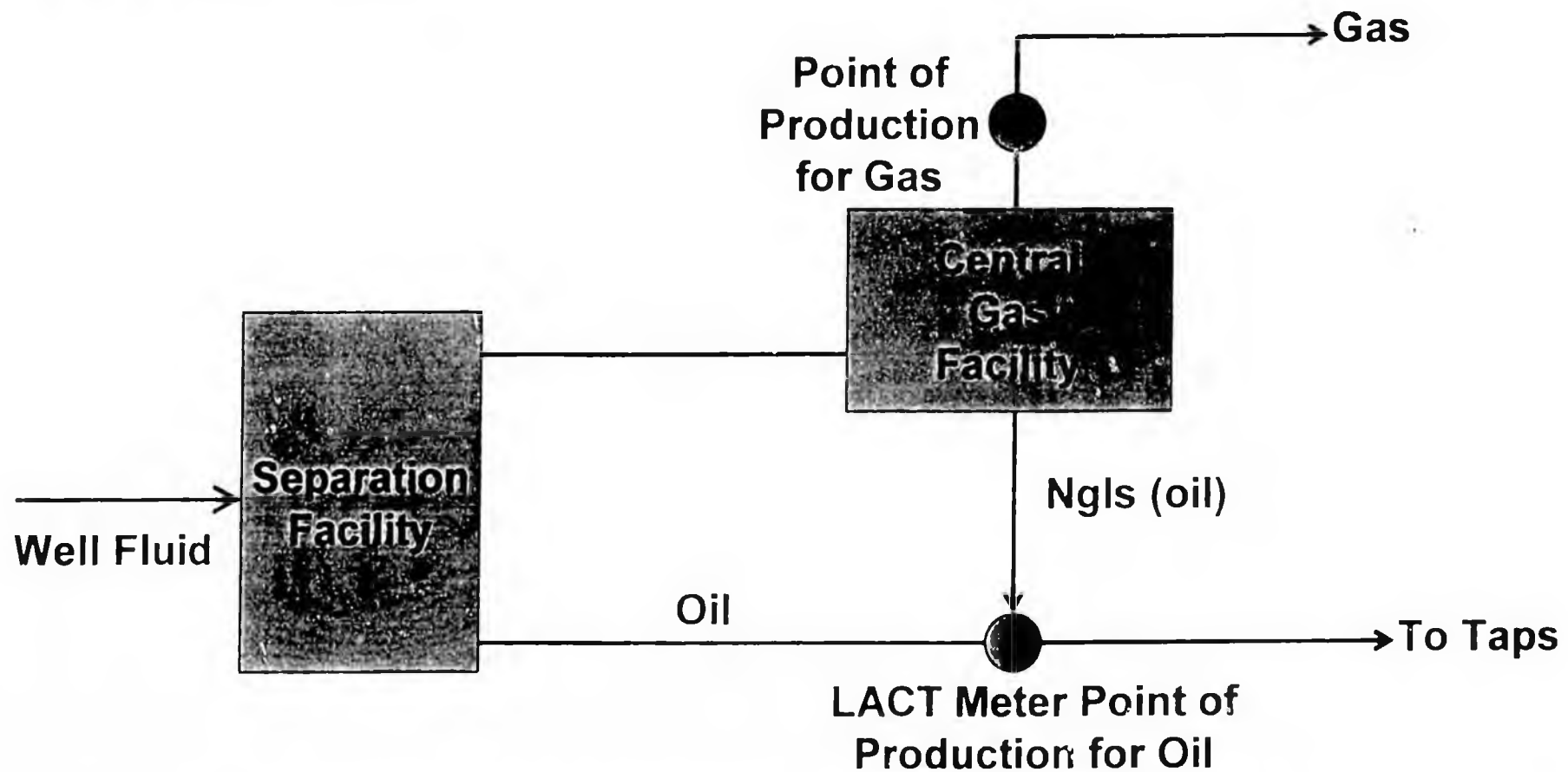
Prudhoe Bay: Point of Production

- Current



Prudhoe Bay: Point of Production

- Proposed



Goal:

- Simplified definitions that will not lead to low value-added conflicts
- Incentivize all production activity

4/3/2006

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

source: DOR

	governor's bill	House Resources CS Version L	Senate Resources CS Version C
tax rate	20% .011(a)--page 3	20% .011(a)--page 3	25% .011(e)--page 3
credit rate	20% .024(a)--page 5	20% .024(a)--page 8	20% .024(a)--page 7
private royalty tax rate	no special rate	5% .011(e)--page 3-4	1.5% (Cook Inlet), 5% other .011(f)--page 3
progressivity surcharge	none	over \$50/bbl WTI, (.3% x (WTI - \$50) x gross; <\$110 rate is 37.5% .011(f)--page 4	over \$40/bbl, (ANSwc - \$40) x .002 x ANSw h x .75 x bbls .011(g)--page 4
special gas progressivity?	n/a	yes .011(i)--page 4-5	no
prcgressivity deductible?	n/a	yes .160(a)--page 18	yes, but not clear
transition	5 yr lookback of capex .160(g)--page 15	3 mo. of capex & opex. ? Sec. 42 uncodified--page 30	5 yrs. lookback capex 2 for 1 recoupment .024(i)--page 10
transition treatment	deduction over 6 yr, if ANSwc >=\$40 .160(g)--page 15	deduction over 9 mo. no oil price test Sec. 42 uncodified--page 30	credit; no oil price test .024(i)--page 10
sunset of transition	no	n/a	3/31/2013 .160(i)--page 10
base allowance	\$73M deduction .160(l)--page 16	\$12M credit (equates to \$60M ded.) .170(a)--page 23	5000 bbl plan .160(g)--page 19-20
sunset of base allowance	none	3/31/2016 (exp incurred) .170(e)--page 24	12/31/2013 .160(h)--page 20
safe harbor	90%, annual true-up, no interest .020(a)--page 3	90% with interest .020(g)--page 7	95% quarterly true-up, no interest .020(a)--page 5
pmt < safe harbor??	interest only .020(a)--page 3	5% penalty + interest .020(h)--page 7	interest only .020(a)--page 5
effective date	7/1/2006 page 20	4/1/2006 Section 45--page 30	4/1/2006 Sec. 38--page 28
transition payment	none	6 mos. pymt on old system; true-up in 7th mo. sec. 39--page 28	6 mos. pymt on old system; true-up in 7th mo. sec. 33--page 26
spill surcharge total	no change (5 cents)	no change (5 cents)	increase 1 cent, to 6 cents
spill surcharge split (2017.30G)	2/3	1/4	1/5
spill surcharge payable	no change	increase 1 cent page 24-25	increase 2 cents page 22-23
surcharge treatment	creditable against PPT page 17-18	not creditable, not ded. .160(d)(2)(L)--page 21	not creditable, not ded. .160(d)(2)(L)--page 17
SB 185 credit	no change	extends 10 years; only usable against PPT .025(b), .025(f)--page 11-12	no change
abandonment	no provision	no credit .024(i)(2)--page 11	deductible; no credit abandonment on old production .024(h)(2)--page 9
credits usable	against PPT only .024(a)--page 3	against PPT only .024(a)--page 8	against PPT only? .024(c)--page 8
credits transferable	yes--20% tax limit .024(d)--(e)--page 6	yes--20% tax limit .024(d)--(e)--page 8-9	yes--20% tax limit .024(d)--(e)--page 8-9
credits refundable?	no	up to \$10M depends on investment .024(f)(5)--page 9-10	no
credits for annual loss	yes, at 20% .024(b)--page 5	yes, at 20% .024(b)--page 8	yes, at 25% .024(b)--page 7
point of production	gas treatment upstream .900(7)--page 19	gas treatment upstream .900(7)--page 25-26	gas treatment upstream .900(7)--page 23
DNR royalty value	yes .150(d)--page 11	yes .150(d)--page 17-18	yes .150(d)--page 14
IRC sec. 482 as a tool	no	no	yes, including 5% penalty .160(l)--page 21
catastrophic oil spill deductible?	yes, if on lease (not precluded)	no .160(c)--page 19	yes, if on lease (not precluded)

4/3/06 10:16 AM

CSSB 305 (RES):
The Rest of the Story

Before the Senate Finance
Committee

Dan E. Dickinson, CPA

Robert E. Mintz, Dept. of Law

April 3, 2006

1
4/3/06
9:04 to 9:44 AM

Sections 1 & 11

- Clarify AS 43.55.020 (f) to reflect consistent department interpretation, upheld in formal hearing decision in 1996
- Prevailing Value is used to set a taxable value for internally refined barrels
- May be moot for a taxpayer using "DNR" or formulaic valuation

Sections 2 & 17

- 1 Amends current statute (AS 43.05.230 and 43.55.040) to clarify rules for using one taxpayer's information to determine another taxpayers tax
- 1 Generally limited to Prevailing value calculation, which may be moot for taxpayer electing alternative valuation formula
- 1 Taxpayer recipients of information are brought under confidentiality provisions of AS 43.05.230

Sections 3 & 4

- Clarify state income tax code that production tax is not a tax “based on or measured by net income”
- Ensures that the PPT is deductible for state income tax purposes.

Section 6

- Amends AS 43.55.017 (a) to conform language to the Internal Revenue Code provision to which it refers

Sections 9, 19, 20

Conforming amendments for language consistency and modernization.

Sections 10, 24, 26

- Repeals and Reenacts AS 43.55.020 (e)
- Simplifies three tiered system where flared gas was either tax free, taxed, or subject to tax and a penalty.
- Now gas and oil are not taxed or subject to conservation surcharges if used for necessary lease operations. (If AOGCC determines they have been wasted, then they are taxed.)

Section 14 and 15

- ▮ Conforming changes to 43.55.030(a)
(dealing with tax returns)
- ▮ Gross/net, and/or, simplified reporting
- ▮ Repeals the \$25 a day filing penalty which predated the 43.05 civil penalties

Section 18

Amends AS 43.55.080

- 1 Conforms statute to constitution
- 1 Namely: recognizes that money from resolved disputes goes into Budget Reserve Fund and not into the general fund

Sections 27, 29

- New definition of “gas”
- Point of production moved downstream
- Gas processing now included in Upstream

- New definition of “oil”
- Liquid hydrocarbons recovered by mechanical separation or gas processing

Section 28

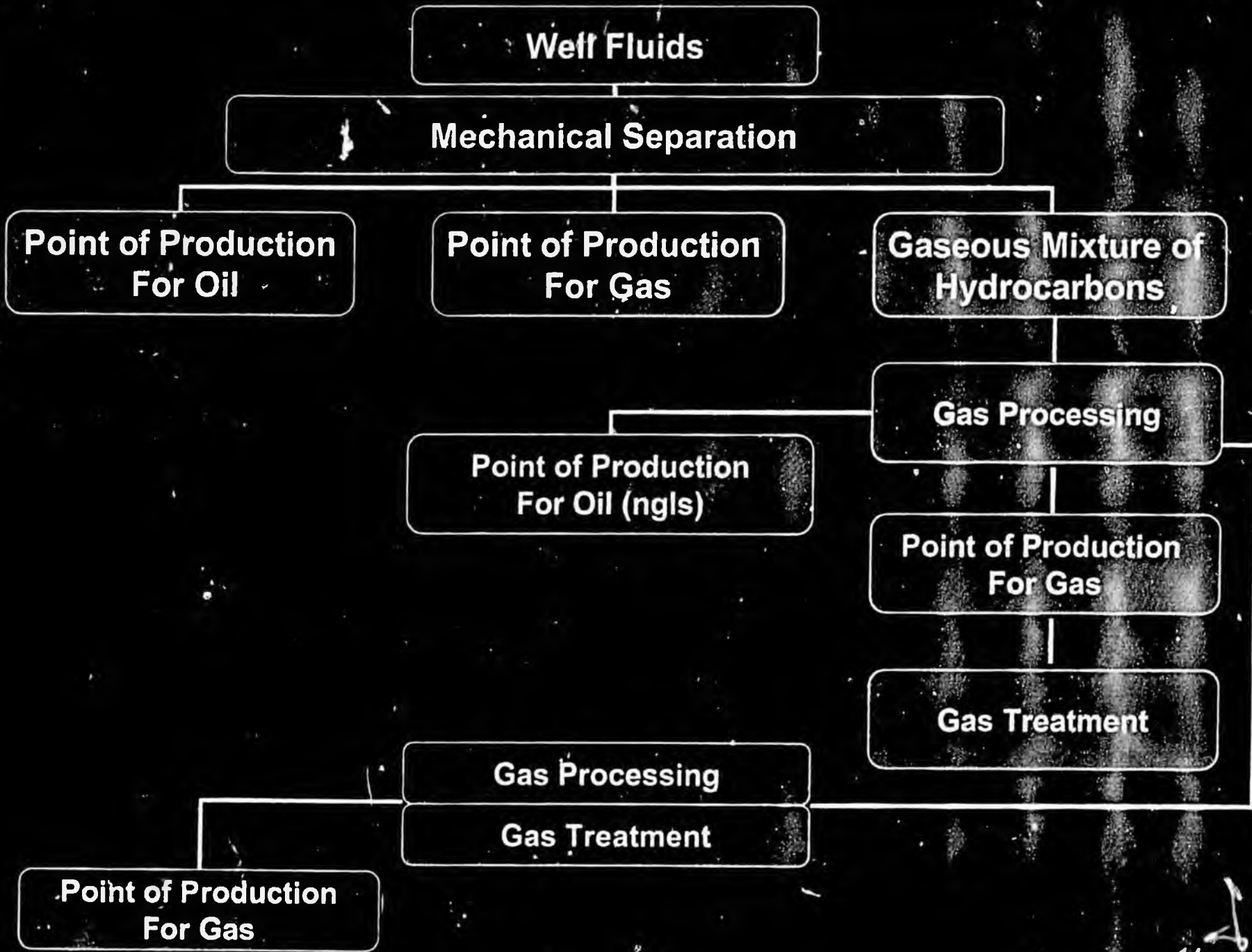
- 1 Redefine “gross value at the point of production”
- 1 Oil pt.-of-prod. definition essentially unchanged (but if there is gas processing, the pt.-of-prod. for extracted liquids is downstream of processing)
- 1 Gas pt.-of-prod. is downstream of any gas processing
- 1 If there is a combined processing/ treatment plant facility, pt.-of-prod. is further upstream point where processing ends or treatment begins

Section 30 (part 1)

- New definition of "Cook Inlet Basin"
- For purposes of the 1.5 percent tax on lessor's royalty share (outside of Cook Inlet Basin the tax is 5 percent)

Section 30 (cont.)

- 1 Define “gas processing” and define “gas treatment”
- 1 Gas processing: physical processes that extract liquid hydrocarbons, upstream of a sales line or gas treatment plant
- 1 Gas Treatment: removing non-hydrocarbon substances and conditioning gas for sales line



Section 31

Repeal of superseded provisions,
including individual gas and oil taxes,
ELF, and some definitions

Sections 32, 33

- ▮ Applicability: Sections pertinent to taxing oil and gas under the PPT apply to oil and gas produced starting April 1, 2006
- ▮ Applicability: Prevailing value clarification of existing law applies to all oil and gas
- ▮ Part-year conventions for 2006
- ▮ ELF based safe harbor for 6 months

Section 34

- 1 Transition provisions --
- 1 Department may develop PPT implementing regulations immediately
- 1 Implementing regulations may have retroactive effect to April 1, 2006

Section 35

Conform headings of statutory provisions

Sections 36, 37, 38

- Effective dates –
- PPT provisions take effect April 1, 2006
 - but if they take effect after April 1, they are retroactive to April 1
- Other provisions take effect immediately

Greenberg Traurig

Memorandum

TO: Senator Gene Therriault, Joe Balash
FROM: Donald C. Shepler
DATE: March 19, 2006
RE: Regulatory treatment of proposed net profits tax credits and deductions associated with investment in North Slope Gas Treatment Plant

fact = gas pipeline

Yesterday you asked whether proposed net profits tax credits and deductions associated with investments in a North Slope Gas Treatment Plant ("GTP") would be flowed-through to customers who ship gas through the Plant. As discussed more fully below, I have found no binding FERC precedent on whether state tax incentives would, in all instances, have the effect of reducing rates. However, there are strong arguments to support that result in the context of investment in the GTP. At the same time, however, arguments could be advanced by the Project Sponsors in support of their right to "retain" the value of the credits and deductions that are presently being considered by the Legislature in the context of SB-305.

BACKGROUND

Under SB-305 the Alaska Legislature is considering a net profits tax program to be applied to oil and gas produced in the State. In conjunction with that program certain credits are proposed that would be based upon investment in oil and gas infrastructure. Further, certain tax deductions are also being considered that would also be based upon investment in infrastructure. Investment by Project Sponsors in a multi-billion dollar GTP as well as the related, upstream "feeder lines"

*distributed by Senator Green
4/3/06
- 9:33 AM -*

that will be necessary to move natural gas from the point of production to the GTP might qualify for such credits and deductions.

Based upon those facts, the question has arisen as to whether the FERC would require that rates for the GTP reflect the Alaska state tax benefits that the Sponsors received if such investments qualify for the deductions and credits. If the value of the tax credits and deductions is reflected in the tariff rates for the GTP (and upstream feeder lines), those rates will be lower than would otherwise be the case. In this context the tax benefits would be said to "flow through" to ratepayers. The alternative ratemaking approach would not reflect the tax benefits received by the Project Sponsors who would therefore be allowed to "keep" or "retain" those tax benefits.

DISCUSSION

As noted at the outset, I have been unable to find any binding FERC precedent that would categorically dictate whether Project Sponsors would be required to flow through the value of state tax benefits and deductions that arose through the Sponsors' construction of FERC-jurisdictional facilities. Consequently, I have attempted to analyze the question by analogy to other comparable circumstances

As you know, the FERC utilizes a cost of service methodology for setting pipeline rates and it is unlikely that this approach will change in the context of an Alaskan pipeline/GTP. Consequently, the ultimate question that the FERC asks is, "What did the facility cost?" Once the cost is determined, then rates can be derived. Application of this simple concept should result in the value of tax credits and deductions that are made possible as a result of the investment in the facility being flowed-through to ratepayers. The logic is simple--by spending the money to build the plant the Sponsors will have obtained quantifiable tax benefits. As a result, the net cost of the

facilities to the Sponsors will be reduced by those amounts. Since reflecting this reduced cost in rates would have the effect of reducing the tariff rates and thus benefiting ratepayers there is a compelling basis for FERC to require flow through.¹

In somewhat analogous circumstances the FERC recently issued a policy statement on the inclusion of an income tax allowance in rates for jurisdictional entities.² There the Commission concluded that it should permit an income tax allowance for all entities or individuals owning public utility assets, "*provided that an entity or individual has an actual or potential income tax liability to be paid on that income from those assets.*" (111 FERC ¶ 61,139 at P 32). The Commission required that any pass-through entity (such as a limited partnership or an LLC) that owns jurisdictional facilities and seeks an income tax allowance in a specific rate proceeding must establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. To the extent that any of the partners or members do not have such an actual or potential income tax obligation, the amount of any income tax allowance will be reduced to reflect the weighted income tax liability of the entity's partners or members.

This Policy Statement suggests that the FERC is very mindful of whether costs to be included in rates were or were not actually incurred by the jurisdictional entity. Applying that policy by analogy to the tax credits and deductions that Sponsors would receive for investing in the GTP under SB-305 suggests that the benefits would be flowed through to ratepayers whose gas is treated at the plant.

¹ It also bears noting that the FERC is generally opposed to requiring the bundling of services (and related costs). This means that one would expect that there will be a tariff for the GTP (and presumably the feeder lines) that is separate from the tariff for the pipeline facility. This allows shippers whose gas does not need treatment to bypass the plant and avoid the costs of that plant. In such case, obviously, those shippers who did not use the plant would not receive any of the tax benefits since they would not be paying the unbundled rates for the use of the GTP.

² *Policy Statement on Income Tax Allowances*, 111 FERC ¶ 61,139 (2005).

Unfortunately, the Commission (with court approval) has not always subscribed to an "actual costs incurred" standard. In *City of Charlottesville, Virginia v. FERC*, 661 F.2d 945 (D.C. Cir. 1981)) the court noted that while ascertaining "actual" expenses is a desirable goal in ratemaking, "the complexities of accounting, business organization and tax laws often preclude finding any one 'actual' cost." (661 F. 2d at 953, n. 38).

The court noted that regulated entities typically use accelerated depreciation for tax purposes but use straight-line depreciation for rate purposes. This results in a higher tax for ratemaking purposes than is actually paid. This deviation from "actual taxes paid," the court noted, has been upheld on appeal (*Id.*).

In *City of Charlottesville* the court rejected on evidentiary grounds FERC's then-effective policy of allowing pipeline rates to reflect tax costs (at the subsidiary level) that were never actually paid because, at the parent company level, profits from the pipeline subsidiary were offset by losses from exploration and production subsidiaries. This policy had been defended on the ground that the shortage of natural gas supported ratepayers paying tax costs that were never actually incurred.³

Thus, one cannot rely entirely on the simple logic that FERC will always require tax benefits to be flowed through to ratepayers. Moreover, additional arguments could be advanced by the Project Sponsors that would allow them to retain the tax benefits. For example, the Sponsors could argue that the tax benefits that they received under SB-305 related to their tax liability as oil and gas producers—not as owners/operators of the GTP. I have not had the opportunity to research

³ Technically, FERC had allowed pipeline rates to reflect the computed tax liability associated with the profits of the jurisdictional pipeline subsidiary even though taxes were actually paid on a corporate-wide (so-called "consolidated") basis and the parent company was able to use losses and tax deductions attributed to the exploration and production subsidiaries to reduce or eliminate millions of dollars of tax liabilities that were computed on the so-called "stand-alone" basis.

the merits of this claim but it would appear to have some validity insofar as FERC's jurisdiction over the owners as gas producers is extremely limited.

In addition, the Sponsors could argue that the tax credits and deductions that they received were provided in order to encourage investment in infrastructure projects in Alaska. As such, the argument could be made that flowing through those benefits would defeat the policy of encouraging investment by giving all the benefits to the ratepayers rather than the investors.

In this context it is notable that in 1971 Congress enacted tax legislation that made investment tax credits available to many industries, including gas pipelines. In that legislation Congress established ratemaking guidelines that allowed taxpayers in certain industries to retain the tax credits so long as certain findings of supply shortages could be made by regulators. The Federal Power Commission made such a "short supply" finding with respect to natural gas in 1972.⁴ This finding allowed gas pipeline companies to retain 100% of the investment tax credits. The short supply finding was ultimately rescinded by the FERC in 1985 (*Order No. 440, FERC Statutes and Regulations, Regulations Preambles—1982-85* ¶ 30,674 (1985)).

While the treatment of federal investment tax credits pursuant to the 1971 legislation is clearly not binding precedent in the context of Alaskan net profits tax credits and deductions, it does lend support to the argument that flow-through of such benefits could thwart public policy encouraging investment in new projects.

This argument is somewhat strengthened by the fact that it arises in the context of an Alaskan pipeline project. FERC has evidenced a willingness to adopt policies and practices with

⁴ Order No 448, 47 FPC 141 (1972)

respect to an Alaskan pipeline that differ from those they would apply to Lower-48 pipelines.⁵ As such, Project Sponsors might be able to persuade the FERC that the unique importance of the Alaskan pipeline project requires that FERC depart from policies that might be thought to discourage the development of the project. If sustained by the FERC such argument would allow the Project Sponsors to retain the value of the State tax credits and deductions.

CONCLUSION

I have not found any clearly binding precedent that answers the question you posed. However, since FERC bases rates on the costs incurred to provide the services, the fact that Project Sponsors received quantifiable state tax credits and deductions as a direct result of investing in a GTP suggests that FERC would be inclined to require that those benefits be flowed through to shippers who make use of the GTP. This would be the result I would expect.

However, as noted above, in the absence of binding precedent on the issue, there are arguments that Sponsors could make that might allow them to retain any net profits tax benefits that result from their investment in the GTP. The fact that the GTP is an essential element of the unique Alaskan pipeline project makes it particularly difficult to predict FERC's final action.

Under the circumstances, I am unable to give you a categorical answer to your question. While I believe FERC would be most likely to require flow-through of state tax benefits, I have to state that the result is simply uncertain.

Please feel free to contact me if you have further questions on this issue or want me to pursue it in more depth than has been possible given the present time constraints.

⁵ For instance, in Order Nos. 2005 and 2005-A the FERC departed from its generally applicable policy requiring incremental pricing on pipeline expansions that would raise the cost for existing shippers and adopted a policy favoring rolled-in treatment of voluntary expansions of an Alaskan pipeline.



Official Business

Alaska State Senate

Senate Finance Committee

Mail Stop 3100
State Capitol
Juneau, Alaska 99801-1182

AGENDA

Tuesday, April 4, 2006

9:00 a.m.

SB 305-OIL AND GAS PRODUCTION TAX

Bills previously heard/scheduled

Angus Aja Walker, ^{Commercial} VP
Tom Williams, Sen Tax Counsel

Sen. G Stevens

TESTIMONY OF RICHARD OWEN
ON PROPOSED CSSB305 TO THE SENATE FINANCE COMMITTEE

April 4, 2006

Madam Chair, Members of the Committee:

Good afternoon. My name is Richard Owen, and I am the Production Manager for ExxonMobil in Alaska and Vice President of ExxonMobil Alaska Production.

I am here today to discuss ExxonMobil's concerns with the Committee Substitute to SB 305. Before I go into our specific concerns, I would like to take a few minutes to describe ExxonMobil's history in Alaska, how tax systems impact investments, and our assessment of the remaining resource potential on Alaska's North Slope.

ExxonMobil has had a presence in Alaska for over a half century, investing more than 11 billion dollars in the State's economy. Currently, ExxonMobil has working interests in Prudhoe Bay, Kuparuk, Erdicott, and Granite Point. We are the operator of the Point Thomson Unit, and we are the largest interest holder in the Prudhoe Bay field. Our current working interest oil production is approximately 180,000 B/D (*Note: EMWI 159,000 EMNI*), and we are the largest owner of discovered gas resource. We are proud of the role our company has played in Alaska through: exploration; initial field developments; construction of TAPS; development of new technology; and the promotion of efficient reservoir management practices. Today, our production from Alaska represents approximately 4% of ExxonMobil's worldwide oil and gas production.

Our Alaska production is primarily from Prudhoe Bay and near-by satellite fields. Prudhoe Bay, along with Point Thomson, has significant remaining potential, but it comes at higher cost and risk.

One of ExxonMobil's objectives – in both the gas pipeline fiscal contract negotiation and the discussion on oil taxes – has been to reduce the risk associated with fiscal changes by working with the State of Alaska to establish a predictable and durable fiscal environment in which to make long term investment decisions. Changes in the fiscal regime for oil directly impact how we view the stability of the Alaska fiscal environment, which in turn, impacts how we evaluate ongoing investment decisions. Tax systems need to be carefully designed to ensure the desired objective of resource development is achieved. To that end, it is critical to take into account the quality of the remaining resource otherwise a change may result in unintended consequences, such as reduced investments and lower reserve recovery.

When I say quality of resource, I mean: the size and nature of the oil and gas reservoirs; the cost and technology required to develop those reservoirs; the distance to market; as well as the tax and royalty system that applies, including the long-term stability of that system. Countries experiencing significant industry investment have achieved the proper balance in their fiscal regimes. ExxonMobil's assessment of the remaining oil resource suggests future growth opportunities will come from: complex enhanced oil recovery (EOR) projects; development of smaller, more marginal oil accumulations; and the innovative development of viscous and heavy oil resources. These opportunities will require the development and application of new technology, higher unit development

costs, and more complex operations to deliver a given production rate. These resources are much lower in quality as compared to Prudhoe Bay and Kuparuk, though they face the similar challenges associated with arctic conditions and distance to market.

Therefore, we are concerned the Administration's original proposal is weighted towards a higher tax which could prevent some of Alaska's challenged resources from being developed. The Committee Substitute contains even higher tax rates, which may prevent more of these challenged resources from being developed.

On February 28, I testified before the Senate Resources Committee about our key concerns with SB 305 as originally proposed. On March 18, I testified again before the Senate Resources Committee about how the proposed changes incorporated in the Committee Substitute bill exacerbate our concerns. I do not intend to cover all of my previous testimony, but I will provide comments on these areas: the increase of the base tax rate and addition of a progressive tax rate component; the Committee Substitute's transition provisions; and the elimination of royalty settlement agreements as a determination of market value.

SB 305, as originally proposed, would represent a significant tax increase on the industry. And as I just outlined, we are concerned the higher tax rate could prevent some of Alaska's remaining challenged resources from being developed. The Committee Substitute bill increases the already high base tax rate to 25% and then further increases it as oil prices increase.

Higher tax rates discourage investment. Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential through a variety of factors, such as increased production or higher prices. When you limit or reduce the benefit Companies can achieve from the upside factors, you reduce the attractiveness of those investment opportunities. The proposal to increase the already high base tax rate and then further increase it as oil prices increase, reduces or limits the upside potential which will result in Companies recalibrating investment decisions. Reduced investment will result in reduced resource recovery, diminished state revenues, and fewer employment opportunities, with a resultant negative impact on the state's economy. Again, let me reemphasize this point. While higher taxes may bring in additional revenues in the short-term, any reduction in investment and subsequent production will significantly impact those revenues in the longer term. We think the focus of the tax bill should be encouraging investment and growing production, which is not accomplished with the higher tax rate and increasing the tax rate with oil price.

I would now like to discuss the Committee Substitute's transition provisions. The benefits from a typical oil and gas investment take many years to be realized. Satellite and tertiary recovery investment decisions by our Company during the last five years were made under the ELF structure, anticipating a lower tax relative to that proposed under the PPT bill. The State appropriately provided this incentive so these challenged and costly projects could be commercially viable. SB 305, as originally proposed, recognized it is not appropriate to suddenly increase taxes on these prior investments without providing some form of consideration. The Senate Resources Committee

included transition provisions in the Committee Substitute bill, but proposed a deduction based on recent investments with the pace of the deductions linked to future spending. As I stated, the purpose of the transition provision is to address the sudden increase in taxes on recent historical investments. Future investment decisions will be made under the new tax system based on the balance between the new tax rate and the credit rate. For this reason, we think the Administration's proposal of providing a deduction based on recent investments, not linked to future spending, is more appropriate.

Finally, I would like to express our disappointment that the provision allowing the use of a producer's royalty settlement agreement to determine the value of oil and gas has been removed from the Committee Substitute bill. That provision addressed a longstanding issue that has divided the State and the industry over the years. Too many years and too much money have been spent in disputes over how to value a single barrel of crude oil or a single molecule of gas. It made little sense in the past and it makes little sense today for the State to have separate divisions determining the value of oil and gas – one for royalty and one for taxes. There is only one value in the market place. SB 305, as originally proposed, allowed the State to value a producer's oil and gas using the producer's royalty settlement agreement, which was negotiated with, and approved by, the Department of Natural Resources. That provision was important to industry as it provided certainty to a producer on the value on which to pay its royalty and production taxes while reducing the administrative and audit costs to both the State and the industry. We urge this committee to reinstate that provision.

In summary, the quality of the resources, the risks undertaken by a producer, and the impact on the State's overall investment climate must be factored into the design of the tax system. While industry needs predictably and durability under which to gauge investment decisions, the attractiveness of that predictably and durability is lost if it comes at too high a cost.

Despite our concerns with the original SB 305, we are prepared to move forward under that system as originally proposed, since it sought to provide a balance of revenues to the state and producers across a range of oil prices, provided sufficient incentive for producers to undertake exploration and development risks, and included reasonable transition provisions for past investments. And, most importantly for ExxonMobil, oil fiscal contract terms consistent with the Administration's proposal would provide the predictability and durability necessary to advance the gas project to the next phase. Potential changes to the Administration's PPT bill should be carefully considered to avoid upsetting the balance contained in the bill – changes would require a reexamination to ensure the underlying health and stability of the oil business is sufficient for a gas pipeline project.

As I mentioned, the proposed Committee Substitute exacerbates our key concerns regarding both tax rates and certainty. For these reasons and the need to move ahead with the review of the Gas Pipeline Fiscal Contract, we urge this Committee to support SB 305 as originally proposed.

Thank you again Madam Chair for the opportunity to testify today.

BP Presentation on CSSB 305 (PPT)

**Alaska State Legislature
Senate Finance Committee
4th April 2006**

For the record, I am Steve Marshall, President of BP Exploration Alaska. I appreciate the opportunity to provide my point of view regarding SB305.

I have watched the oil tax proceedings over the course of the last few weeks with great interest. As the discussion has evolved, I've become increasingly concerned. My concerns center on both the direction of changes and the focus of the discussion itself. I believe the current bill is moving in the wrong direction and will hurt Alaskans. And, while we have many common goals upon which to align our conversation, we have clearly not been successful so far.

It seems to me that while a lot of energy has been brought to bear, we are having the wrong conversation. So what is the right conversation?

We cannot afford an "us and them" conversation. We are all in the boat together. We all benefit from increased production and we all suffer from production decline. As our business faces its middle-age challenge, the day-to-day business is really about battling decline. I know that this doesn't have quite the same sizzle as a big project or new discovery, but this is our shared reality.

So the real issue before us is one of finding a suitable tax structure and rates that will encourage additional investment, stimulate development, get additional barrels in the pipeline; and yes, also give Alaskans a fair share of oil price upside when we all have such good fortune.

So the question is, what tax policy and plan will achieve this? This is the key point of discussion.

While the current high price is of great benefit, it has the tendency at the same time to mask the seriousness of the underlying production decline. We cannot afford to be distracted by the price environment. Instead, we need to recognize the underlying performance of the business, focus on our mutual goal of increasing production and avoid any outcome that creates undue burden across the whole of the business cycle. If we don't work together and get this right, decline will continue unabated and no tax rate will be high enough to generate the level of revenues Alaska needs to remain robust. We will all lose.

I wish I shared the confidence of your consultants that increasing taxes will not reduce investment. As an investor who has spent considerable effort to make Alaska more competitive so that we can successfully compete for increased investment, I have a different view. As I consider this bill, I recognize that my job is going to be much more difficult.

I feel a real personal stake in this today. To some degree, this is a result of my participation in the work over the last several years. An effort by the Alaska organization to develop a tangible plan that extends more than 50 years into the future. But, to a larger degree, it is because I am accountable to over 5,000 employees and contractors who have worked so diligently to develop the plans that underpin this future.

I'm privileged to have led this organization for the last five years. Through that time, the people of BP Alaska have faced many challenges and continued the progress to where we have now turned a corner and see new growth and opportunity. And their efforts and passion have had an impact on me. I have been affected by their commitment to this future, by their commitment to their local communities, by their dreams for their children and by their passion for the richness and unique qualities of living in Alaska.

With this in mind, I remain hopeful that we can return to a common dialog. In this discussion we will align behind the mutual goal of growing the pie and stand firm against the common enemy - production decline. I remain confident that this Committee will re-direct the conversation and the bill in such a way that we all end up with a tax policy that works for the people of Alaska and for investors like BP.

BP remains committed to this legislative process. We will continue to do our part in providing testimony and support with the goal of together creating a balanced structure that results in an infusion of capital, reduces decline, creates growth in state revenue, provides a better balance at high oil price and secures a healthy oil business that bridges us to gas and beyond.

You will hear Angus describe why:

- Production is declining
- Significant additional investment is vital to stem decline
- Production is paramount in maximizing State revenue and benefit to Alaskans
- The current bill is not in the best interest of Alaska.

Thank you for the opportunity to address the members of this committee.

Steve Marshall

BP Presentation on CSSB 305 (PPT)

Alaska State Legislature
Senate Finance Committee
4th April 2006

For the record, my name is Angus Walker and i am the Commercial Vice President of BP Alaska.

I would like to start by thanking this Committee for the opportunity to provide testimony on Committee Substitute for Senate Bill 305.

I will summarize the key issues raised in previous testimony and provide our view of the substantive changes made by the Senate Resources Committee to SB 305.

Alaska has lots of Oil and Gas!

The good news for Alaska is that you have a huge known resource base, enough resources for the next 40 years and beyond.



		Billion barrels equivalent
	Produced	15
	Known Remaining	17.5
	Developed	
	- Light	3.5
	- Viscous	0.3
	Undeveloped	
	- Light	4
	- Viscous	0.7
	- Heavy	3
	- Gas	6
	Yet to Find (Exploration)	5

Recoverable Resource



Source: DOR / USGS / BP

To date we have produced 15 billion barrels, but there are 17.5 billion barrels remaining that we already know about, 3.8 billion barrels of which have been developed to date.

Of the 13.7 billion barrels that are yet to be developed, there are:-

- 4 billion bbls of light oil remaining in the existing reservoirs
- 0.7 billion bbls of viscous oil, similar to that which we have started to produce
- 3 billion bbls of heavy oil lying in shallow formations below the permafrost
- 6 billion bbls of gas which we are working so hard to get to market

The scale of this known resource greatly exceeds that expected from future exploration. Future discoveries are expected to be of the order of 50-150 million barrels. It's not to say you should stop exploring, but you cannot rely on exploration to stem the decline of the North Slope.

While BP isn't exploring in the conventional sense, we are adding barrels. We're not only looking to develop our share of the 17.5 billion barrels, but we're looking to make it even bigger.

To put that in perspective, every time we increase the recovery efficiency by just 1% we access an additional 600 million barrels (400 mmbbls light oil and an additional 200 mmbbls heavy oil).... Every 1% is equivalent to another Alpine!

It is for this reason we are investing in technology. We are exploring within our existing fields.

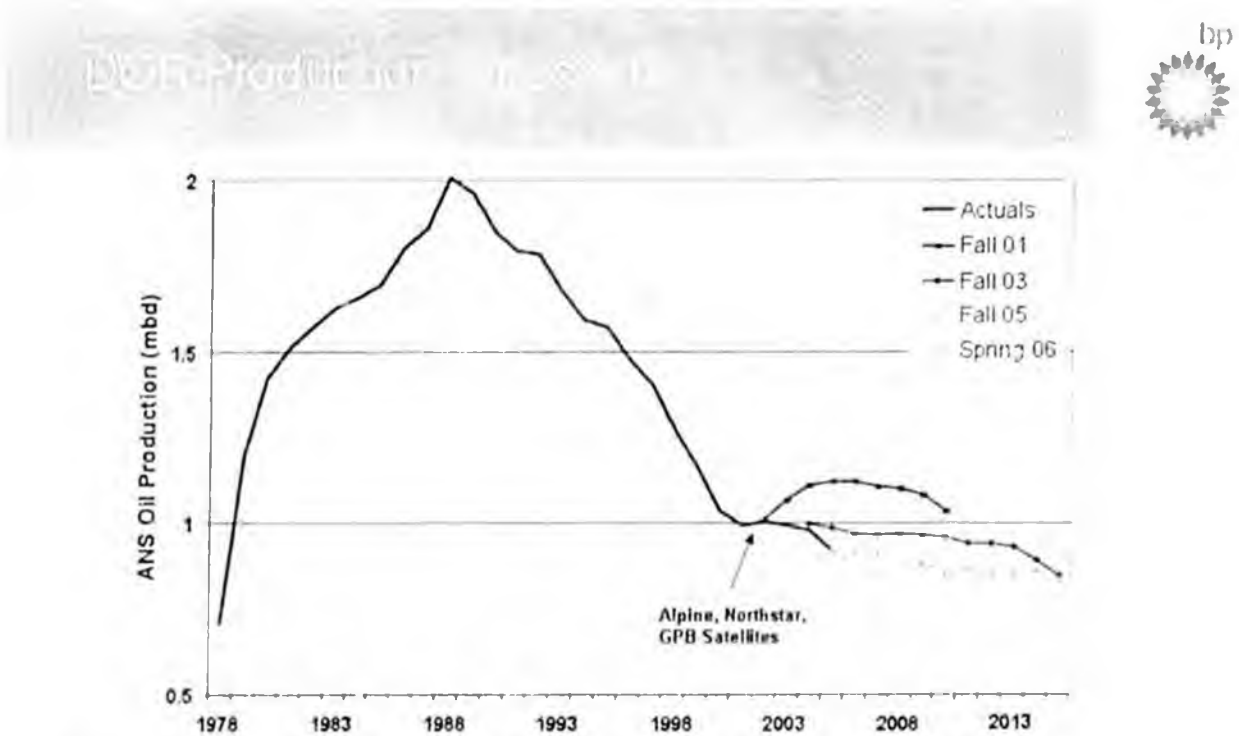
One example is that we're spending in excess of \$100 million implementing innovative technology to increase recovery at Endicott. If we are successful at Endicott it could add hundreds of millions of barrels of production across the North Slope. (Another Alpine?)

To develop the 14 billion barrels we know about would require well in excess of \$100 billion. And that kind of investment can only come from the Major oil companies of the world.

Encouraging new exploration is good but it is a fact, acknowledged by all who have testified, that the resources expected to be discovered through exploration will likely be significantly less than the resources we already know about. **It is investment in the known resources that offers the greatest chance of stemming the decline of ANS production. As you look at incentives for exploration please do not overlook incentives for the investments in known fields, which are more likely to succeed.**

Production is declining:

Since 1999, both Industry and DOR have consistently overestimated production and have annually revised production forecasts down significantly. This is of great concern to us as it should be to you. A one hundred thousand barrel per day drop in production represents a drop in state revenue of around \$500 million per year at current prices.

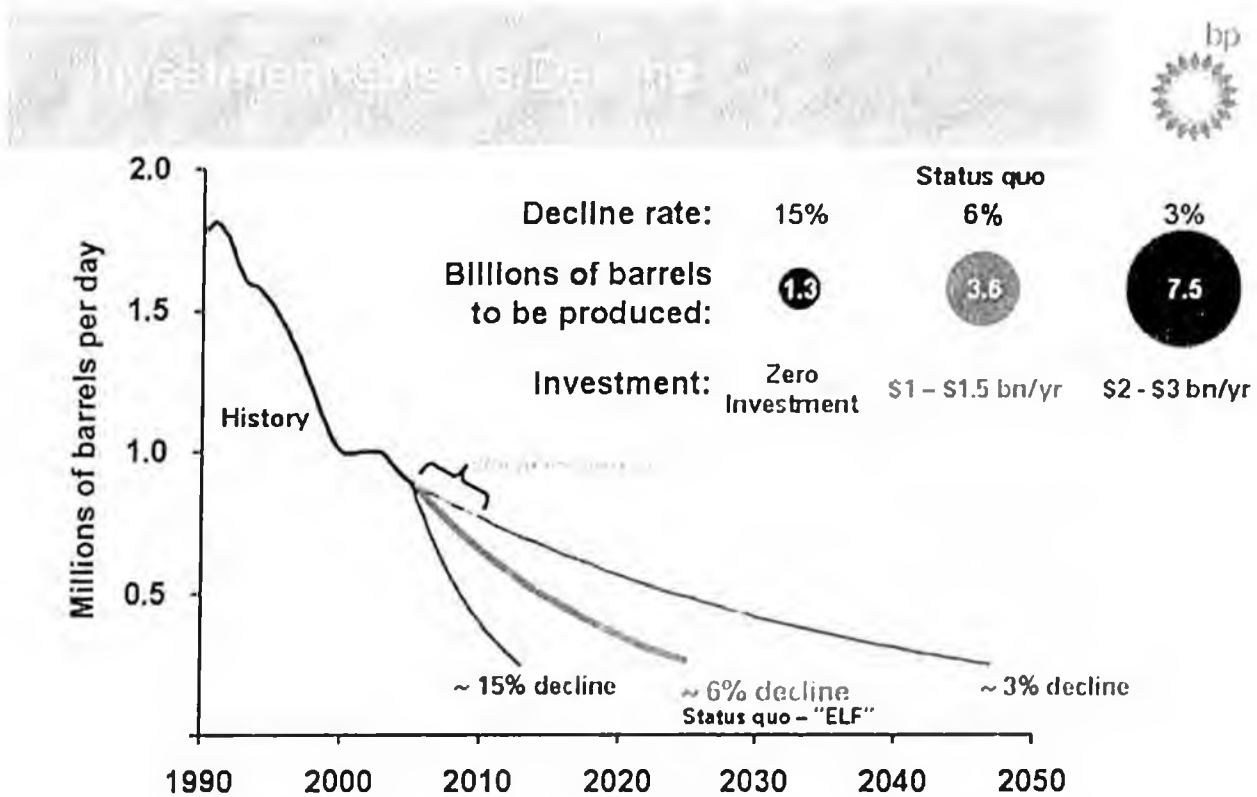


- Historical basin decline has been around 6%
- Flattening of production from 2002-2004 due to Alpine & Northstar
- Decline since 2004 has mirrored historical basin decline

This chart shows a subset of the DOR forecasts from 2001, 2003, 2005, along with the latest view of the Spring 2006 forecast, against actual production in red.

Whilst development of Alpine, Northstar, and the Prudhoe Bay Satellites between 2000 and 2002 successfully flattened North Slope production for a number of years, 2005 saw decline return to the 6% rate that has characterized this basin in the past. Unfortunately for all of us, there are no more fields of Alpine or Northstar's magnitude waiting to be developed.

Significant additional investment is required to offset decline



***DOR Spring Forecast cannot be met without significant additional investment
The vast majority of that investment must be made in existing fields***

With no investment the natural decline of the fields would be the lower red line. At the current levels of investment (\$1-1.5 bn/year) that decline will be around six percent per year. The latest DOR 2006 Spring forecast translates into an approximate 3% decline which you can see is above the current status quo.

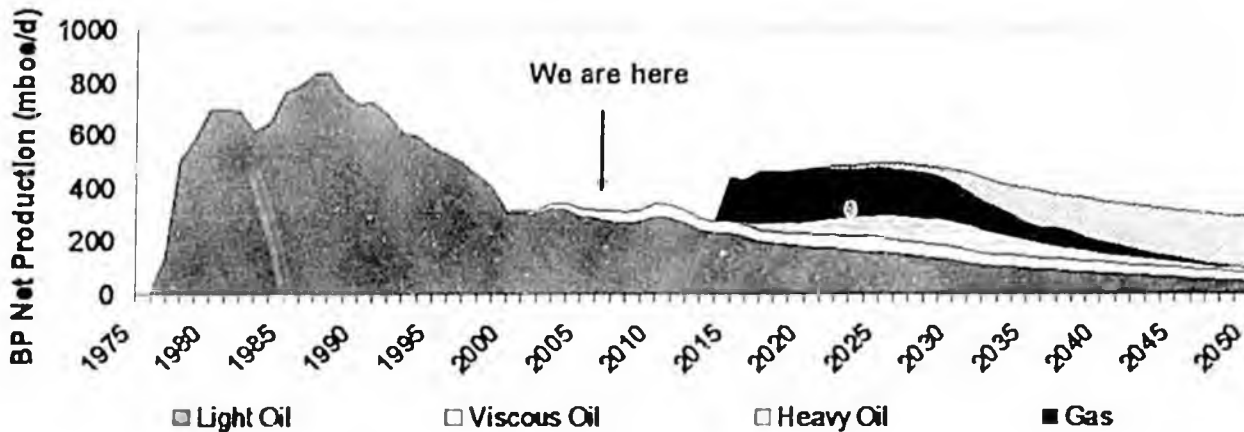
However, the 3% decline cannot be met without significant additional investment, in the order of 2 to 3 billion dollars per year. Unless those investments are made, history will repeat itself, decline will continue at the current rate, and the DOR will be revising its production forecast down yet again.

The real question for you to be asking industry and the consultants is 'what would it take to double investment in the Alaska North Slope?'

So what is BP doing to address the issue of decline?



A 50 year vision



For several years now we have been pursuing our vision of a fifty year future for our business in Alaska. This future will be based on the development of the known resources on the North Slope (conventional light oil, viscous oil and gas).

Creating this future has many challenges and will not be easy to deliver, but we are already in action laying the foundations for the next 50 years.

We are pursuing technology to unlock the difficult oil.

We have been investing in infrastructure to get it ready for the decades to come (including \$1 bn by BP on four new tankers and \$400 million by the TAPS owners to update the pipeline). Each of these investments is designed to reduce costs and increase the wellhead value of Alaska's oil, to the benefit of the industry and the State.

We are hiring people, 200 people this year alone.

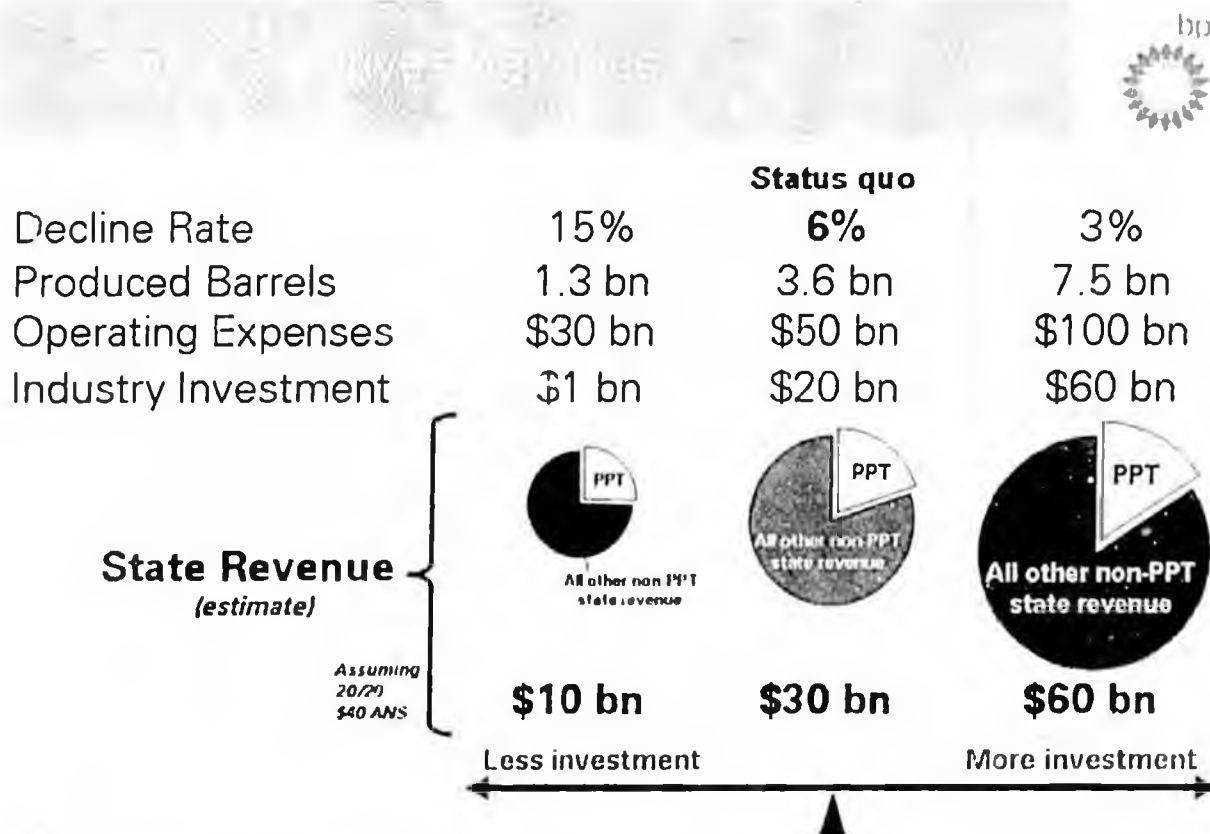
We have plans to invest \$14 billion over the next 10 years in our Alaska business.

We have great hopes for our Alaskan business, but are seriously concerned that without an appropriate fiscal policy that future will not transpire.

Maximizing Production will maximize State Revenue

The tax regime you approve will directly impact how attractive Alaska is for investment and that will translate into what the future decline will be. It is in the interest of all (industry and Alaska) that we focus on growing the pie rather than increasing state take from a declining pie.

The following shows how growing the pie by incentivizing investment is in the best interest of the state over the long term.



Maximizing State Revenue means maximizing Production

The highest state revenue is derived from the scenario which delivers the greatest production regardless of what severance tax (PPT) you collect. You could collect zero severance tax (PPT) and this would be a better outcome for the State than one where you collect a high severance tax (PPT) and have less resource development.

It should also be noted that this analysis does not attempt to quantify the ripple effect on the state economy of a vibrant oil and gas business. Needless to say if the total impact on Alaska's economy, including direct & indirect employment, wages etc., were taken into account the impact of getting it right would be staggering. This is a matter of the utmost importance for Alaska's future.

The size of the pie is the most important consideration. Maximizing the value of resources for Alaskans means maximizing state revenue by maximizing production. Resources left in the ground are simply a wasted opportunity.

This should be the focus of our deliberations. Alaska needs more investment, more jobs, more production, not higher taxes.

Alaska will have the highest tax rates in the United States!

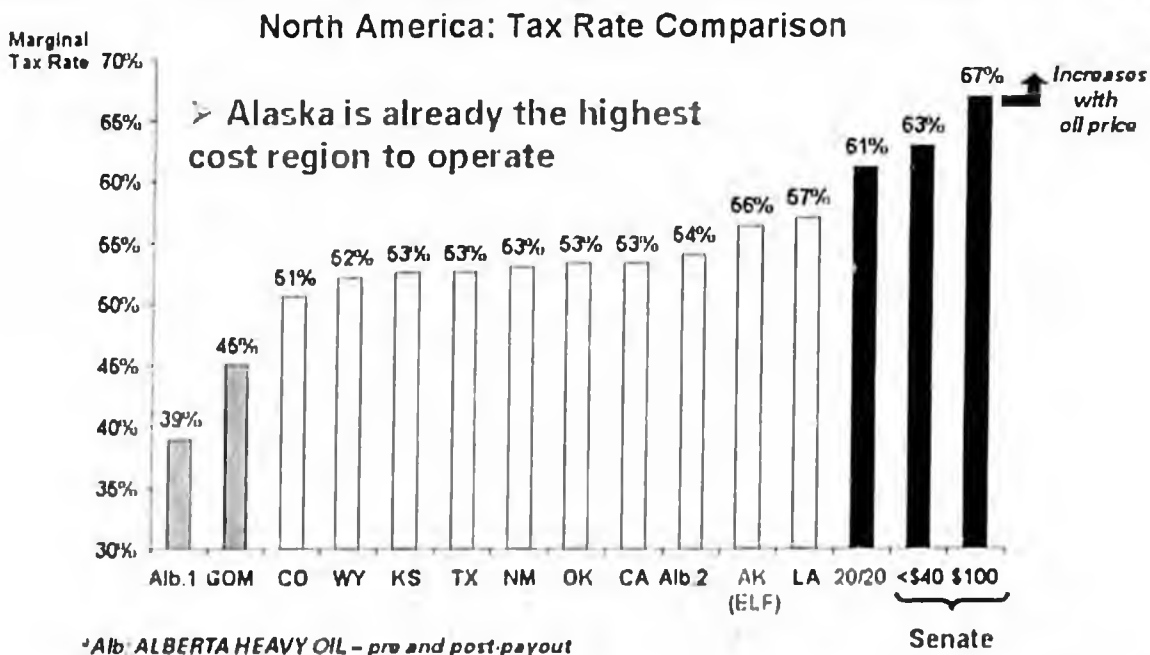
The good news for Alaska is that there is a huge known resource base on the North Slope.

The bad news is that it going to be technically difficult to extract that resource out of the ground. Every barrel gets more difficult.

Alaska is already one of the most expensive places in the world to produce oil and gas.

Assuming the new 25/20 PPT is put in place, Alaska would also become the area with the highest marginal tax rate in the US. Needless to say this introduces one more barrier to attracting investment. The incorporation of yet higher tax rates at higher prices creates a bizarre fiscal regime, being regressive at low prices and progressive at high prices, thus reducing space for industry and creating yet more barriers to attracting investment.

The following graph shows how Alaska compares to other North American regimes both under 20/20 PPT and the scenario outlined in the Senate Resources CS.



Alaska will have the highest marginal tax rate

To maximize the value of the resources in the ground, we should be focussed on maximizing North Slope production by attracting investment. The priority for the state of Alaska should be to encourage investments to help industry develop those known resources, not to make it more difficult and risky than it already is.

Other countries have proven that reducing taxation increases investment:—



“Ordinary measures of Government take throughout the 1990’s made the United Kingdom government appear rather crazy and irresponsible **The “gross benefits” to the UK Government go way beyond direct tax revenues and royalties received from the upstream sector of the petroleum industry. The economic impact of the industrial hyperactivity in the UK sector of the North Sea, a direct result of the “lenient” terms of the 1990’s, is difficult to measure** Furthermore, the activity in the UK started in the late 1980’s and early 1990’s when the UK Government dropped the ring fence for the 75% FRT before Government take, as it is ordinarily measured, was drastically reduced **The UK offshore became the most active offshore province in the world. Reducing the Government take in the following years managed to sustain that boom. Activity and employment in the British petroleum sector is healthy and robust..”**

Daniel Johnston

*23 Oct 2002, Washington DC
Petroleum Tax Design*

There was much discussion over recent weeks about the impacts of reducing taxes in the UK. The UKCS has been our backyard for many years and we couldn’t agree more with Daniel Johnston that reducing taxes firstly created and subsequently sustained an economic boom. The UK’s decision to reduce Government Take led to a significant increase in activity in the North Sea, more production, higher revenues for the Government and a ripple effect throughout the whole economy.

The actions of the UK during the 1980’s and 1990’s provide an excellent role model for any Government hoping to attract investment.

Alberta Heavy oil



Investment boom underway

- Capex increasing up to \$10 billion p.a
- Alaska flat circa \$1 billion p.a

Enabling fiscal regime

- Key reform in 1995
 - 1% Royalty until project payout
 - 25% after payout
 - Federal and State tax of 39%

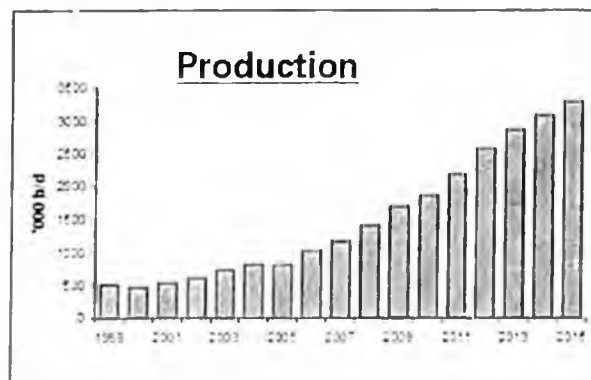
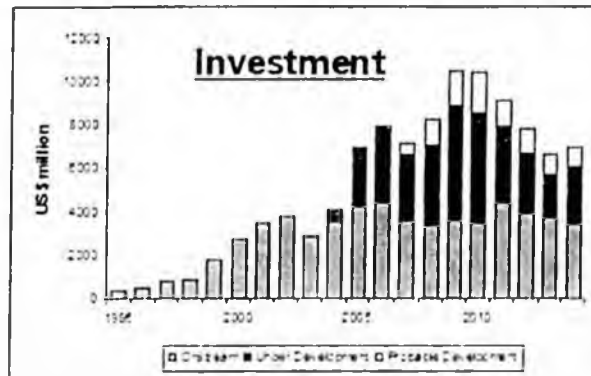
Marginal tax rates

- 39% pre payout
- 54% post payout

Above rates will decline by 4% through 2007

- via phased reduction in Federal tax rates

Source: Wood MacKenzie



If we just take a relatively short trip across the border into Canada and look at what is happening in the heavy oil province of Alberta we find another great example of where cutting taxes has increased investment & state revenues.

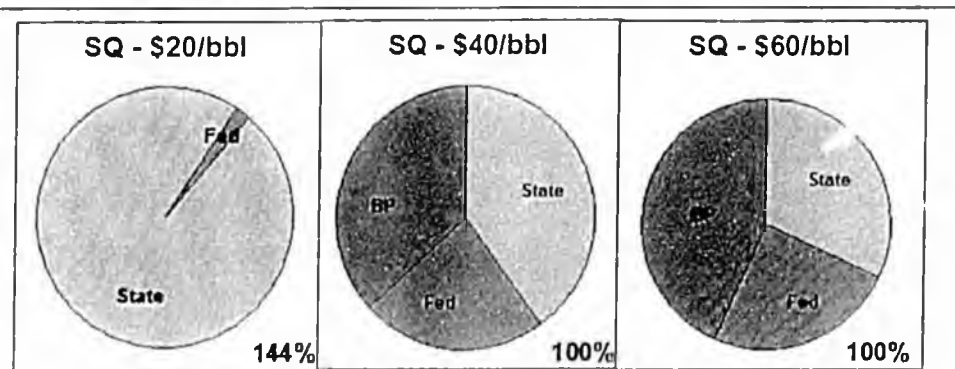
PPT Impacts & Government Take

This chart shows the total Government take at different oil prices for the current Elf based system and PPT.

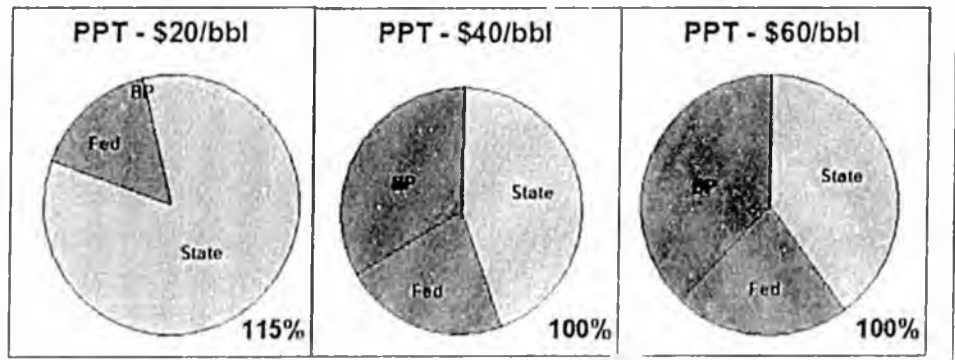
Also note that BP does not make a profit at low oil prices under either regime but the state still receives revenues from the oil industry.



Status Quo



PPT
(20-20)



	\$20		\$40		\$60	
	SQ	PPT	SQ	PPT	SQ	PPT
State	143%	97%	40%	44%	32%	40%
Federal	1%	18%	23%	22%	25%	22%
BP	0%	0%	37%	34%	43%	38%

The current version of SB 305 is not good for Alaska and will not help stem decline of the North Slope and we encourage you to address the following key issues:

1. The increase of the base tax rate to 25% will be a serious barrier to investment
2. The proposed progressivity in the tax rate combined with the significant base rate increase in moving from EII to PPT (25/20) is inappropriate given Alaska's circumstances:
 - a. Challenged resource base
 - b. High cost environment
 - c. Distance to market
 - d. Regressive nature of the rest of the fiscal regime
 - e. Urgent need to attract very large amounts of capital to stem decline
3. Several of the newly introduced terms are unbalanced and will cause problems:
 - a. It contemplates only an increase in tax with no reduction in tax at medium and low prices
 - b. There is no recognition of inflation and thus tax rates will effectively increase with time making the system unsustainable
4. Transition provisions demonstrate to investors that they do not have to bear the full risk of retroactive tax increases. Failure to provide for the full transition without the two-for-one condition will harm the State's reputation with investors.
5. The change in the effective date to April 1 means this tax will be implemented before it is enacted by the Legislature. Retroactive application of taxation policy should be avoided.
6. Simplicity should be a key objective in setting fiscal policy and the current version of the Bill adds significant complexity to one of the most complex fiscal regimes in the world. This will be a further disincentive to investors.

At the highest level we do not believe this Bill as drafted achieves the mutual goal of increasing investment & stemming decline.

Key Messages

I would like to leave you with the key messages from this testimony.



- Alaska has lots of oil & gas but production is declining!
Decline is our common enemy!
- Significant additional investment is required to stem decline
- Maximizing production will maximize State revenues and benefits to Alaska
- With a 20% tax rate Alaska will have the highest tax rate & the highest cost structure in the US(25% is even worse!)
- The bill as drafted will not maximize benefits to Alaskans
- The UK and Alberta have successfully attracted significant investment and increased production by reducing taxes and are thus great role models

We believe that the changes made to SB 305, if enacted, would be a serious mistake for Alaska and we urge you not to adopt them but to return instead to a bill close in structure to the original Bill.

In order to maximize the value of Alaska's resources we believe you should be adopting tax rates lower than those proposed by the Governor. In so doing you would maximize investment, maximize production and maximize jobs for Alaskans. You would also take an important step towards creating a healthy oil business which will be the foundation for gas.

We recognize the burden on your shoulders in making these decisions. There are many people advising you to increase taxes, which will indeed increase state revenue, but for how long? One year? Two years?and at what cost to future production?

This is a matter of urgency. All Alaskans should be concerned. Short sighted increases in tax will jeopardize future oil investments, future oil production and the gas pipeline project itself.

We will continue to participate fully in the legislative process and will be available to assist this committee in whatever way we can.

On behalf of BP I would like to thank you for this opportunity to testify.

SB 305 (CS) Testimony

ConocoPhillips Alaska
April 5, 2006

Slide 1

ConocoPhillips

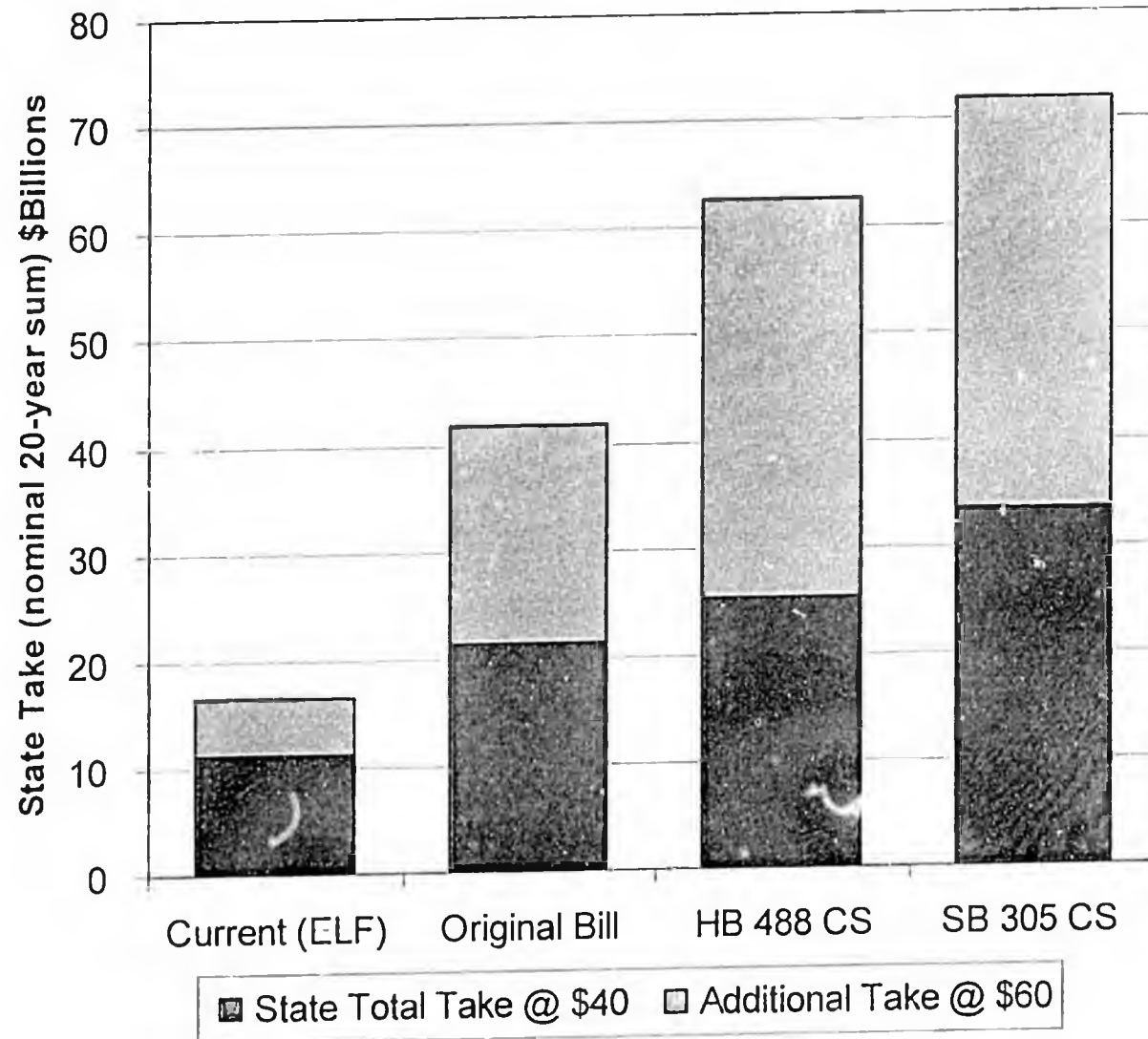
4/5/06

Jim Bowles
President
ConocoPhillips Alaska

Marianne Kah
Chief Economist
ConocoPhillips

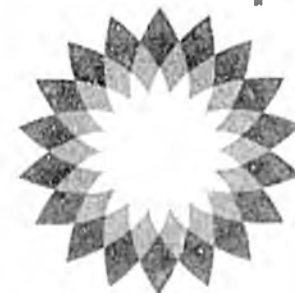
David Bramley
CRA International

Projected Production Tax Revenues



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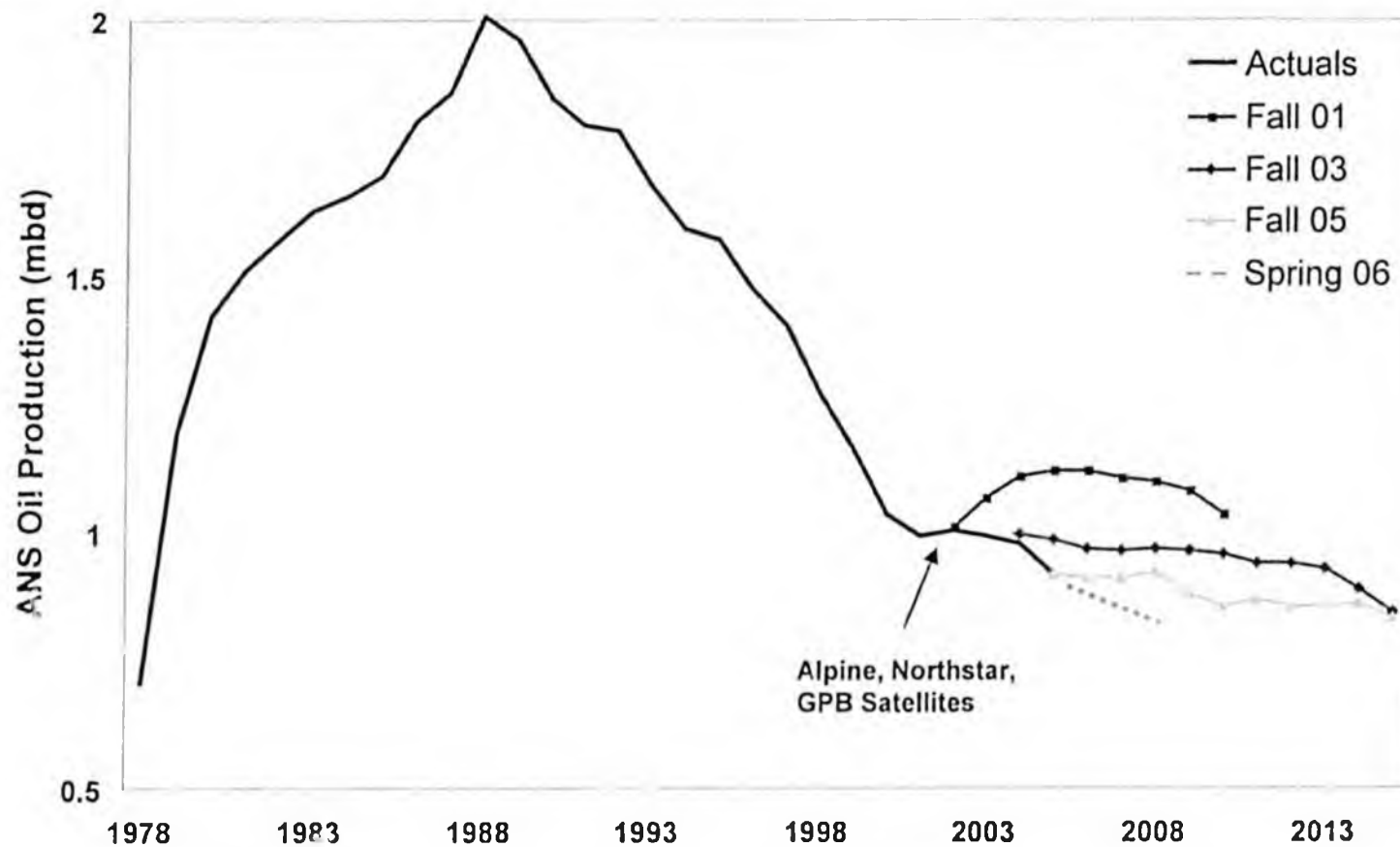
bp



Juneau

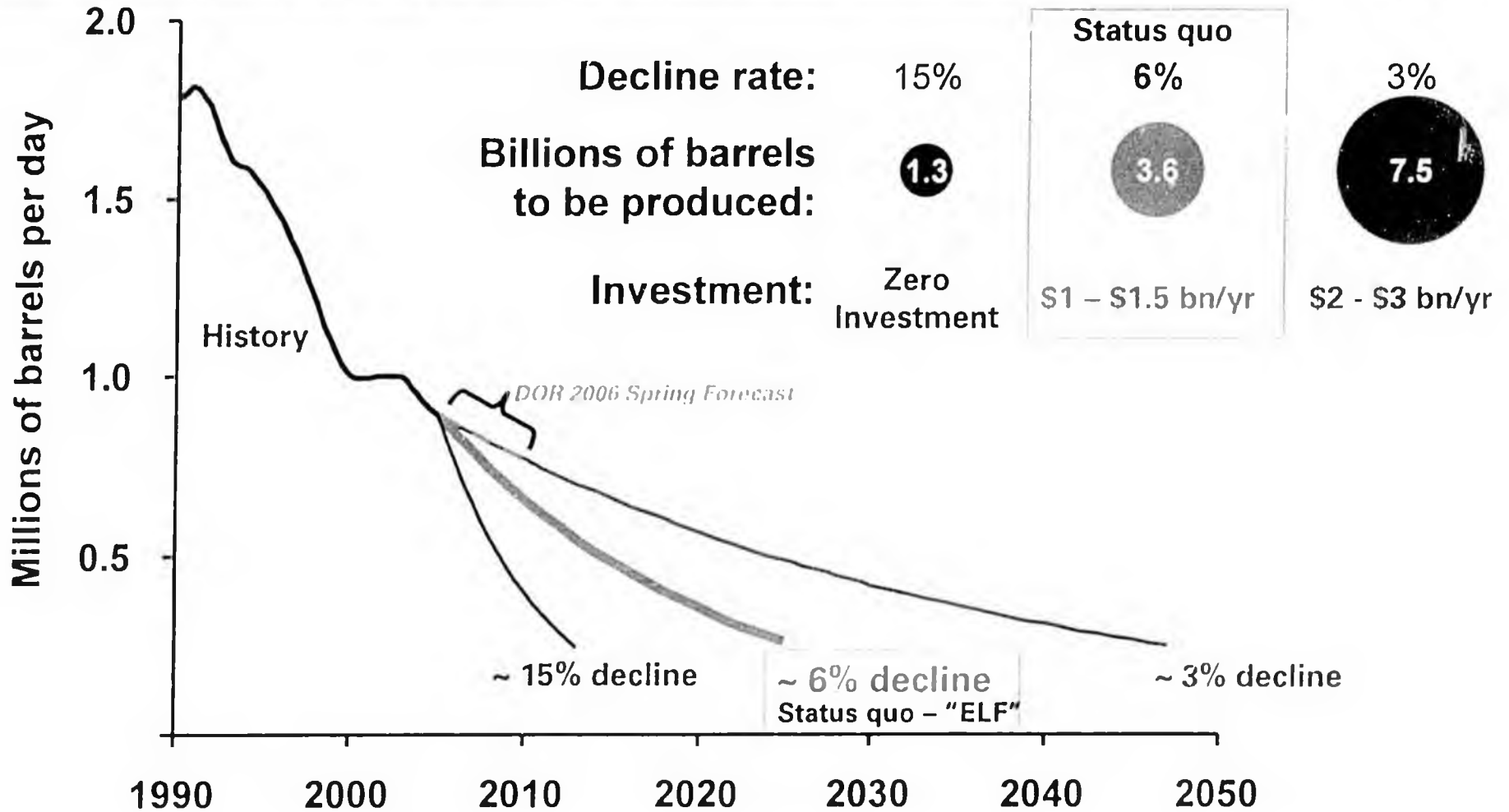
04 April 2006

DOR Production Forecasts



- Historical basin decline has been around 6%
- Flattening of production from 2002-2004 due to Alpine & Northstar
- Decline since 2004 has mirrored historical basin decline

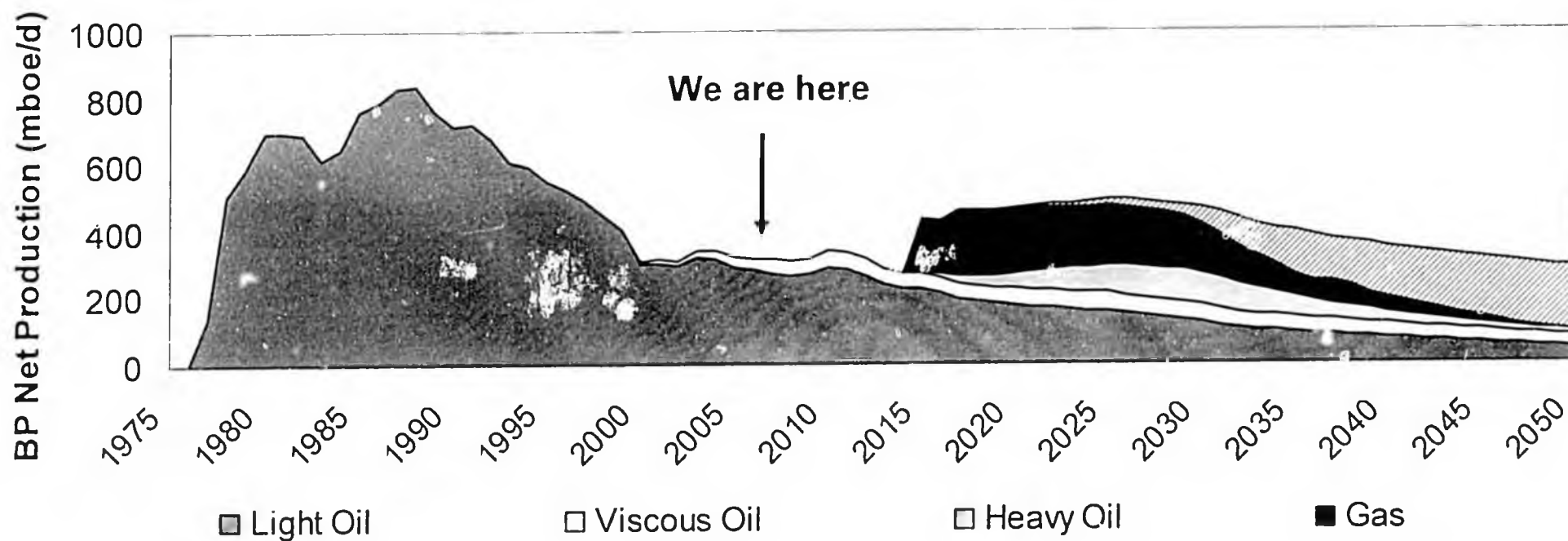
Investment Offsets Decline



***DOR Spring Forecast cannot be met without significant additional investment
The vast majority of that investment must be made in existing fields***



A 50 year vision



Production Drives Revenue



Decline Rate	15%	Status quo 6%	3%
Produced Barrels	1.3 bn	3.6 bn	7.5 bn
Operating Expenses	\$30 bn	\$50 bn	\$100 bn
Industry Investment	\$1 bn	\$20 bn	\$60 bn

State Revenue
(estimate)

*Assuming
20/20
\$40 ANS*



All other non-PPT
state revenue

\$10 bn



All other non-PPT
state revenue

\$30 bn



All other non-PPT
state revenue

\$60 bn

Less investment

More investment

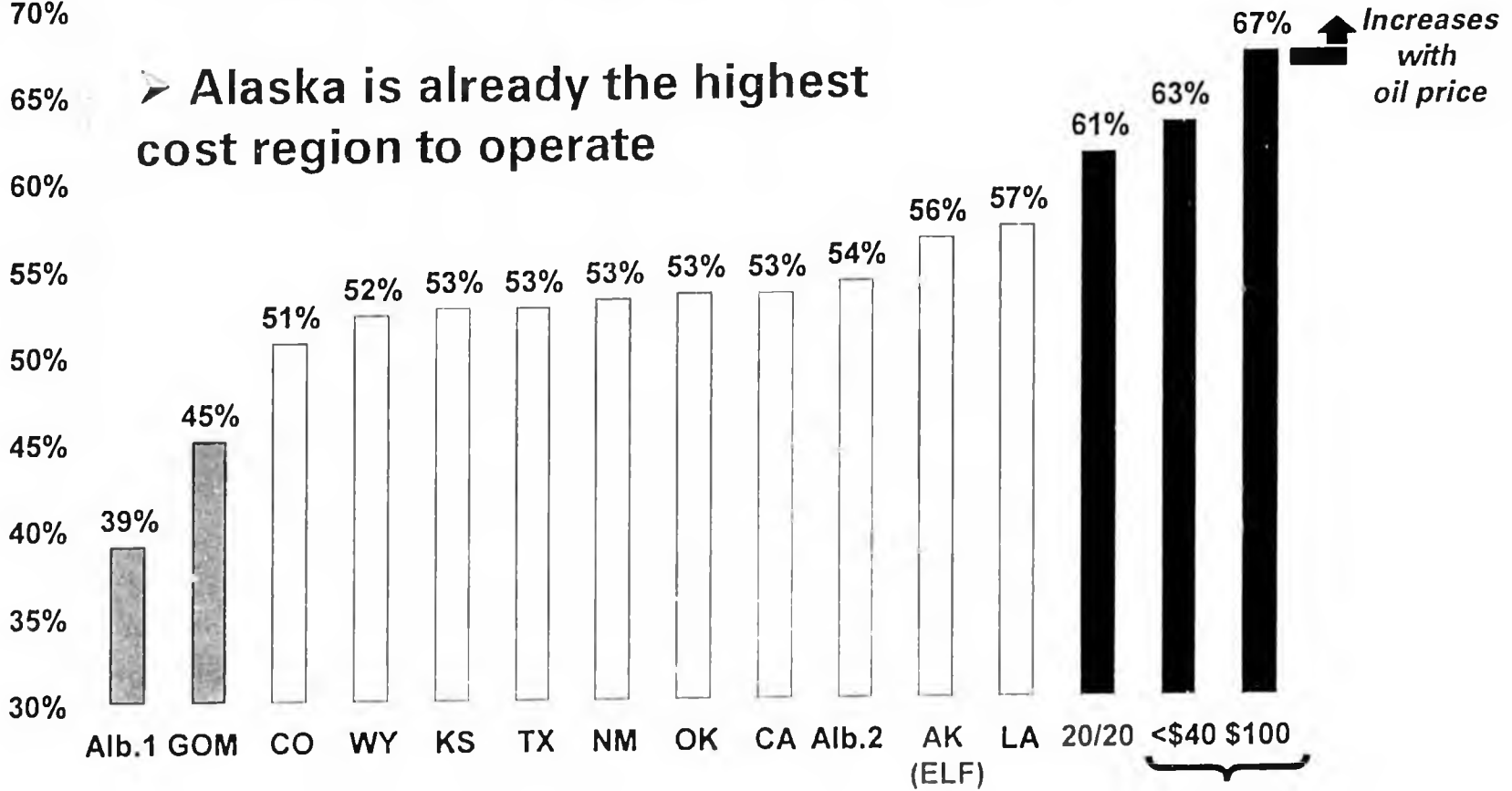
Maximizing State Revenue means maximizing Production

US Marginal Tax Rates



North America: Tax Rate Comparison

Marginal Tax Rate 70%



➤ Alaska is already the highest cost region to operate

*Alb: ALBERTA HEAVY OIL – pre and post-payout

BP data

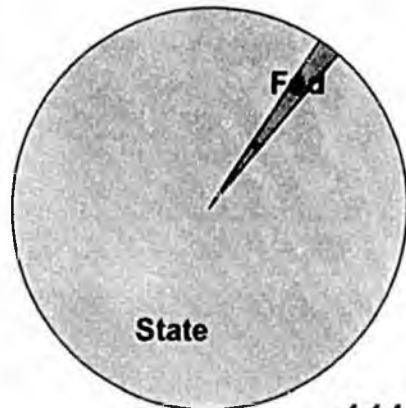
Alaska will have the highest marginal tax rate

PPT Impacts Government Take (%)



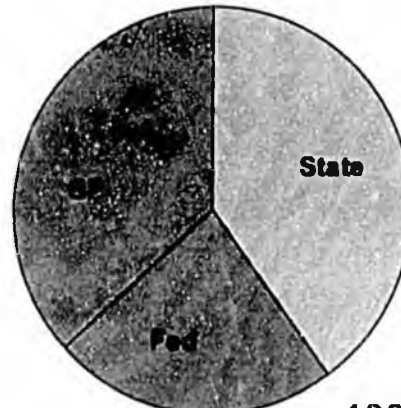
Status Quo

SQ - \$20/bbl



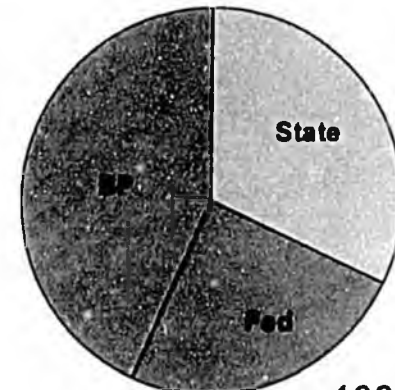
144%

SQ - \$40/bbl



100%

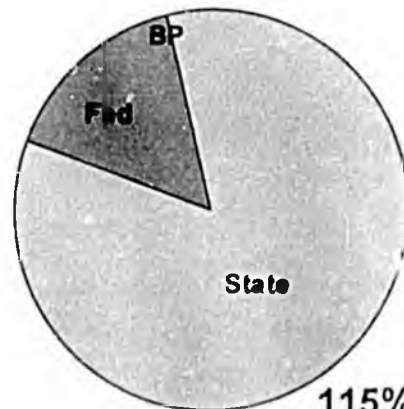
SQ - \$60/bbl



100%

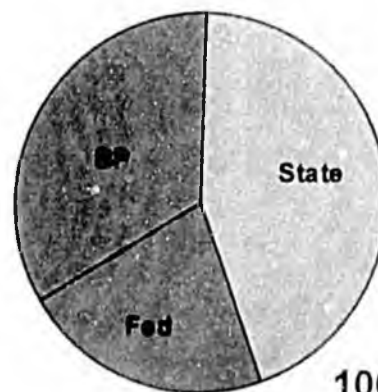
PPT
(20-20)

PPT - \$20/bbl



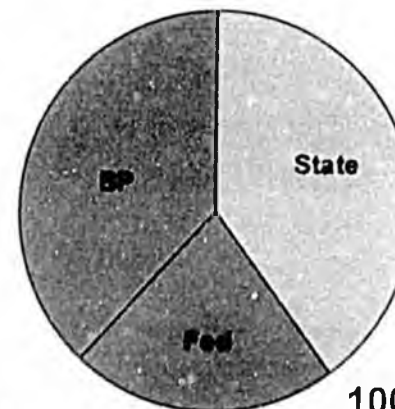
115%

PPT - \$40/bbl



100%

PPT - \$60/bbl



100%

CSSB 305: Key Issues



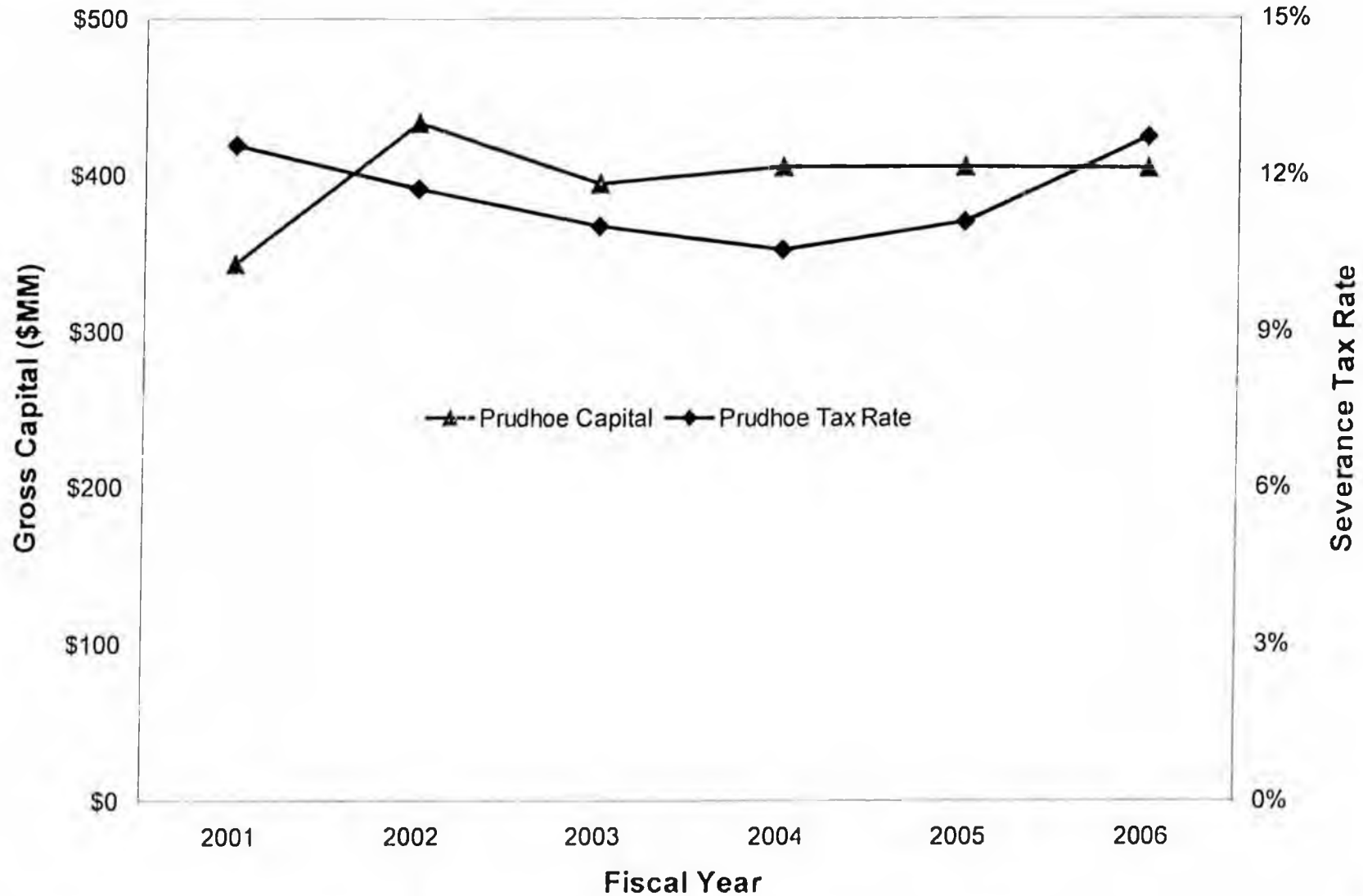
- The increase of the base tax rate to 25% will be a serious barrier to investment
- The proposed progressivity in the tax rate combined with the significant base rate increase in moving from Elf to PPT (25/20) is inappropriate given Alaska's circumstances
- Several of the newly introduced terms are unbalanced and will cause problems
- Failure to provide for the full transition will harm the State's reputation with investors
- The current version of the Bill adds significant complexity to one of the most complex fiscal regimes in the world
- We do not believe this Bill as drafted achieves the mutual goal of increasing investment & stemming decline

Key Messages



- Alaska has lots of oil & gas but production is declining!
Decline is our common enemy!
- Significant additional investment is required to stem decline
- Maximizing production will maximize State revenues and benefits to Alaska
- With a 20% tax rate Alaska will have the highest tax rate & the highest cost structure in the US(25% is even worse!)
- The bill as drafted will not maximize benefits to Alaskans
- The UK and Alberta have successfully attracted significant investment and increased production by reducing taxes and are thus great role models

Prudhoe Gross Capital Spend vs. Severance Tax Rate

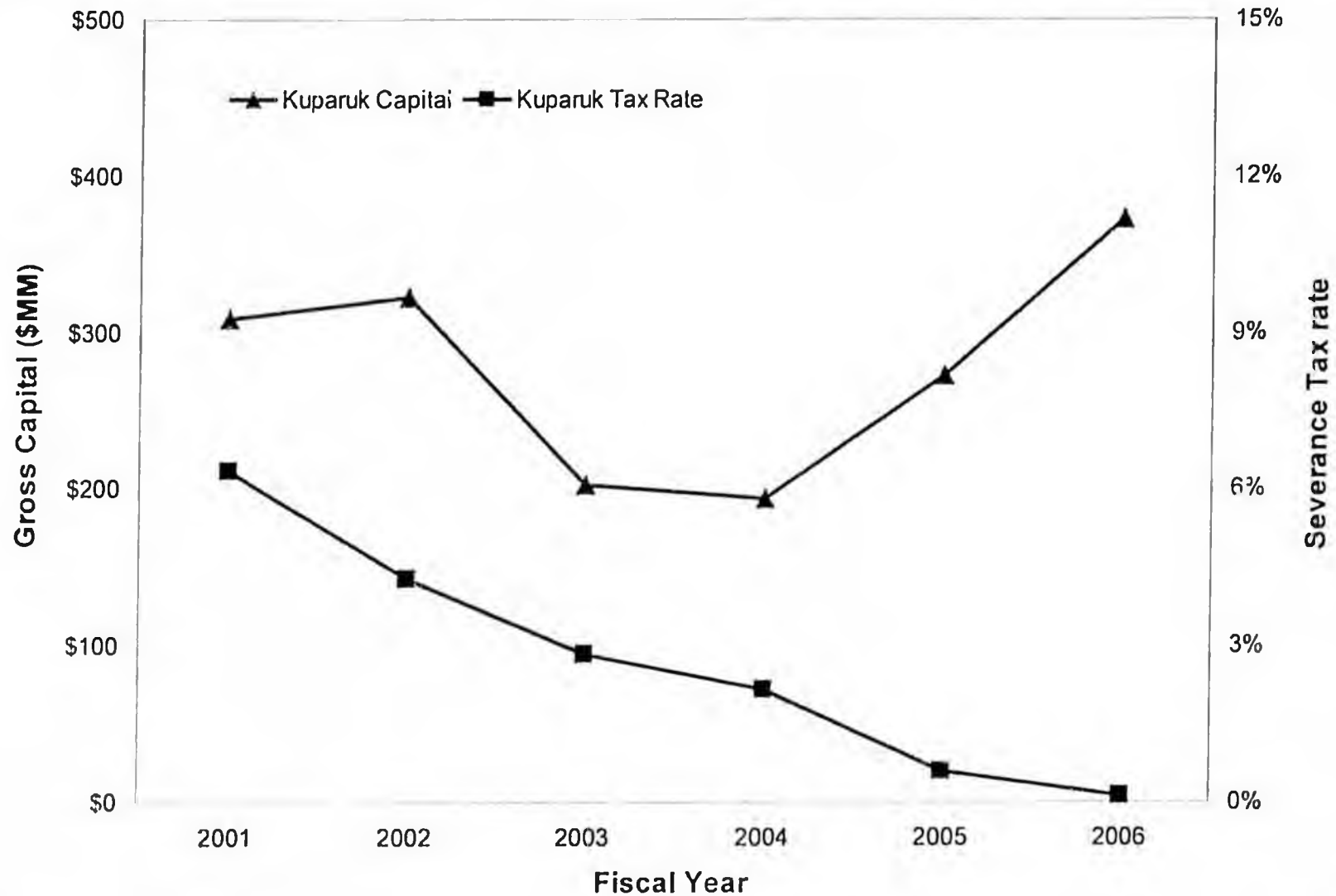


Note: Capital converted from calendar to fiscal year assuming capital spend equal in each half of year

(Note: the graph lines on this chart were inadvertently reversed. See S.T. 10:24 AM)

4/5/06
9:13:24 AM
2 10:24 AM

Kuparuk Gross Capital Spend vs. Severance Tax Rate



Note: Capital converted from calendar to fiscal year assuming capital spend equal in each half of year

9:15:02AM
4/5/06

ConocoPhillips Alaska



Alaska's No. 1 Oil Producer

Alaska's No. 1 Gas Producer

Alaska's No. 1 Explorer

Largest Owner of State & Federal Leases

Largest Industry Community Supporter

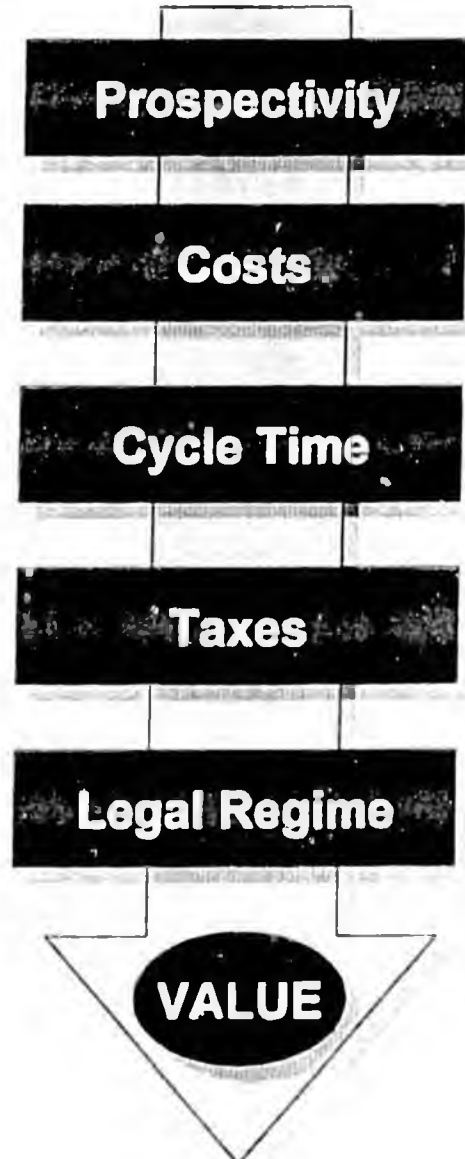
Largest Royalty and Tax Payer

Key Employer

David Bramley
CRA International

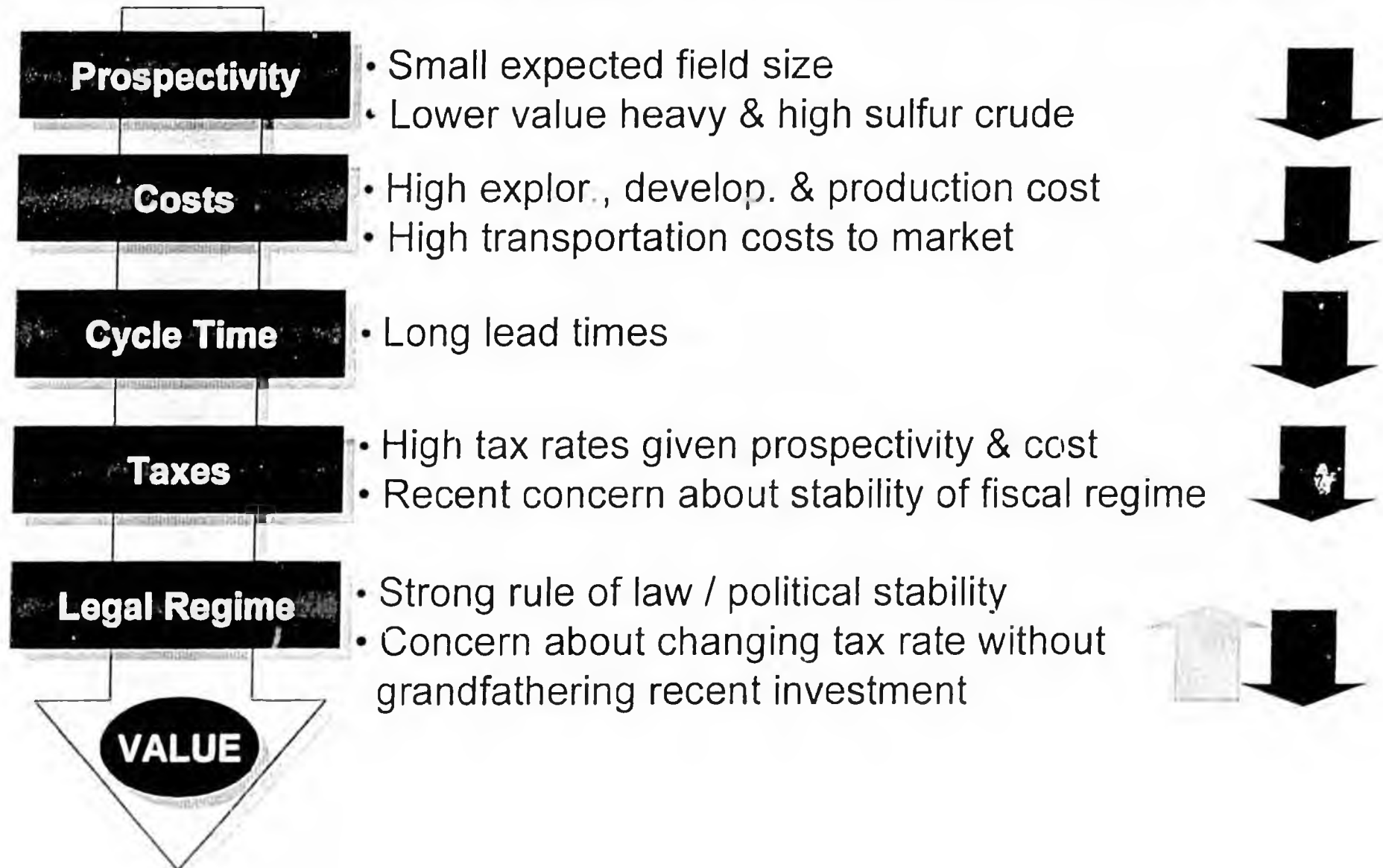
Marianne Kah
ConocoPhillips Chief Economist

Investment Criteria

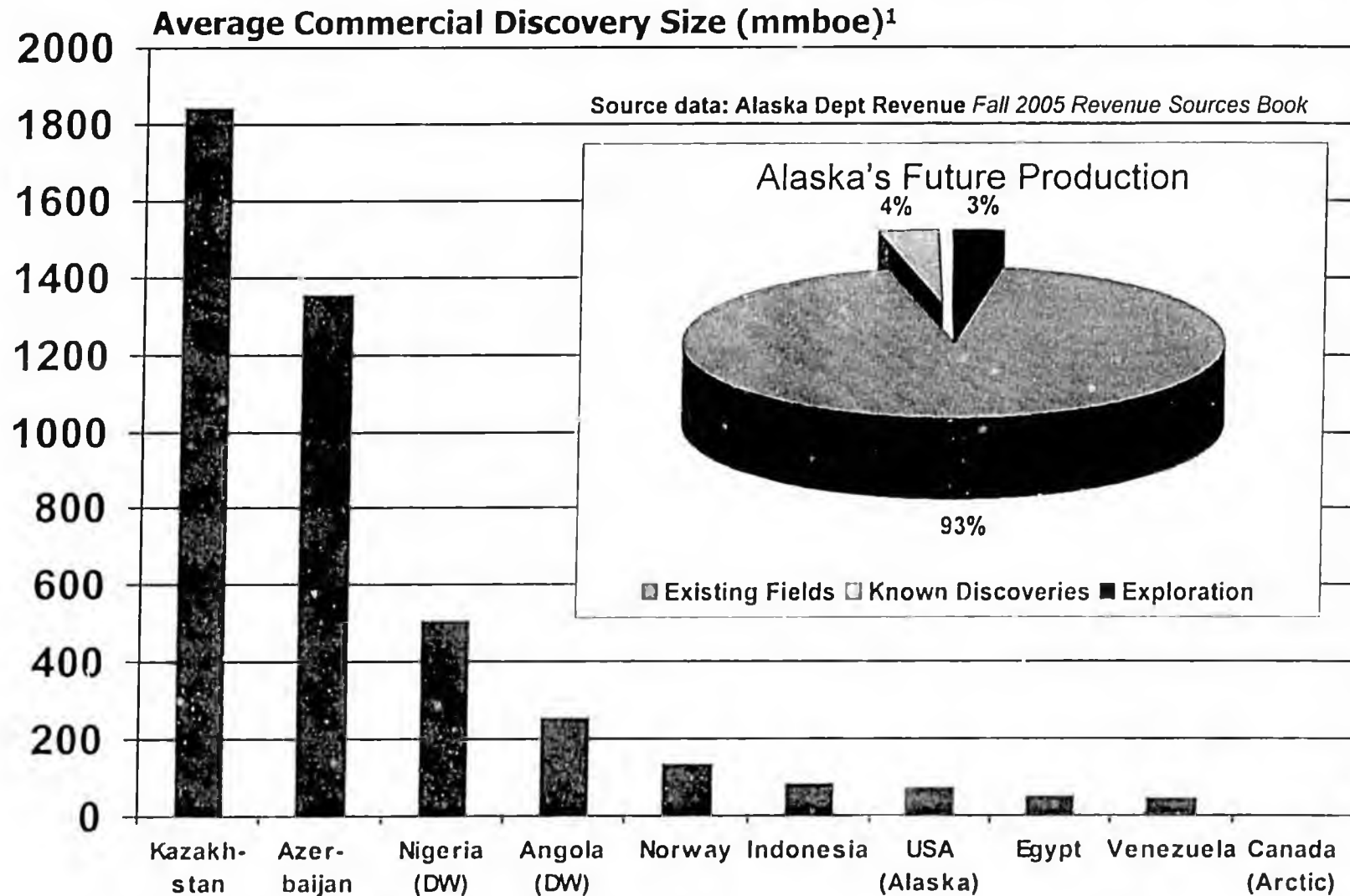


- Expected field size / maturity
- Crude quality
- Exploration, development & production cost
- Transportation costs to market
- Time to production
- Tax rates given prospectivity & cost
- Stability of fiscal regime
- Strong rule of law / political stability

Investment Criteria - Alaska Rating



Global Average Commercial Discovery Size

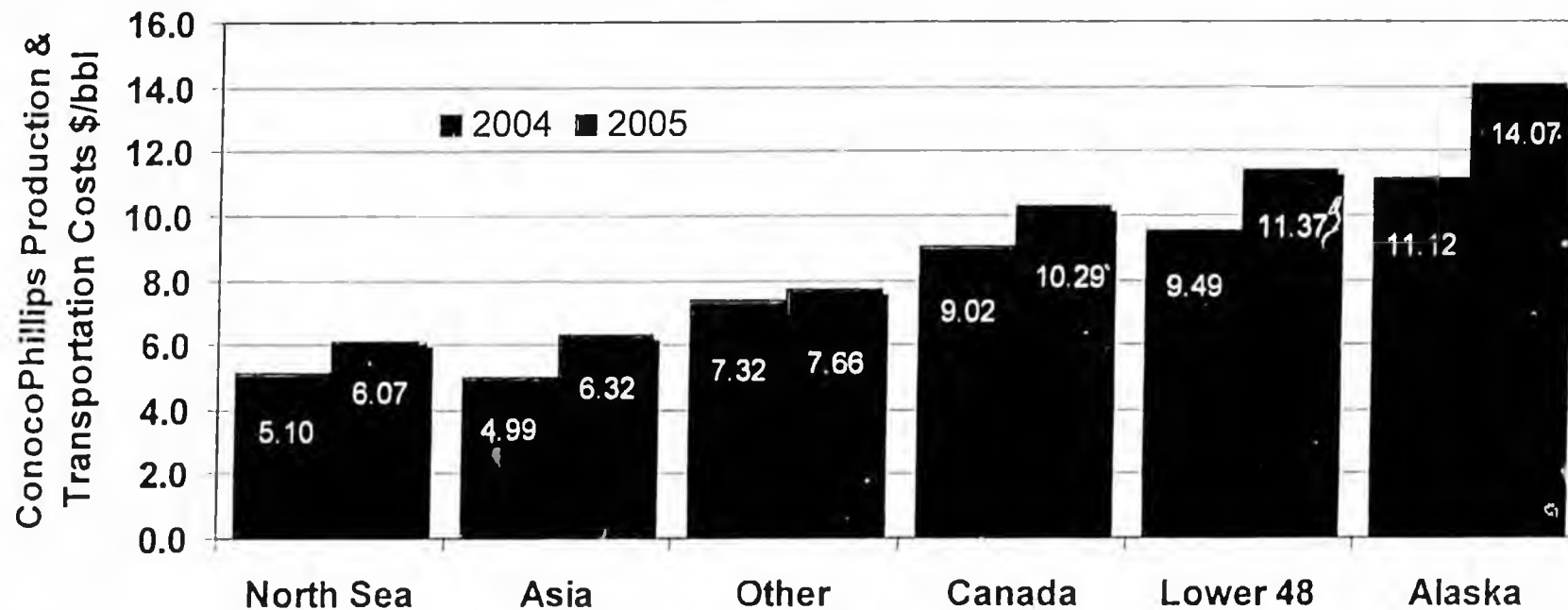


¹ Average commercial discovery size from 1994 to 2003.

² The average discovery size is calculated as: total commercial reserves discovered (1994-2003) / total commercial discoveries (1994-2003)

Increasing Production Costs

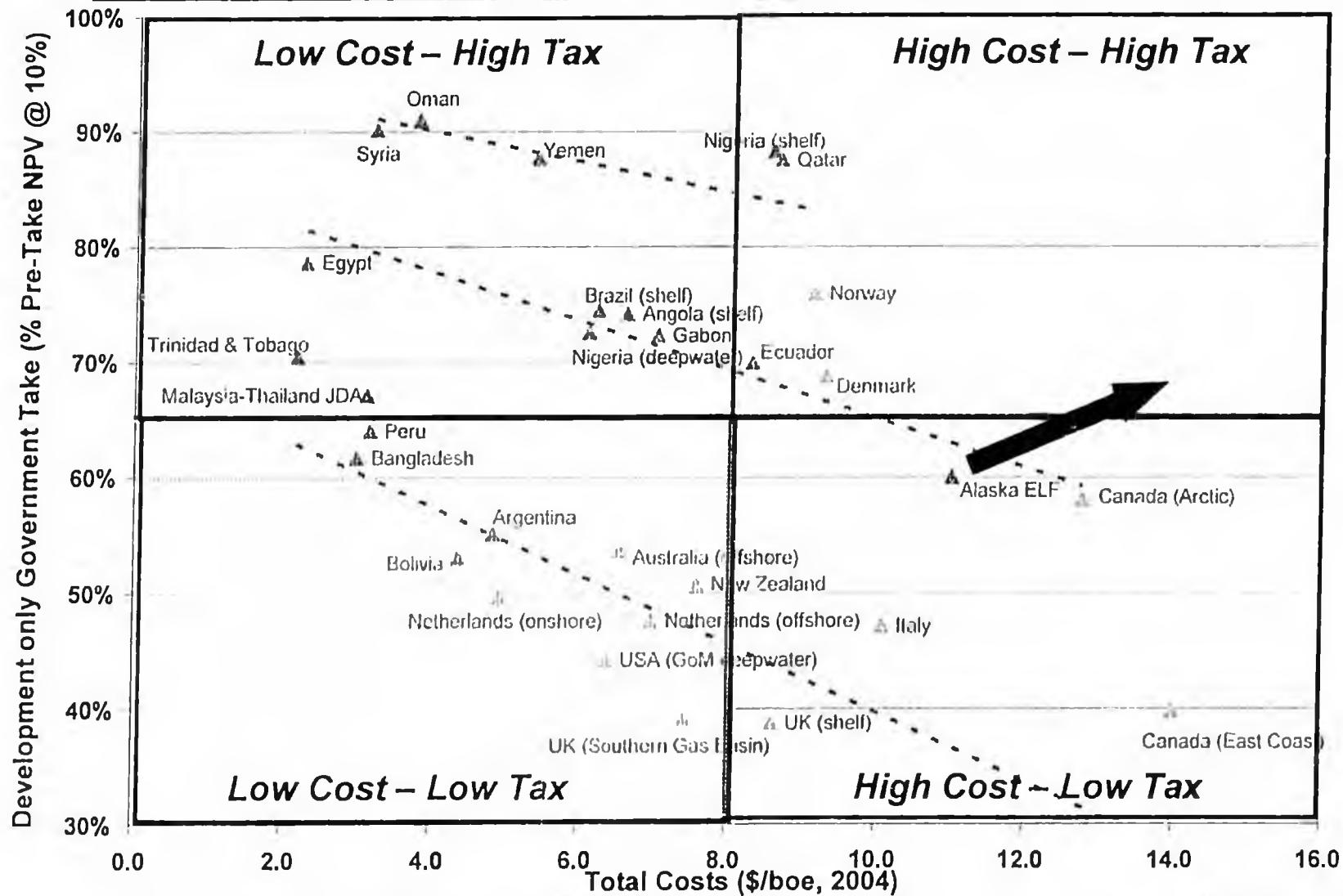
Source: ConocoPhillips 2004 Annual report and 2005 10-K



- Alaska has the highest cost structure in ConocoPhillips Portfolio
- Alaska costs are increasing at greater rate than other areas
 - Aging infrastructure concerns and increasing well work
 - Market Forces
 - Regulations
 - Smaller, more complex field developments

Alaska – High Cost, High Tax?

Countries with no equity participation or not carried

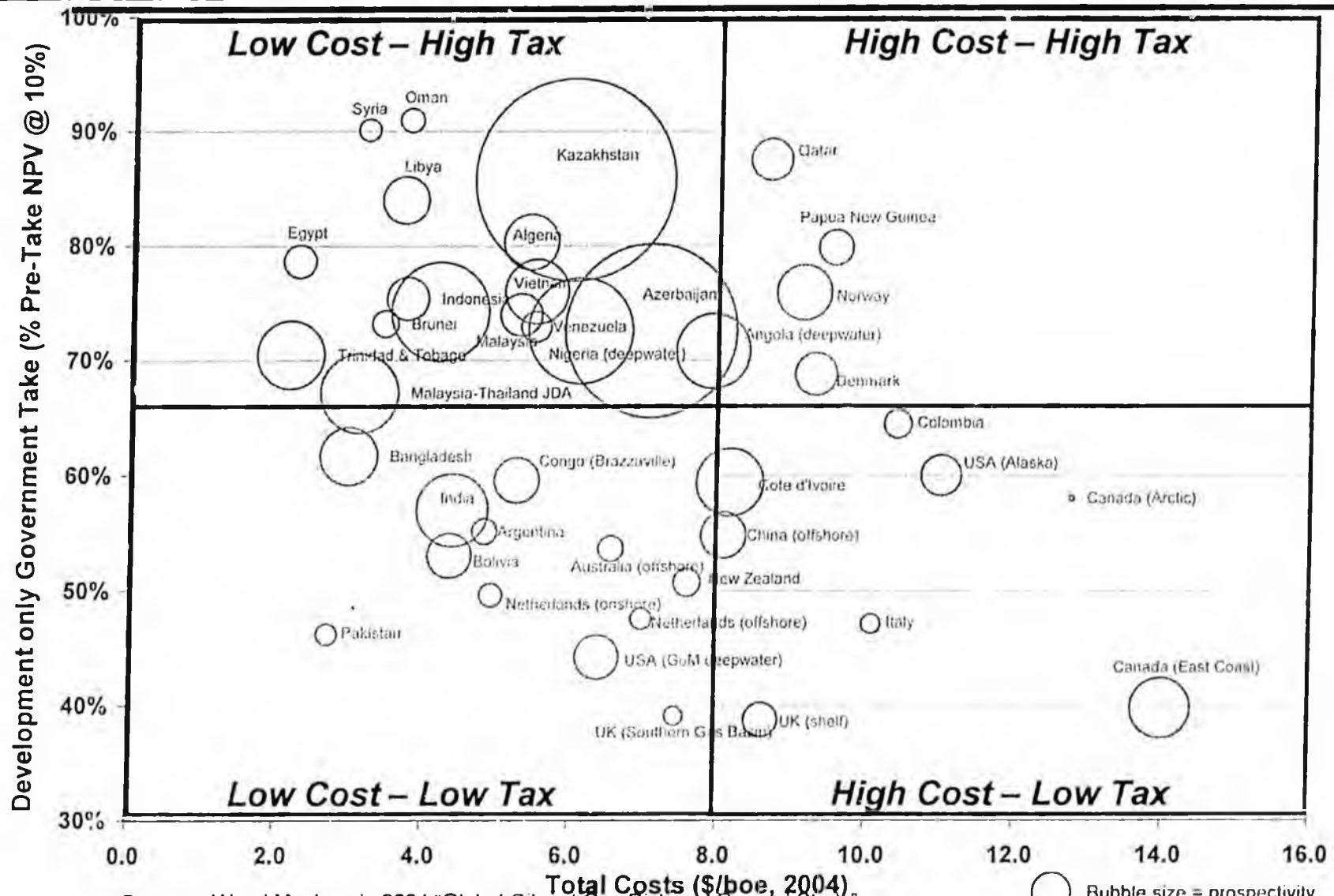


Source: Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study".

Total cost includes capital and operating elements averaged over 10 year period (1994-2003), Economics were run at \$35/bbl long term real Brent price

▲ OECD Countries

Alaska – High Cost, High Tax & Low Prospectivity



Source: Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study".

Total cost includes capital and operating elements averaged over 10 year period (1994-2003), Economics were run at \$35/bbl long term real Brent price

Prospectivity = Average commercial discovery size (1994-2003)

Higher Taxes Will Reduce Investment

- Reduces after-tax cash flow available for investment
- Adversely changes risk / reward balance
- Capital goes elsewhere to:
 - Other countries
 - Other energy sources
 - Other industries

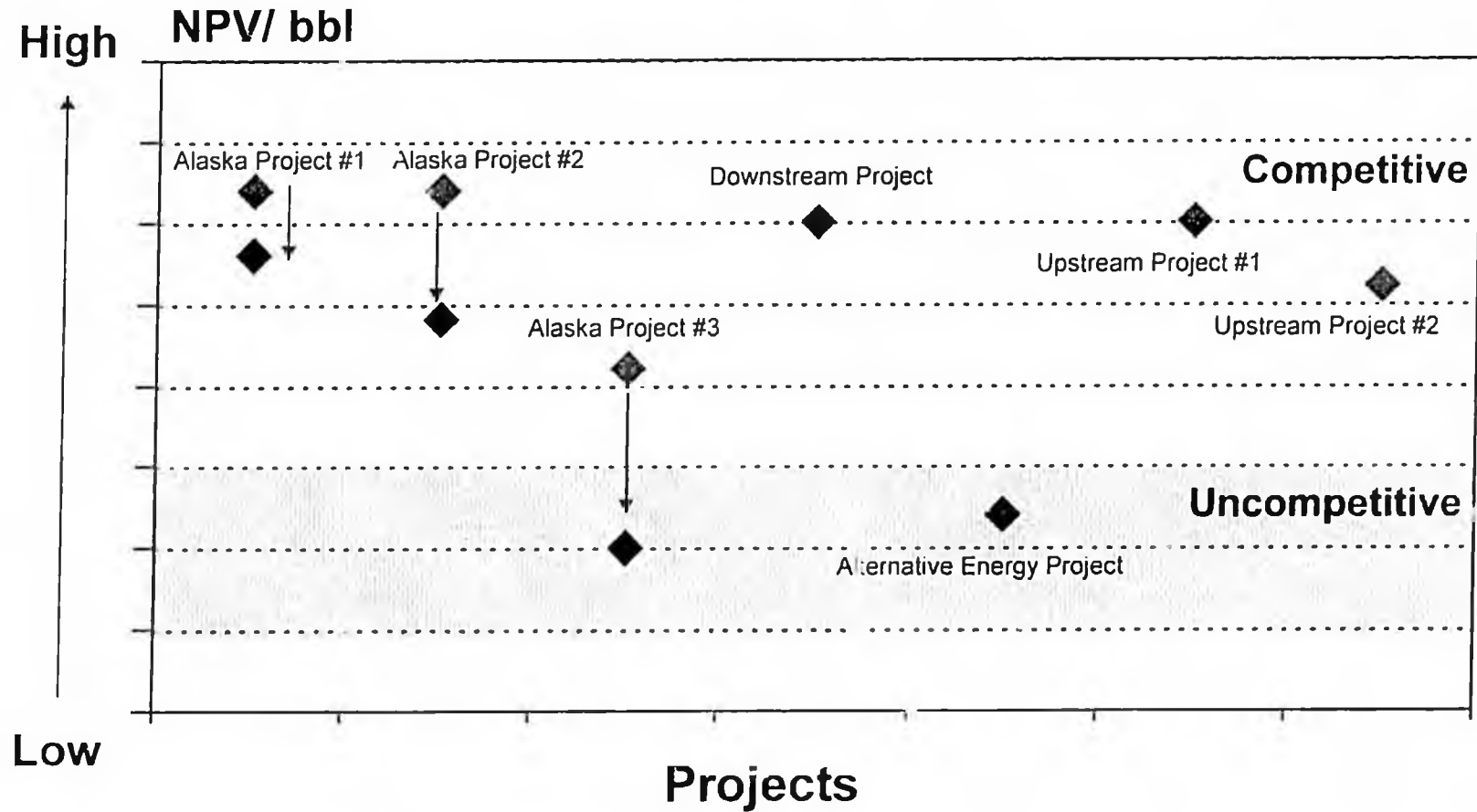
“If You Tax Something, You Will Get Less of It”

ConocoPhillips' Major Upstream Projects



¹ Negotiations are under way.

Portfolio Comparison



- ◆ Before tax increase
- ◆ After tax increase

What's Wrong With Windfall Profits Taxes

- “What a windfall profits tax does is introduce a lot of distortion. It reduces investment, it increases a sense of political risk and it doesn’t achieve the goal that is intended ... it will really lead to decreased supply”.

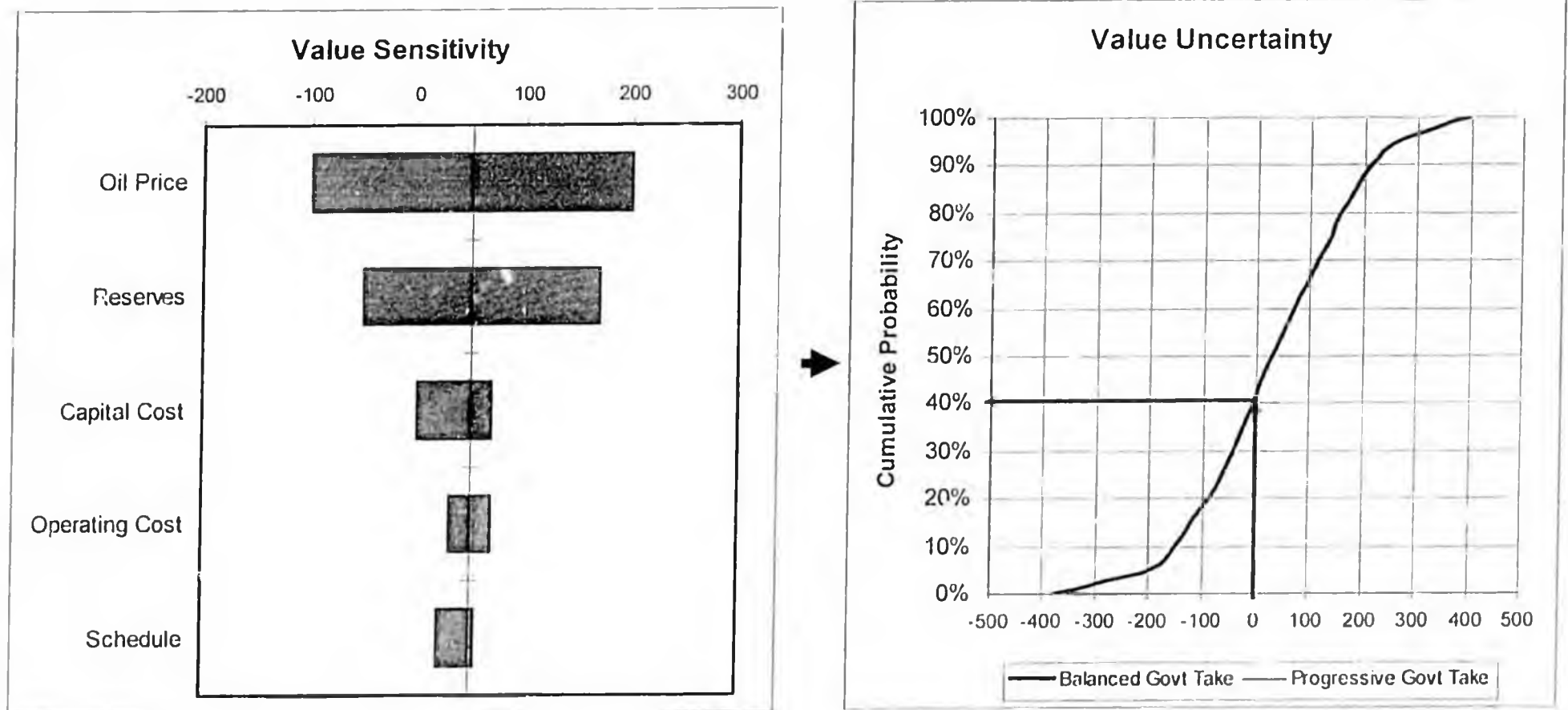
Daniel Yergin interview, Capitalism Magazine, November 11, 2005

- “If it is again enacted, a windfall profits tax can be predicted to result in a diminution of domestic energy production... Sadly, the recent clamoring by some for new energy taxes indicates that the lessons of the 1970s were not learned.” *Open Letter to America's Elected Officials, 250 economists, October 25, 2005*

Non-partisan Congressional Research Service assessment of 1980 Windfall Profits tax on domestic crude oil:

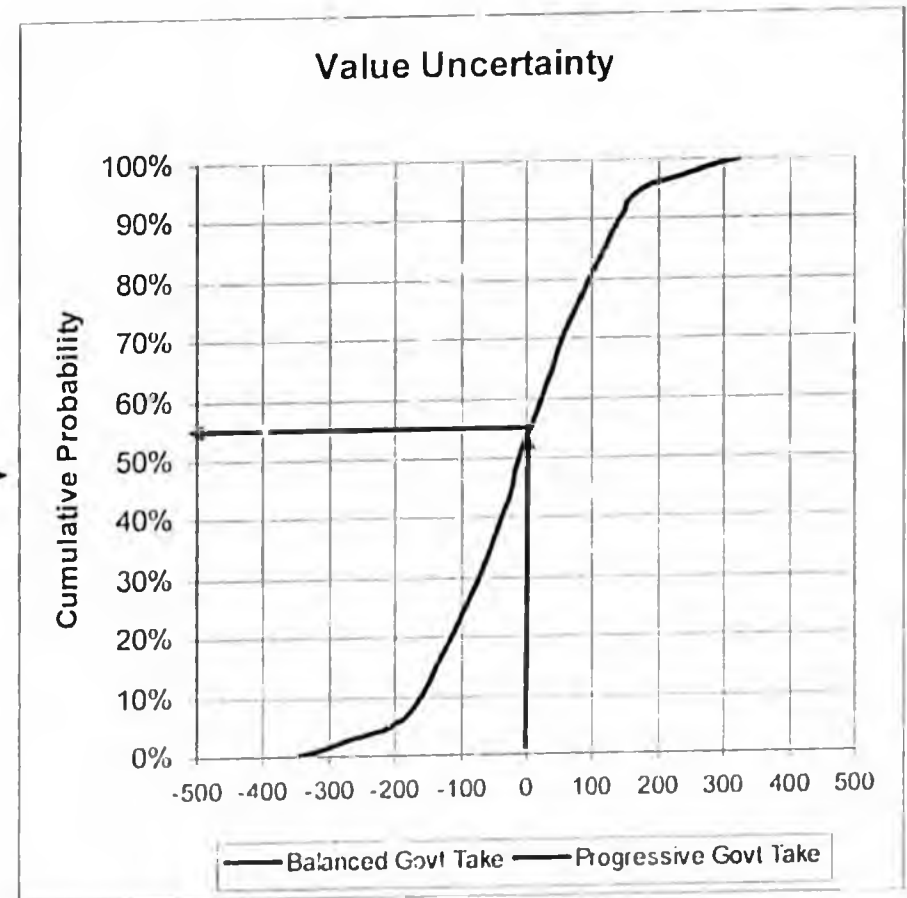
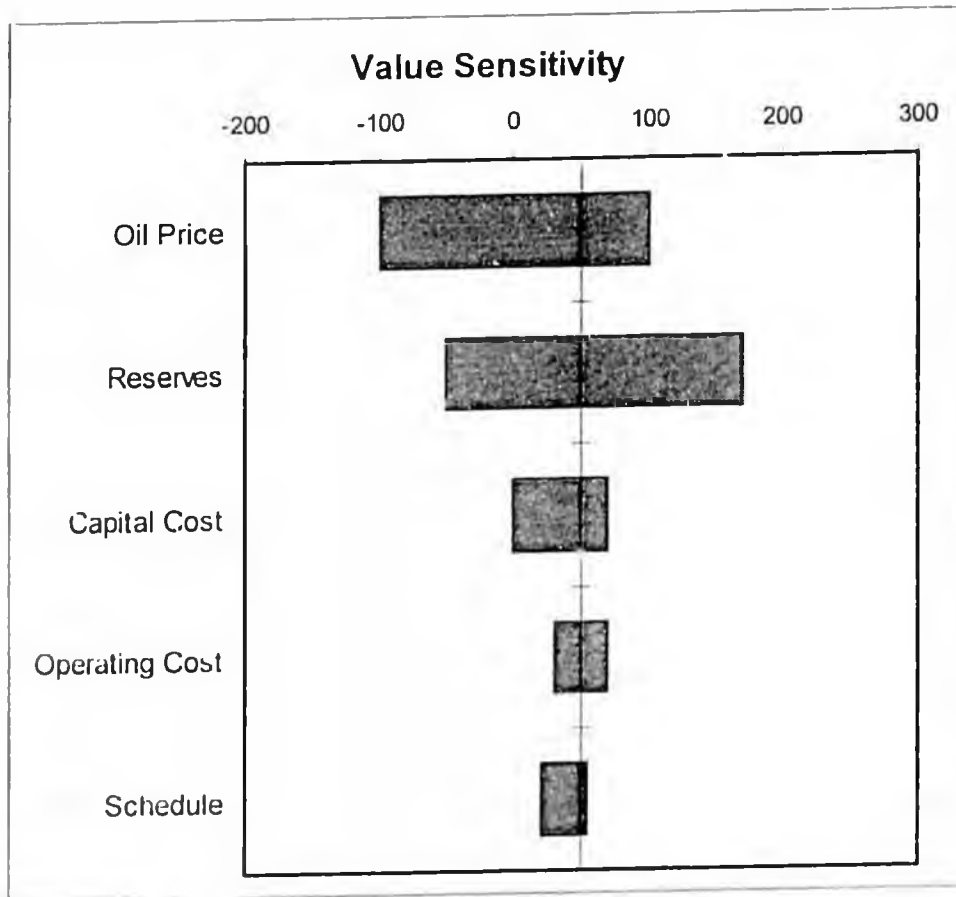
- Removed \$79 billion in gross revenues from industry that could otherwise have been invested
- Reduced domestic oil production by up to 1.6 billion barrels between 1980 - 1986
- Generated only 20% of expected gross revenues

Value Uncertainty in Balanced Government Take



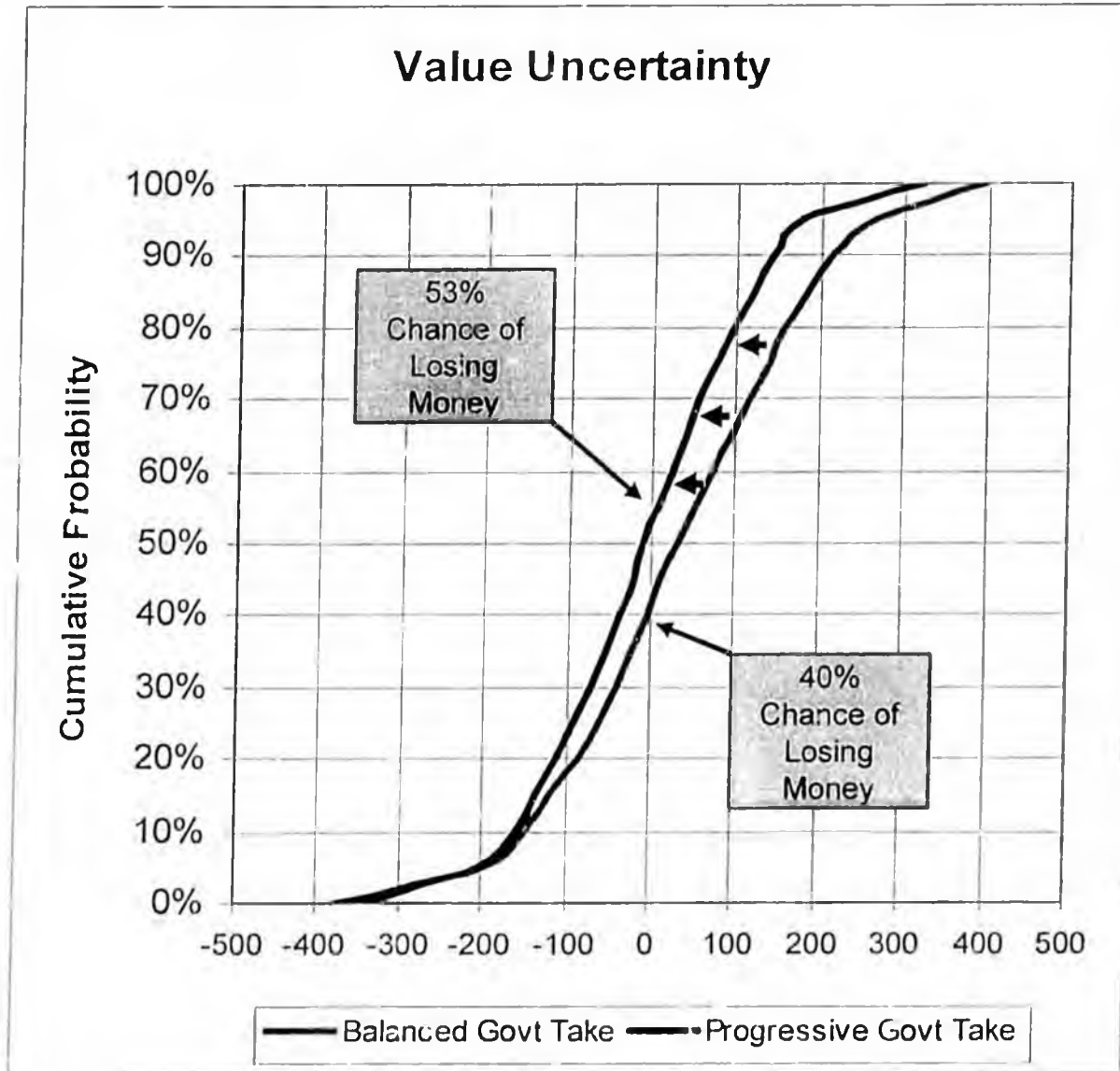
60% of the time, the project adds value (40% of the time it loses value)

Value Uncertainty in Progressive Government Take



47% of the time, the project adds value (53% of the time it loses value)

Balanced and Progressive Value Uncertainty Comparison



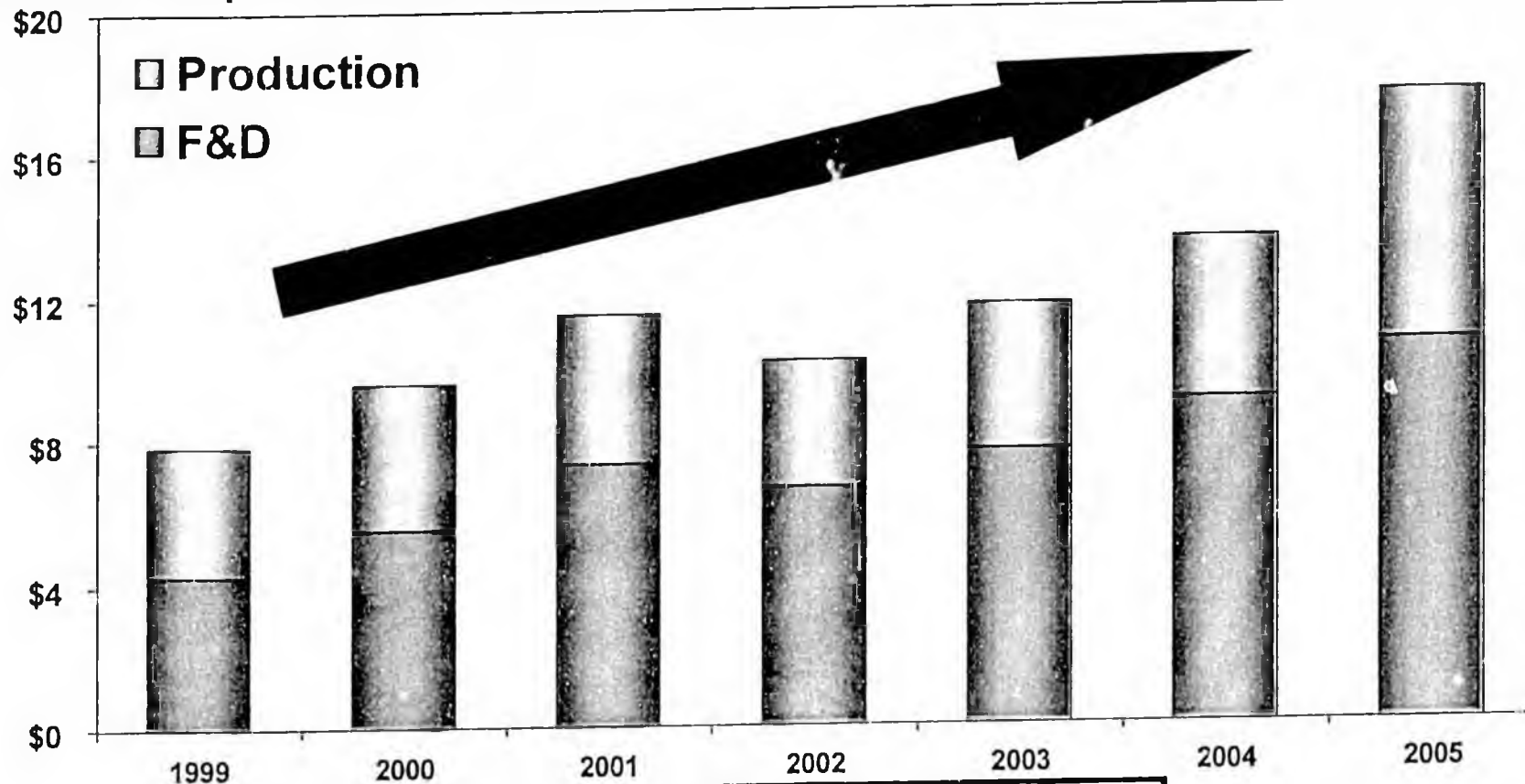
In this example:

- Under a balanced government take the project would be developed
- Under the progressive government take the project would not go forward.

Finding, Development & Production Costs

More than Doubled Since 1999

2006 Dollars per Barrel of Oil Equivalent



Excludes all government take (\$20-25/bbl),
adjustment for the time value of money &
a cost of capital return

Source: J.S. Herold

Key Messages from Corporate Perspective

- Current tax rate already uncompetitive given cost & prospectivity
- Proposed tax increases will reduce investment & production in Alaska
- U.S. federal windfall profits taxes lowered production and failed to produce expected revenues

Jim Bowles

Summary

- Higher taxes will reduce investments
 - 20% strikes the right balance
 - Increased Tax rate and windfall profits surcharge decreases project value
- Recognition of transition investments is fair
- Reasonable start date

CRA International
Review of Alaskan Fiscal Proposals

Presentation to Alaska Senate Finance Committee



INTERNATIONAL

David Bramley

April 5, 2006

9:23:02 AM
4/5/06

Overview of CRA Approach

Will the proposed changes to Alaska's fiscal system support new investment?

**Comparable group
of
mature OECD
producers**

Economic potential

- Maturity / Prospectivity
- Cost base

**Fiscal Terms:
Total Government
Take**

Investor Capital Allocation Decisions

Comparing Alaska's fiscal proposals to other mature OECD producing areas is the basis for a realistic appraisal of their impact on investment

OECD¹ Oil & Gas Peer Group

- Alaska
- Australia NW Shelf
- Canada Oil Sands
- Norway
- UK North Sea
- US GoM Deep Water
- US GoM Shallow Water

Common Investment Characteristics

Similar strategic roles in overall investment portfolios

- Large, established oil and gas producers
- Similar political and business risks

High level of comparability

- Remaining potential and costs are comparable from public data
- Similar fiscal structures

¹ Organization for Economic Cooperation and Development

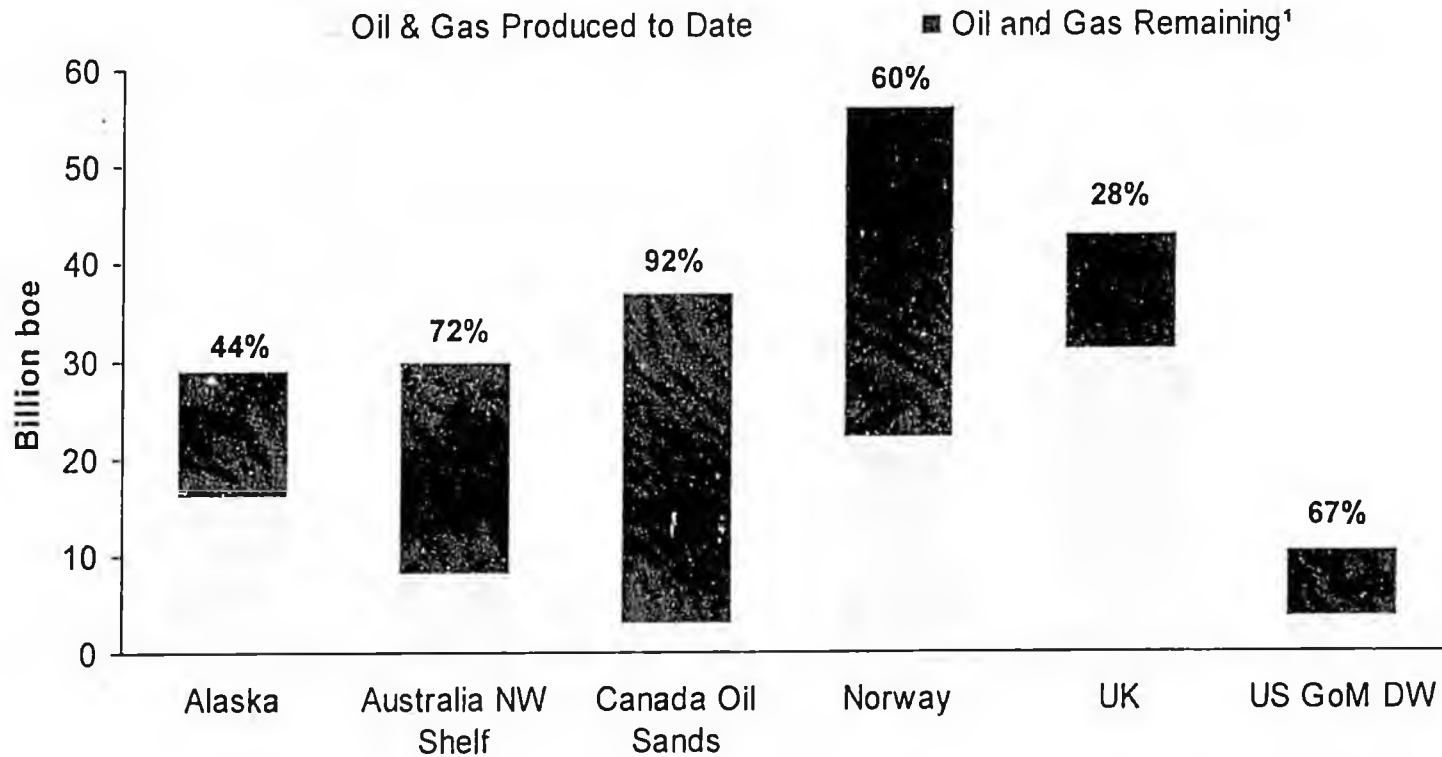
Alaska's production declined by 6% between 2000 and 2004: in the middle of the group

Total Hydrocarbon Production Change 2000-2004		
Region	2004 Production (mboe/day)	Growth/decline since 2000
US GoM SW	738	-27%
Australia NWS	403	-27%
UK	2,144	-19%
Alaska	946	-6%
Norway	3,180	8% ¹
US GoM DW	1,037	26%
Canada Oil Sands	997	64%

¹ Norway's production dropped by 10% between 2004 and 2005, the loss almost entirely through decline in oil production
 Source: CRA Analysis of public sources of production history in each area

Alaska has 44% of its known conventional oil and gas reserves remaining

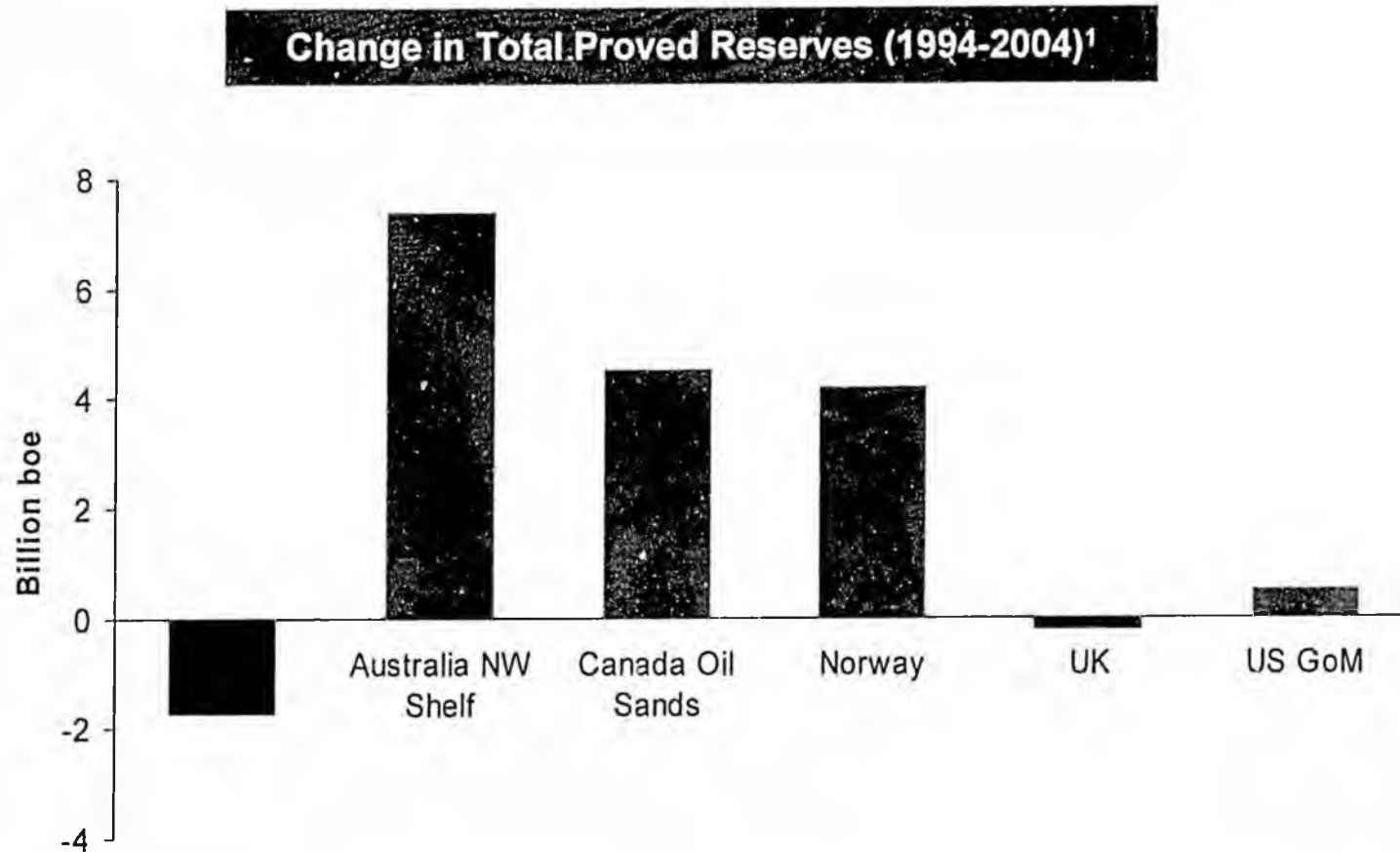
Total Hydrocarbons Produced/Remaining



¹ Future estimates based on available data on '2P' or P50 basis: i.e. a central estimate of remaining potential
Numbers in red are percentage of total remaining
Sources: MMS, DOIR, Canadian Association of Petroleum Producers, NPD, DTI, DOE



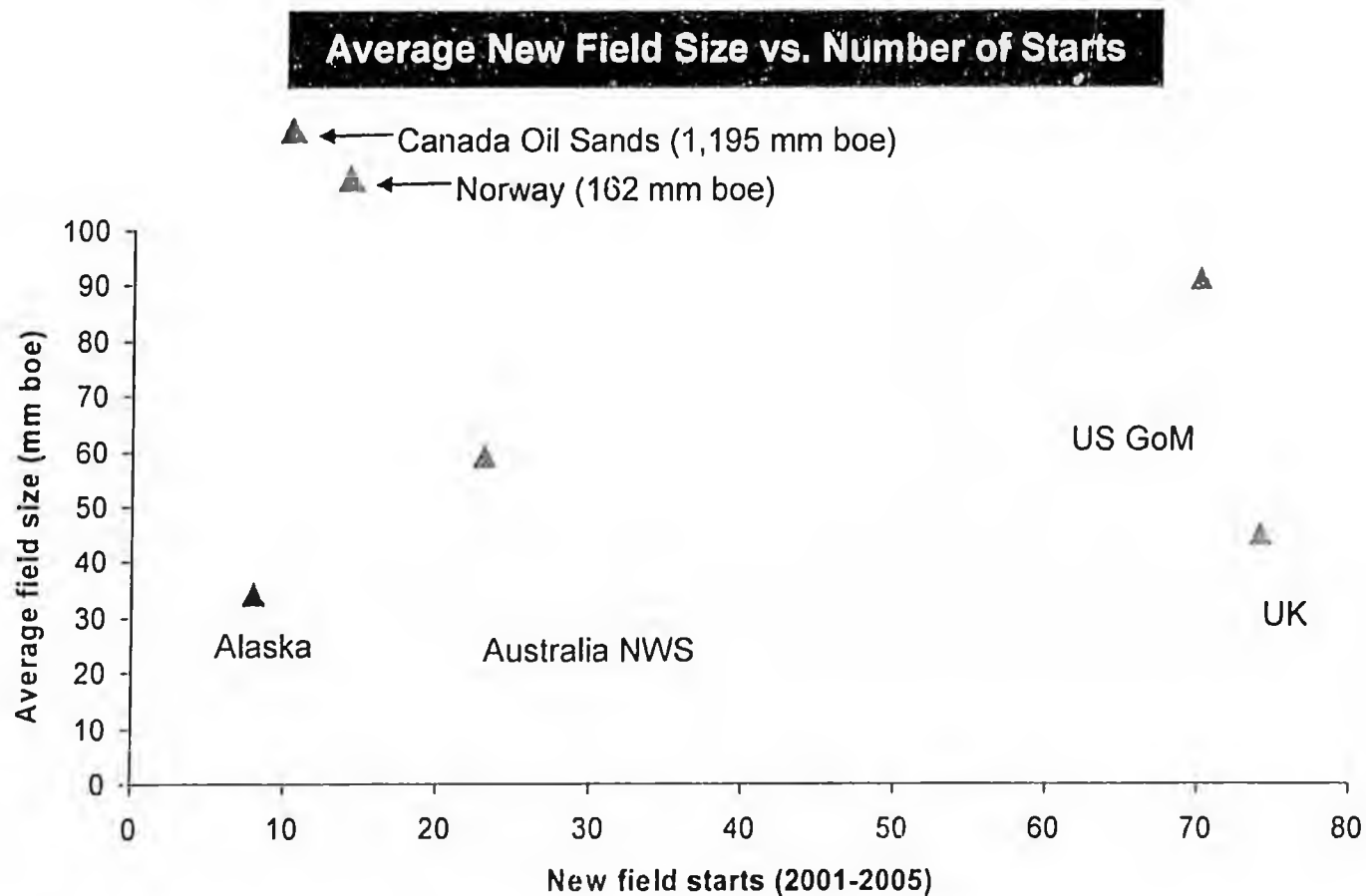
Alaska and the UK are the only regions within the OECD group to show a decline in proven oil and gas reserves over the last decade



¹ – Figures based on proved (P1) reserves
Sources: BP Statistical Review & EIA



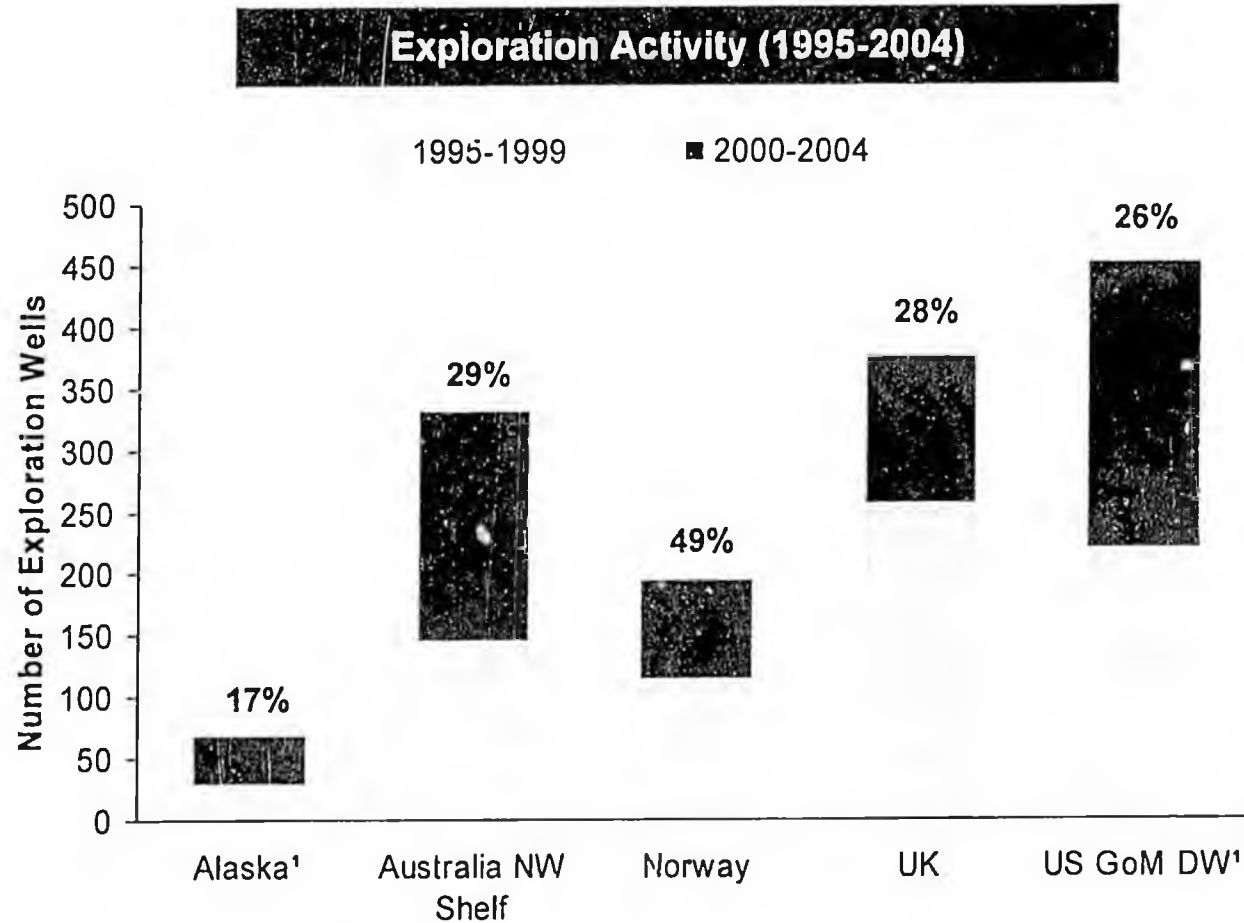
Alaska has had only eight new fields start production since 2001 and the average field size was the smallest of the group



Note the logarithmic scale on the vertical axis

Sources: Alaskan DNR, WA Government, NPD, UK DTI and Offshore Magazine

Alaska has the lowest exploration (wildcat) activity and success rate in the OECD comparison group



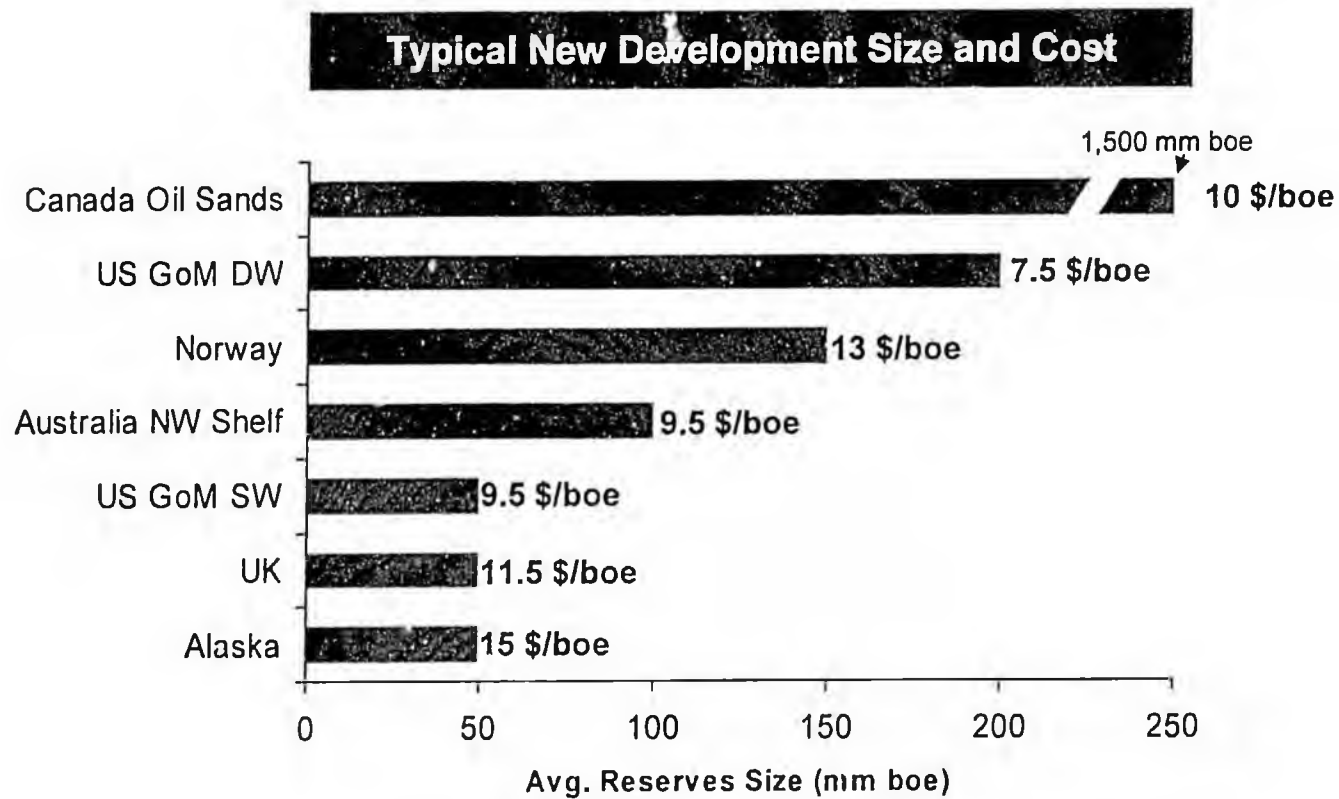
Numbers in red show exploration success per region in the period 2000-1H2004

¹ Alaskan and US GoM drilling numbers discounted by 50% from DNR / MMS figures for Exploration and Appraisal drilling

Sources: Alaskan DNR, Oil & Gas Resources of Australia, NPD and UK DTI, MMS



Likely new developments in Alaska are relatively small and high cost



Figures in red show total technical costs: CRA estimates of capex and opex for a typical field.




NB Alaskan total costs include an allowance for the incremental effects of TAPS transportation and Jones Act shipping requirement costs.

Source: CRA Analysis of public sources of field development activity in each area.

Alaska emerges on a variety of measures as a relatively mature and high cost petroleum area

	Alaska	Australia NWS	Canada Oil Sands	Norway	UK	US GoM DW	US GoM SW
Production Trend	-6%		64%	8%		26%	
Reserves Produced		28%	8%	40%		33%	
Proved Reserves Replacement		Very Positive	Very Positive	Very Positive	Slightly Negative	(Positive)	
New Field Starts/Field Size		22 / 59 mm boe	10 / 1,195 mm boe	14 / 162 mm boe	70 / 45 mm boe	65 / 91 mm boe	
Exploration Wells		320	n/a	180	350	450	(Large)
Exploration Success Rate		29%	n/a	49%	28%	26%	(Mid-range)
New Field Technical Cost (\$/boe)		9.5	10		11.5	7.5	9.5

Key to remaining prospectivity levels

High  Mid-range  Low 

Source: CRA Analysis

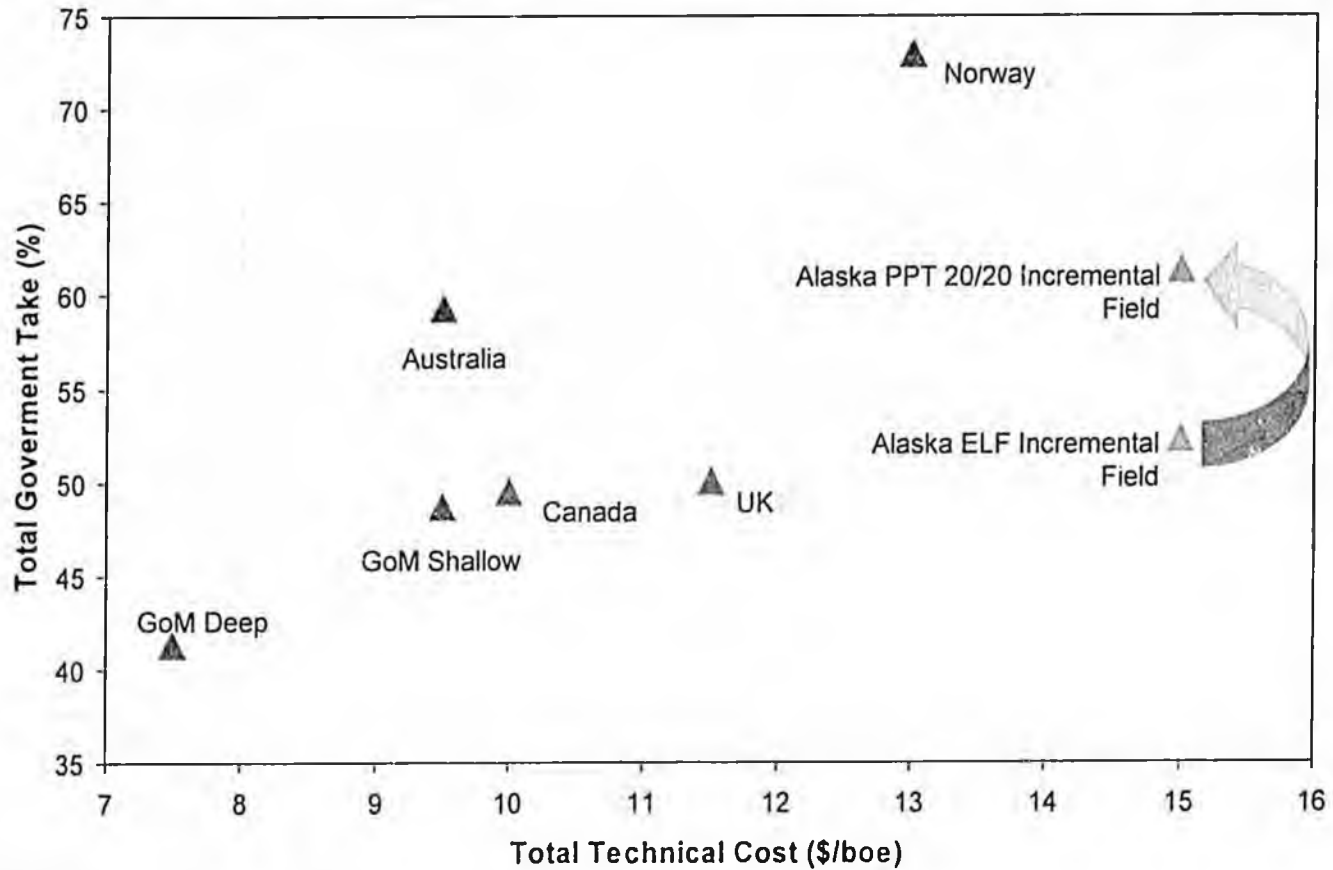


INTERNATIONAL

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The basic¹ PPT 20/20 proposal gives Alaska the second highest level of total government take within the group

Total Government Take versus Total Technical Costs

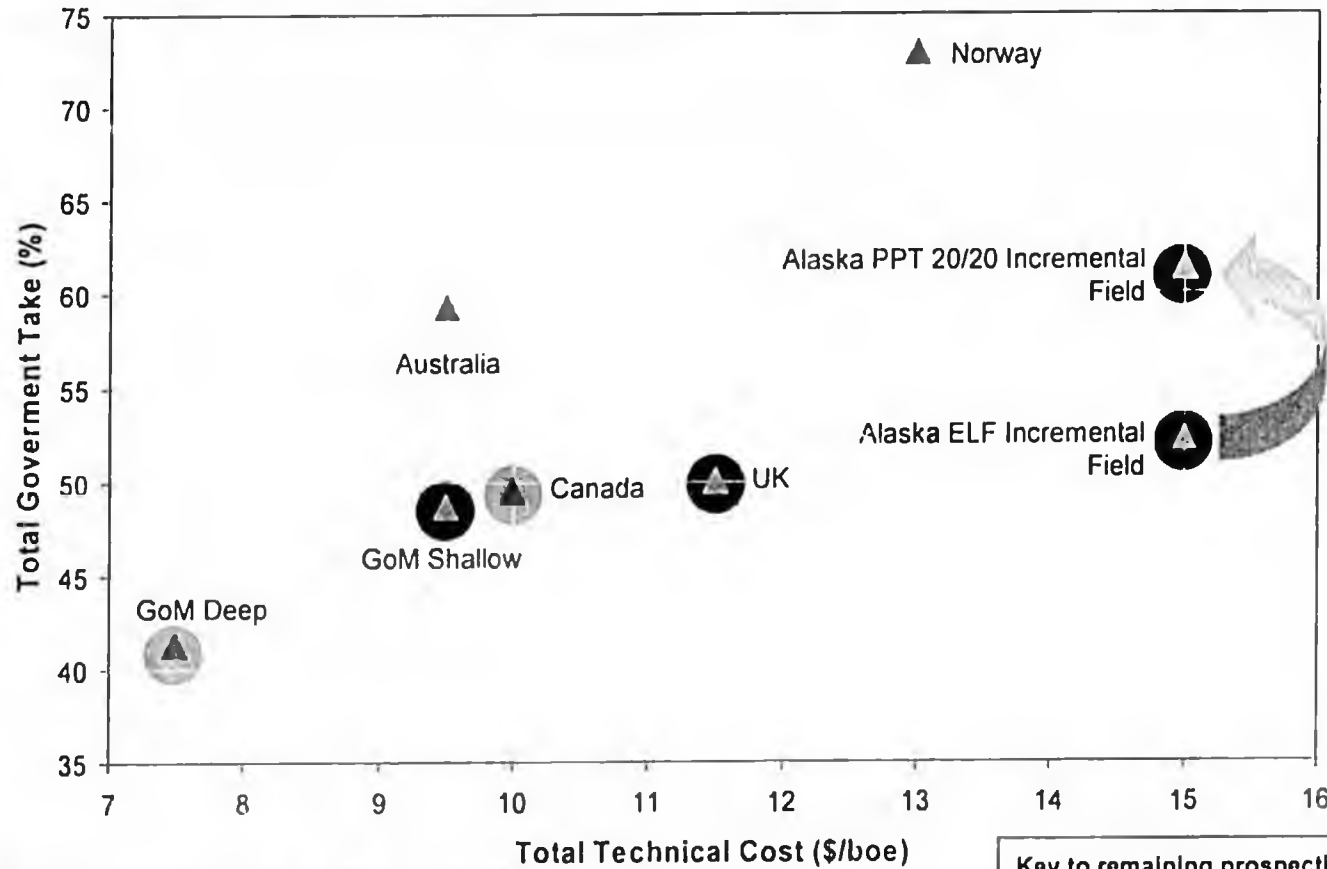


¹ i.e. the original SB 305.
Calculations are based on a \$35/bbl real oil price
Source: CRA Analysis



High costs and lack of prospectivity compound the impact of Alaska's high overall government take

Total Government Take versus Total Technical Costs



Colors indicate CRA's assessment of prospectivity in each region.
 Calculations are based on a \$35/bbl real oil price
 Source: CRA Analysis

Key to remaining prospectivity levels

High Mid-range Low



INTERNATIONAL

Alaska's largest potential is in its producing fields, heavy oil and gas resources: PPT 20/20 is a dis-incentive to investment in these

Alaska's Resource Potential		
Resource Type	Comparative Size	Incentivised by PPT 20/20 proposal?
Producing Fields / EOR	2-5 bn boe	Higher tax take is a direct disincentive
Known Undeveloped Resources: <i>Conventional Oil</i>	~0.5 bn boe	Only small and/or new players have some incentive
Known Undeveloped Resources: <i>Conventional Gas</i>	6-8 bn boe	Higher tax take is a direct disincentive Gas pipeline may transform attractiveness
Known Undeveloped Resources: <i>Heavy Oil</i>	5 bn bbl	Higher tax rates may cause serious delay to heavy oil development
Exploration Potential (YTF)	<1 bn bbl oil potential? Gas potential may be higher	Only small and/or new players have some incentive

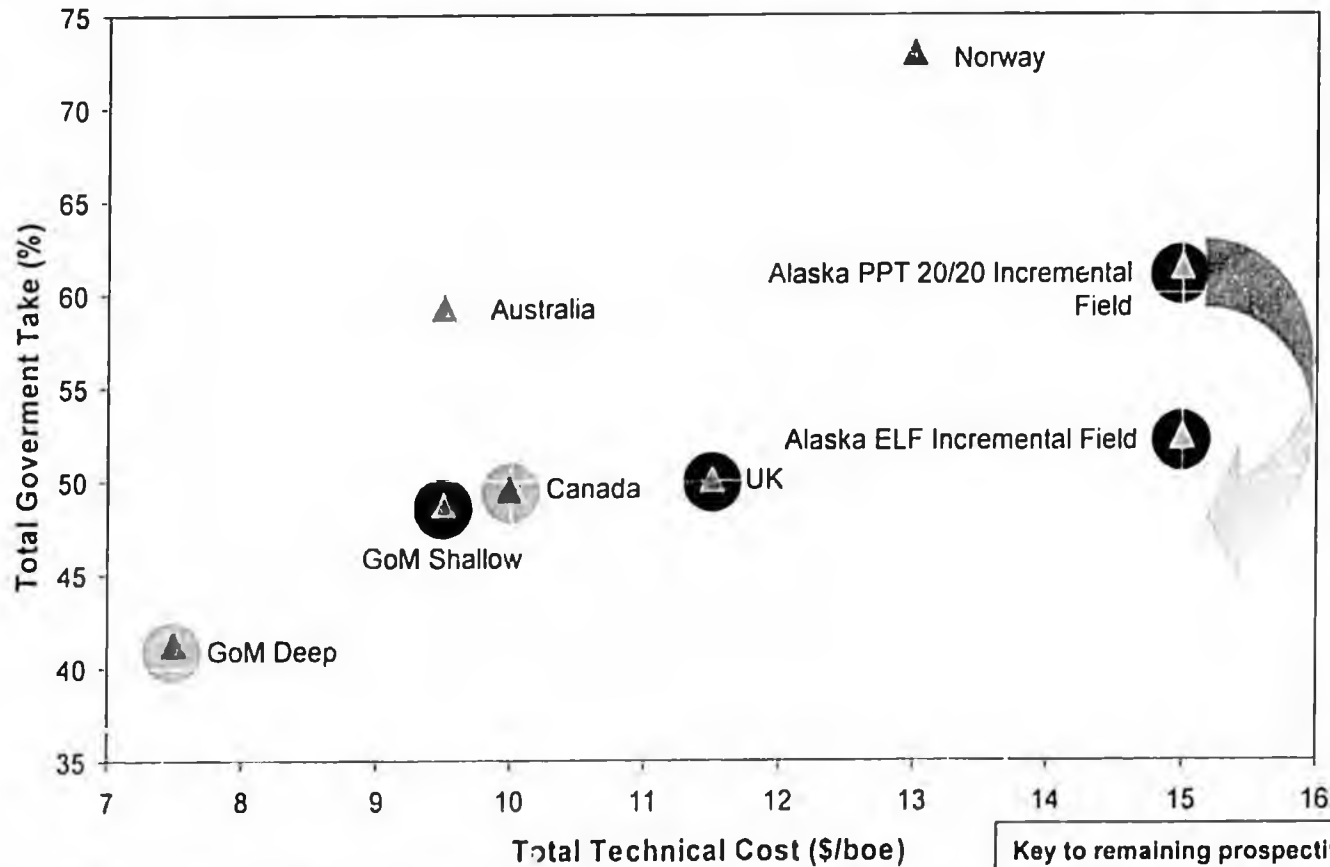
NB YTF = "Yet to Find"

Source: Alaska DNR, USGS, CRA estimates of incremental potential



If Alaska wishes the new legislation to stimulate investment, a new system that reduces total tax take would be required

Total Government Take versus Total Technical Costs



Colors indicate CRA's assessment of prospectivity in each region.
Calculations are based on a \$35/bbl real oil price
Source: CRA Analysis

Key to remaining prospectivity levels

High	Mid-range	Low
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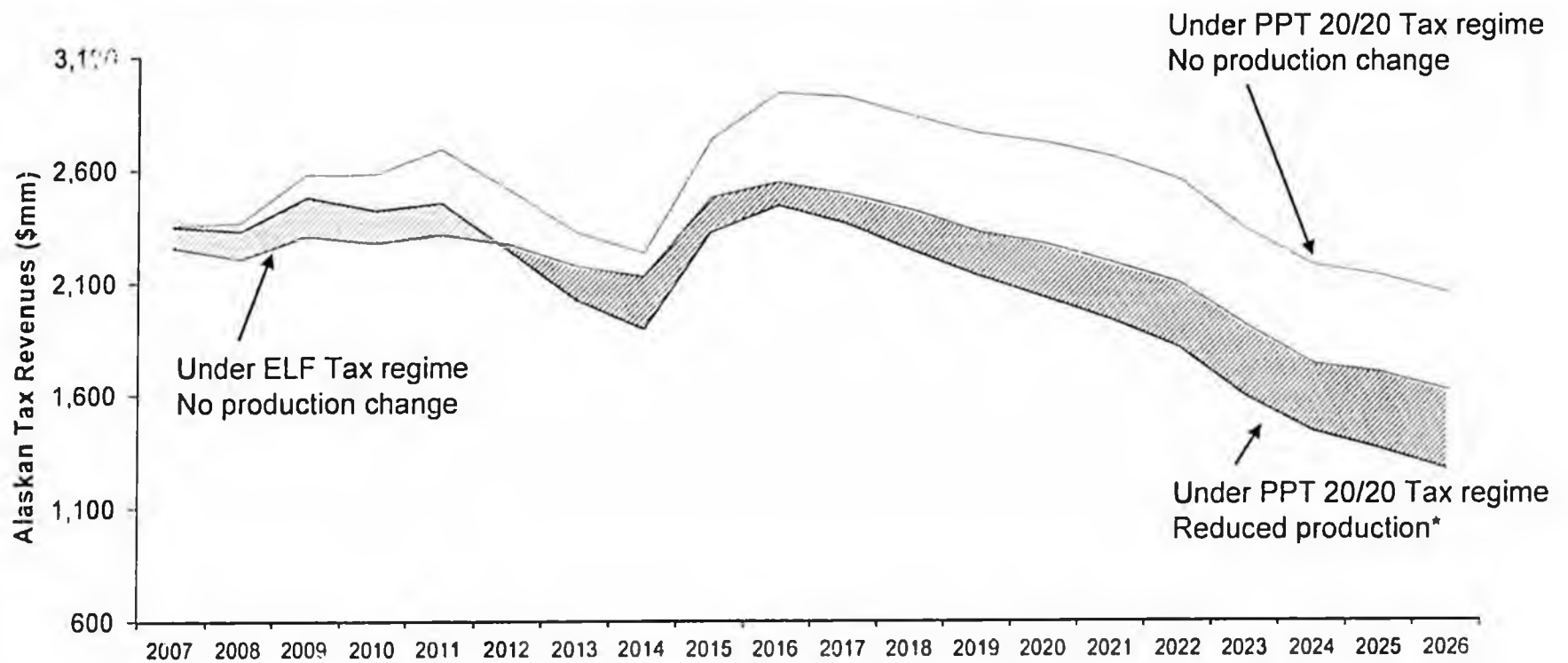


Why is CRA more pessimistic about investment than previous testimony?

- **Investors have choices, and more tax will drive some capital away**
 - CRA 'portfolio pricing model' rather than 'threshold model'
- **Tax credits don't offset the impact of higher tax rates**
 - CRA's 'typical Alaskan field' shows clearly the economic penalty of PPT 20/20
- **Fiscal structure biased towards tax credits likely to be a dis-incentive for most investors**
 - Tax credit bias erodes upside
 - High price environment means scale, efficient use of scarce human resource, is key factor
- **Alaska's investment attractiveness low for current ELF levels of government take**
 - PPT 20/20 is already a significant dis-incentive
 - Higher rates and/or progressivity will compound the impact on investment

So what might the future look like? Some illustrative numbers

Tax Revenues To Alaska



NB

1. Base production assumes 3% decline per annum up to 2014
2. Includes all taxes to the State of Alaska: Royalty, Ad Valorem, Severance or PPT, State CIT (average rate assumed @ 3%)
3. Calculations are based on a \$35/bbl real oil price

* Reduced production case assumes capital spending reduction of 20%, which leads to additional production decline of 2.0% per year

Source: CRA Analysis



What could this mean for Alaska? Some illustrative numbers

Taxes: Gains and Losses ¹		Investment Reduced	Jobs: Lower Activity ²	
2007-2011	+\$700m	20% reduction means \$2-3 bn lost over 10 years	Direct Loss	500-1000
2012-2016	-\$700m	\$1bn lost from Alaskan GDP?	Indirect Loss ³	1500-3000

¹ Relative to ELF base case (when production profile is unaffected)

² Assumes 30% of capex and 50% of opex relates to employment and average employment cost is \$100,000 per year

³ Assumes employment multiplier of 3 times, although previous studies (AOGA, 2001) have suggested 6 times

Source: CRA estimates, based on testimony of Alaskan investors



Increasing Alaska's oil and gas taxes will have a price

- **We recognize the dilemma of balancing revenues and investment**
- **Alaska is mature, but has undeveloped potential**
 - Low prospectivity and new field size
 - High cost base
 - BUT huge known resources, heavy oil especially
- **Current fiscal proposals do not help competitiveness in OECD peer group**
- **Loss of competitiveness will mean less investment and lower production**

Testimony of Marianne Kah, Chief Economist, ConocoPhillips
Senate Bill 305

Good afternoon. I am Marianne Kah, the Chief Economist for ConocoPhillips in Houston. I am glad to be back here after testifying at the Resource Committee hearings last month. I am part of the Corporate Planning function and I am here to share with you our views on how this proposed tax change might impact Alaska's competitiveness from the perspective of a global investor. Thank you for affording me this opportunity.

Investment Criteria: Let me start by showing you the general criteria we use at corporate headquarters to value upstream investment opportunities. The first factor we generally consider is the prospectivity of the country or opportunity. We would consider such elements as the maturity of the area, potential field size, remaining reserves and the quality of the reservoirs and crude oil. There are also a number of places around the world that have known reserves but they are difficult to develop. The larger the size of those reserves, the more feasible it will be to economically develop them.

The second factor we generally consider is the cost of the region or opportunity. This would include exploration, development and production costs as well as transportation costs to bring the crude to market.

The third criteria that is used to judge the value of opportunities is the cycle time or the amount of time it takes from exploration to first production. The value of the project is highly dependent upon whether it can be brought to

Presented 4/5/06¹

the market quickly or whether it takes 7-8 years or longer before first production.

The fourth factor we consider is the attractiveness of the tax and fiscal terms and whether or not they are commensurate with the prospectivity and cost of the region or opportunity.

The fifth and last factor we consider is whether the country has a strong rule of law and efficient regulations for energy development. The stability of the political regime and the fiscal terms are also very important considerations in terms of the degree of risk that the value will turn out to be significantly lower than we anticipated.

With that said, let me show you how we would assess Alaska's competitiveness using these criteria. I will start with an overview of all of these criteria and then provide more detail on a few of them.

Investment Criteria with Alaska Rating: Starting with prospectivity, CRA has already showed that Alaska has fewer and smaller field sizes than even the other mature areas in OECD countries. The crude quality is moderately high sulfur and getting heavier. These are negatives.

Alaska also has high exploration, development and production costs, and a long cycle time to get to markets given Arctic drilling conditions and limited drilling seasons.

The strong rule of law and political stability have been positive factors that

explain why we have been investing in Alaska all these years. However, we are now concerned at the prospects of changing the tax regime after investments have been made without grandfathering these investments under the tax regime that was in effect when the investments were undertaken. The worst thing that you can do to an investor is to change the rules of the game after the investment is made. This significantly raises Alaska's risk profile and reduces the potential attractiveness of investing here.

Global Average Commercial Discovery Size: Looking at prospectivity in greater detail, this slide compares the average commercial discovery size in Alaska with various countries around the world. Areas with high prospectivity can generally assess higher tax rates, while maintaining investment. The Alaska North Slope, however, has limited prospectivity as compared to many parts of the world. Tax rates need to reflect that.

But it is also important to acknowledge that although exploration will continue to play a role in halting Alaska's production decline, it will be a small one. Based on the State's forecast, exploration will account for about 3% of production over the next 10 years and about 8% over the next 20 years. Known discoveries which have yet to be developed or are economically challenged, also play a small part in Alaska's future.

The core legacy fields such as Prudhoe and Kuparuk will still produce over 80% of the total North Slope production in 2015, providing the base infrastructure on which these smaller fields will depend. Significant capital will be required to maintain this infrastructure, as well as, in-field drilling and well work to mitigate decline. Discovered heavy oil resources would be

included in this category. However, the State's consultant acknowledged that technology limitations and development costs will constrain heavy oil production in the near term, and it could be many years before this resource reaches its production potential. The technology required to develop this resource will require huge expenditures, which the long-term major producers, such as ConocoPhillips, are more likely to make than smaller companies.

Over the next 10 years, approximately 100% of the investment in existing fields, 100% of the investment in known discoveries, and probably about half of the exploration investment (or about 98.5% of the total investment over the next decade) will come from companies that are already here. If you are interested in Alaska's future, you are interested in seeing the major existing players continue to invest here.

Increasing Production Costs: This slide compares the production costs (includes severance but no other taxes) of all of the major regions in ConocoPhillips' portfolio. Alaska is the highest cost region in our portfolio. And costs in Alaska are rising at a faster rate than in other regions, in part because of the aging infrastructure and declining field size. Cost also needs to be taken into account when setting the tax take. The countries with the lowest costs can afford to have higher tax rates while remaining competitive. Similarly, higher cost countries need to offset these conditions with lower tax takes.

Alaska – High Cost, High Tax: My next slide shows total capital and operating costs as a function of government take for about 30

countries/states in the world. This data, representing costs from 1994 to 2003, was taken from the Wood Mackenzie 2004 "Global Oil and Gas Risks and Reward Study" and was calculated at a \$35 per barrel price. The study included more countries but we removed the ones where the government was carried through exploration in response to the Legislature's consultant, Daniel Johnston's, criticism of Wood Mackenzie for not accounting for this carried equity in their government take calculation.

As can be seen, there are four quadrants shown on this chart. The one on the bottom left shows countries that are trying to attract investment. They have low costs and still maintain low rates of government take. The quadrant on the top left contains low-cost countries that are then able to maintain high tax rates while remaining competitive. The quadrant on the bottom right contains high-cost countries but they compensate for their high costs by maintaining lower tax rates. The quadrant on the top right contains countries that have high costs and high taxes. Countries that position themselves in this quadrant may not get sufficient investment since their tax rates are not commensurate with their cost structure.

This plot also shows that there are inverse relationships between Government take and Total Costs. As previously mentioned, high-cost countries often lower their tax rates to remain competitive. The lower line tends to represent net crude-importing countries who want to maximize investment. The upper line tends to represent net oil-exporting countries.

Alaska under the ELF is shown as the Red Triangle. The PPT will move Alaska into the High-Cost, High-Tax Quadrant at the same time that costs

are rising at a faster rate than in other locations.

This chart also shows with Green Triangles the OECD countries that CRA believes are more appropriate peers. Peer areas such as the Gulf of Mexico and UK North Sea are still significantly more favorable investment regimes. The high cost in the Arctic and the types of fields that are likely to be found suggest that the proposed fiscal regime could detract, rather than encourage, significant additional investment.

Alaska – High Cost, High Tax (with prospectivity): Now I am showing you the same slide but adding in bubbles to indicate the prospectivity of some of these countries. You can see that a number of the countries that have high tax takes also score high in prospectivity. That is why they can keep tax rates high and still be competitive.

The other point I wanted to make about this chart is that the Governor's consultant assessed the competitiveness of Alaska's tax rates by comparing tax rates of different regimes around the world applied to similar-sized fields in all locations. That is not the way investors look at it. When we compare investments in Russia versus Alaska, for example, we compare the prospects of accessing a very large field with very high tax rates in Russia versus finding a much smaller field with lower tax rates in Alaska. The greater prospectivity in Russia may compensate for the higher tax rates. Thus, it is not meaningful to compare the competitiveness of Alaskan tax terms with Russia's terms or those in Azerbaijan and Angola at the same field sizes.

Higher Taxes Will Reduce Investment: I will now switch gears and talk

about a concern I have with the testimony of all of the state's consultants. They would have you believe that you can raise tax rates without concern about substantially reducing investment or production in the state. This flies in the face of economic reality. To quote a phrase from Dr. Margo Thorning, the Chief Economist of the American Council on Capital Formation, "one of the axioms of public finance scholars is that if you tax something, you get less of it"¹.

There are three reasons why higher tax rates will reduce investment. The first is that there will be less cash flow available to re-invest. Another less obvious reason is that you have changed the risk / reward balance. You will effectively increase the marginal cost of production and thereby lower the rewards, while at the same time increasing the perception of risk that the rules of investment will be changed after investments are made. Making the tax rate too progressive in a higher price environment also negatively impacts the risk / reward balance by shaving off the benefits of better times disproportionately more than helping in a lower price environment. Our industry invests a tremendous amount of capital on projects with long lead times and significant exploration, technical, price and economic risk. We need the tax system to be stable and to allow us to keep enough upside that we can earn adequate returns for our shareholders on average over the long price cycles our industry experiences.

The third reason why higher taxes will reduce investment is that Alaska will be viewed as a less attractive place to invest and capital will migrate to

¹ Dr. Margo Thorning, "Deja-vu on Windfall Profits Tax on Oil Industry, American Council on Capital Formation", Capital Formation Newsletter, January-February 2006, Volume 31, Number 1.

countries that have tax regimes commensurate with their cost and prospectivity. The state may also receive less investment from long-time investors who believe they have been treated unfairly by the state in the transition to a new tax regime by not being given due consideration to recent investments made with different fiscal regime expectations.

There are a growing number of countries around the world who have increased their tax rates in this high price environment, which is probably making you think that Alaska can still be competitive despite the proposed tax increases. However, private investors will shift from investing in conventional oil in all of these places with higher tax rates to investing in LNG, downstream and other energy projects that have more favorable tax terms. For example, our company is now more willing to invest in downstream and infrastructure projects than we were historically when we believed that upstream investments had higher and less risky returns. If current trends continue, conventional oil will end up being the domain of national oil companies who have lower return requirements than private investors.

And finally, capital will flow out of the energy industry if tax rates rise to the point that the energy industry looks less attractive than other industries.

COP Major Upstream Projects: While I believe there will likely be a long-term adverse impact on investment from rising tax takes around the world, let me bring the discussion back to corporate allocation decisions we face in the next 5 years.

This slide represents the pipeline of upstream investments ConocoPhillips is pursuing in the next 5 years. We are planning on continuing investments in our base legacy OECD areas, such as Alaska. But we also are planning investments in global gas and other international areas. Investments in Alaska must be able to compete with investments in these other areas. The tax rate needs to be commensurate with Alaska's high cost and low prospectivity to ensure this state maintains its important place in our investment portfolio.

Portfolio Ranking: Another concern I have with the state consultants' assessment that Alaska can raise its tax rates without hurting investment is their implicit assumption that all projects with a positive net present value will be undertaken. That assumes that there is unlimited human and financial capital. Our shareholders expect companies to exercise capital discipline and to avoid doing marginal projects. We also have limited manpower and focus on projects that have sufficient scale to make a difference to the company.

As indicated in this concept slide, when Alaska raises its tax rates, some projects, like Alaska project number one, will still be in the competitive range but it may be moved down to a lower ranking than other projects the company is planning on, such as upstream project number one and the downstream project shown here. Other projects, like Alaska project number two could slip from being competitive to being deferred. And finally, some projects, like Alaska project number three could slip into the uncompetitive range.

What's Wrong With Windfall Profits Taxes: The proposed bill has a surcharge based on ANS West Coast oil prices over \$40 per barrel. This is tantamount to a windfalls profit tax because it shaves off the upside without helping on the downside.

The U.S. federal government has recently debated the merits of a windfall profits tax on domestic production, and this concept drew great criticism from a broad range of economists and investors across many industries. I have provided two quotes that represent the criticism of such a tax. Daniel Yergin of Cambridge Energy Research Associates stated in an interview that “what a windfall profits tax does is introduce a lot of distortion. It reduces investment, it increases a sense of political risk and it doesn’t achieve the goal that is intended ... it will really lead to decreased supply”². A group of 250 economists from academic and other institutions across the nation, including Milton Friedman, the Nobel Laureate in Economics, recently sent a letter to the U.S. Congress stating their opposition to such a tax, indicating that it would reduce domestic production and expressing sadness that politicians hadn’t learned any lessons from past experience with this type of tax³.

The non-partisan U.S. Congressional Research Service (CRS) assessed the impacts of the federal windfall profits tax on domestic crude production that was in effect from 1980 to 1988⁴. CRS concluded that the tax reduced

² Daniel Yergin interview, *Capitalism Magazine*, November 11, 2005

³ Open Letter to America’s Elected Officials, 250 economists, October 25, 2005

⁴ Salvatore Lazzari, “The Windfall Profit Tax on Crude Oil: Overview of the Issues”, Congressional Research Service, September 12, 1990

industry gross revenues by \$79 billion that could otherwise have been used for investment. As a result, the tax was estimated to have reduced domestic production by up to 1.6 billion barrels between 1980 and 1986, before the collapse in oil prices. It also increased oil imports by up to 16% during this period. The study also noted that the actual gross tax revenue collections were only 20% of what the federal government had expected. This was because prices did not remain at the very high levels of 1980 and domestic production ended up lower.

Value Uncertainty in Balanced Government Take: Now I want to demonstrate how a windfall profits tax would impact our project economics and investment decisions. In evaluating investment opportunities, ConocoPhillips considers risk and opportunities associated with an investment. Assuming a stable fiscal environment, factors that most often impact our North Slope investments are:

- *Oil price uncertainty, which accounts for the majority of NPV variance,*
- *Reserves and capital spending,*
- *Operating costs, and*
- *Schedule, which is particularly important in Alaska as construction windows are limited. Missing a key construction window (e.g. a sealift) can easily delay the project by a year*

The impact of the sensitivities for these key variables are demonstrated in a chart called a Tornado Diagram. In a Tornado diagram, the impact of a given variable on the project value is tested by holding all other key variables at their mean value and varying the variable being tested through

the high and low end of its expected ranges. For example, in the tornado diagram pictured on the left, if the high end of the reserve range was experienced, then everything else being the same, the project value would increase to over \$100 million. If the project was significantly delayed, then the project value would decrease to around negative \$100 million.

Once we have identified the key value drivers to a project, and assume a probability distribution for each of the key variables (e.g., 50% chance price at the mean price, 25% chance at low and 25% chance at high price), we run multiple simulations to identify a range of potential outcomes that are expected. The sum of those simulations is shown in the chart on the right, which is called a cumulative probability curve. This particular cumulative probability curve is showing that the project has a 40% chance of losing value and a 60% chance of having a positive net present value. The "probabilistic" expected value or the value at the 50th percentile is a positive \$50 million in this example. Projects that have a positive expected value would then be considered for acceptance.

Value Uncertainty in Progressive Government Take: I would like to demonstrate what happens when a windfall profits tax shaves off upside price risk. In the tornado chart on the left, the price bar is truncated so that there is more downside than upside price risk. After running all the probabilistic simulations, this would shift the cumulative probability curve to the left so that the project loses money 53 percent of the time and has a positive net present value only 47 percent of the time. The expected value, reading across to the 50th percentile is now slightly negative. This decrease in project value is purely associated with reducing the upside potential

associated with oil price. In other words, shaving off higher price risk creates greater risk that the project will not increase value. Thus, the project will probably not be approved.

Balanced and Progressive Value Uncertainty Comparison: This slide summarizes how shaving off the upside price risk reduces the chance that the project will be profitable and reduces the expected value. In this case, the project is far less likely to be undertaken without upside price risk.

It is also important to understand that our shareholders invest in energy companies because they want to be exposed to upside price risk. We will have trouble attracting capital if we were no longer exposed to this risk. Being a high cost area, Alaska in particular, is a high-price play, and shaving off the price upside will disproportionately impact investment in the state.

Finding, Developing & Production Costs: The last point I want to make about a windfalls profits tax is that some of what is being perceived as a windfall is actually higher reserve replacement costs. Let me explain.

While price increases across all of our energy products have recently increased our industry's earnings to record levels, it is only temporary as we are also experiencing enormous cost inflation as the industry ramps up its investment to increase supplies. This chart shows that industry finding, developing and production costs have more than doubled since 1999, excluding government take. F&D and production costs are the components of replacement cost most quoted because they are the easiest to measure in the financial statements of oil companies. However, this chart is missing a

number of the components of reserve replacement costs. It is missing all government take, which on average was probably about \$20-25 per barrel in 2005. It is also missing a cost-of-capital return and an adjustment reflecting compensation for the time value of money because you are spending money in year zero and getting production and revenues many years later. If replacement cost is being stated in terms of WTI prices, these numbers are also missing additional quality and transportation costs because most crudes are more remote and lower quality than WTI. When you add all these costs up, it is easy to see that replacement costs today are probably over \$50 per barrel. In fact, several financial analysts (e.g., Goldman Sachs, Bernstein) who track the energy business believe that long-term reserve replacement costs today are over \$50 per barrel when government take and the increased risk around cost uncertainty are included in the cost calculation.⁵

While oil prices may have peaked, spending levels and costs are continuing to rise. Some of this inflation reflects temporary conditions such as service industry capacity not keeping pace with industry spending levels and the high cost of materials like steel due to particularly strong industrial growth in China. Some of the cost increase is structural, and more permanent, though, reflecting the fact that our industry is investing in prospects that are smaller, more complex or remote and higher cost.

We are concerned that some of what people perceive is a “windfall” today actually reflects the tremendous cost inflation that has taken place in the industry. In addition, the size of the majors’ earnings sounds large to most

⁵ Bernstein Research Call, November 4, 2005, page 2; Goldman Sachs, Jeff Currie, “The sustainability of higher energy prices, April 2005, page 21

people but it reflects the scale of our business and required investment levels and enormous risk involved in replacing reserves.

This matters because if the alleged “windfall” is taxed at higher rates and reserve replacement costs really are between \$50-60 per barrel, our industry will not be able to profitably re-invest even at today’s prices.

Key Messages from Corporate Perspective: I will stop here and summarize my key messages.

- It is our opinion that the current tax regime isn’t competitive when compared with Alaska’s prospectivity and cost versus the other opportunities we have to invest in around the world.
- Thus, we believe that increasing the tax rate will significantly reduce our investment and production in Alaska.
- We are also concerned about the windfall profits tax the CS would put in place as it would reduce the cash we have to invest, and it would adversely impact the risk/reward balance of investing in Alaska.
- The federal government has tried a windfall profits tax in the past and it reduced investment and production and failed to generate the expected revenues.

ConocoPhillips has been a long-term investor in Alaska. Including our heritage companies we have more than 50 years of business history in

Alaska. We believe there can be a great future in this state, and although mature, there remains a lot of potential. We want to be part of this future.

Thank you for your attention.

Presented 4/16/06

1:10:09 PM

April 6, 2006, Comments To Alaska Senate Finance Committee
CS For SB305 – Petroleum Production Tax
By Ken Thompson

Introduction

For the record, my name is Ken Thompson. I reside in Anchorage. I am the Managing Director of Alaska Venture Capital Group, or AVCG, an independent oil exploration company with a focus on the North Slope of Alaska. AVCG is a consortium of 15 independent oil and gas companies and individuals from Kansas and my personally owned company, Pacific Star Energy, here in Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with newly opened offices in Anchorage. Many of you know me as the former President of ARCO Alaska, Inc., and a past Executive Vice-President over ARCO's Asia Pacific region.

AVCG has been very active in the past six North Slope (NS) areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired in the recent March 1, 2006, NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-150+ million barrels range, fields that may be too small for the giant producers but fields that can be produced profitably by smaller companies like ours. We believe there are hundreds of millions if not billions of barrels of oil left on the North Slope in smaller fields of this size and these fields near infrastructure can be brought on more quickly. Our first exploration well in partnership with Pioneer Natural Resources – the Cronus #1 about 10 miles southwest of the large Kuparuk Field – completed drilling last week but results will remain confidential for some time.

AVCG plans two NS exploration wells next winter and two wells the following winter. Our 3-year exploration budget is \$46 million and with any future discovery success, we could have a gross development budget of \$500 million to \$1 billion in future years.

Let me now focus my comments on the CS for Senate Bill 305. As background, I reluctantly supported the Governor's proposed 20/20 PPT and even many details of the initial House version of the bill, HB488. But, somehow, things are beginning to derail. The CS SB305 and CS HB488 with their revisions from the original draft of a simple petroleum profits tax have evolved into very complex bills that are no longer a win-win for the State and industry, in my opinion. I don't fully understand how things began to derail into such complexity...perhaps it was due to anger at the Big 3 producers and the Governor for not revealing the natural gas contract details before demanding a new oil tax fiscal structure. Perhaps its anger at the Big 3 companies who are demanding tax certainty for 30 years when asking for three full decades of certainty truly is an unreasonable demand with Alaska's legislative type of democracy.

1:14:14

pm

I don't understand all the dynamics of the past three weeks in the legislature, but this I do know. The CS for SB305 needs to be greatly simplified and it needs to move somewhere between what it is now and the Governor's proposal if a win-win solution is to be the end result that balances more revenue share for the State but in balance with attracting more new entrants and increased investment amounts.

I am an optimist. I personally think there is still time to avoid a train wreck in this complicated business of restructuring Alaska's petroleum taxation system...if the Senate Finance Committee acts quickly. I, for one, have not given up hope that there is a version – easier to understand and to implement - that can be a win-win for both the State and the industry. There is a simpler and better way, in my opinion, for the State to improve government take while not dampening exploration and development investment. Let me outline my suggestions for a win-win and my suggestions for simplification.

1:15:30

pm

AVCG Owners' Perspectives

First, however, let me say that while I am Managing Director of AVCG, our other owners disagree strongly that any change should be made to the 20/20 PPT formula proposed by the Governor. The 20% PPT tax rate and the 20% credit originally presented in the Governor's bill should be the tax rate and credit enacted. Some of the AVCG owners, however, do not even support the PPT concept and believe the petroleum tax should be as simple as 10-14% of revenues and exclude any economic limit factor.

Quite honestly, the AVCG owners listened in disbelief when I told them the production profits tax rate being considered in the current CS to SB305 draft could add a "surcharge" at high prices that could significantly ramp up the additional taxes above the base PPT rate of 25%. And this surcharge will be in addition to the higher other revenues the State and Federal governments will already benefit from at higher oil prices: the State's 12.5-16.7% royalty, the ad valorem property tax, the 3-9% corporate income tax, lease bonus bid amounts, the ongoing annual lease rental amounts, and the Federal income tax rates averaging 20-35% of taxable income.

It all adds up, and AVCG Owners are saying, "enough is enough."

When I was communicating the latest CS to SB305 details to the AVCG owners by teleconference and email recently, I felt two overwhelming emotions. The first emotion was discouragement. My business judgment tells me the State crossed the line to excessive taxation that will dampen capital investment. Why invest in Alaska where you lose the upside gain at high oil prices to offset exploration risk when the government take will exceed 60%? There are politically secure opportunities in other U.S. states, Canada, the Gulf of Mexico offshore, the U.K., and other nations where government take is 55% or less. CS to SB305 takes away too much of the upside potential from the investor who is taking the risk.

But I also found interesting another strong emotion during that teleconference which surprised me a great deal. I was embarrassed. Here I was, telling a group of outside investors that recently put all of their focus and personal exploration budgets on the North Slope of Alaska, and now I was telling them that Alaska was creating the most complex, confusing production tax bill ever created since the disastrous Federal windfall profits tax. The windfall profits tax – structured similarly to the CS SB305 revenue surcharge - stalled investment in the U.S. oil and gas industry, resulting in an alarming increase in U.S. foreign oil imports which our nation lives with to this day. I was telling them that Alaska was levying the highest tax rate and government take in North America.

1:19:46
pm

To back my points up, please let me cite some statistics. Currently, the total Alaska and Federal governments' take is just over 50%. The Governor's proposal moved this to 53% or so then ~~the original SB305~~ moved the government take closer to 55%. Then the CS to SB305 with a 25% PPT boosted the government take to over 60% with its "surcharge." This compares to following total government take including Federal government shares:

sb
← HB 488

Alaska currently	50%+ or less, dependent on oil price and field size
Alaska Governor's bill	53%
Alaska original HB488	55%
Alaska CS SB305	60%+
U.S. Gulf of Mexico	45%
Colorado	51%
Wyoming	52%
Kansas	53%
Texas	53%
New Mexico	53%
Oklahoma	53%
California	53%
Louisiana	57%

These tax rates apply to newer fields. Older, more mature fields at low production rates typically get exempted from these maximum tax percentages in various ways.

U.K.	50%
Canada	39-56%

The lower rates in Canada apply to the oil sands projects where billions of dollars for new investment are occurring with Canada's vision to lower government take on this resource base.

1:22:47
pm

My overall key recommendation in my comments today is this: the State should not exceed a threshold of 55% total government take, 45% producer take. The State does own the resource and may be due more than a 50% take. On the other hand, it is the producer who is taking the capital risks and deserves at least 45% for making things happen...for moving an innovative exploration or development idea into production without which no revenues would flow.

Let me say that I'm excited about what's happening in Alaska's oil patch right now, and let's not dampen the spirit. The current versions of SB305 and HB488 have dampened my spirit. I am discouraged. Let's have a new tax bill that encourages, not discourages new entrants. But I do believe it is time the State share more in the take at high prices but there is a much simpler way.

1:24:11 pm
My Personal Perspective

Now let me shift gears in my comments to you. Because I could not get buy-in for any alternatives from the AVCG owners except the 20/20 case, I have decided to speak out alone. As an Alaskan, I am concerned and feel I must try to share a personal perspective trying to balance what is best for my continued involvement in Alaska's oil and gas industry in balance with how the State must change its system to be competitive in the world and realize a higher government share.

So, let me turn my attention to what key changes I would make to the CS of SB305. Again, my views are not supported by AVCG owners or others in industry; rather they are my personal views.

1:27:27 pm
1) Make Tax Rate Progressive But Greatly Simplify The Taxation Formula

When the Governor's office first announced a 25% tax rate then amended that to 20%, I could see the move by legislators to somehow bridge the gap from 20% to 25%. However, the approach used by the legislative committees based on the legislature's outside consultants' work is simply too complex and will be arduous to implement. I think – and perhaps all of you think – the Federal tax code is too complex. The changes to SB305 are also too complex and will lead to different interpretation, "gamesmanship" possibly by some companies because of the unwieldy progressive tax structure formula, and future costly lawsuits when the State disagrees with a company's calculations. And the number of accountants to keep track of these complexities on both sides will balloon! I urge you to simplify, simplify, simplify...yet still have some progression at higher prices.

For my company which drills the smaller oil traps that may add up, we do not have a lot of upside potential in seeing these smaller fields grow much larger in reserves over time in contrast to the giant Prudhoe Bay and Kuparuk fields. So our main upside is in oil price escalation to offset exploration risks and to offset the cycles of oil prices downward, a reality over time for any commodity. I urge you to consider a PPT rate of 20% at lower prices but gradually escalating to the 25% level only at higher prices.

I found it so interesting to see the Econ1 consultants and consultant Daniel Johnston saying the government should take more and more at high prices when not one member of the legislature asked them a very important question they should have been asked: "how much are you and your company investing in Alaska?" I was

shocked to see that these consultants, when calculating the future revenues to the State at various escalating rates, used the same oil production curves. In reality, less capital will be spent by industry at exorbitant production profits tax rates (tax rates above 25% when coupled with all other payments such as royalty, corporate income tax, ad valorem tax, lease costs and rentals, etc.). With less capital spending, the production curve will be lower...an increasingly higher tax rate may not in the end yield the forecasted revenues for the State.

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PM

On a related note, our company plans to go into the private or public equity markets to raise capital for future development. Such equity investors invest in the oil markets to be fully exposed to crude price upside. When they look at investments all over the world, and see that Alaska could tax with an escalating "surcharge" when others have a predictable flat tax, they will place their capital elsewhere to continue their exposure to higher crude prices. The consultants did not address this issue of the private and public equity markets and the desire for such investors to fully benefit from upside commodity price swings without hedging or escalated taxation at high prices. This was indeed a major oversight by Econ 1 and Daniel Johnston.

I also could not believe that the consultants failed to show capital spending elasticity graphs from different countries. They did the legislature a disservice by not doing so. By convincing legislative committees to adopt a complex progressive tax rate structure, or windfall profits tax, the consultants may feel they have been successful, but not one of these consultants will be around to defend their views in the future when capital spending declines at increasingly higher tax rates above the 25% level.

So, what is a simpler alternative? What is an alternative to yield more revenues to the State at higher oil prices with a balance to attract increased investment?

I suggest that the Finance Committee revise the bill to keep the production profits tax simply that...a tax on production profits, and not a complex way to further burden gross revenues with a surcharge. A simpler way in getting the progressive rate from 20% to 25% without the surcharge treatment complexity is to adopt a graduated PPT that does accomplish a higher State take at higher prices, yet leaves a reasonable producer take.

I recommend the following production profits tax schedule as a suggested one to "simulate" revenue results somewhere between the Governor's proposal and the CS to SB305 proposal. It is one that everyone could easily understand and implement with the State realizing upside at higher oil prices yet not too much upside is taken away from explorers/producers for re-investment:

1:34:39
PM

Up to monthly average wellhead price of \$50/barrel for a company:	PPT rate of 20%
When monthly average wellhead price is between \$50-75/barrel:	PPT rate of 22.5%
When monthly average wellhead price exceeds \$75/barrel:	PPT rate of 25%

1:35:17 PM

Let's be honest with ourselves: the surcharge is simply a windfall profits tax under a different name. I highly respect industry consultant Daniel Yergin who has an excellent reputation among industry personnel and government officials alike. In November, 2005, Mr. Yergin said this about a windfall profits tax: "What a windfall profits tax does is introduce a lot of distortion. It reduces investment, it increases a sense of political risk and it doesn't achieve the goal that is intended...it will really lead to decreased supply."

I urge the Finance Committee to seriously consider this simpler approach. I personally ask that you have the Department of Revenue run the above case to compare the State revenues from the Governor's proposal to the current CS SB305 proposal, and to the existing ELF severance tax program. But when DOR models this approach, also ask them to run some sensitivity cases to reduced capital expenditures and reduced future oil production levels if CS SB305 stays in its current form. Please greatly simplify the bill. The complexity is simply not needed.

1:36:47 PM

2) "Trigger Points" For Escalating PPT Should Not be WTI But Wellhead Value

Let me now address a second, very leveraging issue. The "trigger point" that increases the PPT tax rate from 20% should not be based on ANS West Coast (ANS) oil price. The "trigger point" should be when a company's average realized wellhead price in Alaska exceeds \$50 per barrel. Some say the trigger point should be at a lower price like in SB 305, but I do think there is strong merit that those who have invested and taken exploration risk and exposure to low prices should be able to benefit from the increased profits at higher prices..."share the pain, share the gain"...to this \$50/barrel wellhead level. However, I personally am fine with the State gradually increasing the PPT tax rate eventually to a cap of 25% when wellhead prices exceed \$50/ barrel.

Why should the State tie the PPT calculation to a company's realized wellhead price instead of to West Coast crude price? In reality on the North Slope, not one company ever sees West Coast crude prices. Every crude oil in Alaska is different in quality with viscous crude receiving less than the lighter crude oils, and oil produced from wells farther away from infrastructure receiving less wellhead value due to higher shipping costs. Conversely, oil in the Cook Inlet is close to actual refining or on the water to ship out of state and thus realizes on average a much higher wellhead value than most North Slope crude oils, a substantial plus to Cook Inlet operators who face higher operating costs with maturing fields.

So I ask, why should the tax rate increase with a price index such as West Coast price when there is such a variance in crude oil pricing factors on the Slope at the wellhead that directly affect each field's economics and economic limit differently? The production profits tax rate should not escalate at the same time for those who produce viscous crude or oil from a farther distance as compared to those who have

good quality oil right next to the TAPS line. If there is a "trigger point", it should be one based on a company's average monthly realized wellhead price for production.

1:40:
23
pm

I recommend that the "trigger point" for PPT tax rate escalation be \$50 per barrel realized wellhead price based on a company monthly average and not be based on \$40 West Coast price, thus allowing explorers and producers to share in the upside profits at prices to this level with no higher burden than the 20% PPT tax rate (plus burden of royalty, corporate income tax, ad valorem tax, Federal tax, etc.). Dr. Pedro van Meurs also recommended that the threshold level of \$40/bbl be re-considered. As also recommended by Dr. van Meurs, this threshold price should be linked with inflation.

1:41:37
pm

3) The Transitional Deductible Allowance

Jumping immediately from the prior ELF severance tax to the PPT formula overnight wreaks havoc with a company's budgeting and their forecast of available cash flow for near-term capital investment. A transition adjustment of some sort is appropriate and is fair.

I support the CS to SB305 that allows for a producer to take a credit with part of a producer's transitional investment expenditures between April 1, 2001, and before April 1, 2006.

1:42:10 pm

4) The Tax Credit "Standard Allowance"

The Governor proposed a \$73,000,000 annual allowance of production profits that would not be taxed by the PPT, essentially giving a \$14.6 million tax credit per company. The Senate Resources Committee revised this downward to a \$50,000,000 annual allowance as a reasonable compromise, or a \$10,000,000 tax credit; CS HB488 further changed this to a flat \$12,000,000 annual credit. The CS to SB305 further proposed that this be changed to an annual "standard tax credit allowance" for the first 5,000 barrels per day of production.

This "standard deduction" is very important to a startup company like AVCG/Brooks Range Petroleum trying to establish a foothold in Alaska and someday contribute substantial oil revenues to the State.

I favor the HB488 solution of a \$12,000,000 annual flat tax credit exemption due to its simplicity and it is a level playing field for producers of various crude oils with different wellhead values.

1:43:55
pm

5) Institute A Tax Credit Repurchase Program

As protection for explorers and new entrants to Alaska, the version of the profits tax in the House, CS to HB488 devised a tax credit repurchasing program for those

credits a company earns on expenditures up to \$10,000,000 per year for investments in exploration and/or lease purchases in Alaska.

This is important to explorers like AVCG who does not yet have production revenues. Without such a repurchase program, our company might be able to sell our annual tax credits to one of the major producers but have to accept only 90-95% on the dollar or less. On the other hand, the State would not be giving up anything to repurchase the credits at 100% of value because the major producers would otherwise use the credits to reduce their tax bill and reduce revenue to the State. But using the State repurchase approach, the small explorer could turn around and re-invest the State-refunded credit into new leases, seismic or exploration drilling.

I recommend the Finance Committee support the tax credit repurchase program outlined in the CS to HB488 and amend CS to SB305 to incorporate a similar tax credit repurchase program.

1:45:35
pm

Other Revenue Sources

As a concluding remark, I urge the State in this period of high oil prices to not simply try to gain into that upside by pulling only one lever excessively...the lever of petroleum production taxes. The State could be well advised to ensure they gain additional revenues from oil in Alaska by being an entrepreneur and considering revenues from other new related business, such as acquiring a 12.5% interest in the TAPS pipeline and stop paying \$3.70/barrel profitable tariffs to major producers when you could be sharing in those profits.

1:46:47
pm

And work with the Federal government now to ensure that they share part of the Federal royalties with the State on future offshore oil and gas production from the Beaufort Sea which I consider to be of great potential as evidenced by major leasing recently by Shell and other companies. Other states are pursuing a share of Federal offshore royalties.

And the Alaska gas pipeline revenues will be significant. The State should own 20%.

Concluding Remarks

The above comments are my personal views offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices. I do believe the Senate Finance Committee can get things "back on track" and better balanced.

I sincerely thank the Committee for the opportunity to present my comments.

Respectfully submitted by: Ken Thompson



State of Alaska Petroleum Production Tax
Testimony to Senate Finance Committee
(SB 305 RES)
John A Barnes

April 6, 2006


Marathon

10:43:49 AM

Presented
4/6/06

Marathon Testimony – Alaska PPT

Impact of SB 305 (RES) on Alaska Natural Gas

- ◆ Cook Inlet Natural Gas Summary: Pre PPT
- ◆ Financial Impacts of PPT
- ◆ Consequences of PPT
- ◆ What Is Needed



10:45:05 AM

Cook Inlet Natural Gas Summary: Pre PPT

- ◆ Declining reserves and production rate.
- ◆ High operating and capital costs as compared to lower 48 natural gas provinces.
- ◆ Difficult permitting and regulatory arena.
- ◆ Need for additional exploration and development to moderate price increase to consumers and to continue to provide industrial feedstock.
- ◆ Historical price differential to Henry Hub.



10:45:24 AM

Cook Inlet Gas Supply and Demand

May 9, 2005

State of Alaska
Department of Natural Resources
Division of Oil and Gas



Alaska Department of
Natural
Resources

<http://www.dog.dnr.state.ak.us/oil/products/products.htm>

10:46:07 AM

Cook Inlet Areawide Lease Sale Results

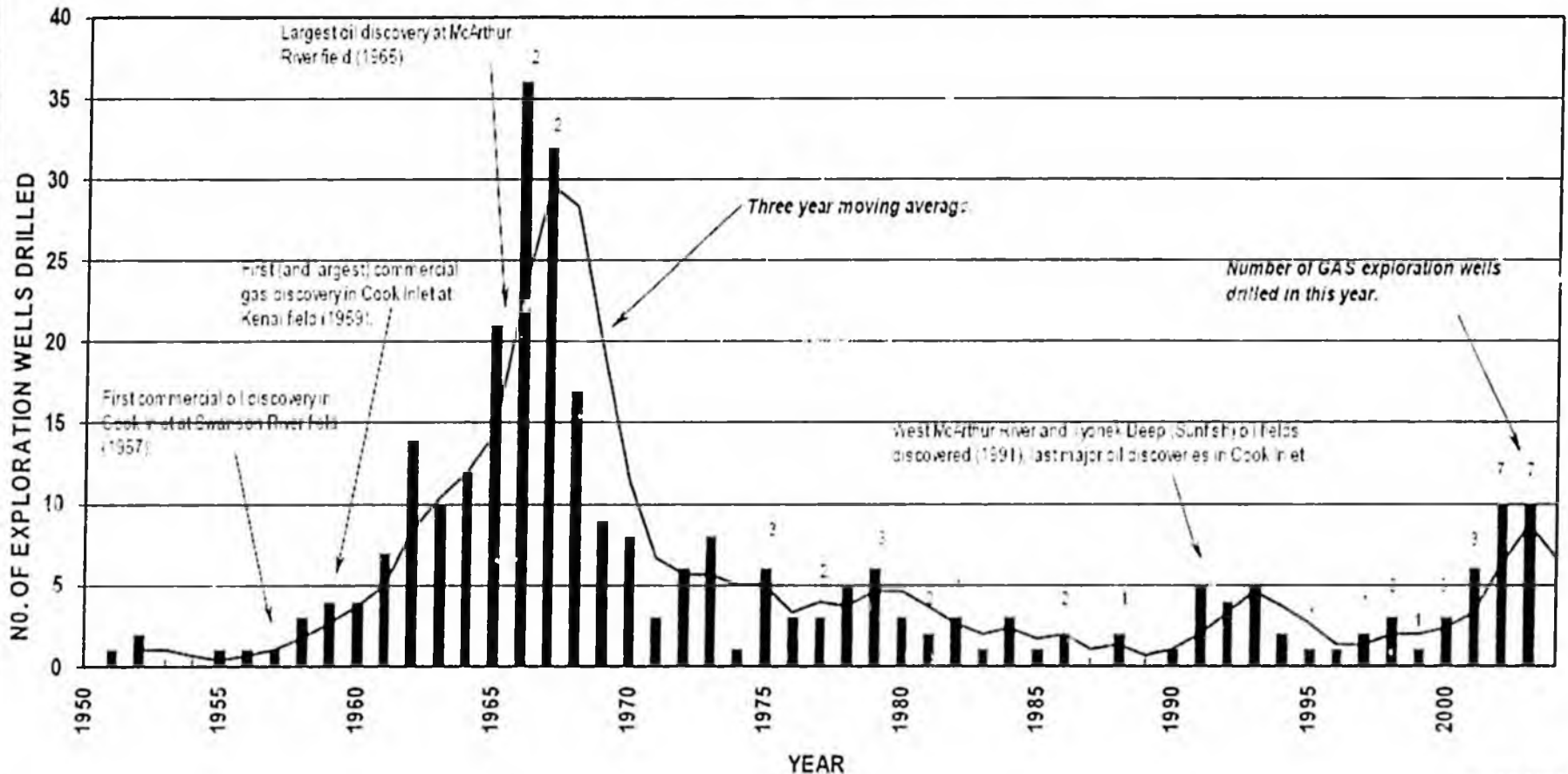
	Number Bids Rec'd	Number Tracts Sold	Multiple Bid Tracts	Total Acreage Sold	Total Bonus Rec'd	Avg Winning Bid	Max Bid Rec'd
				<i>Acres</i>	<i>\$</i>	<i>\$ / Acre</i>	<i>\$ / Acre</i>
2000	27	27	0	69,928	\$609,358	\$8.72	\$36.01
2001	31	29	2	102,523	\$928,085	\$9.05	\$22.18
2002	24	21	3	64,923	\$421,840	\$6.50	\$27.03
2003	28	27	1	103,680	\$887,059	\$8.56	\$33.28
2004	77	72	5	363,520	\$2,629,820	\$7.23	\$40.25
TOTAL	187	176		704,574	\$5,476,162		
AVERAGE	37	35	2	140,915	\$1,095,232	\$8.01	\$31.75

RICHFIELD HITS OIL
PRODUCTION CHIEF FLIES HERE

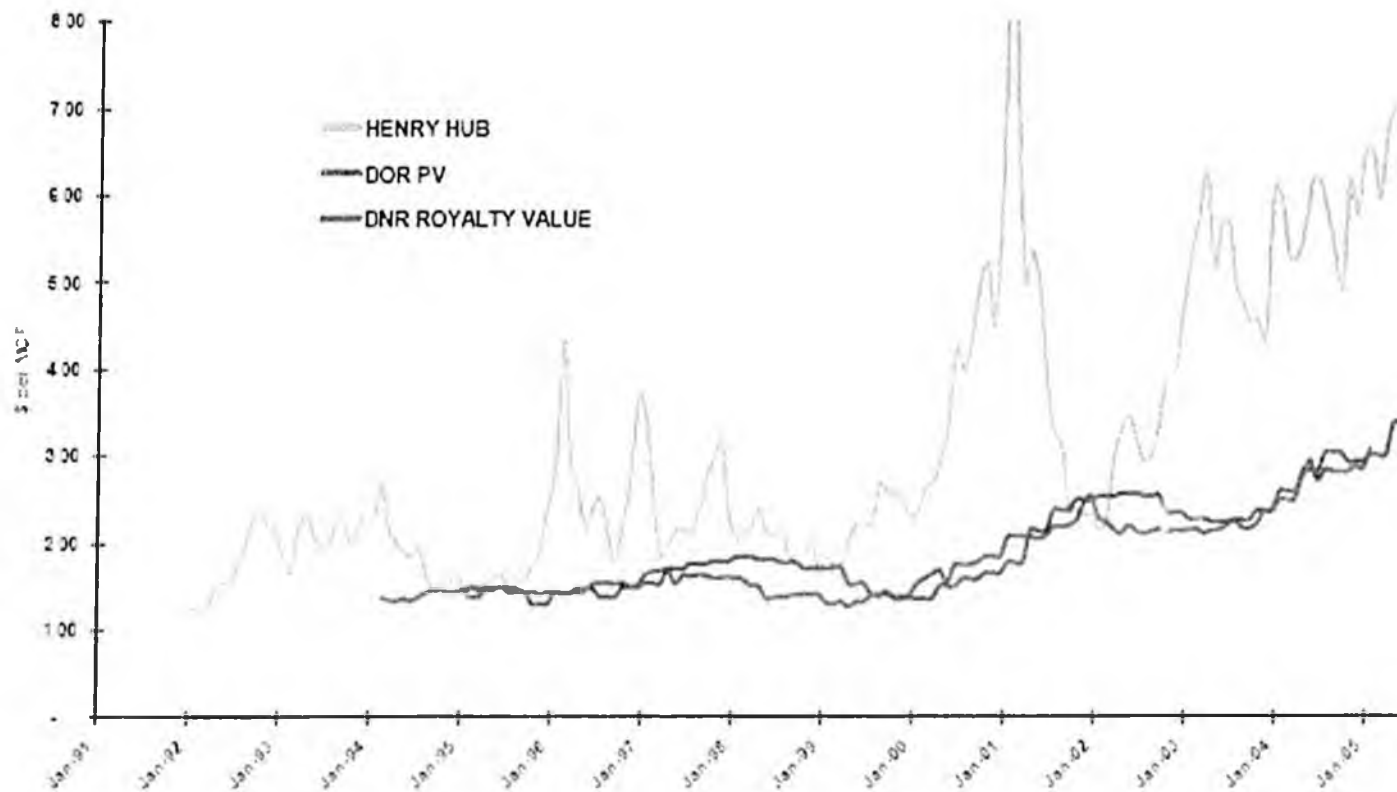


Timeline of Cook Inlet Exploration

COOK INLET EXPLORATION WELL DATA AND IMPORTANT EVENTS



Historic HH, DOR PV and DNR Royalty Value



Future of Supply

- We have moved from an “Excess Supply” market to a “Supply & Demand” market
 - Cost of Natural Gas will go up
 - More supply contracts are needed and will likely be for smaller volumes
 - Supply contracts will likely be more complicated
 - Pipeline system will be more complicated to operate
- We are working to identify and evaluate options to meet future demand
 - LNG Imports may be economic at some point
 - Storage options are being explored for peaking purposes
 - We have achieved Federal support for an in-depth DOE study of In-State demand and for conceptual engineering of a spur pipeline to Nenana Basin / Fairbanks

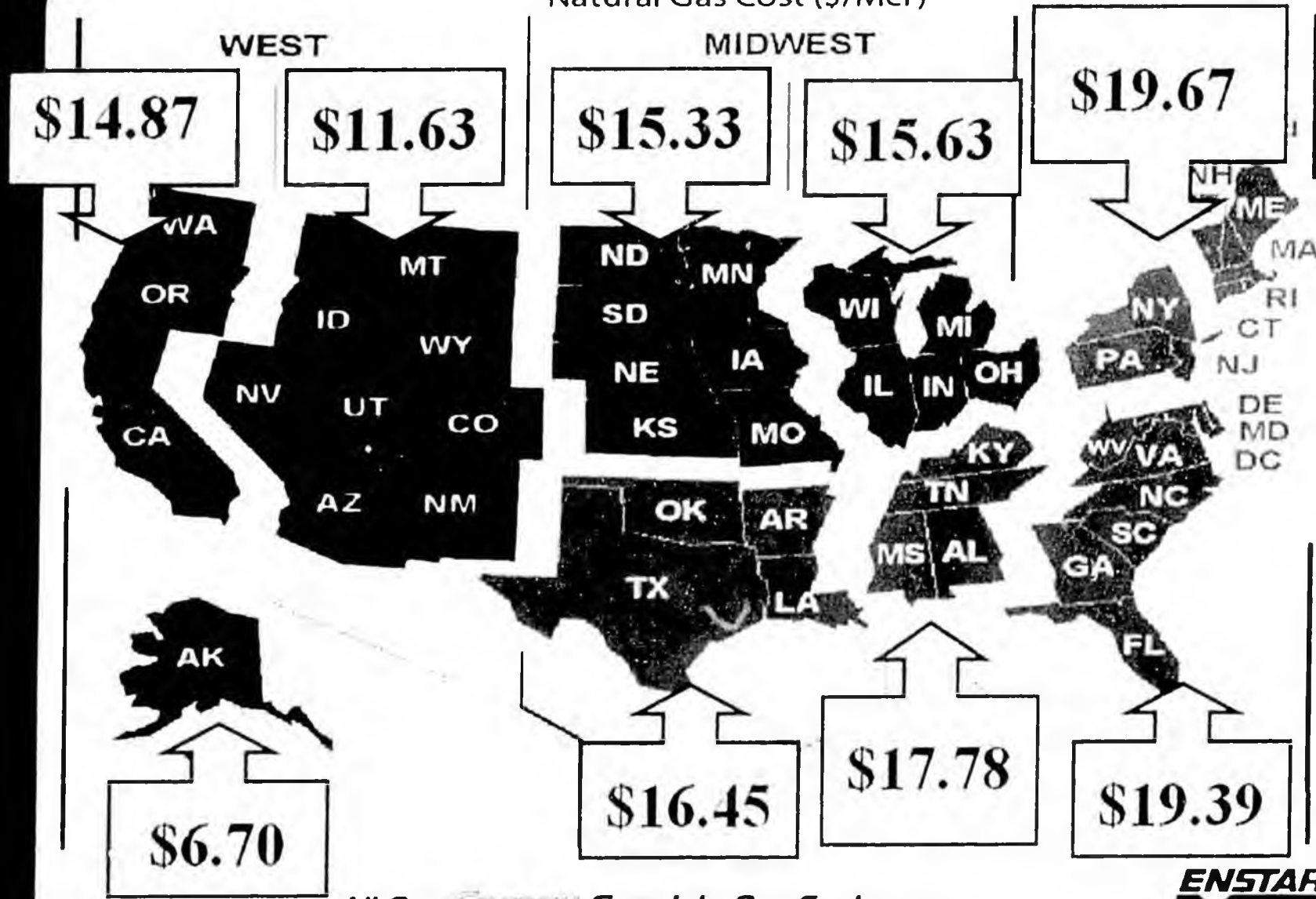
All Our ~~Energy~~ Goes Into Our Customers

ENSTAR
Natural Gas Company

10:48:27 AM

Residential Costs-By Region

Natural Gas Cost (\$/Mcf)



All Our *Energy* Goes Into Our Customers



10:48:49 AM

Conceptual Competitive Comparison

Common Input – Per Well Analysis

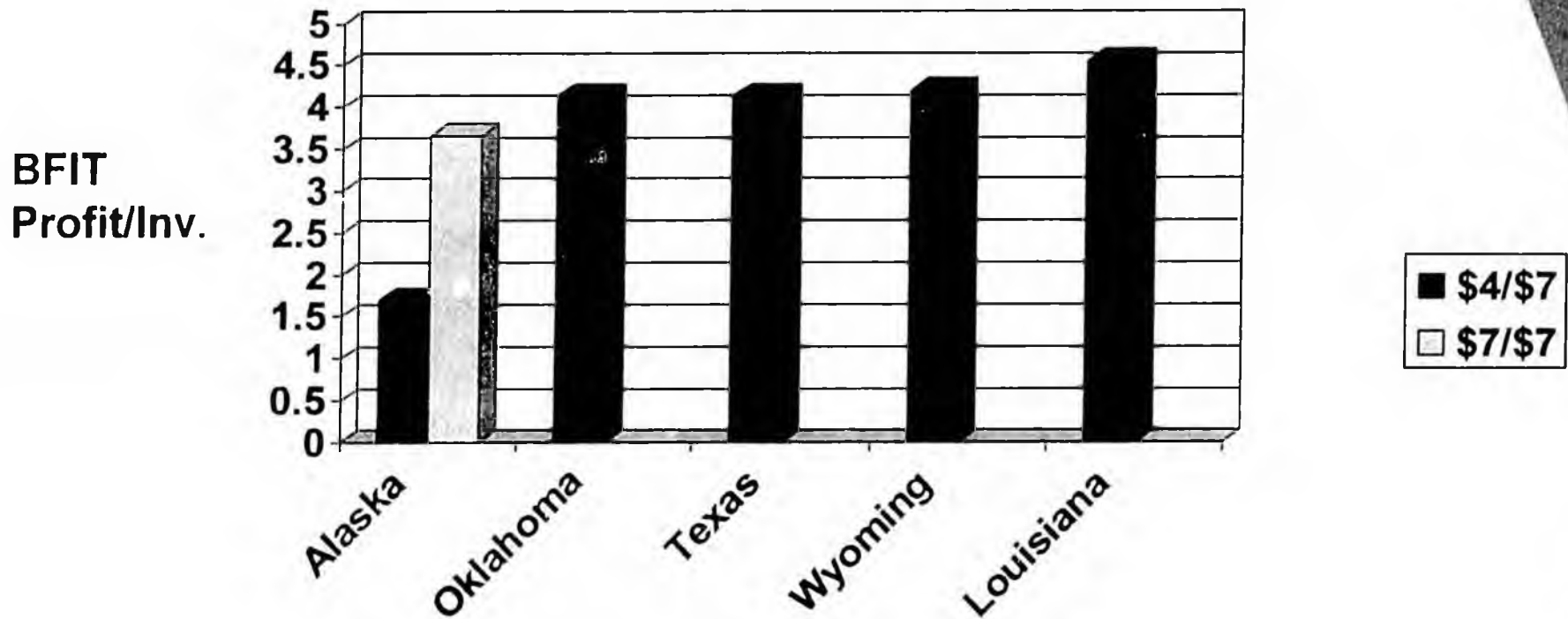
Recoverable Reserves	5 BCF
Development Cost (Capital)	\$5 million
Operating Cost	\$0.50/mcf
Royalty	1/8

Based on House PPT (SB 305, RES) and domestic severance tax rates



10:50:35 AM

Competitiveness Comparison: Cook Inlet Natural Gas Investments Disadvantaged Against Competition



Based on ~~House~~ PPT (SB 305, RES) and domestic severance tax rates
Senate



also 10:50:35 AM

Cook Inlet Competitive Analysis

- ◆ Must compare Cook Inlet to N American gas opportunities
 - Cook Inlet does not have world class exploration opportunities
 - However, viable smaller exploration opportunities exist
- ◆ Good access to lands
- ◆ Disadvantaged by high costs
- ◆ Disadvantaged by permitting and regulatory burden
- ◆ Disadvantaged by price and closed market
- ◆ Disadvantaged or incentivized by fiscal regime?????

10:53:10 AM



Consequences of SB 305 (RES) – Cook Inlet Gas

- ◆ Existing Fields

- Nothing wrong with ELF for Cook Inlet natural gas
- Loss of ELF and higher tax rate in low gas price environment will result in
 - Higher rate required to pay for costs (economic limit)
 - Fields will be shut in at higher production rates
 - Reserves will be lost.

- ◆ New Exploration and Development

- Higher taxes will result in:
 - Less competitive opportunities compared to N American gas provinces
 - Renewed decline in Cook Inlet exploration and development
 - Cancelled projects
 - **NO NEW RESERVES DEVELOPED**

- ◆ Loss of industrials and jobs

- ◆ **Higher and volatile costs to utility consumers**

10:54:10 AM



Cook Inlet – What is Needed

- ◆ Problems with Progressivity
 - Potential higher tax rate at lower margins
 - Must not link Cook Inlet PPT to volatile non-related index
 - Link to Cook Inlet Department of Revenue Prevailing Value
- ◆ Must include provision for marginal low rate fields
 - 5/20 Plan for Cook Inlet
- ◆ Prioritize efforts to incentivize, not hinder exploration and development
 - Include some form of transitional investments credit
- ◆ Actions by this Legislature will have immediate and measurable impact on Cook Inlet oil and gas industry

11:02:04 AM





Chevron
Testimony on SB 305
Finance Committee

John P. Zager
General Manager, Alaska

April 6, 2006

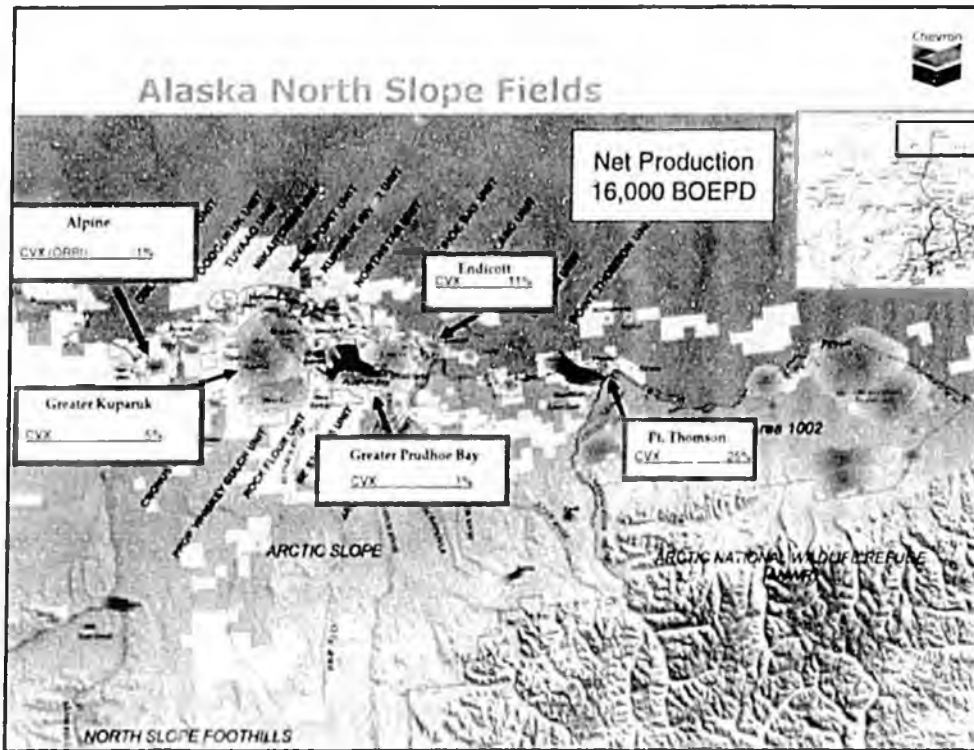
Chevron's Alaska Presence



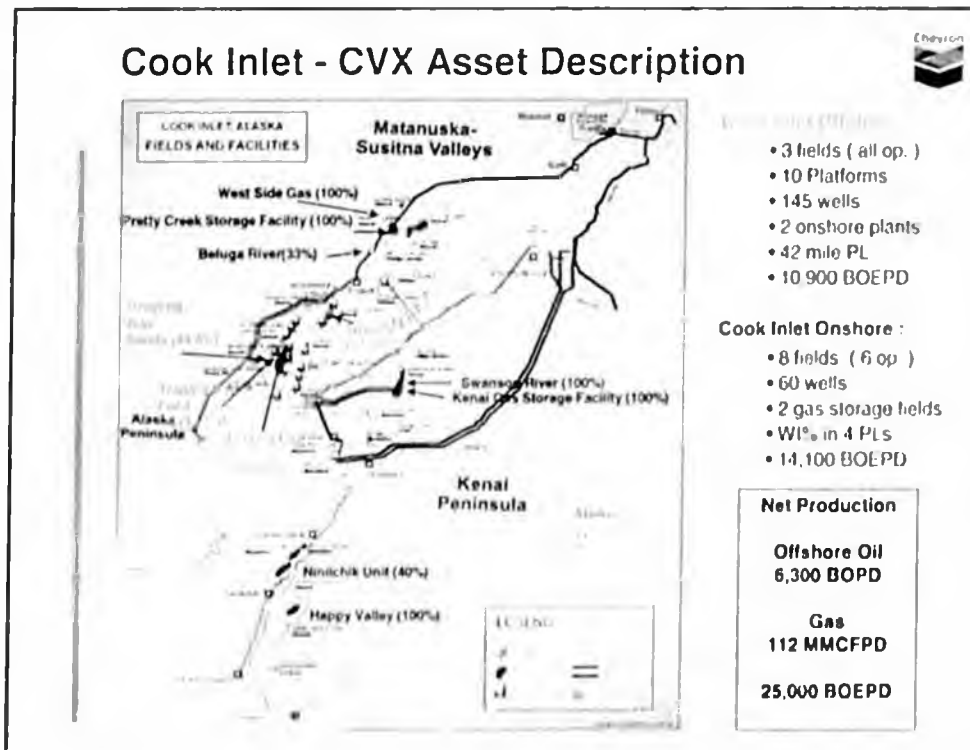
- Current Asset base is formed by combination of heritage Chevron and Unocal assets
 - Both companies have been active in Alaska for many years
- 4th largest producer in state
- 3rd largest operator
- 382 employees or full time contractors
 - 272 on the Kenai Peninsula
 - Payroll of >\$45 million
- Key customers: Tesoro, Enstar, Chugach Electric, Agrium, Aurora
- Chevron is the only producer in the state with a relative balance of assets in the Cook Inlet and on the North Slope
 - Both production streams are large enough to trigger PPT
- Chevron's Cook Inlet offshore assets are uniquely positioned to suffer from the proposed PPT

9:07:40 AM

Presented
4/6/06

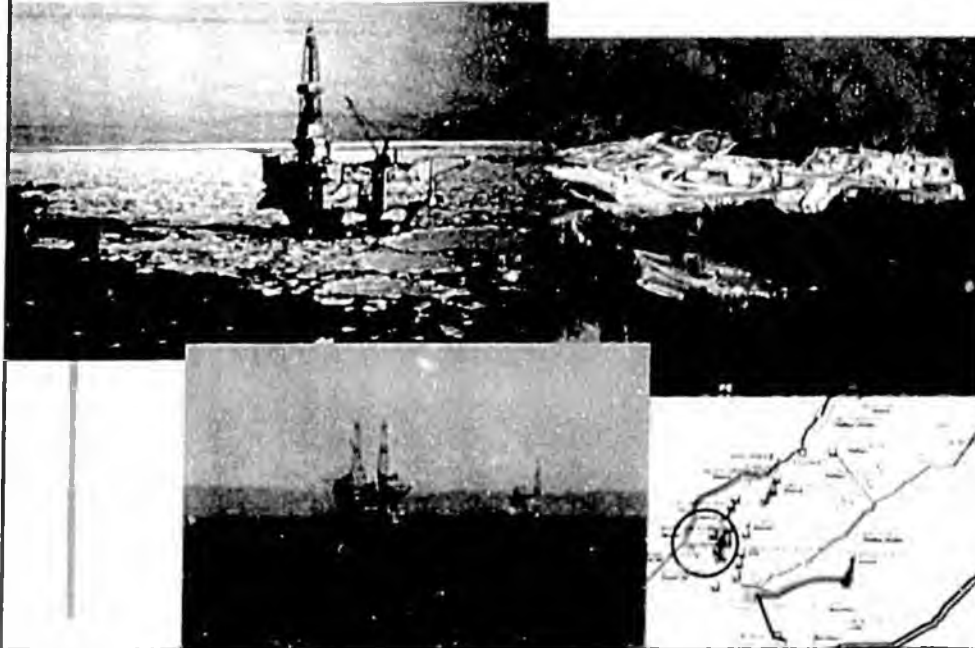


9:09:17 AM



9:10:14 AM

Trading Bay Unit

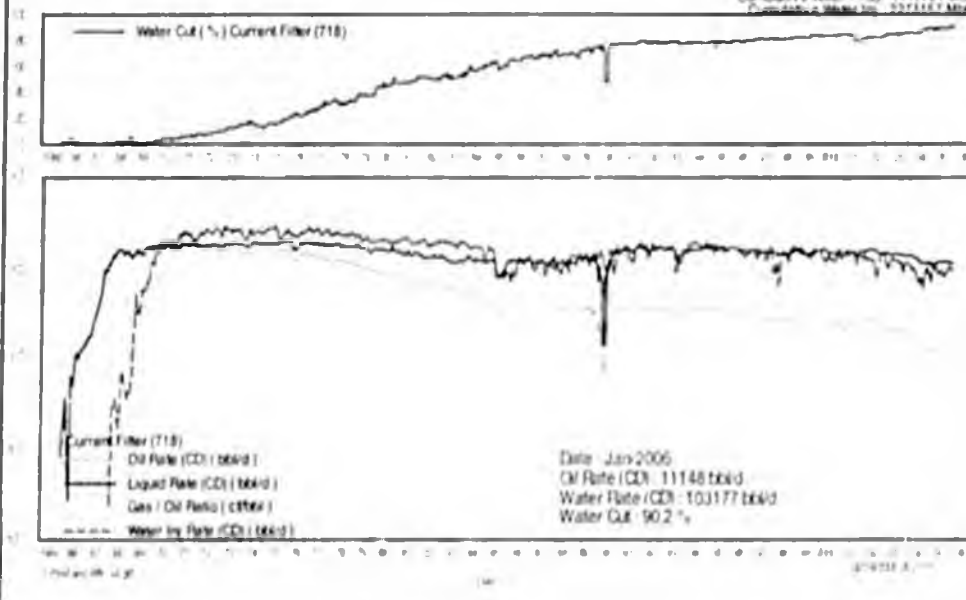


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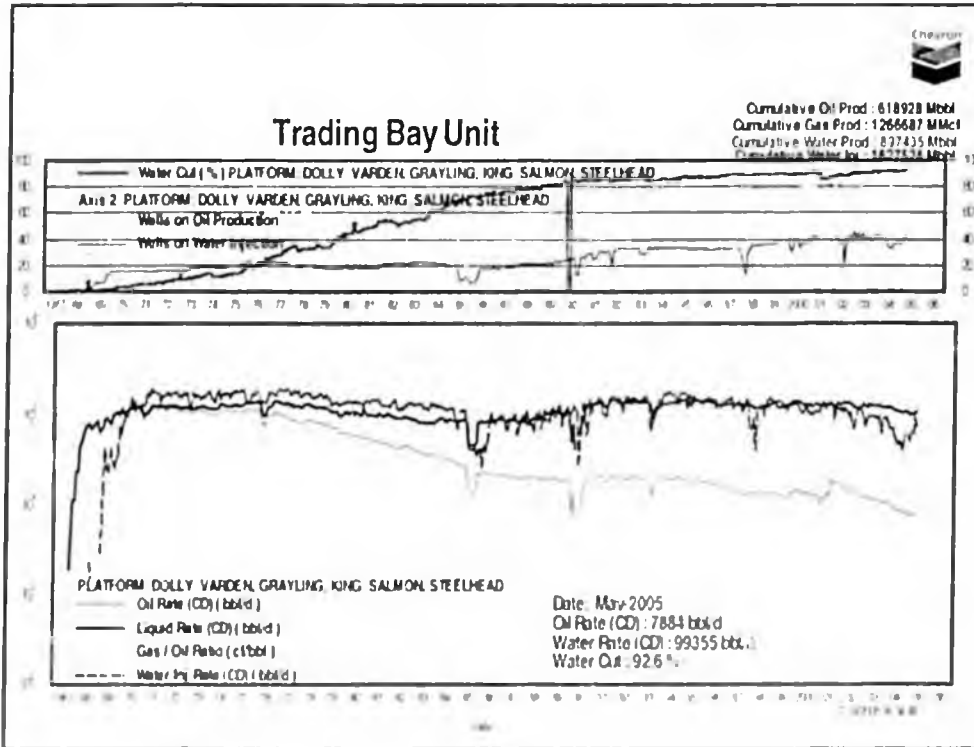
Cook Inlet Offshore



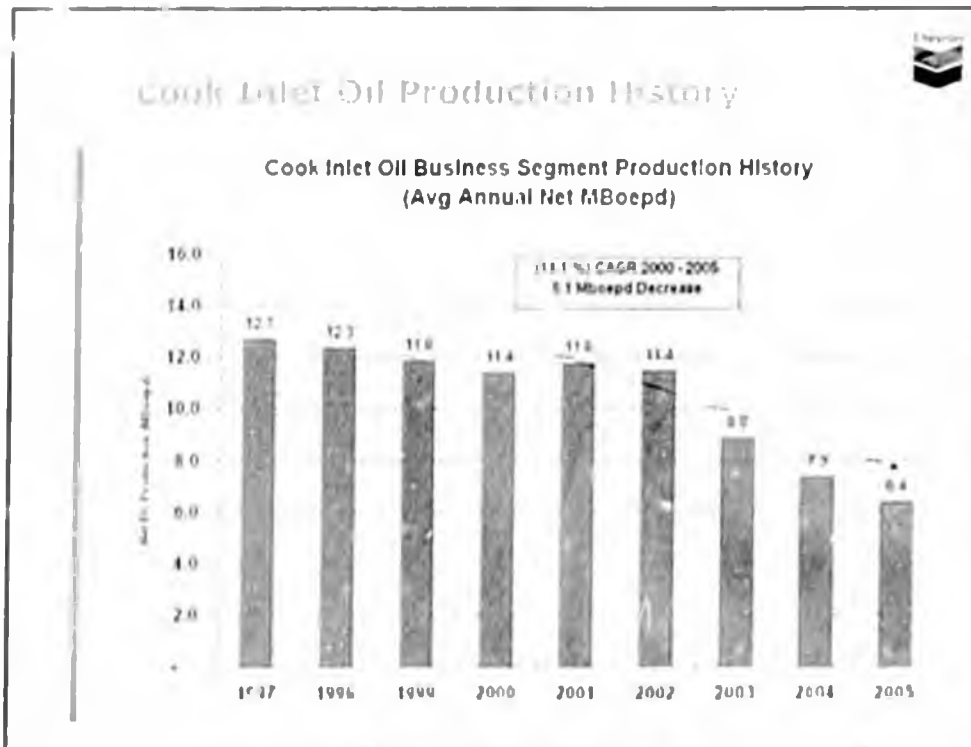
Cumulative Oil Prod: 1030570 Mbbl
 Cumulative Gas Prod: 1587463 MMcf
 Cumulative Water Prod: 1117381 Mbbl
 Cumulative Water Cut: 32.2187 Mbbl



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Cook Inlet Offshore Oil

- Cook Inlet Oil is very high cost
 - Direct lift cost \$20 - \$25 per BOE
 - Currently breakeven on Cash Flow @ ~ \$30/BOE
 - Currently breakeven on Earnings @ ~ \$40 - \$45/BOE
 - Further production declines will raise breakeven prices
- Significant operational risks
 - Two platforms are currently shut-in
 - Must maintain critical mass of operations
- Cook Inlet Offshore cannot afford an additional tax burden

9:14:33 AM
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Chevron Cook Inlet Strategic Study

- August 10, 2005 Chevron acquires Unocal
 - Much speculation about Cook Inlet asset fit in Chevron Portfolio
- October 2005 - January 2006 - Strategy work completed
 - Determined that there are incremental investment opportunities in the Cook Inlet although they are in the lowest quartile of Chevron's investment portfolio, many projects did not make the cut
- February 2006 - Great news - announce decision that Chevron will retain all Cook Inlet assets with the intent to begin a multiyear investment program
 - Chevron will retain the current office locations

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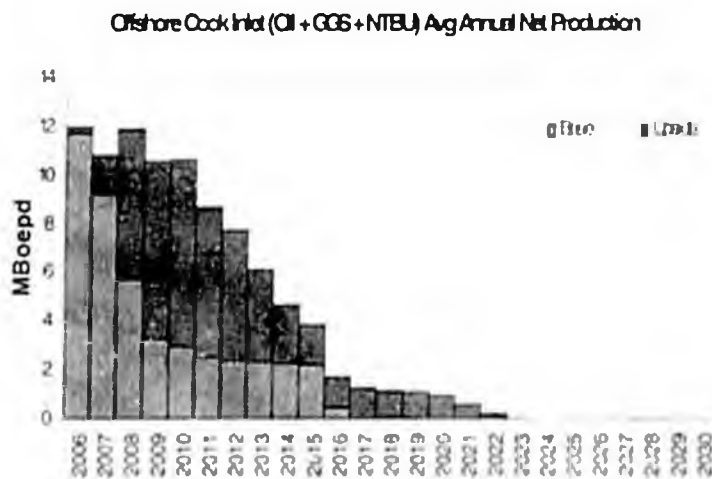
Great news, so what's the problem?



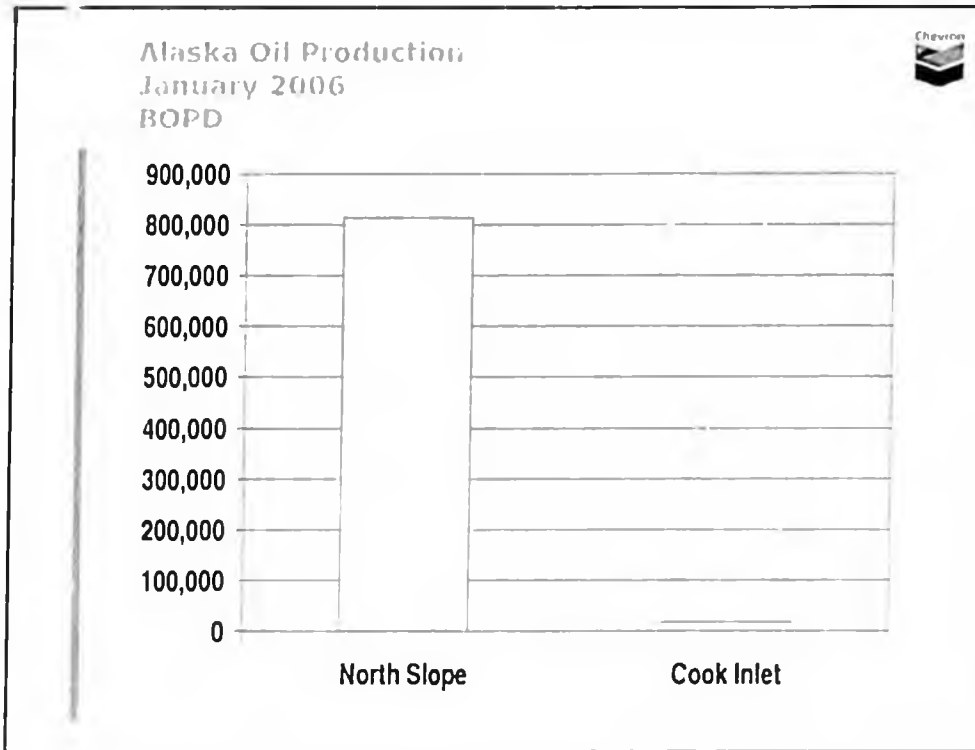
- The Cook Inlet reinvestment program was evaluated using the current severance tax assumptions (zero severance tax)
- When modeled under the proposed 20/20 PPT the economics on some projects are degraded, some projects are improved, overall poorer economics for the program
 - Oil production taxes will go up dramatically
 - Will cause investment decision to be reconsidered
 - Higher taxes will cause less capital to be spent
 - Enhanced PPT terms could significantly expand the list of economic projects in the investment program and significantly extend the life of offshore oil production

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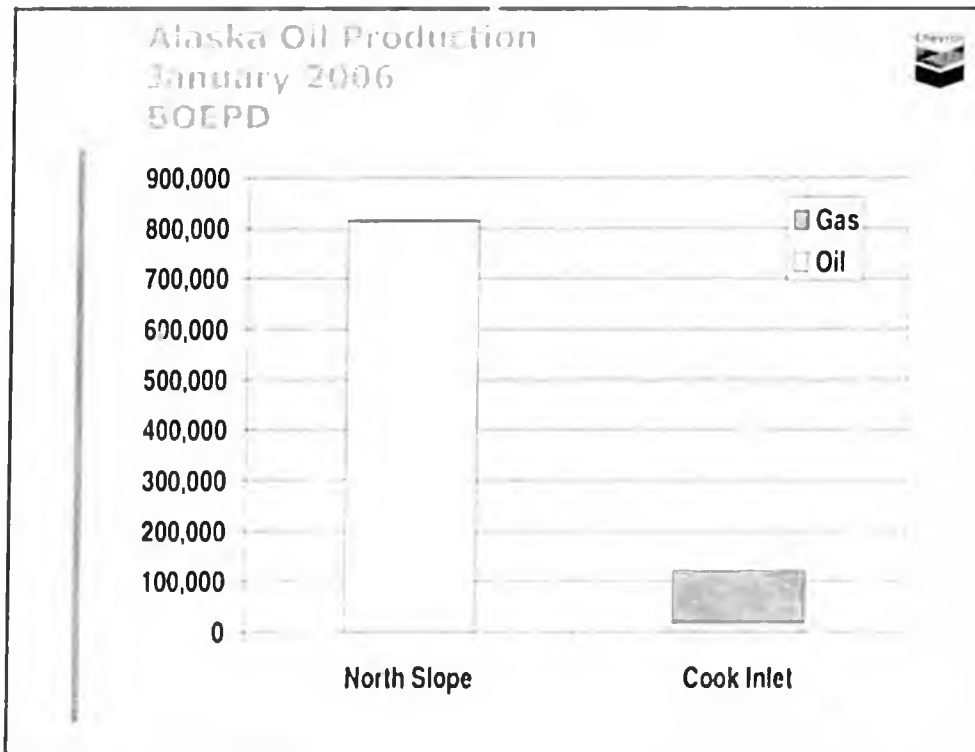
Cook Inlet Production Forecast with Four Year Capital Plan



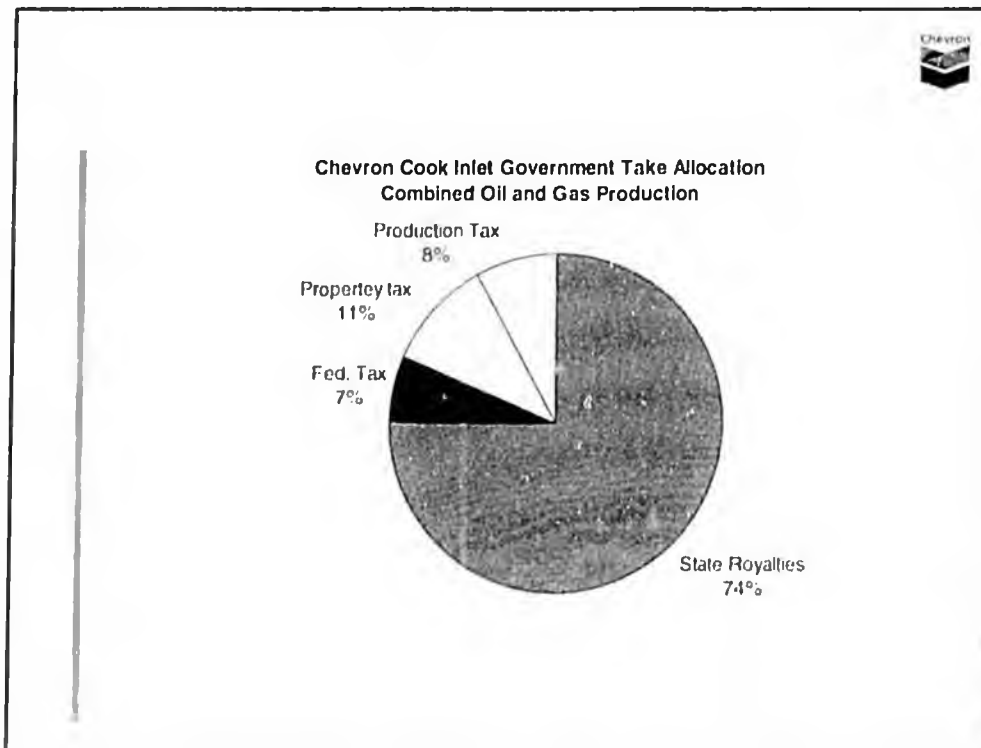
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9:24:24 AM
 2 9:28:14 AM

- 
- Reasons to Lower Taxes and Provide Incentives
for Additional Cook Inlet Investment**
- Gas is running out
 - Home heating, electrical generation, industrial consumption
 - Additional gas supply is critical to state's economy
 - Other options are much more expensive than Cook Inlet gas
 - Production tax is a pass through on most utility contracts
 - Tax increase represents increase in gas price to consumers
 - Oil redevelopment will maintain and add new jobs and will extend field life
 - Cook Inlet competes for capital with other areas in North America, does not compete for global capital
 - Under PPT Alaska will have the worst fiscal terms in the U.S.

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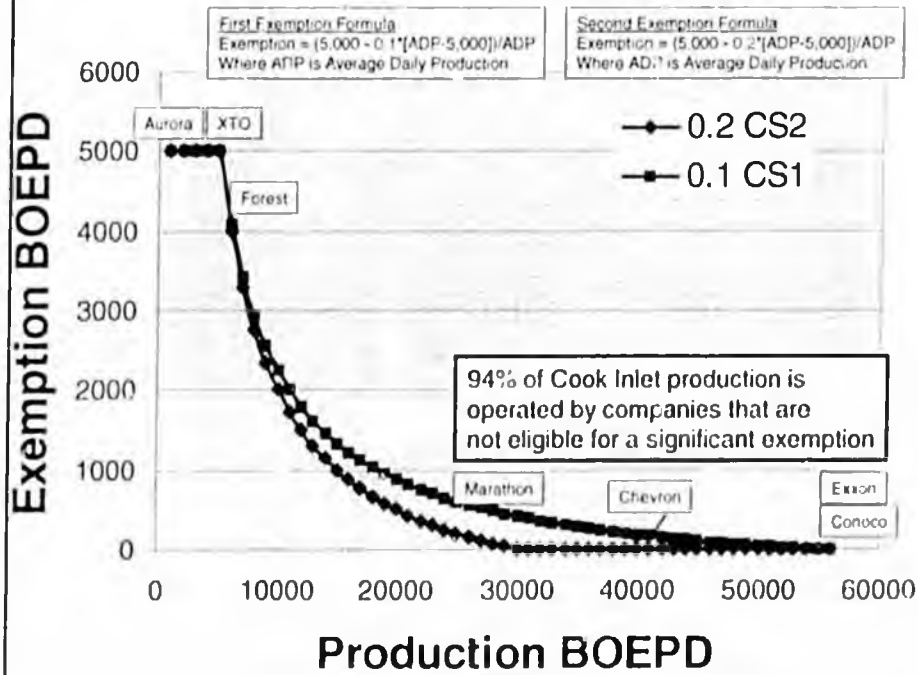
Cook Inlet Provisions to Date



- House Resources - None
- Senate Resources - "5,000 BOPD exemption"
 - Fails to provide any real help to Cook Inlet
 - May be a "small company provision", but is not a "Cook Inlet provision"
- Any "Cook Inlet Provision" should be specific to the Cook Inlet
- Reasons given not to consider Cook Inlet provision
 - Adds complication
 - Some additional complication to help Cook Inlet is justified
 - System must be uniform over entire state
 - We already have statutes that distinguish geographic areas

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Senate CS - BOE Exempted



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Senate Resources CS - The unique value and challenged position of the Cook Inlet is not adequately addressed



- Revisions as proposed in the CS lowers the economics of capital investments in the Cook Inlet
 - Puts Chevron's four year capital program in jeopardy
 - At the very least, increased taxes will lower investment
 - Without capital McArthur River Field is gone in ~4 years
 - Critical mass for Cook Inlet oil industry is gone

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Recommendation on Cook Inlet



Consider the following options:

- Carve out Cook Inlet
 - Leave under current system
- Apply PPT methodology to keep taxes near current levels
 - Adjust tax rates lower (5%)
 - Retain overall incentive rates (20%)

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General Comments on CS



- 25% tax rate is too high and will discourage investment, a return to 20% overall rate is in the best interest of Alaska
- Prefer \$12 million credit to 5,000 BOEPD exemption
- Transition capital must be earned again on 2:1 basis
 - + Prefer original proposal, this is better than nothing, suggest extending time period to 10 years
- April 1, commencement date, not practical, punitive penalty and interest rate
- Progressivity – do not support - taking away the "windfalls", no matter how you couch it, lowers expected value to investors, and therefore will lower overall investments

9:59:24 AM

Alternative Progressivity (Windfall Profit) Provision



- Reason for the state to support progressivity
 - To get a "fair share" when there is a price run up accompanied by large profits
 - NOT to raise taxes if the price increase is gradual over time and is accompanied by increases in costs and thus not accompanied by increased profits – NO! a creeping tax increase
- Problems with progressivity as currently proposed
 - "Trigger" price tied to WTI (or Henry Hub) is not inflated
 - Over time prices and costs will rise – 30 years is a long time
 - "High cost" oil will be produced in increasing quantities
 - Over the long term a fixed trigger price will not work as intended
- Consider changing the trigger from commodity price to a "net profits" trigger

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How would a "net profits" trigger work?



- Each company already will calculate a "net profits" every month
 - Divide monthly net profits by production to get a "net profits/boe"
- Set trigger point and escalation factor based on "net profits/boe"
 - Suggest \$50/boe net profits trigger and 2.0% for each \$10 increase in profits
 - Minimum general rate of 20% tax on net profit
 - Maximum general rate of 30% tax on net profit
- Advantages
 - Self correcting for inflation, costs, commodity, high cost production (avoid discussion of WTI, ANS, Henry Hub, well head, etc.)
 - Fully captures the "windfall" upside, without creating unintended consequences
 - System is fair, since taxes and progressivity will only be attached to actual company profits

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Examples of "Net Profits" Trigger



1 - Windfall Case - Price double - Costs fixed

Average Rev/BOE	60.00	110.00
Expense Per BOE	7.00	7.00
Capital Per BOE (incl. Cap credit)	3.00	3.00
Net "Profit" per BOE	50.00	100.00
PPT %	20.0%	30.0%
actual tax per BOE	\$ 10.00	\$ 30.00

2 - Increase Profits - Price double - Costs up

Average Rev/BOE	60.00	110.00
Expense Per BOE	7.00	37.00
Capital Per BOE (incl. Cap credit)	3.00	3.00
Net "Profit" per BOE	50.00	70.00
PPT %	20.0%	24.0%
actual tax per BOE	\$ 10.00	\$ 16.80

3 - Constant Profit - Price double - Costs keep pace

Average Rev/BOE	60.00	110.00
Expense Per BOE	7.00	57.00
Capital Per BOE (incl. Cap credit)	3.00	3.00
Net "Profit" per BOE	50.00	50.00
PPT %	20.0%	20.0%
actual tax per BOE	\$ 10.00	\$ 10.00

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General Comments on CS



- Debate between "get it now" and "grow the pie"
 - "Get it now" option will balloon short term revenue creating a state windfall that must be well managed
 - "Grow the pie" option will create long term opportunities for investors and for Alaska
 - I am optimistic about the ingenuity and technology available in our industry and the people of Alaska to greatly extend oil production for the next generation
- Consultants will one day leave and we will be left to deal with our decisions
 - First you vote on behalf of the people of Alaska
 - Then over the coming years investors vote with their dollars
 - Original industry support was astounding
 - However, Investors Big and small, old and new, are now saying that the Senate Resources CS structure will discourage investment in Alaska

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Summary Comments on CS



- Chevron cannot support the Senate Resources CS in its current form
- Urge return to original PPT terms, while inserting a 5/20 Cook Inlet provision
- Recommend inclusion of an additional capital credit for heavy oil or tertiary recovery (CO2) projects statewide
- Chevron has been in Alaska for many years and intends to continue an active exploration and production operation in the state if a sound and stable fiscal regime can be offered

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PIONEER
NATURAL RESOURCES ALASKA

SB 305 PPT

Senate Resources

Committee

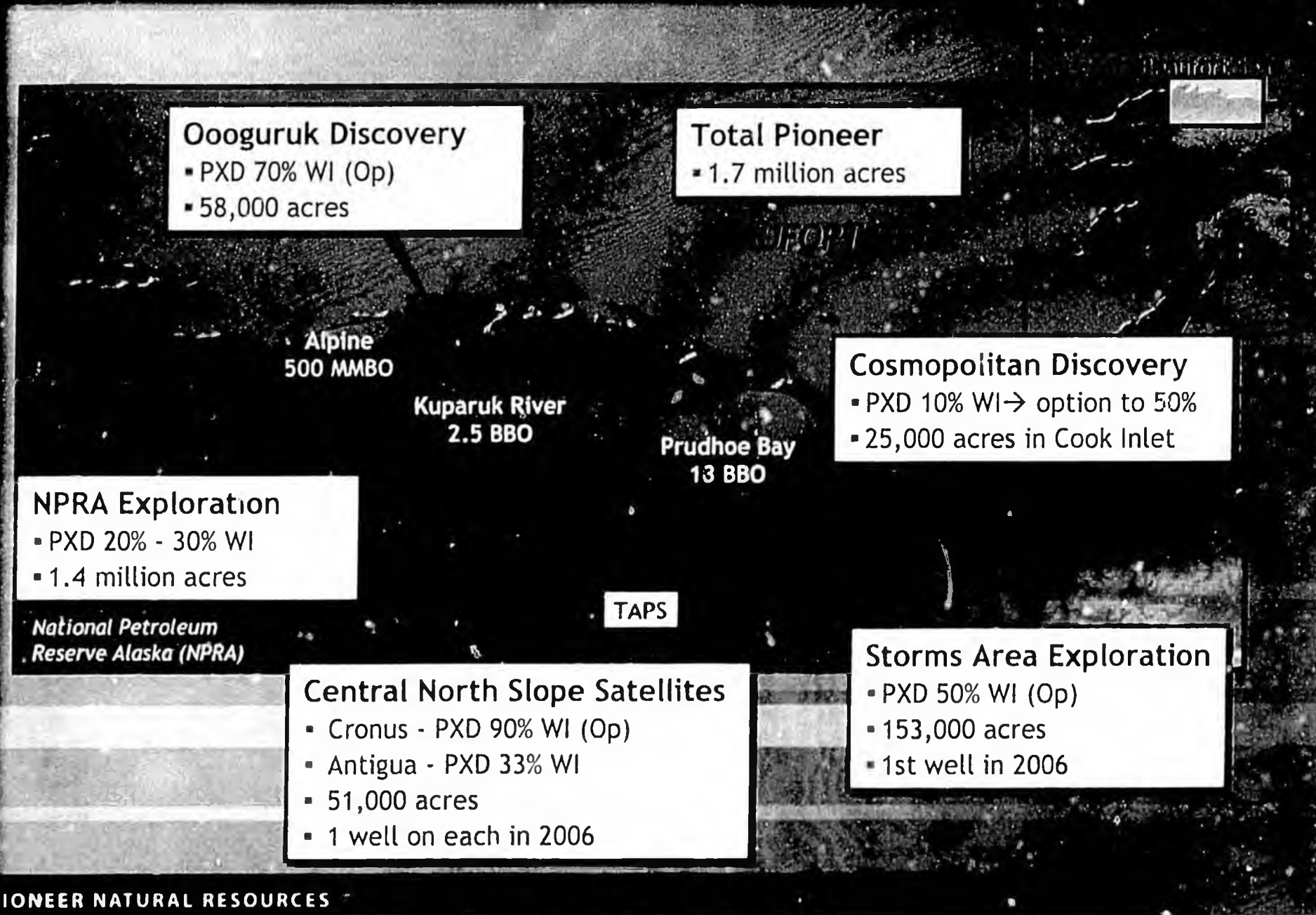
Juneau, Alaska

April 7, 2006

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Pat Tola 4/7/06

Pioneer's Alaska Acreage

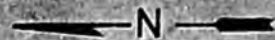


Oooguruk Development Project

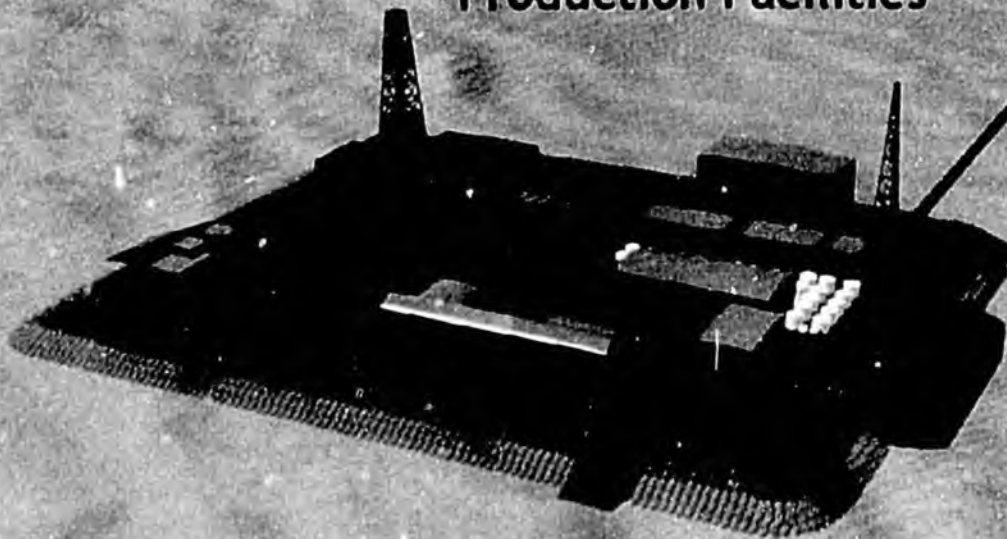


- Development Cost: \$450 – 525 million
- Reserve Potential: 50 – 90 million bbls
- Peak Flow Rates: 15 – 20,000 bbls per day in 2010

Tie-in to COP
Kuparuk River Facilities



**Drillsite and
Production Facilities**



Harrison Bay
(4.5' water depth)

Oooguruk Major Project Construction Components



▪ Winter 2006

- Gravel Mining
- Gravel Placement - Drillsite & Onshore Pad

▪ Winter 2007

- Flowline Installation
- Facility & Equipment Installation

▪ 2008 – 2011

- 38 Well Drilling Program



Alaska's Challenges



- **Some of the Highest Costs in the World**
 - Large Minimum Economic Field
- **Future Exploration & Development Challenges**
 - Smaller Reservoirs
 - Remote Resources
 - Viscous Oil Resources
 - Gas
- **Long Cycle Times (5 to 10 years)**
- **Investment Uncertainty**
 - Exploration & Reservoir Risk
 - Price Risk
 - Fiscal Certainty

Alaska. Climate that Encouraged Pioneer



- **Emerging Business Opportunities**
 - Investment Opportunities Offered by the State
 - Cooperation re: Facility Access
- **Attractive Fiscal Policy**
 - Reasonable Lease Terms & Availability
 - ELF Formula: Low Taxes on all but Largest Fields
 - Exploration Incentive Credits

Alaska's Competitiveness



- **To Attract Most Independents, Alaska must effectively compete with onshore oil and gas Resource Plays**

– Resource Plays (tight sands, coalbed methane, shales) are attracting huge amounts of investment

- Lower Risk
- Lower Cost
- Shorter Project Cycle Time
- Lower State Tax

Benefits of Administration's PPT Proposal



- **Balanced Tax/Credit Rate of 20/20**
- **Fair Principles**
 - Tax Based Upon Profits
 - Compensation for Transition Capital
- **\$73MM Exemption Mitigates New Exploration**
- **Tradable Credits allow Quick Monetization**
- **Modest Incentives for Exploration, New Investment**
- **Reduces Minimum Economic Field Size**

***We believe the proposal would encourage new investment in
Alaska, grow the resource pie and increase***

PPT Tax Rate



- **20% Rate Reasonably Balanced with Credit**
- **If Rate is Higher it must be Balanced with Credit**
 - Credit must apply to both Exploration and Development
 - Rate / Credit Balance is Affected by PPT
- **Higher Tax Rate:**
 - Reduces Incentive to Invest
 - Raises Investment Threshold
 - Fewer Exploration Wells Drilled
 - Marginal Resources Left Undeveloped

Tax Rate Progressivity



- **Increasing Oil Prices Lead to Increasing Profits**
 - 2005 W. Texas Drilling Costs Increased 20%
 - Steel prices more than doubled in 2005
 - Costs for all Services Escalating Rapidly
- **Profits not Directly Proportional to Oil Prices**
- **If Enacted, Progressive Tax Rate**
 - Should be Profits Based
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 - Different basis is un-necessarily complex
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5,000 BBL "Start-up" Exemption



- **New Entrant Challenges**
 - New Entrants do not hold Existing Infrastructure
 - Smaller Investors lack Operating Economies of Scale
 - Most New Investment Opportunities are Challenging
- **Exemption Mitigates High Alaska Start-up Costs**
 - Local, Highly Skilled Technical Employment
 - Requires Building an Expensive G&G Database
 - Companies w/ AK Employees Pay Income Tax
- **Exemption Sunset is not Fair or Practical**
 - Discovery to Production cycle time is 5 – 10 years
- **Phase out of Credit/Exemption is Discriminatory**

**We believe "Start-up" Exemptions are essential to attract
investors and give them a better return.**

Fair Value for Tradable Tax Credits



- **Tax Credit Value is Diminished to New Value**
 - Held Credits diminish through time by discounting
 - Sold Credits would likely sell at a discount
 - Discount value captured by purchaser
 - Credit Cost to State remains 100%

- **“Refundable” Credits Increase Value to New Value**

- **Pioneer’s Investments Will Generate Substantial Cash Refunds**
 - Consider a State Cash Refund at Higher Oil Prices

Transitional Capital Recovery



- **Fairness Issue**
 - Investments were made under old tax system
 - Tax System is changing
 - Pioneer has recouped nothing from investments
- **Pioneer's Alaskan Investment Begins to Pay Off**
- **Pioneer's Cumulative Investment Over Time**
- **Transition Capital Look-Back is Appropriate**
- **Look-Back w/ 2:1 Future Requirement is OK**

Pioneer Key Messages



- **Pioneer Goal: Establish Alaska as Core Production State**
- **Priorities for State of Alaska:**
 - Provide Incentives to Convert Resources
 - Attract New Investment
 - Effectively Compete w/ North America
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PIONEER



SB 305 PPT

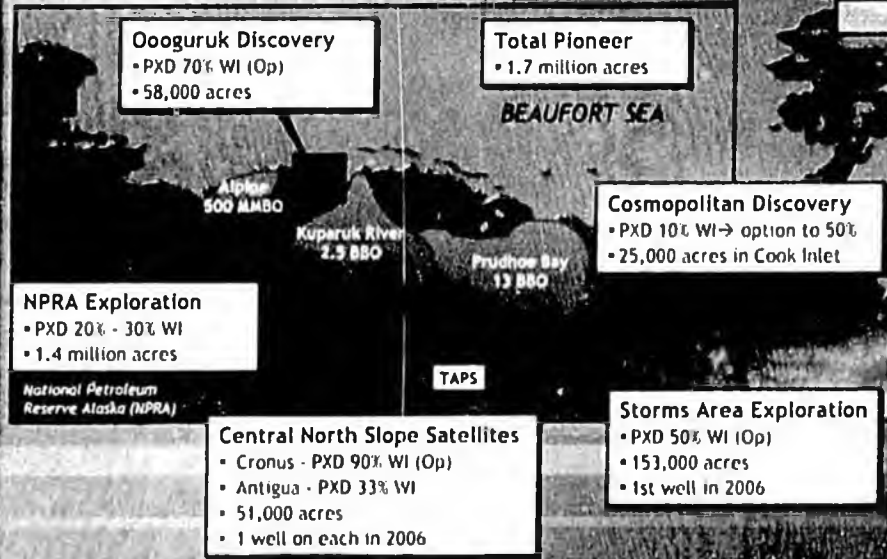
Senate Resources

Committee

Juneau, Alaska

April 7, 2006

Pioneer's Alaska Acreage



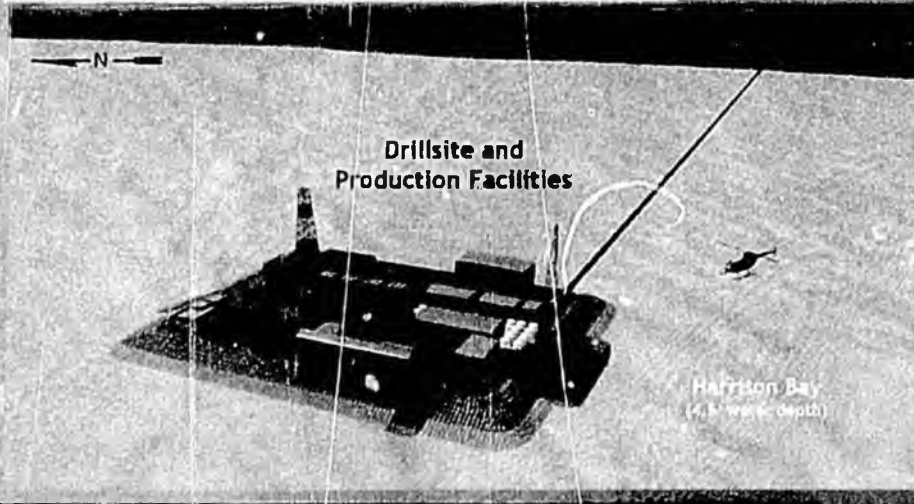
PIONEER NATURAL RESOURCES

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PIONEER NATURAL RESOURCES

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PIONEER NATURAL RESOURCES

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MINNER NATURAL RESOURCES

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PIONEER NATURAL RESOURCES

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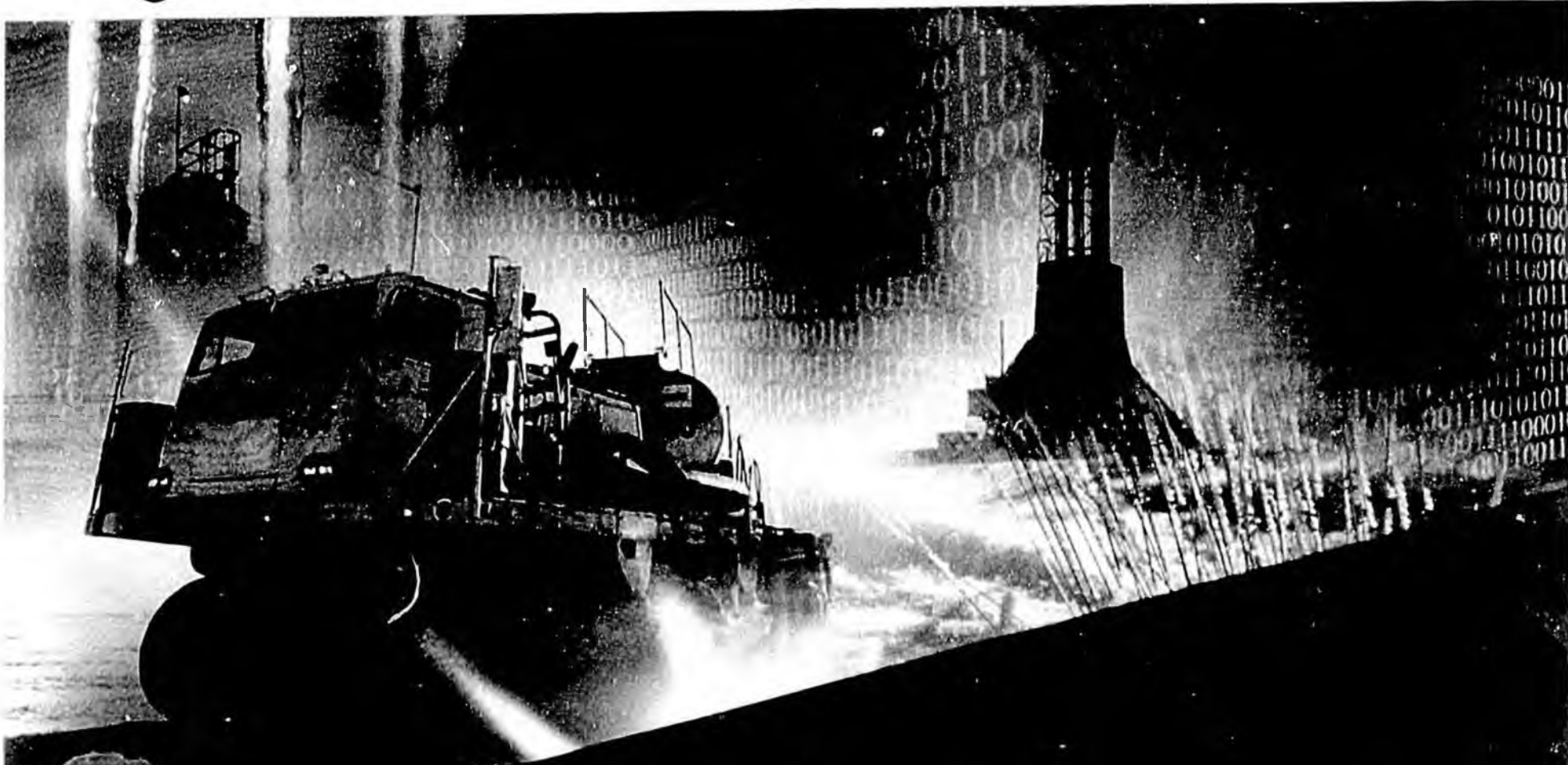
PIONEER NATURAL RESOURCES

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PIONEER NATURAL RESOURCES



PPT Discussion

Anadarko[®]
Petroleum Corporation

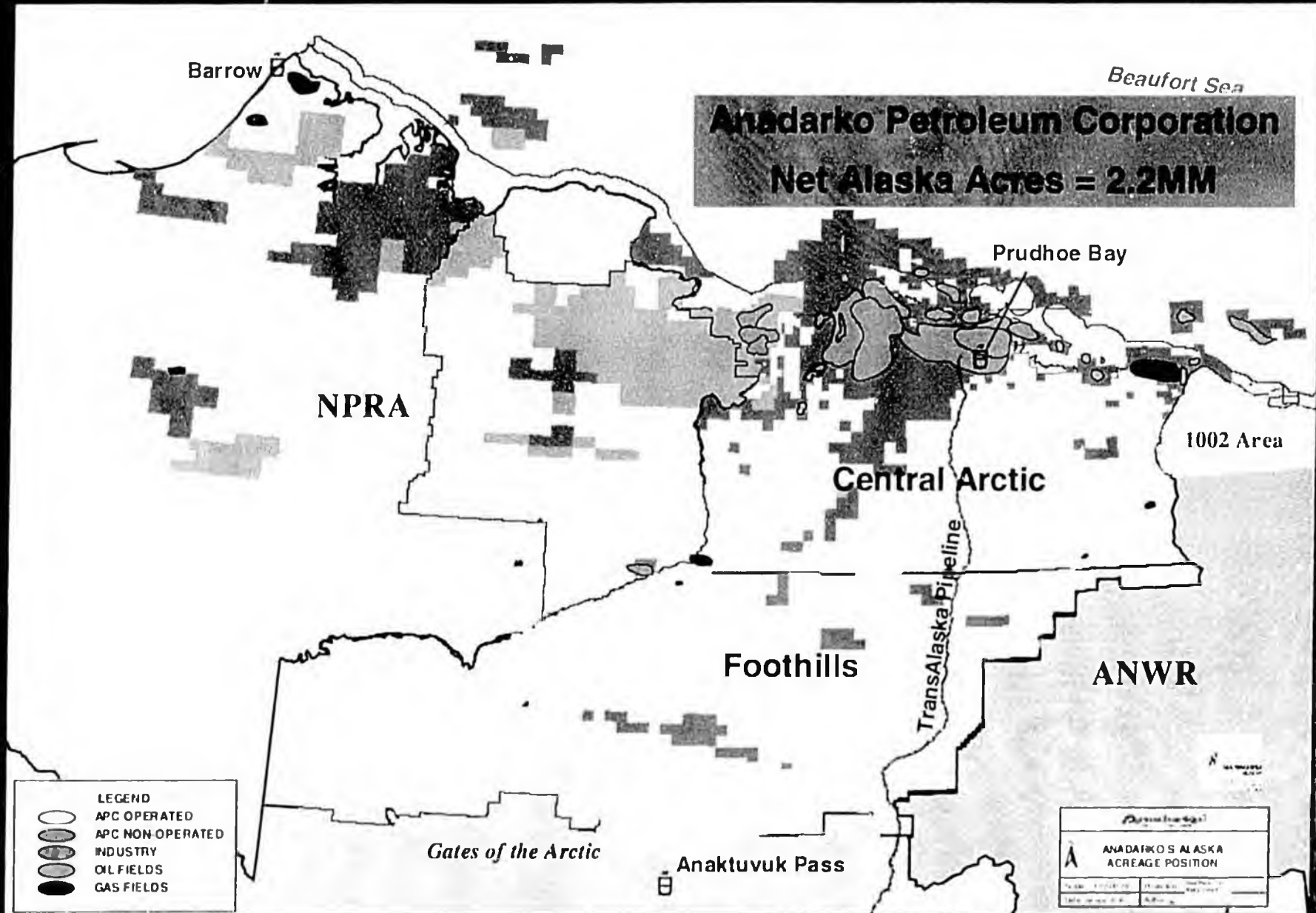
April 7, 2006 Senate Finance Committee¹

4/7/06 Mark Hanley

Overview of Anadarko Petroleum



Anadarko's Alaska Acreage Position



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Alaska Opportunities

- ▶ World class petroleum basin
- ▶ Significant remaining resource potential
- ▶ Legacy type prospectivity (i.e. Anchor Fields)
- ▶ Favorable political environment
- ▶ Abundant new entrants/partnering opportunities

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* Alaska Challenges

- ▶ **Maturing basin/materiality**
- ▶ **High costs**
- ▶ **Lack of infrastructure and competition**
- ▶ **Extremely long lead-time exploration**
- ▶ **Seasonal drilling & regulatory timing requirements**
- ▶ **Lack of gas market**

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How about PPT?

- ▶ **We support original bill**
- ▶ **Administration did a good job balancing issues & priorities**
 - *We pay more in taxes, but our exploration economics improve and there is some downside price protection- should increase exploration investment*
 - *State receives substantially more revenue than under current system*

More production needed

- 4 **Declining production is primary driver of lower state revenue**
- 4 **Increased investment (compared with today's levels) needed to increase production & stem decline**
- 4 **Original bill offset tax increase with credits & allowances**
 - *Our exploration economics generally improved*
- 4 **Tax rate increases and allowance decreases (with no credit offsets) reduce our economics**
 - *Minimum economic field size increases*
 - *Amount of economically recoverable oil & gas decreases*

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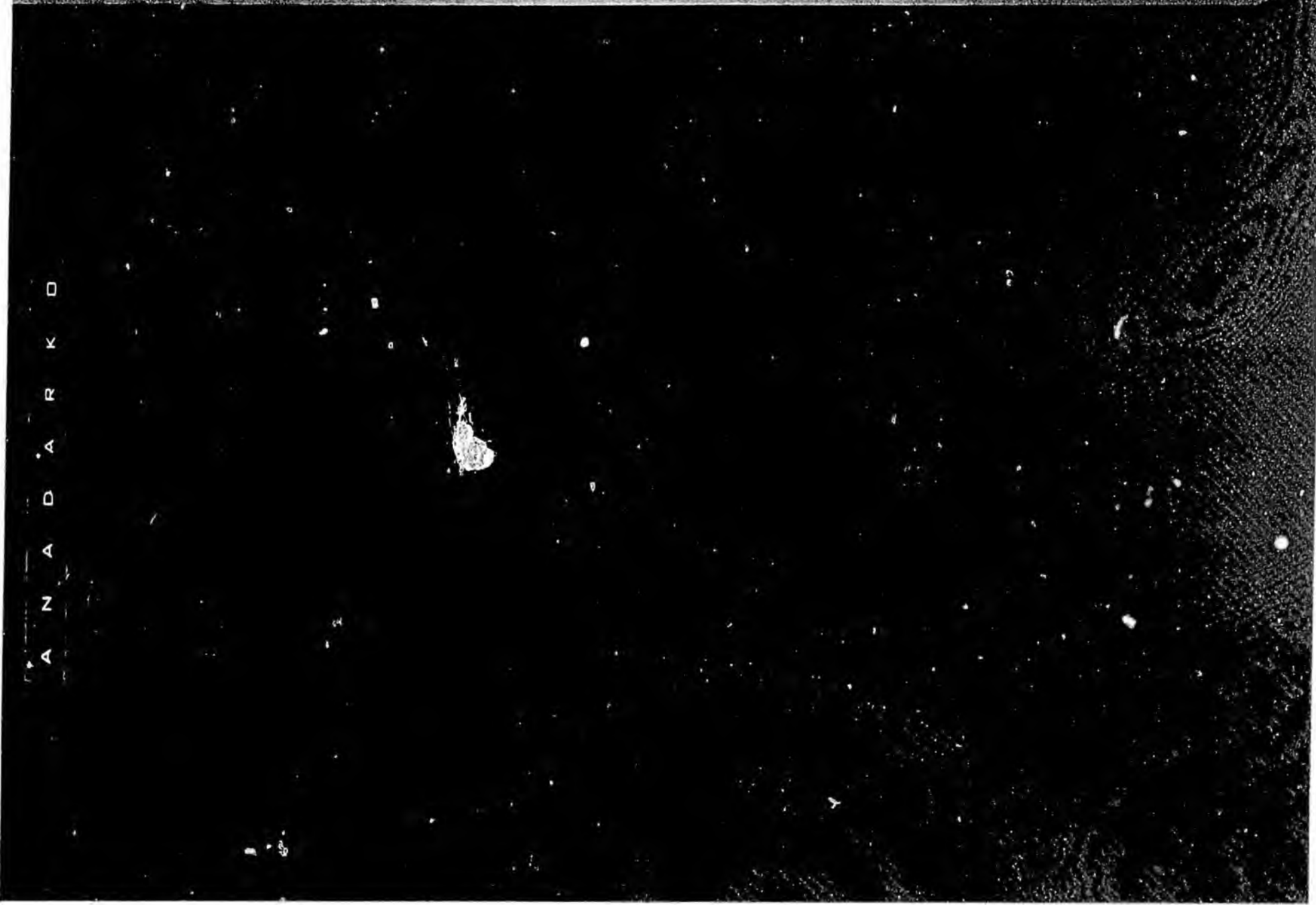
Key Issues

- ▲ Tax Rate
- ▲ Tax Escalator
- ▲ \$73 million allowance
- ▲ Transition allowance
- ▲ Point of production
- ▲ Gas economics
- ▲ Credit additions

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Backup

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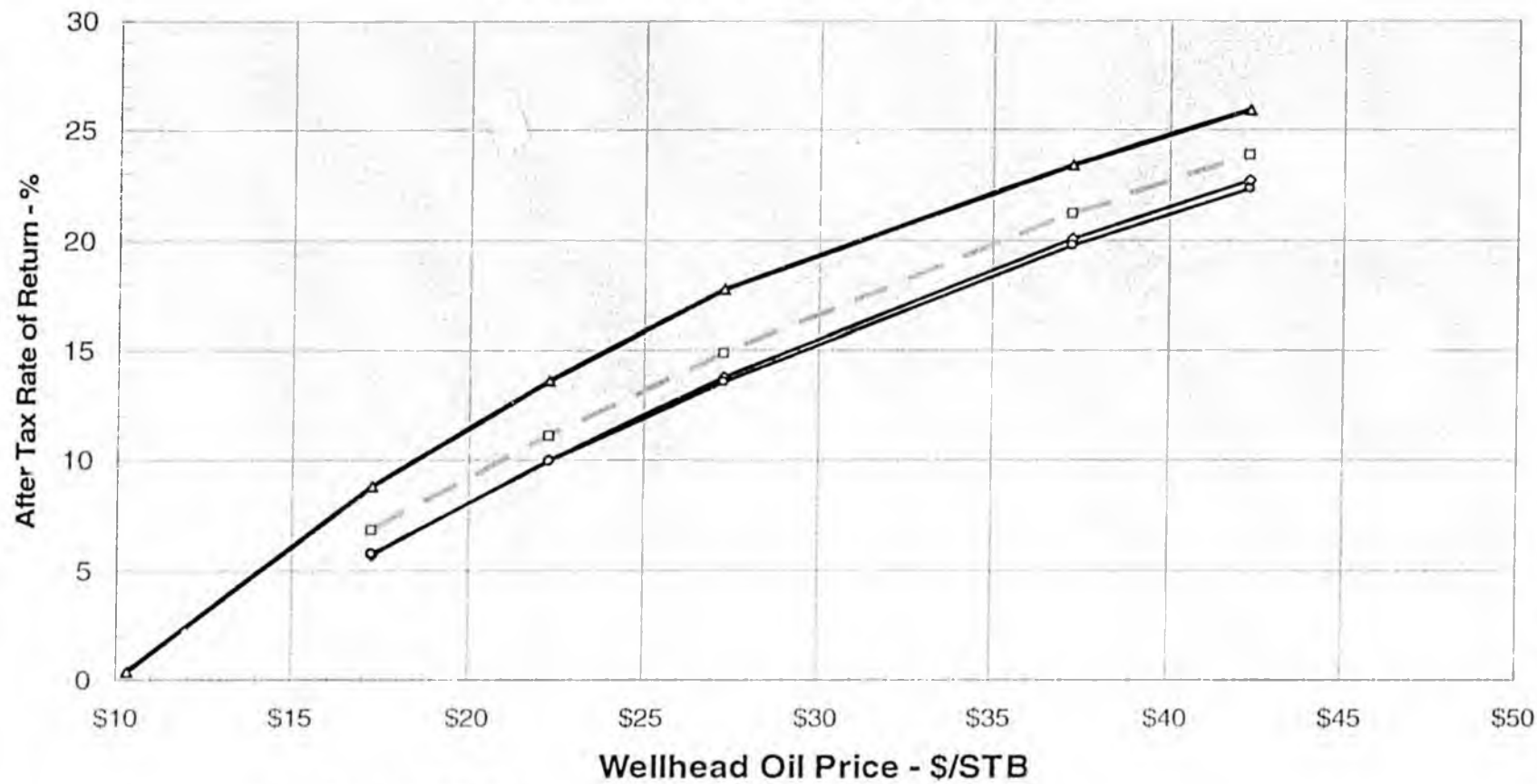


New Small Oil Development

- **Ultimate recovery is 47 million barrels.**
- **Peak oil production rate is 15,000 BOPD.**
- **Capital expenditure is 316 million dollars.**
- **Timing from discovery to first production is 6 years.**
- **The development concept is a satellite to an existing oil field. The satellite has a separate ELF calculation from the existing oil field.**
- **The satellite field pays an oil processing charge to the existing facility of \$5.00 per barrel. This is treated as a deduction to the wellhead price.**
- **The royalty is 12.5%.**

Small Oil Development- Rate of Return

After Tax Rate of Return as a function of Wellhead Oil Price
Small Oil Development



- Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer : \$73MM Exemption Applied Elsewhere
- △— 20%-20%-\$73MM Proposal - New Entrant : \$73MM Exemption Applied to this Evaluation
- ◇— 25%-20%-\$73MM Sensitivity Calculation - Existing Producer : \$73MM Exemption Applied Elsewhere

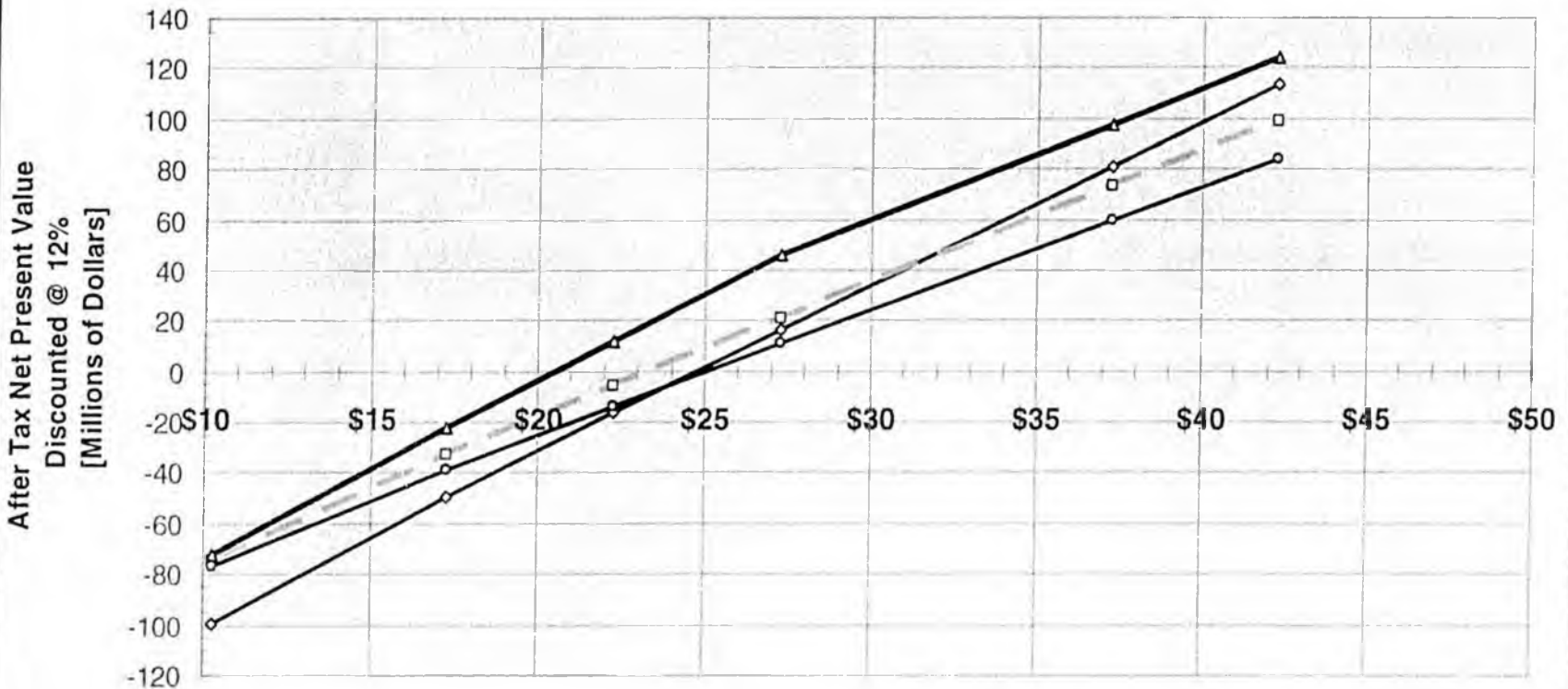
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Small Oil Development- Net Present Value

After Tax Net Present Value Discounted @ 12 % vs. Wellhead Oil Price

Small Oil Development



Wellhead Oil Price - \$/STB

- ◇— Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer : \$73MM Exemption Applied Elsewhere
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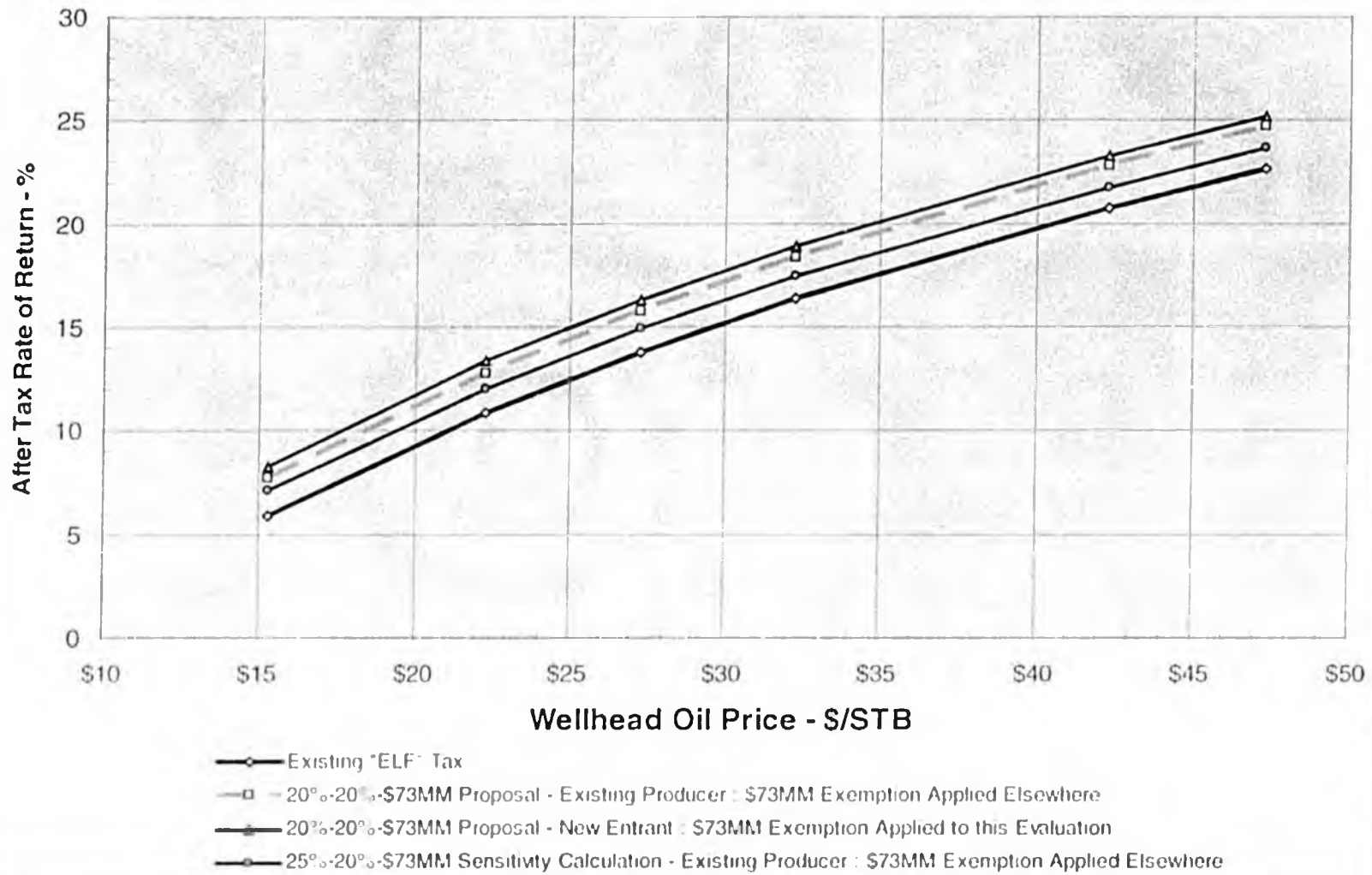
Risked Exploration Economics for Oil Prospect

- ▶ **Commercial chance of success is 15% at a \$32/Bbl wellhead oil price**
- ▶ **Mean commercial prospect size is 345 million barrels**
- ▶ **Capital expenditure is 1.1 billion dollars**
- ▶ **The peak production rate is 55,000 BOPD**
- ▶ **Royalty is 12.5%**

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Medium Oil Prospect- Risked Rate of Return

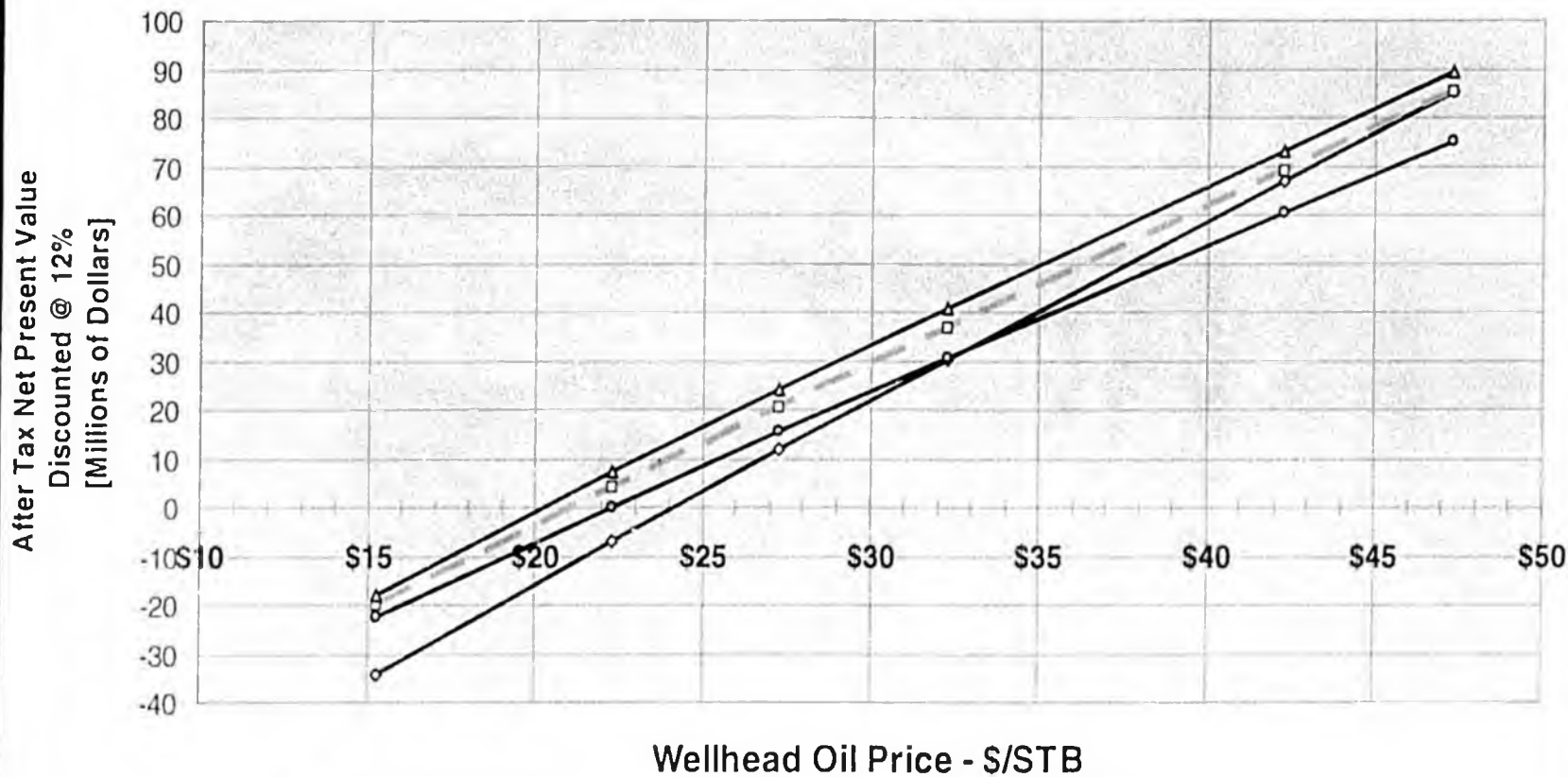
After Tax Rate of Return as a function of Wellhead Oil Price
 Risked Pre Drill 345 MMBO Prospect Exploration Economics



ANADARKO

Medium Oil Prospect- Risked Net Present Value

After Tax Net Present Value Discounted @ 12 % vs. Wellhead Oil Price
 Risked Pre Drill 345 MMBO Prospect Exploration Economics



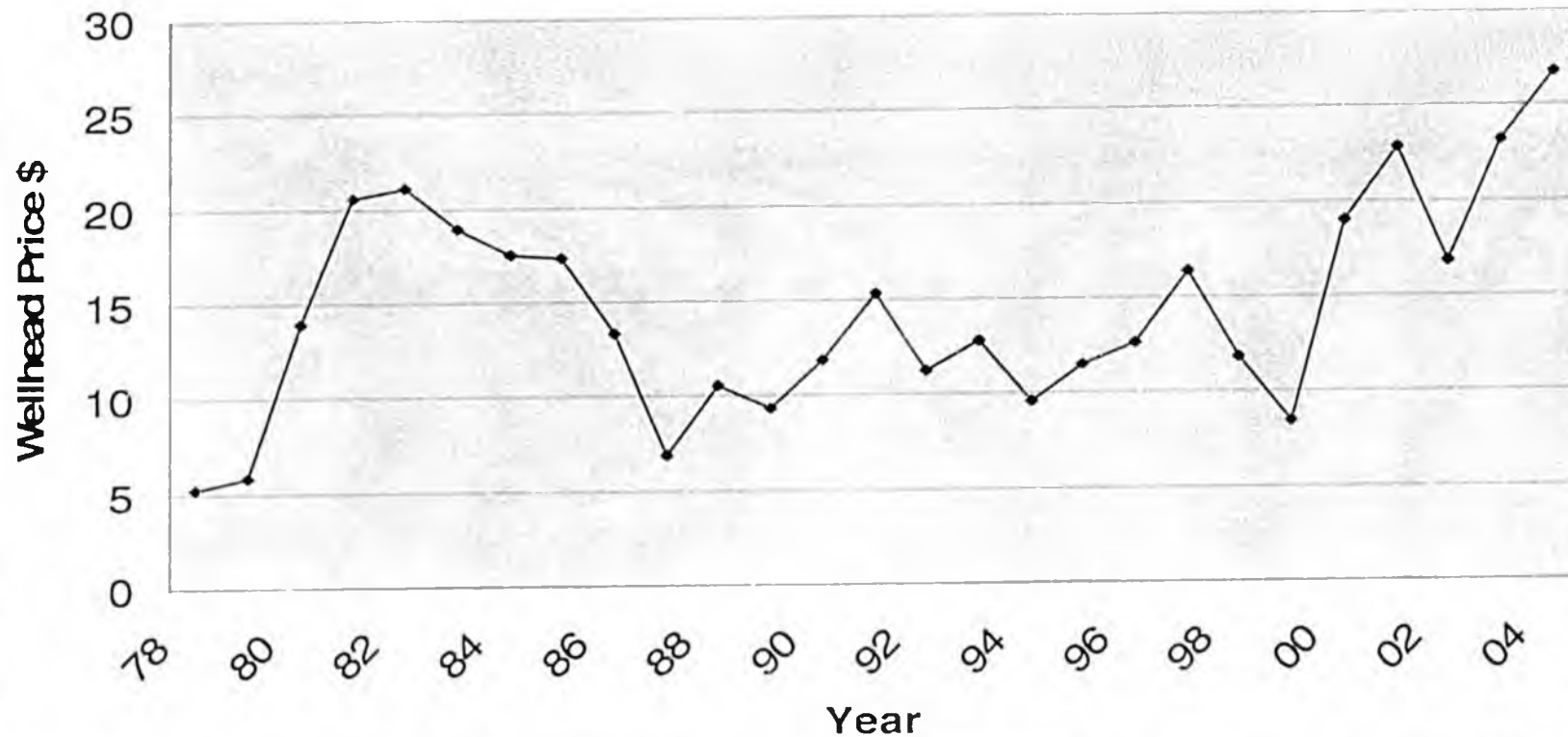
- ◇— Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer : \$73MM Exemption Applied Elsewhere
- △— 20%-20%-\$73MM Proposal - New Entrant : \$73MM Exemption Applied to this Evaluation
- 25%-20%-\$73MM Sensitivity Calculation - Existing Producer : \$73MM Exemption Applied Elsewhere

A N A D A R K O

Historic Alaska North Slope Crude Prices

ANS Wellhead Crude Oil Price

From AK Dept. of Revenue, Tax Division



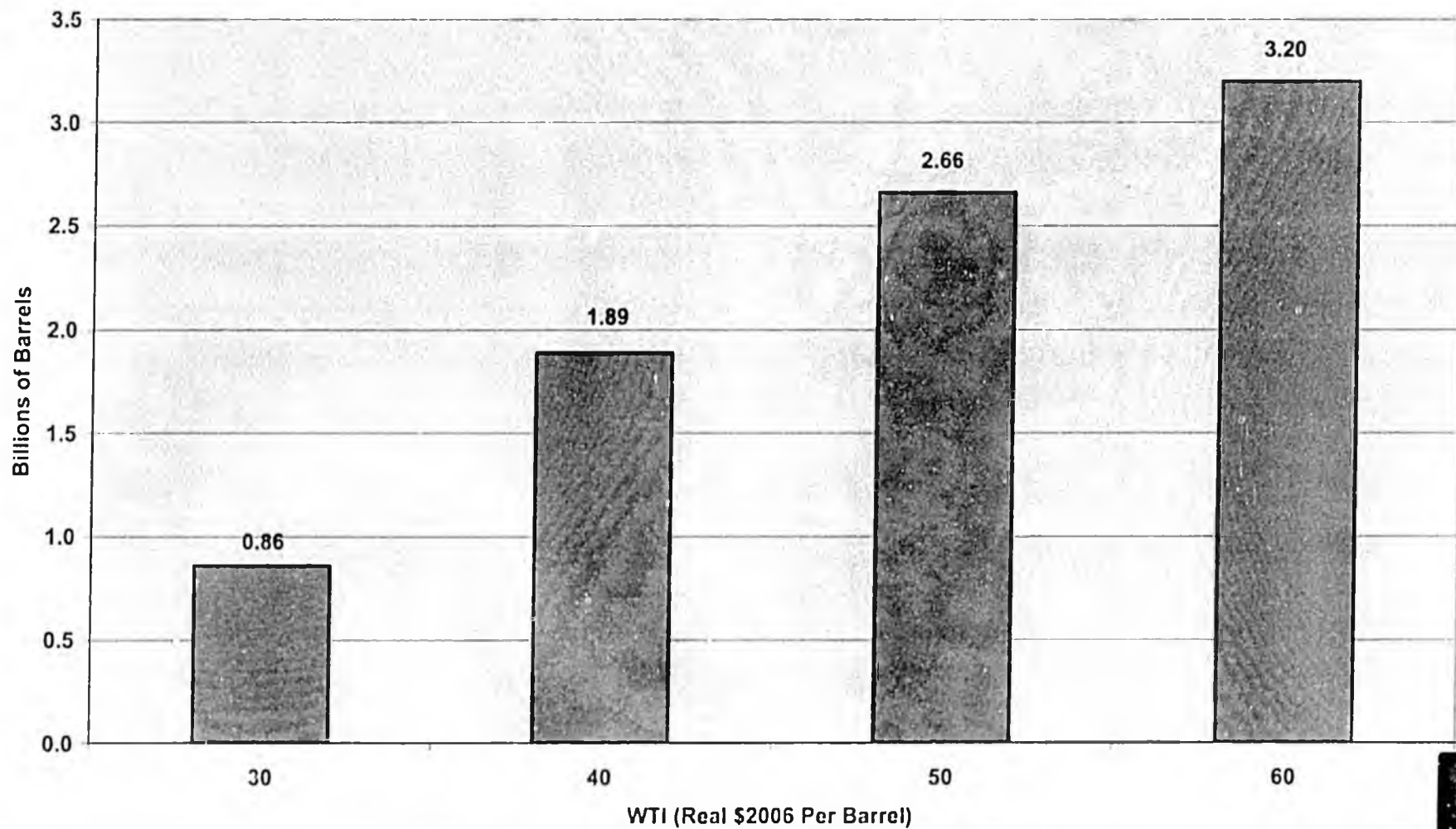
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This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that its goals will be achieved. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this release. While Anadarko makes these forward-looking statements in good faith, neither Anadarko nor its management can guarantee that the anticipated future results will be achieved. Anadarko discloses proved reserves that comply with the SEC's definitions. Additionally, Anadarko may disclose estimated reserves, which the SEC guidelines do not allow us to include in filings with the SEC. See Additional Factors Affecting Business in the Management's Discussion and Analysis (MD&A) included in the company's Annual Report on Form 10-K.

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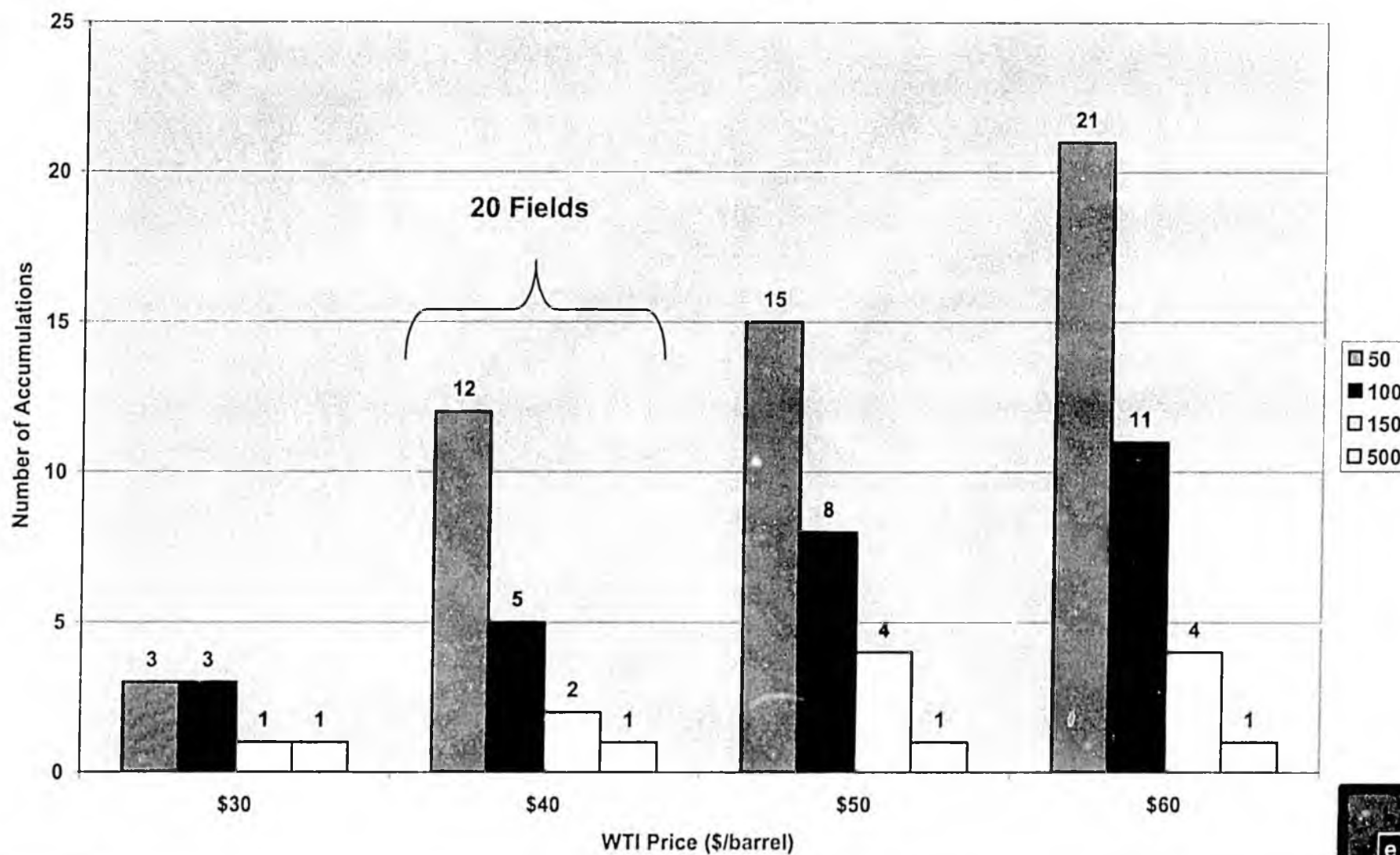
Economic Oil Reserves in Central North Slope Alaska At Alternative Prices

Economically Recoverable Reserves
Central North Slope
Mean Estimate
(No ANWR)



Expected Discoveries Under Alternative Prices

Expected Discoveries under Alternative WTI Prices
Central North Slope



Jim Weeks
4/7/06
testimony
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Testimony of James D. Weeks
On CS SB 305
Oil and Gas Production Tax
Alaska State Senate Resources Committee
FINANCE

06 April, 2006

Madam Chairman, distinguished members of the Senate Finance Committee. For the record, my name is Jim Weeks, and I am here today representing UltraStar Exploration LLC, a very small all Alaskan owned independent explorer, with strategically located leases on the North Slope. The Company was formed in 2002 by John Winther, Dale Lindsey and me, for the purpose of exploring and developing leases on the North Slope. UltraStar is 100% owned by Alaskans. I am Managing Member, and moved to Anchorage in 1984 with ARCO, and have had a presence here ever since. Dale, whom most of you know, was born and raised and still lives in Seward. John, whom most of you also know, was born in Fairbanks and raised in Juneau. He currently lives in Petersburg. Thanks for the invitation to testify on what I believe to be a very bad bill.

During the last several weeks, I've listened to a lot of testimony on the Governor's original proposal, not only in this committee, but in the other committees in both houses of the legislature. I have witnessed an already complicated PPT proposal become so complicated that I sincerely doubt it can ever be fully and fairly administered, and the cost of such administration, for both the State and industry, will be huge. It will be even more overwhelming for small start-up guys like us, who don't have tax accountants and tax attorneys on staff, and will need to acquire these services at market prices outside of our organizations. This bill is so bad that if it were the only alternative, we'd be better off with what's now on the books. But that's not the only alternative. The proposal by the Administration was complicated, but one we supported, and still could, but we can't support this one. Gross simplification is needed. Some taxes are to be applied to net profits, others to gross revenues. Sometimes ANS prices at the North Slope are to be used. Other times ANS West Coast prices are to be used. This creates un-necessary complexity and opens the door to years of disputes and lawsuits. The Charter for Development may be a good example of how simple things can be made.

I will now offer a few specific comments on the bill. You've heard lots of testimony supporting the 20-20 tax and exploration/development incentive split, and the arguments in favor of these provisions have been articulated very thoroughly and clearly, and I certainly cannot embellish on them, so I won't even try. I'll just add UltraStar's strong support for the positions of the existing producers and independents and explorers on these issues.

Of more concern to me is the so called need for a progressive feature, where the State takes a higher percentage at higher oil prices. Wildcatters gamble for the upside. Upside reserves and upside prices. Taking away that upside will cause exploration investment to decrease. This smells to me like the federal windfall profits tax that so successfully drove industry from our shores in the early 1980's.

There needs to be a mechanism for the State to buy back or otherwise allow use of any un-used exploration credits. The market for these credits is very limited, and I expect any that we may have would be sold at a considerable discount. It would help if the State provide an option to buy them, or allow holders of the credits to use them for other oil and gas related expenditures, such as bonus bids, lease payments, permitting and filing fees.

The bill grants a 5000 barrel per day exemption to companies with less than 55,000 barrels/day production. This is a provision with which we can agree, but I don't think it goes far enough. If the Committee wants every company, large and small, current producer, or wannabes like us, to be looking for new oil then the 5000 barrels per day should apply to all new oil, regardless of the size of the company that drilled found it. I suggest the following:

When the PPT becomes effective, establish a "ring fence" around existing, producing units. If peripheral drilling outside of that ring fence confirms commercial hydrocarbons and justifies unit expansions, then production from those expanded areas should be eligible for the tax exemptions and exploration and development credits in the bill, regardless of the size of the company that drilled them. Deeper and shallower accumulations, drilled within existing units after the effective date of the bill, should also be eligible. If the big, current producing unit owners were to receive the 5000 barrel per day allowance for exploration credits on new pools within an existing or expanded unit, it would provide a more meaningful incentive for all the industry.

I question the need for a 7 year time limit after which the tax exemption will expire. UltraStar is a small, start-up company that is poking around the fringes of existing units and known reservoirs. Our leases are too small to stand alone, so access to existing facilities, owned mostly by the major producers, is the only way we can develop anything we might find. It took our sister company, Winstar, 6 years to negotiate access with the KRU to enable the drilling of the well they completed in 2003. UltraStar has been in negotiations with the PBU for over 3 1/2 years now to get seismic data and facility access to enable the drilling of our Dewline Prospect. It takes a long time for these things to get done, and I question why our investments should be put at risk with this relative short sunset provision, whereas the major producers demand a 30 year period of assured fiscal certainty.

Thanks for the opportunity to comment.

Jim Weeks
907-258-2969

PPT Issues for Discussion by the Question and Answer Panel
Senate Finance Committee
April 10, 2006

No.	Issue	Comment
1.	The impact on exploration, investment and production at various proposed tax rates and credit rates (15% - 30%)	Discuss the relationship between tax and credit to identify the best balance.
2.	WTI vs. ANS	
3.	\$73 million allowance vs. \$12 million credit vs. 5000 bbl plan	Discuss the different impact each option has on the state, the majors and the independents.
4.	Point of Production	Further explanation
5.	Credits and deductions applicable for capital investments in the gas pipeline	What is, what isn't
6.	Re-openers	Discuss 30 year commitments and suggest alternatives
7.	Incremental Cost/bbl by ANS Cost (Sensitivity)	Discuss the incremental costs of lifting a barrel of oil as ANS rises
8.	Acceptability of 2 for 1 provision and appropriateness of a sunset.	
9.	Progressivity on net vs. gross	Discuss options
10.	Cap on Progressivity	Discuss options
11.	Progressivity trigger	Discuss options
12.	Cook Inlet Provision	Should Cook Inlet be treated differently
13.	Transitional Capital Look-Back	Discuss options
14.	Impact of PPT on Facility Access Fees	
15.	Profit in Tankering/Pipeline	Should profit in transportation be included as a cost
16.	Effective Date	April 1, 2006 or July 1, 2006
17.	95% safe harbor and quarterly true-up	How the industry is treated by other tax collectors

1 meter or device through which the oil enters into the facilities of a carrier
 2 pipeline or other transportation carrier in a condition of pipeline quality; in the
 3 absence of an automatic custody transfer meter or device, "gross value at the
 4 point of production" means the value of the oil at the mechanism or device to
 5 measure the quantity of oil that has been approved by the department for that
 6 purpose, through which the oil is tendered and accepted in a condition of
 7 pipeline quality into the facilities of a carrier pipeline or other transportation
 8 carrier or into a field topping plant;

9 Point of Production (B) for gas, other than gas described in (C) of this paragraph,
 10 that is

11 (i) not subjected to or recovered by mechanical
 12 separation or gas processing, the value of the gas at the first point
 13 where the gas is accurately metered;

14 (ii) subjected to or recovered by mechanical separation
 15 but not gas processing, the value of the gas at the first point where the
 16 gas is accurately metered after completion of mechanical separation;

17 (iii) subjected to or recovered by gas processing, the
 18 value of the gas at the first point where the gas is accurately metered
 19 after completion of gas processing;

20 (C) for gas run through an integrated gas processing and gas
 21 treatment facility that does not accurately meter the gas after the gas
 22 processing and before the gas treatment, the value of the gas at the first point
 23 where gas processing is completed or where gas treatment begins, whichever is
 24 further upstream;

25 * Sec. 29. AS 43.55.900(10) is repealed and reenacted to read:

26 (10) "oil" means

27 (A) crude petroleum oil; and

28 (B) all liquid hydrocarbons that are recovered by mechanical
 29 separation of well fluids or by gas processing;

30 * Sec. 30. AS 43.55.900 is amended by adding new paragraphs to read:

31 (17) "Cook Inlet basin" means the area bounded by

1 (A) the north boundary of Township 18 North, Seward
2 Meridian;

3 (B) the Seward Meridian;

4 (C) the south boundary of Township 7 South, Seward
5 Meridian; and

6 (D) the west boundary of Range 19 West, Seward Meridian;

7 (18) "gas processing"

8 (A) means processing a gaseous mixture of hydrocarbons

9 (i) by means of absorption, adsorption, externally
10 applied refrigeration, artificial compression followed by adiabatic
11 expansion using the Joule-Thomson effect, or another physical process
12 that is not mechanical separation;

13 (ii) for the purpose of extracting and recovering liquid
14 hydrocarbons; and

15 (iii) upstream of any gas treatment and upstream of the
16 inlet of any gas pipeline system transporting gas to a market;

17 (B) does not include gas treatment;

18 (19) "gas treatment"

19 (A) means conditioning gas and removing from gas
20 nonhydrocarbon substances for the purpose of rendering the gas acceptable for
21 tender and acceptance into a gas pipeline system; and

22 (B) includes incidentally removing liquid hydrocarbons from
23 the gas.

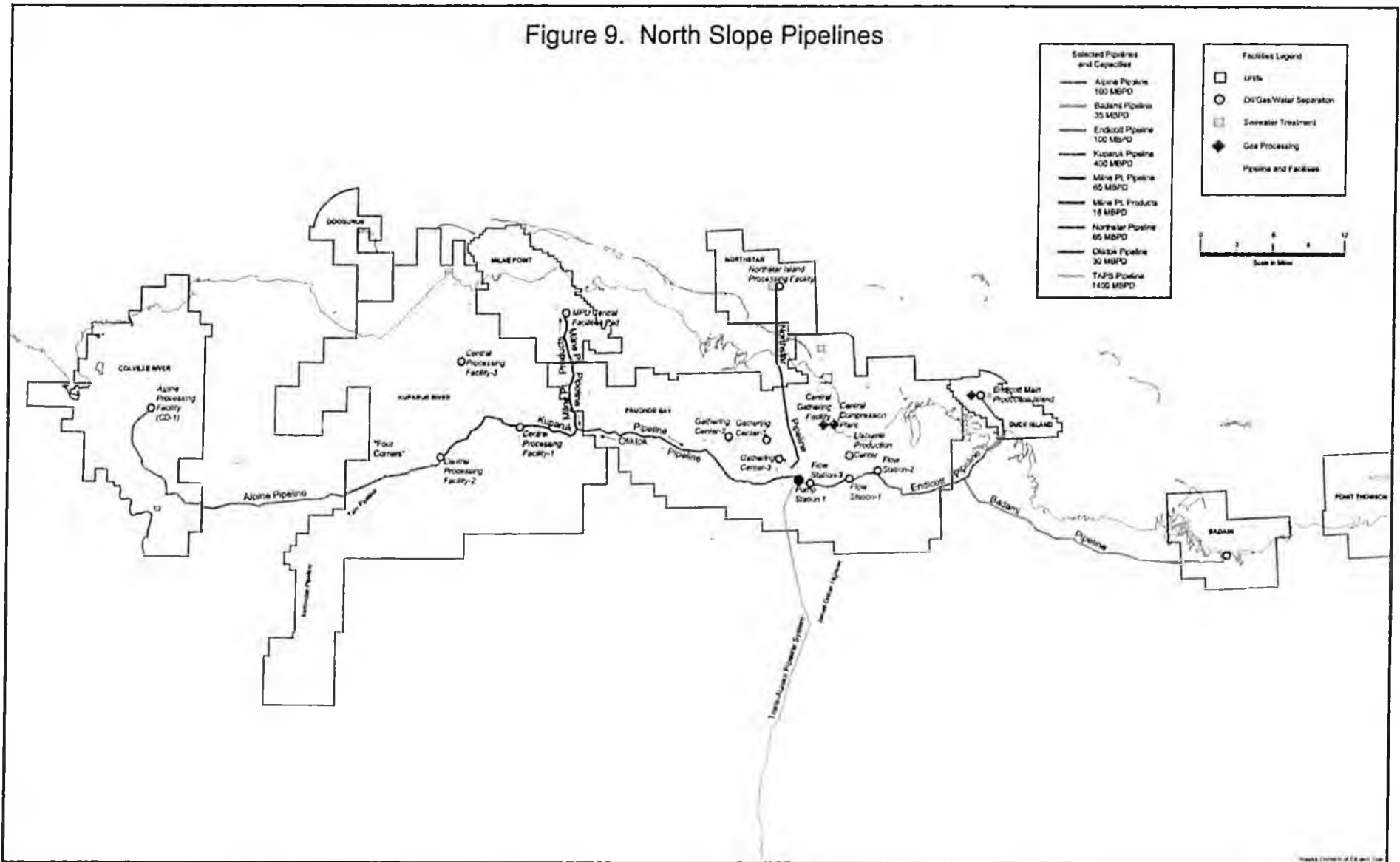
24 * Sec. 31. AS 43.55.011(a), 43.55.011(b), 43.55.011(c), 43.55.012, 43.55.013, 43.55.016,
25 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12), and 43.55.900(16) are repealed.

26 * Sec. 32. The uncodified law of the State of Alaska is amended by adding a new section to
27 read:

28 APPLICABILITY. (a) Sections 5, 7 - 10, 12 - 14, 16, and 20 - 31 of this Act apply to
29 oil and gas produced on or after April 1, 2006.

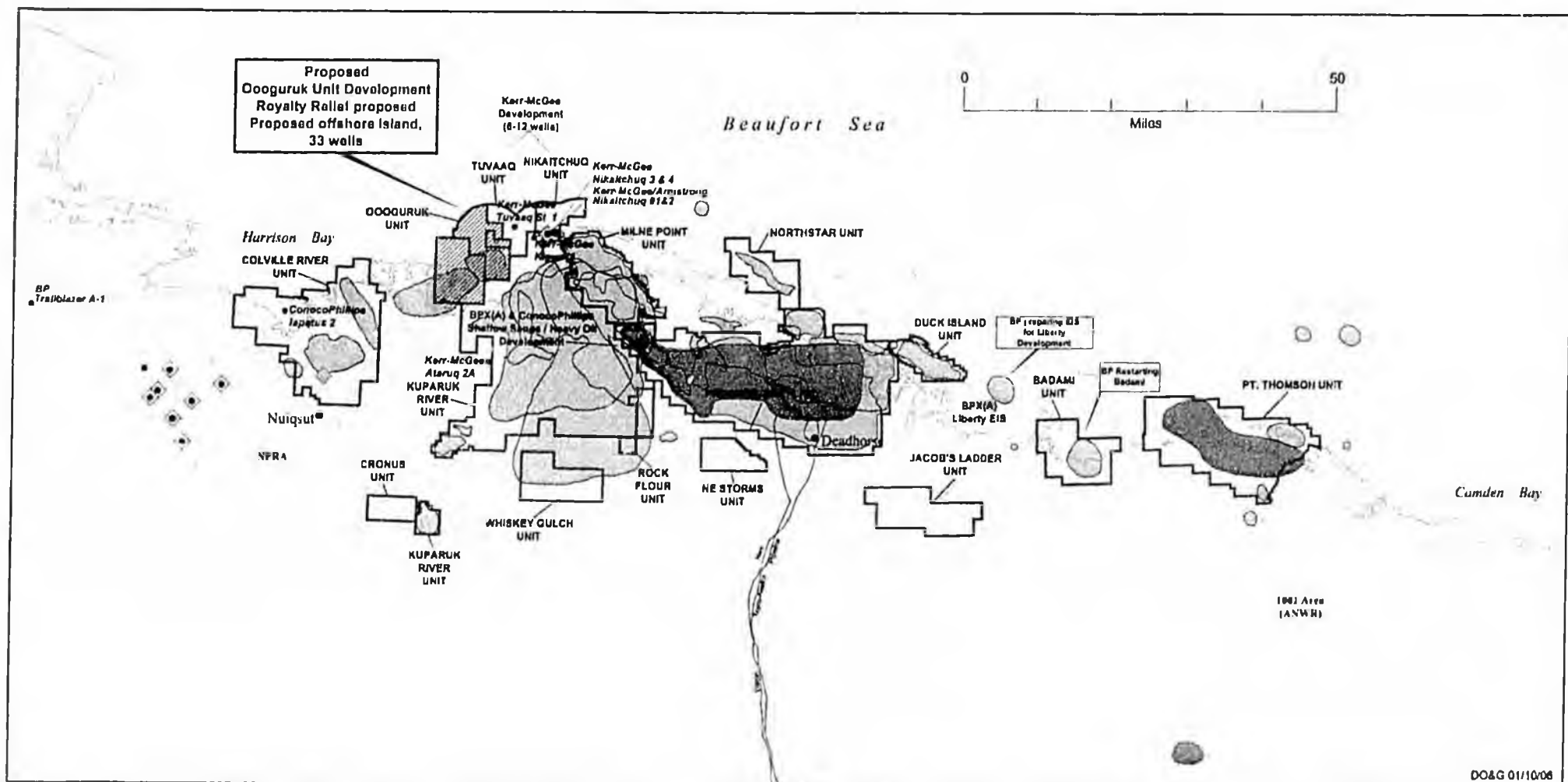
30 (b) Section 11 of this Act applies to oil and gas produced before, on, or after the
31 effective date of sec. 11 of this Act.

Figure 9. North Slope Pipelines

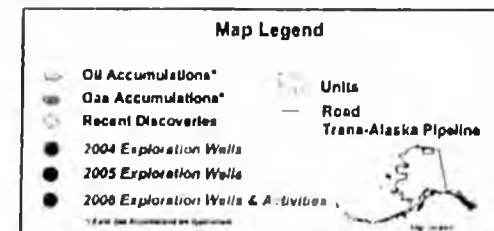


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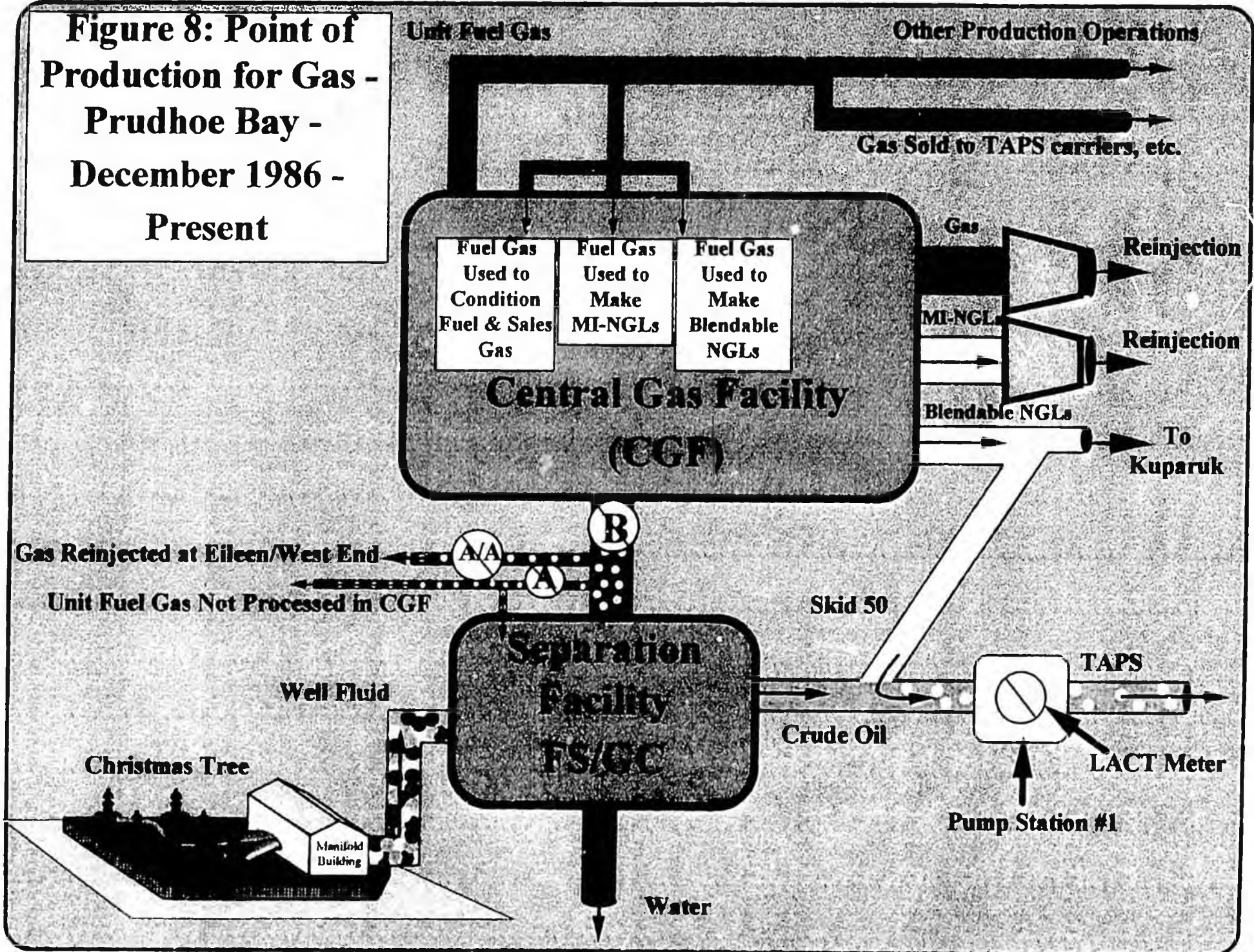
North Slope Oil & Gas Activity & Discoveries January 2006



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Figure 8: Point of Production for Gas - Prudhoe Bay - December 1986 - Present



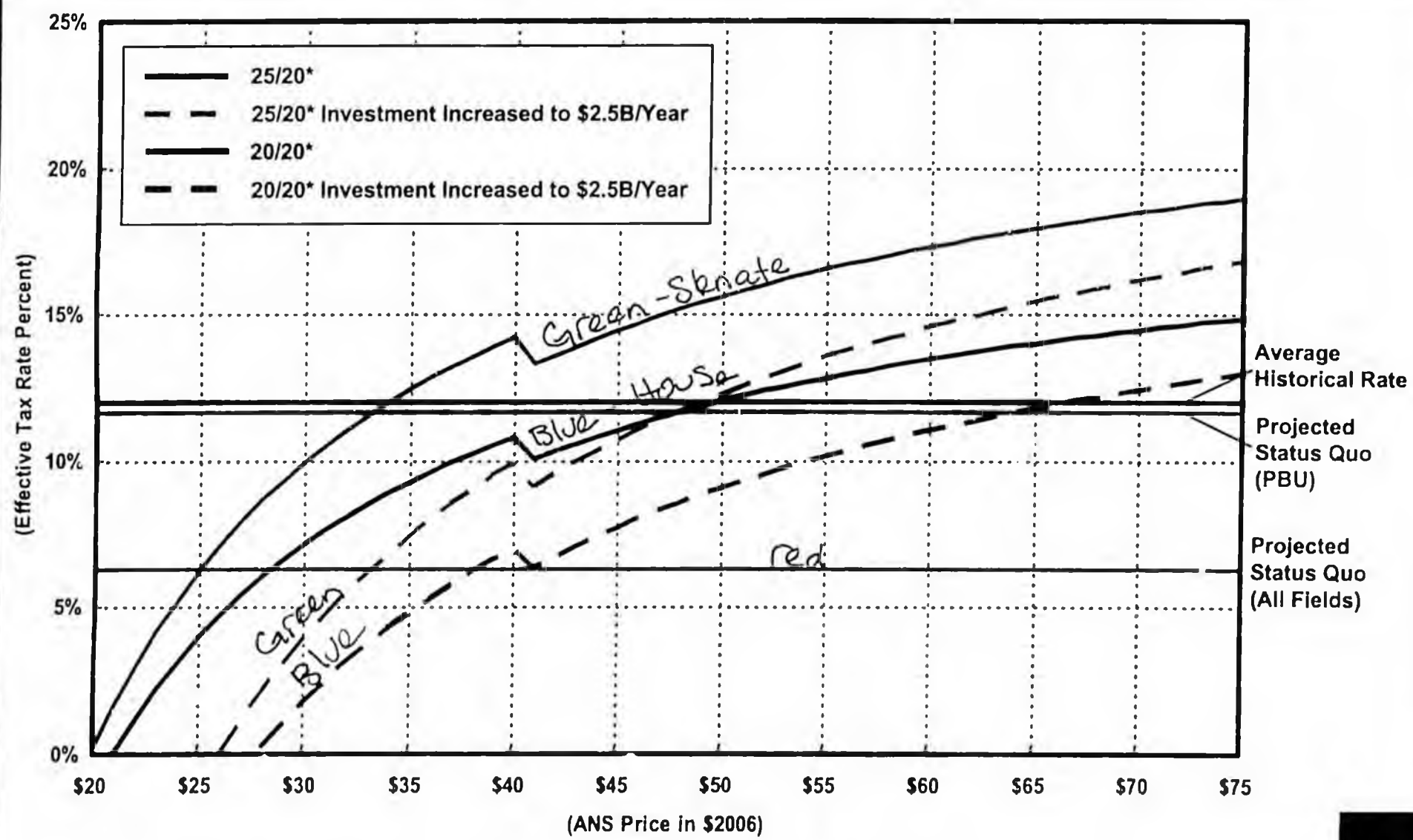
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Effective Average Tax Rates at Various Price Levels

Impact of Increased Investment

(FY 2007-2016)



* Calculated from July 2006. Includes 8-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies volumes per DOR Fall 2005 Forecast with Oooguruk projection
 Source: Historical Alaska Department of Revenue



Hanley, Public Affairs Manager Alaska

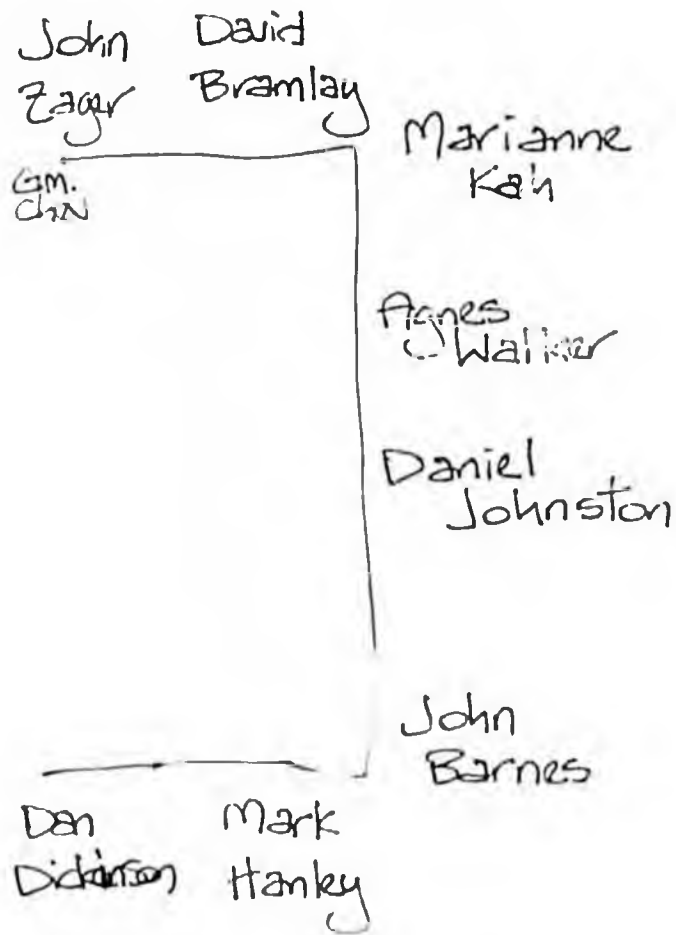
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Marianne Kah C.P.
Dan Dickinson Admin - Gov.'s Office
Angus Walker BP
John Zager Chevron
Mark ~~Hendley~~ Amudarko
Tony Finizza (teleconference) ~~FINNIZZA~~ LB+A Consultant
Daniel Johnston Leg. Cms. - LB+A Consultant
John Barnes Marathon
David Bramley, VP ERA International

Anthony Finizza

ELON ONP Consultants

4/10/2006



ExxonMobil Production Company
P.O. Box 196601
Anchorage, Alaska 99519-6601
907 561 5331 Telephone

Richard J. Owen
Alaska Production Manager
Joint Interest U.S.

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APR 18 2006

ExxonMobil
Production

April 12, 2006

The Honorable Lyda Green
Co-Chair, Senate Finance Committee
State Capitol (MS 3101)
Juneau, Alaska 99801-1182

Dear Senator Green:

Thank you and the Senate Finance Committee for providing the opportunity on April 4, 2006 for ExxonMobil to testify regarding our thoughts and concerns with CSSB 305. Attached are ExxonMobil's responses to the questions from the Senate Finance Committee which were provided to us on Thursday, April 6.

Please let us know of any further questions that may arise from your deliberations.

Sincerely,



RJO:jpc
Attachment

cc. Senate Finance Co-Chair Gary Wilken
House Finance Co-Chair Mike Chenault
House Finance Co-Chair Kevin Meyer

Committee Questions on CSSB305

Questions	Response
<p>1. The PPT rate in the bill as introduced was 20%, while the rate in the Senate Resources CS is 25%. The consultants retained by the Legislature advise that the rate could be 25% without materially affecting the industry's investment in oil and gas development in Alaska.</p> <p>a. Do you agree with this statement?</p> <p>b. In your opinion, what should the PPT rate be in order to increase industry's investment here and why?</p> <p>c. Further more, if you think the PPT rate should be less than 20%, why did your company agree to a 20% rate?</p>	<p>a. It is not clear to us that all the consultants retained by the Legislature support a tax rate higher than 20%. Specifically, during the panel discussion before the House Finance Committee on April 6, the Econ One representatives stated that the PPT tax rate should not be increased beyond 20%. Tax systems need to be carefully designed to ensure the desired objective of resource development is achieved. To that end it is critical to take into account the quality of the remaining resource, otherwise a change may result in unintended consequences, such as reduced investments and lower reserve recovery. ExxonMobil's assessment of the remaining oil resource suggests future growth opportunities will come from: complex enhanced oil recovery (EOR) projects; development of smaller, more marginal oil accumulations; and the innovative development of viscous and heavy oil resources. These opportunities will require the development and application of new technology, higher unit development costs, and more complex operations to deliver a given production rate. These resources are much lower in quality as compared to Prudhoe Bay and Kuparuk, though they face the similar challenges associated with arctic conditions and distance to market. We are concerned that the higher base tax rate could prevent some of Alaska's remaining challenged resources from being developed.</p> <p>b. While higher taxes may bring in additional revenues in the short-term, any reduction in investment and subsequent production will significantly impact those</p>

Questions	Response
	<p>revenues in the longer term. We think that the focus of the tax bill should be to encourage investment and grow production. This is not accomplished with the higher tax rate and the proposal to further increase it as oil price increases.</p> <p>c. Despite our concerns with the original SB 305, we are prepared to move forward under that system as originally proposed, since it sought to provide a balance of revenues to the state and producers across a range of oil prices, provided sufficient incentive for producers to undertake exploration and development risks, and included reasonable transition provisions for past investments. And most importantly for ExxonMobil, oil fiscal contract terms consistent with the Administration's proposal would provide the predictability and durability necessary to advance the gas project to the next phase.</p>
<p>2. The Senate Resources CS proposes a tax in addition to the regular PPT in order to make the system more progressive when prices are high for oil. The House Resources CS proposes similar progressivity for gas as well as oil.</p> <p>a. If we include some kind of progressivity feature to deal with exceptionally high prices, will this have a material effect on industry investment in Alaska?</p> <p>b. Is, please explain why, and how material the effect would be.</p> <p>c. Is there any price level above which the effects of progressivity on new investments would become immaterial?</p>	<p>a/b. Higher tax rates will discourage investment. Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential through a variety of factors, such as increased production or higher prices. When you limit or reduce the benefit that companies can achieve from the upside factors, you reduce the attractiveness of those investment opportunities. The proposal to increase the already high base tax rate and then further increase it as oil prices increase, reduces or limits the upside potential which will result in companies recalibrating investment decisions. Reduced investment will result in reduced resource recovery, diminished state revenues and fewer employment opportunities, with a resultant</p>

Questions	Response
	<p>negative impact on the state's economy.</p> <p>c. The PPT in the original SB305 is progressive. The effective PPT take percentage increases with oil and gas prices. We do not recommend any further progressive features.</p>
<p>3. We have been told there is a trade-off between the tax rate in the PPT and the percentage for tax credits against the PPT, and that an increase of five percentage points in the credit percentage will approximately offset the effects of an increase of the tax rate of one percentage point.</p> <p>a. Do you agree a trade-off exists, and if so, is the 5-to-1 ratio correct?</p> <p>b. Is there a law of diminishing returns at work here that decreases the effect of a credit after it gets to a certain percentage?</p>	<p>a. While there is a trade-off, it depends on a range of assumptions including level of income and investment. However, it is not a fixed ratio. This can be demonstrated in the following simplified cases:</p> <ul style="list-style-type: none"> - $(\\$1000 \times 20\%) - (\\$100 \times 20\%) = \\$180$ - $(\\$1000 \times 21\%) - (\\$100 \times 30\%) = \\$180$ - $(\\$1000 \times 20\%) - (\\$200 \times 20\%) = \\$160$ - $(\\$1000 \times 21\%) - (\\$200 \times 25\%) = \\$180$ - $(\\$1000 \times 20\%) - (\\$500 \times 20\%) = \\$100$ - $(\\$1000 \times 21\%) - (\\$500 \times 22\%) = \\$100$ <p>As you can see, the relationship between tax rate and credit rate is dependent on the income and investment rates which are highly variable and specific to the resource being developed.</p> <p>b. While the investment tax credits of 20% could enhance the present value economics of new investments, the 20% tax rate will result in lower overall cash flow. The combination of a 20% credit along with a 20% tax rate may not be adequate to support development of all the remaining ANS opportunities.</p>
<p>4. The original version of SB 305 provided three alternatives for determining the "gross value at the point of production" for taxable oil and gas: 1) using the royalty netback settlement determined under a royalty</p>	<p>a. The use of a producer's royalty settlement agreement to determine the value of oil and gas addresses a longstanding issue that has divided the State and the industry over the years. There is only one value in the</p>

Questions	Response
<p>settlement agreement with the State, 2) using a "formula" prescribed by the Department of Revenue (DOR) based on a netback value or netback methodology approved by the government, and 3) using "another formula" by DOR that reasonably estimates a value for the oil or gas at a specific geographic location. The Senate Resources CS deletes the first alternative, but keeps the latter two unchanged.</p> <p>a. What specific issues or problems do you foresee because of this deletion?</p>	<p>market place. SB 305, as originally proposed, allowed the State to value a producer's oil and gas using the producer's royalty settlement agreement, which was negotiated with, and approved by, the Department of Natural Resources. That provision was important to industry as it provided certainty to a producer and the State on the value on which to calculate royalty and production taxes while reducing the administrative and audit costs to both the State and the industry.</p>
<p>5. What do you think the effective date should be for the PPT and why?</p>	<ul style="list-style-type: none"> ExxonMobil believes that tax increases should be prospective, so the effective date should be sometime after the date of enactment. A period should be provided to allow systems to be put into place and a true-up between estimated payments and actual obligations to occur.
<p>6. The Senate Resources CS allows a credit for investments made during the five years preceding the effective date of the PPT, but limits the credits so that new capital investments will have to be twice as much as the old ones in order for the credit to be fully used.</p> <p>a. How will this two-for-one transitional credit make a difference in your company's investment decision – making?</p> <p>b. Is this approach fair to both major and independent producers?</p>	<p>a/b. Investment decisions are based on the resource opportunity and are evaluated on a range of factors including geologic, technical, execution risks as well as risks associated with fiscal and political stability. The purpose of the transition provision is to address the sudden increase in taxes on recent investments. Future investment decisions will be made under the new tax system based on the balance between the new tax rate and the credit rate. For this reason, we think the Administration's proposal of providing a deduction based on recent investments, not linked to future spending, is appropriate.</p>
<p>7. In committee, it was mentioned that the safe harbor provision in the Senate Resources CS, requiring</p>	<p>a/b. The monthly tax payments under the PPT are based on estimates of lease expenditures, production volumes</p>

Questions	Response
<p>taxpayers to calculate their monthly tax payments to a 95% accuracy, is a very difficult target to hit and unreasonable.</p> <p>a. Do you agree with this statement and if so, what do you consider reasonable?</p> <p>b. Do you feel the quarterly true-up provision is manageable or should it be an annual true-up as proposed in the original version of the bill?</p> <p>c. What is the traditional relationship in this regard between the oil and gas industry and tax collectors in other state?</p>	<p>and capital expenditures. As a production tax based on estimates of profit, we believe the PPT tax should follow the federal model – 90% “safe harbor” with a true-up after the close of the year. Provided the safe harbor is met, there is no interest or penalties assessed on any remaining balance.</p> <p>c. In our experience with state income tax, including Alaska, most jurisdictions generally follow the federal model for estimated payments, safe harbor and true-up.</p>
<p>8. Please take this opportunity to describe any other provisions of the Senate Resources CS to SB 305 that cause considerable concern for your company and deserve additional discussion by the Senate Finance Committee.</p>	<p>We would recommend the following changes to the CS:</p> <ul style="list-style-type: none"> • Return PPT tax rate to 20% • Eliminate additional progressive feature • Remove linkage of transition provision to future spending • Specifically allow Royalty Settlement Agreements for valuation • Make effective date the later of the enactment date or July 1, 2006. • Estimated payments should mimic federal model

bp

Steve Marshall
President, Alaska



BP Exploration (Alaska) Inc
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5422

April 11, 2006

The Honorable Lyda Green, Co-Chair
Finance Committee, Alaska State Senate
State Capitol, Mail Stop 3100
Juneau, AK 99801-1182

Re: Questions on SB 305

Dear Senator Green:

Thank you for the questions posed in your letter of April 5th. Attached, please find BP's response, which I hope you will find helpful.

Please advise if we can be of any further assistance in this matter.

Sincerely,

Steve Marshall



Provided 4/12/06



**BP's Response to
Senate Finance Committee Questions
on SB 305
April 11, 2006**

1. *The PPT rate in the bill as introduced was 20%, while the rate in the Senate Resources CS is 25%. The consultants retained by the legislature advise that the rate could be 25% without materially affecting the industry's investment in oil and gas development in Alaska.*
 - 1.1. *Do you agree with this statement?*
 - 1.2. *In your opinion, what should the PPT rate be in order to increase the industry's investment here and why?*
 - 1.3. *Furthermore, if you think the PPT rate should be less than 20%, why did your company agree to a 20% rate?*

Response

1.1: Do you agree with this statement?

BP strongly disagrees with this statement. We believe that increasing tax rates at this time will have a material impact on future investment. BP considers the PPT tax rate to be the most important feature in the bill and the single most important decision to be made by the legislature. Getting it wrong will have major impacts on the petroleum industry in Alaska for years to come.

We are acutely aware that investment decisions made here affect not only BP's shareholders, but our Alaskan employees & contractors, their families, the communities they live in, our suppliers, the local economy and of course the State itself. We all want to maximize the *potential* value of the resources in the ground and convert them into *real* value or wealth.

As the operator of Prudhoe Bay, Endicott, Northstar, GPMA, Milne Point, and Badami, as well as a major investor in Kuparuk our view of North Slope Production is as follows.

- North Slope production is declining at approximately 6% per year
- at this rate of decline production will be as low as 450 mboed in 10 years time.
- operating costs are increasing due to a worldwide shortage of petroleum industry resources
- fixed costs and declining production means that margins will continue to shrink
- the level of investment required to achieve the DOR's latest production forecast is double current levels
- oil price will change and that is something nobody has any control over
- the technical challenges involved in producing the remaining oil are getting more difficult, and will in many cases require new technologies that does not exist today

We believe that the recommendations of the State's and the Legislature's consultants have been crafted assuming that Alaska's oil production is declining more slowly than it is and that increasing taxes will have no impact on investment. We believe both these assumptions to be in error and dangerously misleading.



1.2: In your opinion, what should the PPT rate be in order to increase the industry's investment here and why?

In our opinion the PPT structure has real merit, but the tax rate should be significantly lower than the 20% proposed in order to attract the investment required to stem decline and to provide the Production, Revenues, Economy and Jobs which Alaska requires.

We believe the best thing the Legislature can do to maximize the value of the petroleum resources for Alaska is to create an environment that encourages investment. We believe the Gulf of Mexico, the UK, the Alberta Heavy Oil Province are good models to emulate. They show the impact of creating an unambiguous, attractive investment climate by adopting appropriate fiscal terms. The Alberta Heavy Oil Province, the Gulf of Mexico deep water and the UK of the 1980's and 1990's are wonderful illustrations of where attractive, *not tolerable*, tax rates encouraged huge investments that resulted in increased production and increased revenues for the government and significantly increased economic activity.

Production is declining faster than anyone has been predicting. The impact of production decline is being masked by the current high oil prices. This is not the time to raise taxes, but the time to adopt a fiscal policy which will attract investment.

We strongly urge the Legislature to adopt a tax rate significantly less than the 20% in the original bill (a 15/25 (15% tax and 25% credit) would be significantly better than the 20/20 originally proposed) and furthermore we urge the Legislature to look towards the UK, Gulf of Mexico and the Alberta Heavy Oil Province for inspiration from counties / states who have successfully attracted investment by adopting specific fiscal policies.

1.3: If you think the PPT rate should be less than 20%, why did your company agree to a 20% rate?

Very simply, we agreed not to oppose the 20% rate as part of a package deal which would enable us to proceed with gas. That package includes the other terms of the Governor's PPT bill, including the transition provisions among others.

It is important to remember the negotiating range defined by the Producers' first offer and the Governor's first offer was between 12.5% and 20%. At the end of the day, the Governor was successful in pulling the producers to the upper end of that range, a point which many in the legislature mistakenly interpret as a starting point.

The 20% should not be looked at in isolation but as part of the total package. We believe the 20% rate in conjunction with the rest of the provisions in the original bill created a *tolerable* climate for investment, not an *attractive* climate for investment. Alaska should be looking to create an attractive climate for investment in order to stem production decline, which is why we have consistently recommended that the Legislature adopt a tax rate less than the 20% proposed by the Governor.



2. *The Senate Resources CS proposes a tax in addition to the regular PPT in order to make the system more progressive when prices are high for oil. The House Resources CS proposes similar progressivity for gas as well as oil.*

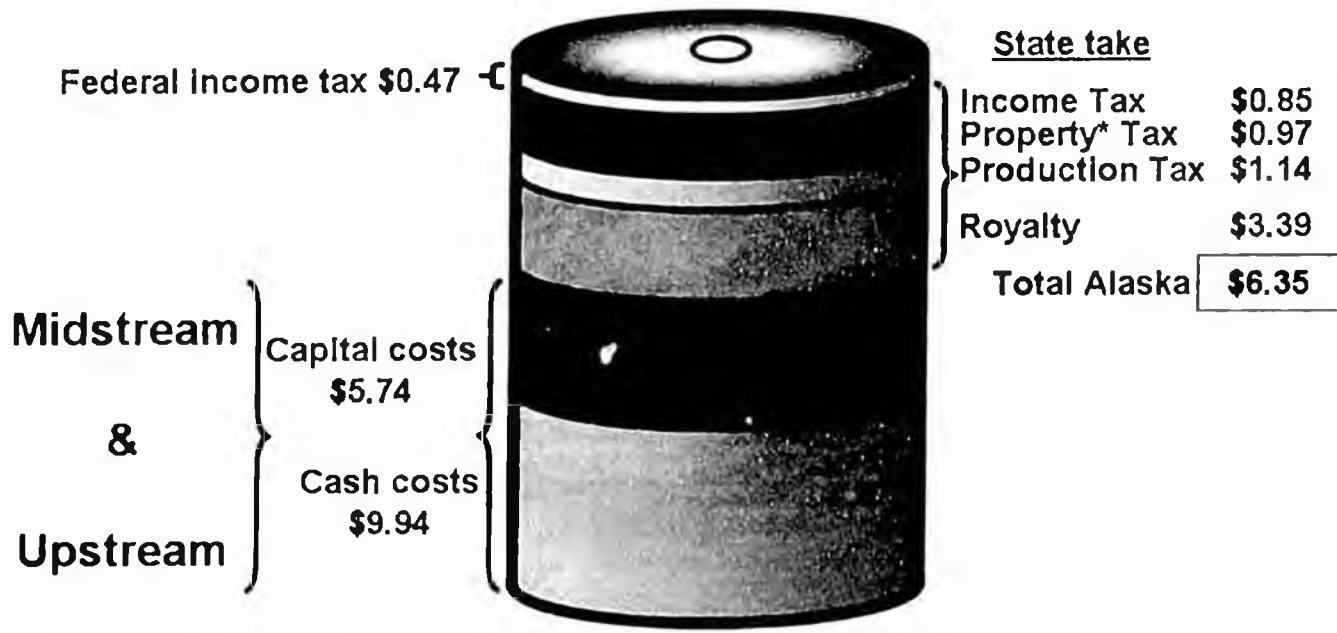
- 2.1. *If we include some kind of progressivity feature to deal with exceptionally high prices, will this have a material effect on industry investment in Alaska?*
- 2.2. *If so, please explain why, and how material the effect would be?*
- 2.3. *Is there any price level above which the effects of progressivity on new investments would become immaterial?*

Response

Reiterating the answer to question 1: **higher taxes generally result in less investment & lower taxes generally result in higher investment.**

As we have previously stated, at prices below \$22.50 ANS / barrel BP does not currently make a profit in Alaska. As ANS production declines our fixed costs will remain and the breakeven oil price will rise.

Breakeven Barrel \$22.50



Upward pressure created by inflation (driven by high oil price) and production decline



We should all share in the upside of high oil prices and we have agreed that it is appropriate for the State to take a higher share than that which they enjoy today based on the existing ELF system as part of a new fiscal regime.

In itself, the 20% PPT rate gives the State progressivity and significantly increases the State's share at high oil prices. Under the Governor's proposal DOR estimates that the State will receive an additional \$1bn / yr at current prices.

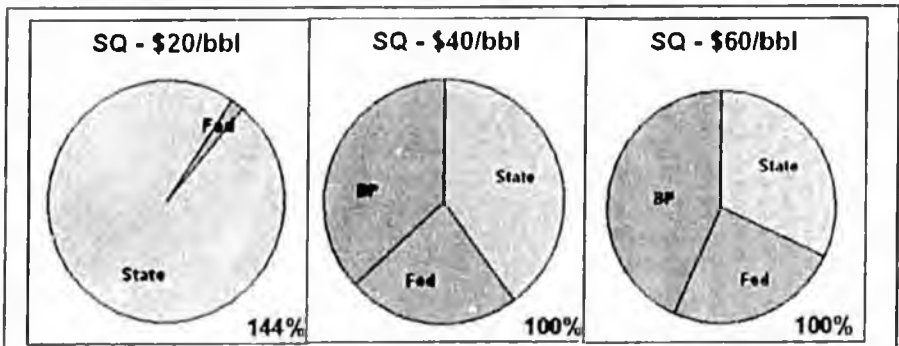
The pie charts below illustrate the split between State, Federal and BP take under the current regime and the original PPT 20/20 at low, medium and high prices. Under PPT 20/20, we would continue to make a loss at \$20. At \$40 the State gets a considerably higher share than BP. At \$60 under the original PPT 20/20, i.e. without any price surcharge, the State's and BP's take is balanced.

Introduction of progressivity squeezes our profit at higher prices even more than the original PPT and would create an extremely unbalanced system. Given the high government take in Alaska at low prices, this imbalance will make investments less attractive.

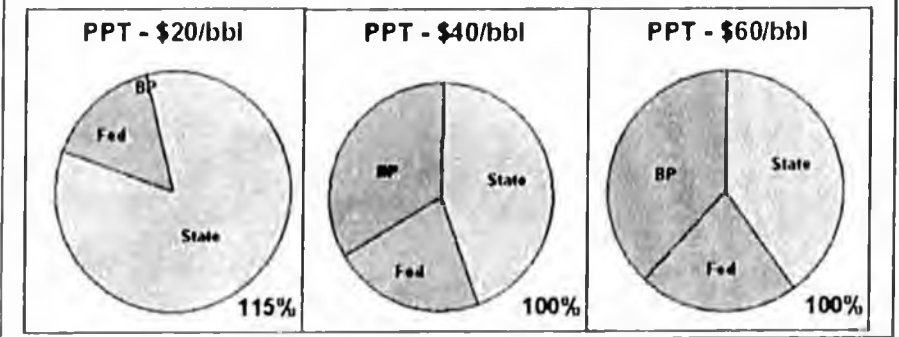
PPT Impacts
Government Take (%)



Status Quo



PPT
(20-20)



	\$20		\$40		\$60	
	SQ	PPT	SQ	PPT	SQ	PPT
State	143%	97%	40%	44%	32%	40%
Federal	1%	18%	23%	22%	25%	22%
BP	0%	0%	37%	34%	43%	38%



The impact on investment will depend on the design of the system. If the Legislature is convinced that the ultimate solution must include progressivity we would encourage them to adopt the following principles:

Keep it simple. Alaska already has one of the most complex tax regimes in the world. Complexity breeds ambiguity and disputes and is a deterrent to investment.

Increase PPT tax rate with price rather than introduce an independent 'surcharge' based on gross revenue. PPT is a tax on net cash flow and thus it is appropriate that any incremental take at high prices or reduced take at low prices is based on net cash flow.

Create no more than 3 price bands with different tax rates:

- a low price band which provides real relief to industry at low prices when industry is struggling due to Alaska's very high costs and the regressive nature of royalties.
- a mid price band which spans the mid to high range of expected prices and at which the tax rate is reasonable (lower than 20%) and makes Alaska an attractive place to invest.
- a high price band over which a higher tax rate would not be a significant deterrent to investment.

In order that the system will endure and serve Alaska well it would be necessary to:

1) ensure price trigger points are based on the actual value of the product (i.e. Wellhead value is best, ANS is better than WTI)

& 2) ensure trigger points do not become outdated by inflation proofing them.

3. *We have been told there is a trade-off between the tax rate in the PPT and the percentage for tax credits against the PPT, and that an increase of five percentage points in the credit percentage will approximately offset the effects of an increase in the tax rate of one percentage point.*

3.1. *Do you agree a trade-off exists, and if so, is the 5-to-1 ratio correct?*

3.2. *Is there a law of diminishing returns at work here that decreases the effect of a credit after it gets to a certain percentage?*

Response

The most important driver in the PPT equation is the tax rate. The credits are, however, important and there is a trade-off between the PPT tax rate and the tax credit. The question of how much this trade-off is — whether it is 5-to-1, 6-to-1, or something else — does not have a simple answer. This is because other factors affect the balance point where a change of 1 percentage point in rate is balanced by a change of X percentage points in the credit. These other factors are the price of oil, the operating cost per barrel relative to the oil price, and the capital investment relative to the value of the oil currently being produced. We would be happy to illustrate this relationship with examples if that would be helpful to you or the committee.



4. *The original version of SB 305 provided three alternatives for determining the "gross value at the point of production" for taxable oil and gas:*
- *using the royalty netback determined under a royalty settlement agreement with the State*
 - *using a "formula" prescribed by the Department of Revenue (DOR) based on a netback value or netback methodology approved by the government, and*
 - *using "another formula" by DOR that reasonably estimates a value for the oil or gas at a specific geographical location."*

The Senate Resources CS deletes the first alternative, but keeps the latter two unchanged.

4.1. What specific issues or problems do you foresee because of this deletion?

Response

We believe that the deletion was a mistake.

The Royalty Settlement Agreement (RSA) netback not only has a methodology that reflects current market conditions, but it also includes a procedure for either side to "re-open" part or all of that methodology and adjust it as market conditions change.

This re-opener procedure has worked extremely well in the decade and a half since the *Amerada Hess* lawsuit over North Slope royalties was settled by the companies.

We believe using RSA netback values as much as possible in the PPT is a good idea.

Using RSA netbacks for PPT would minimize the need in DOR for an entire second group of administration, audit and enforcement, and dispute-resolution staff paralleling the existing one for royalty netbacks. The only need for DOR to have netback specialists for PPT would be to deal with producers that do not have an RSA with the State, but this need should be very small. When the other companies in the *Amerada Hess* case made their settlements with the State, they were given the option of patterning their RSA after ARCO's RSA (now ConocoPhillips' RSA), BP's RSA, or ExxonMobil's RSA. We see no reason why DNR would not extend a similar option to any new companies coming to the North Slope.

Although we advocate using existing RSA netbacks where possible for PPT, we recognize that an RSA developed for Cook Inlet production is inappropriate for the North Slope, and vice versa. We believe an RSA should be used only for the region or basin for which it was developed. Consequently, as oil and gas exploration and development occur in areas besides the North Slope and Cook Inlet, the PPT legislation should provide authority for DOR by regulation to designate other regions or basins within which the RSAs for them would be recognized and effective for PPT purposes as well.



5. *What do you think the effective date should be for the PPT and why?*

Response

The effective date should be no earlier than July 1, 2006. An April 1st effective date already involves retroactivity, and that retroactivity grows greater with each day that passes. Retroactivity in taxes is inherently unfair, and all the more so when such a major overhaul is being made to such a significant tax.

6. *The Senate Resources CS allows a credit for investments made during the five years preceding the effective date for the PPT, but limits the credit so that new capital investments will have to be twice as much as the old ones in order for the credit to be fully used.*

- 6.1. *How will this two-for-one transition credit make a difference in your company's investment decision-making?*
- 6.2. *Is this approach fair to both major and independent producers?*

Response

Keeping the transition provisions sends a very loud and clear message to existing and potential new investors that Alaska treats investors fairly, and that Alaska is open for business.

We believe that allowing a transitional credit is the right thing to do. These investments were made under the ELF-based severance tax, and now the tax is being changed in a very significant way. It is common for governments to provide such transitional relief when they make major tax changes. Alaska itself has allowed such transitions in the past when it has made major changes to its fiscal regime.

We believe the two-for-one investment proposal is an elegant solution and we could support it provided it is simplified to ensure that companies who make future investments get the benefit of the transition provisions.

To this end we would suggest that the \$40 test be removed and the 2013 sunset date be extended.



7. *In committee, it was mentioned that the safe harbor provision in the Senate Resources CS, requiring taxpayers to calculate their monthly tax payments to a 95% accuracy, is a very difficult target to hit and unreasonable.*

7.1. *Do you agree with this statement and if so, what do you consider reasonable?*

7.2. *Do you feel the quarterly true-up provision is manageable or should it be an annual true-up as proposed in the original version of the bill?*

7.3. *What is the traditional relationship in this regard between the oil and gas industry and tax collectors in other states?*

Response

The whole approach in the safe-harbour provisions is mistaken, not just the 95% figure.

The use of federal tax concepts and principles presents several important advantages.

First, the federal definitions are clear and well defined, both by statute and regulations and by administrative and judicial precedent.

Second, since the federal standards apply, producers can use the same accounting systems for these parts of the PPT that they use for the federal income tax.

Third, and of particular value for the State, the use of these federal tax concepts and rules means that the IRS, rather than DOR auditors, can do the heavy lifting in terms of auditing and enforcing these federal standards. As with federal principles adopted under the state income tax, the DOR auditors merely have to say "me too" on those matters once the IRS is done with its audit of a producer.

The federal system, however, is based on tax years rather than tax months. The whole notion of the PPT being a monthly tax is merely a carry-over from the present severance tax. There is nothing inherent in the severance tax, nor the PPT, that requires it to be a monthly tax instead of an annual one. The only reason for having PPT be paid monthly is to provide the State a more uniform stream of tax revenue from month to month, and this can be accommodated just as well under an annual PPT by having producers make monthly estimated payments with an annual true-up once the year is over.

The federal income tax uses a similar system of estimated payments for businesses. Once a quarter a business has to make an estimated tax payment, with a final payment due in March of the following year. To deter deliberate underpayment of the quarterly estimates, the Internal Revenue Code has an underpayment penalty if the total of those estimated payments is less than 90% of the actual amount of tax due for that year.

There are sound reasons behind the federal system of estimated payments with a true-up after the end of the year, and they apply equally well to the PPT system.

We recommend changing the tax period from a calendar month to calendar year, with monthly estimated payments that, on a cumulative basis each month, bring the total paid up to that point to at least 90% of the total PPT for that portion of the year based on the data available to the producer at the time it reports and makes its monthly estimated payment. At the end of March the following year, the full amount of the PPT for the year comes due, and anything not paid then not only accrues interest at the statutory rate, but is also subject to underpayment penalties if there is not sufficient cause to justify the underpayment.



Apart from being monthly instead of quarterly, our proposal is essentially the federal system. Two key elements of the PPT — namely, the “necessary and reasonable” nature of the expenses claimed as deductible lease expenditures, and the amount of such expenditures that are capital in nature instead of operating expense — are based on federal tax concepts and principles, and thus it is appropriate to follow the federal system for estimated payments.

8. *Please take this opportunity to describe any other provisions of the Senate Resources CS to SB 305 that cause considerable concern for your company and deserve additional discussion by the Senate Finance Committee.*

Response

It is our understanding that the tax committee of the Alaska Oil and Gas Association is working to finalize a half dozen or so technical amendments and recommendations regarding CSSB 305(RES). We expect they will be submitted very soon, along with a letter or written testimony explaining them. Some of those AOGA suggestions may cover material we have discussed here. Since AOGA takes positions on tax matters only by consensus without objection, the fact that AOGA will be presenting them to you will itself be evidence that BP endorses those proposals. In addition to the issues raised in this letter I would ask you to give full consideration to the issues raised by AOGA.

Presentation to
House Finance Committee
4/9/06

**Further Discussion
of
Senate Bill 305 and House Bill 488**

Daniel Johnstons Testimony

**Juneau, Alaska
9 April, 2006**

**Daniel Johnston & Co., Inc.
www.danieljohnston.com
60 Shady Lane
Hancock, NH 03449**

Where do we stand today?

Oil Industry threatens:

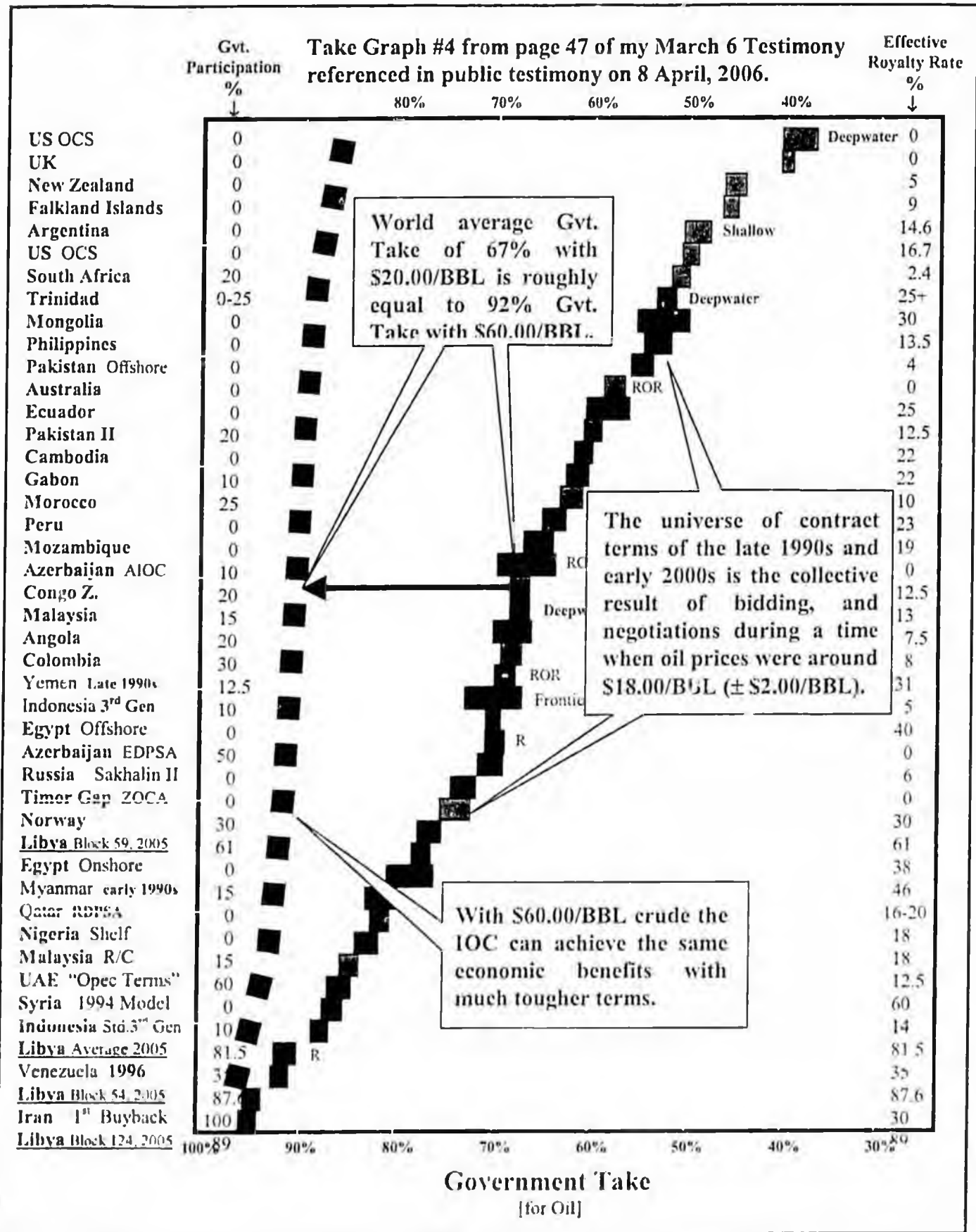
- (1) That Investment will dry up with the 25/20% proposal and a progressive feature.**
- (2) Alaska reputation will be seriously harmed**
- (3) There may be no Gas Pipeline**
- (4) Philanthropic donations are at risk (ConocoPhillips)**

Oil Industry has lobbied hard with every means available
(Can't blame them, but . . .)

I still have problems with some of the Peer Groups we keep getting compared to.

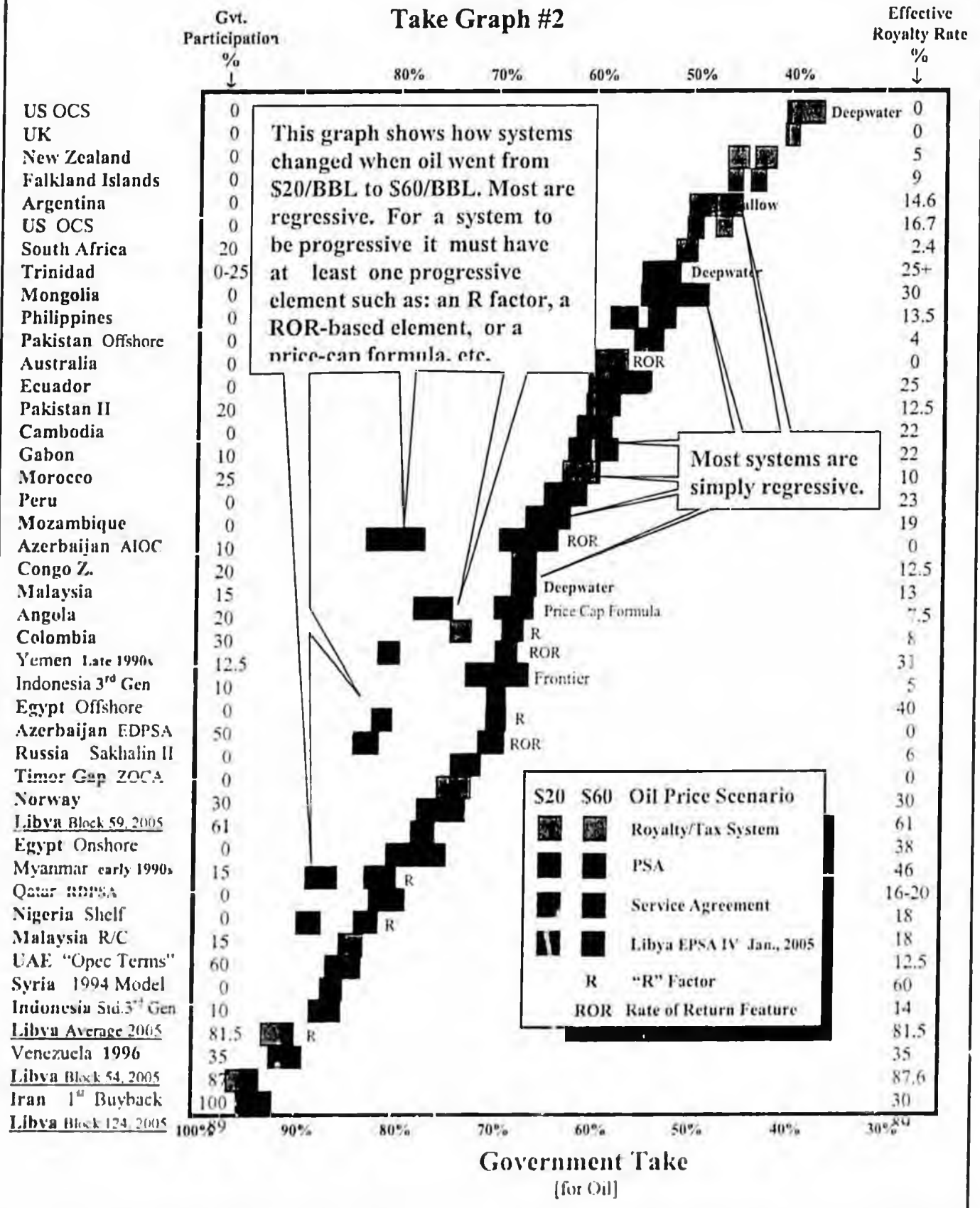
Who really thinks comparing Alaska to the likes of Kansas or Colorado is reasonable?

Russia provides some good analogs: both with PSAs as well as the Royalty/Tax arrangements there: very tough terms.



What terms would yield the same economic benefit at \$60/BBL?

Take Graph #2



Difference between \$20/BBL and \$60/BBL

<http://news.morningstar.com/news/DJ/M04/D04/200604040854DOW:JONESD:IONLINE000295.html?Cat=Energy>

04-04-06 08:45 AM EST

Beijing -(Dow Jones)- China's Ministry of Finance Tuesday issued rates for a newly implemented windfall profit tax on crude oil that is sold above US\$40 a barrel in the country.

"(The tax is aimed at) pushing forward the reform on oil price mechanism and promoting continuous, healthy and coordinated development of the national economy," the ministry said on its Web site.

In late-March, the National Development and Reform Commission, China's top economic planning agency, said it was immediately implementing a windfall profit tax on domestic crude oil sales, but didn't disclose the tax rate.

The tax took effect on March 26 and the tax rate ranges from 20% to 40% of the amount that companies get above US\$40.

The tax applies to enterprises and joint-venture companies that produce and sell oil onshore and offshore China, the ministry said.

Income generated from the windfall tax will be included in the central government's budget management, and taxes will be collected by the MOF.

The tax will be calculated monthly and should be paid quarterly, the ministry said, adding that since the tax is regarded as a company cost, it can be deducted before income tax.

Below is a table of the tax rates

<u>Crude Oil Selling Price (US\$ per Barrel)</u>	<u>Tax Rate On Portion Of Price Above US\$40</u>
40-45 inclusive	20%
45-50 inclusive	25%
50-55 inclusive	30%
55-60 inclusive	35%
above 60	40%

-Zheng Kiaolu contributed to this story, Dow Jones Newswires; 8610 6588-5848;
tracy.zheng@dowjones.com

Edited by Tracy Gan

Comments of Dr. Juan Carlos Boué

The following selected quotes come from Chapter 11 of an upcoming book by Dr. Juan Carlos Boué of Oxford University in the UK. I sincerely appreciate the insights from Dr. Boué and his permission to quote him as extensively as I have here. My commentary is confined to sections within brackets [such as these] to preface or expand on quotes from Dr. Boué's work. I would like to take this opportunity to publicly thank Dr. Boué for his concern and for his insights. DJ

The following quotes are from:

A QUESTION OF RIGS, OF RULES, OR OF RIGGING THE RULES? UNDERSTANDING THE PROFITABILITY AND PROSPECTS OF UPSTREAM OIL ACTIVITIES IN THE OFFSHORE US GULF OF MEXICO.

Copyright Oxford Institute for Energy Studies 2006. Juan Carlos Boué

11 CONCLUSIONS: WHAT SHOULD THE WORLD LEARN FROM THE SUCCESS STORY OF THE DEEPWATER GOM?

[The first of Dr. Boué's quotes regarding "basin masters" comes from a McKinsey Company study by; Conn. C., and White D., 1994, Revolution in Upstream Oil and Gas - Strategies for growth beyond 2000; McKinsey & Company, Australia. DJ]

"11.1 Basin Mastery: Adding Value in Global E&P Activities

McKinsey gave the name "basin masters" to those companies that managed to build dominant acreage and logistical positions in difficult new plays, partly because of their skills at resource development, technology and integrated project management but chiefly by virtue of their stealing a march on competitors in remote areas where scale and infrastructure were of paramount importance. [pg 334-335]

The cornerstone of this type of control [as basin master] is their dominant position in early infrastructure corridors (often over-built, with a view towards future discoveries), which allows the basin masters to extract rents from other players through access charges to this infrastructure. Frequently, this is bolstered by cosy relationships with governments, licensing agencies and NOC partners (the latter in provinces where PSA's [production sharing agreements] prevail), all of which tend to complicate the lives of potential competitors (through the appearance of bureaucratic and other, less wholesome, type of barriers) while simplifying the lives of incumbents (cast as they are in the enviable role of 'operator of choice' for licensing agencies). In this way, basin masters can ensure that they will be able to capture the majority of the value in a given province, including that generated from operations in fields not discovered by themselves. [pg 336]

Basin mastery may translate into very comfortable lives for a few bureaucrats and politicians in key positions in the governments of certain countries. However, for these governments as a whole (and even more so for the populations they represent), basin mastery effectively means stunted competition for acreage and consequently lower acreage process, higher upstream entry barriers, a high degree of fiscal dependence on very few operators . . . [pg 339]

"Furthermore, during subsequent years [subsequent to 1998], the magnitude of oil company [share] buybacks [around \$20 Billion per year or so] and cash holdings has made it painfully clear that these companies always had far more funds available for investment than attractive prospects to plough them into. The way in which domestic Russian firms succeeded in ensconcing themselves in the driving seat in their country, largely marginalizing international oil companies from Western Siberia, has made the dearth of attractive investment opportunities for the latter even more conspicuous." [pg 346]

11.3 The Issue of Tax Breaks

A landmark study commissioned by the Wyoming legislature (prompted in large part by a fiscal crunch in that US state, whose fiscal dependence towards oil income is second only to Alaska's) found that, *over a forty year period*, a once-and-for-all drop of 2 per cent in the state's severance tax rate would increase total oil recovery by less than one percent (50 MMBOE) and employment by 300 persons (i.e. 7.5 jobs *per year*), while causing a 17 percent reduction in the present value of severance tax collections. In contrast a doubling of the state severance tax (from 4 to 8 per cent) was found to reduce ultimate recovery by around 6 per cent, while increasing tax revenue, in present value terms, by over ninety per cent.³⁵ [pg 347]

[Footnote 35 is as follows: "Gerking *et al.* 2000. These conclusions had been foreshadowed by GAO 1990. This study found that some petroleum production incentives actually "provided incentives to make petroleum production investments that have pretax returns below those of investments in other industries" (p. 5). An even earlier GAO study 1985b: 32) had found that a 40 per cent reduction in Windfall Profit Tax for EOR projects had led to only one GOM project."]

[The UK]

Likewise, the resurgence of UK North Sea output after what is seen to be its production peak in the mid-1980s is often put forward as a prime example of the power of more flexible taxation schemes to coax higher output from maturing fields.³⁶ A study focusing on this issue concluded that, out of a total production of 2.676 MMBD in 1995, only about 355 MBD would not have been produced without the modifications to the British fiscal regime introduced from 1983 onwards.³⁷ [pg 347]

[Footnotes 36 and 37 are as follows: "36 Production of liquid hydrocarbons in the UK peaked (for a second time) in 1999 at 2.82 MMBD, after having languished at 1.88 MMBD during 1988-89. 37 Martin 1997: ii-iv"]

BP Graph of Production vs. Tax Rate

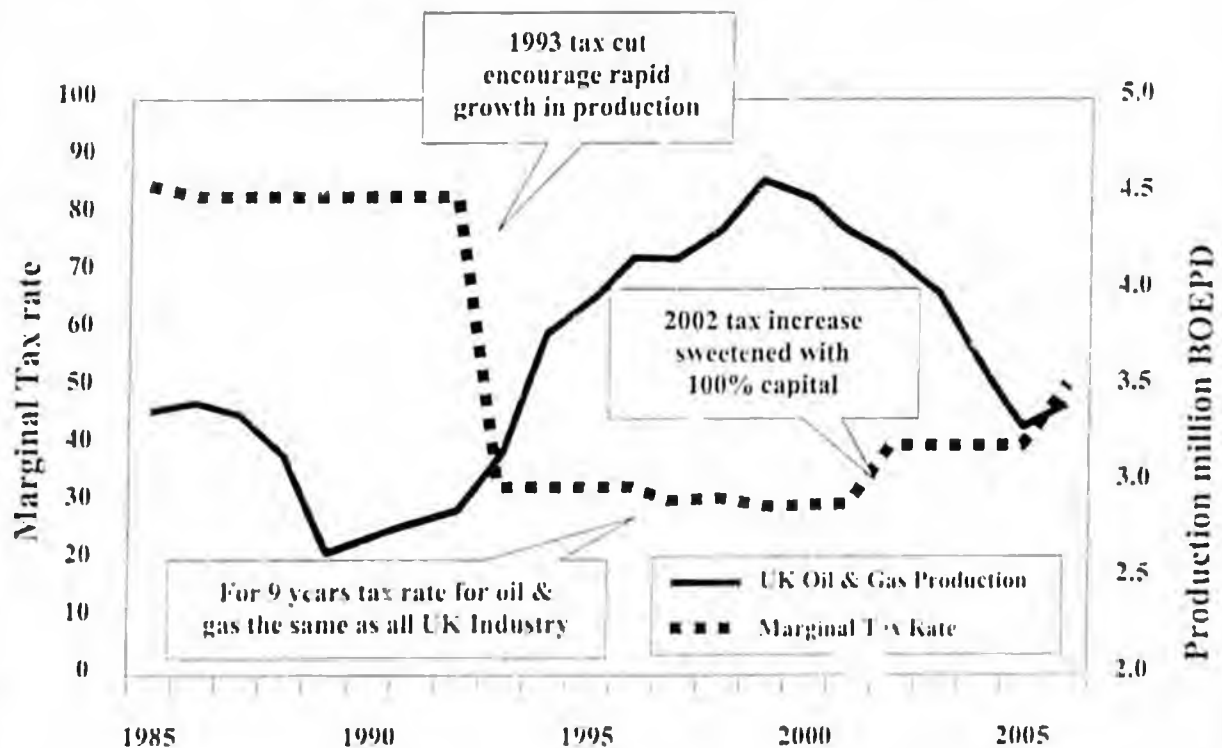
The graph below is not a fair representation of what the result of lowering the tax rate in 1993 was. In fact exploration expenditures went down significantly in 1994 and development expenditures did not go up (see following page). They went down but not as dramatically as exploration expenditures.

I think every Alaskan should consider this carefully and compare it to the data on the following page.

I experienced the "boom" in the mid-1980s in the UK sector of the North Sea that resulted from incentives provided that were very similar to the "credits" proposed here in Alaska. The increase in production was the result of exploration that occurred years before the 1993 reduction in taxes as one would expect. I do not see how it could be possible for industry to gear up and respond as quickly as this graph would suggest.

Please consider my work on the following page with caution. I had very little time to respond to this graph on such short notice with the busy schedule here in Juneau. With a bit more work we can verify — it is so important.

... But lowering tax rates will encourage investment



Source: BP presentation to Alaska Legislature 28 February, 2006 (page 8)

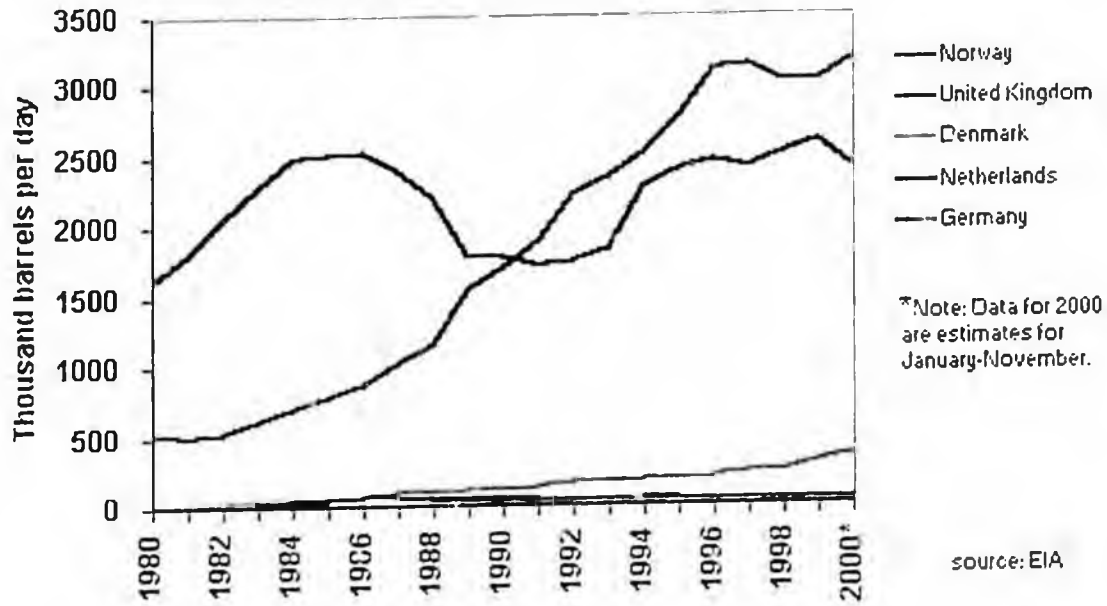
UK Drilling Activity History — Wells Drilled per year

This data was “reduced” from a graph from another UKOOC document and generated at 1:AM March 6, 2006. It begs verification and “real data” but I believe it confirms the fallacy of the claim that the reduction of Government take from around 85% to 33% enhanced investment activity in the UK in 1993.

More work needs to be done but it is clear to me that something is wrong with the conclusions drawn by BP regarding the 1993 fiscal event.

Year	Exploration	Appraisal	Development	Total
1974	67	33	19	119
1975	81	38	19	138
1976	58	28	52	138
1977	67	39	92	198
1978	38	25	92	155
1979	34	16	97	147
1980	31	22	117	170
1982	48	27	131	206
1983	69	44	111	223
1981	78	52	92	222
1984	108	78	102	288
1985	94	66	128	288
1986	73	41	81	195
1987	70	64	123	258
1988	94	86	159	339
1989	95	91	150	336
1990	163	66	122	350
1991	108	81	142	331
1992	75	58	161	294
1993	52	59	158	269
1994	63	38	197	297
1995	61	38	239	338
1996	72	41	256	369
1997	63	34	253	350
1998	47	33	272	352
1999	16	19	222	256
2000	27	33	213	272
2001	25	36	275	336
2002	16	31	258	305

North Sea Oil Production, 1980-2000*



BP Fields Brought on-stream after 1993

Andrew, Harding, Foinaven, Schiehallion, and ETAP (Eastern Trough Area Project includes 7 fields in the Central North Sea).

BP fields brought on-stream after 1993						
	Recoverable Reserves		Discovery Date	Start-up Date	Production 2000 MBO/D	
	MMBBL S	TCF				
Andrew	160	0.25	6/1974	6/1996	50	
Harding	719	0.27	1/1988	4/1996	87	
Foinaven	362	0.22	10/1992	1/1997	92	
Schiehallion	±300		10/1993	1/1998	100	
ETAP	450	1.1				

Norwegian Development Activity

Development Activity Investment

5 years <u>Before</u> 1993 (1988-1992 inclusive)	NKr 134,251 MM	\$ 20,340 MM	
5 years <u>After</u> 1993 (1994-1998 inclusive)	NKr 205,730 MM	\$ 31,170 MM	+ 53%

Norwegian Exploration Activity

Exploration Activity Investment

5 years <u>Before</u> 1993 (1988-1992 inclusive)	NKr 30,112 MM	\$ 4,560 MM	
5 years <u>After</u> 1993 (1994-1998 inclusive)	NKr 30,978 MM	\$ 4,694 MM	+ 3%

(Assumed exchange rate = NKr 6.6/US\$ 1)

North Sea oil and gas

The long goodbye

March 16th 2006 ABERDEEN

From The Economist print edition

High oil prices have helped slow the North Sea's decline. Government flip-flopping could accelerate it again

NOBODY disputes that Britain's part of the North Sea is past its prime. Oil and gas production peaked at 4.5m barrels a day in 1999 and has fallen steadily ever since, to 3.3m now (see chart). Yet in Aberdeen, Britain's main oil town, talk of an old "province" in decline is not tolerated. "The North Sea is enjoying a vibrant middle age," insists one oilman. "I think I'd describe it as mature rather than declining," muses another. Indeed, most of the industry's problems seem to be the sort associated with a boom, not a bust. Oil bosses complain about a shortage of skilled labour and the astronomical price of rig rentals, which have doubled since 2003.

A combination of high oil prices and some new government policies have made it profitable to keep working in what is an increasingly difficult and expensive place to drill for oil and gas. Investment has risen by 30% this year, and more exploration and appraisal wells are being drilled than at any time since 1997. The UK Offshore Operators Association (UKOOA), a trade body, thinks that the rate of decline will slow markedly next year. By 2007, production should be slightly higher than last year.

That will be music to the ears of a government determined that the North Sea should still be pumping 3m barrels a day in 2010. The petrochemical wealth off Britain's eastern shores supports a quarter of a million jobs and has helped to insulate the country from the vagaries of the international oil market for decades. Were the decline to continue at historic rates, production would be all but finished in 20 years.

There is no shortage of hydrocarbons: although 34 billion barrels have been produced, some 23 billion barrels are thought to remain. But many of the big, easily accessible fields are running down, and what is left is much harder to reach. That is changing the character of the industry.

One way to keep production up is to explore the waters off northern Scotland, the Shetland Islands and the deep Atlantic to the west of Scotland, where little exploration has so far been done. Two of the biggest recent finds—Buzzard (with around 500m barrels of oil and gas) and Lochnagar (perhaps 250m barrels)—were found off the beaten track. But developing them can be difficult. Rhum, a big gas field in the northern North Sea, was first discovered by BP in 1977, but the high pressure and temperature in the field meant that gas was not produced until December of last year. "A decade ago, a lot of this stuff would have been literally impossible to extract," says

Mike Tholen, UKOOA's economics director. "But technology has moved on."

Another option is to scrounge every last drop of oil and gas from existing fields. Finance, not geology, determines when an oil company quits a field, and it may leave behind substantial amounts of oil that are technically (but not economically) recoverable. The dregs of the big fields are often of only marginal interest to the big firms, which prefer chasing bigger and easier finds in other parts of the world such as the Gulf of Mexico or west Africa. Smaller, leaner companies are often able to pull the remaining oil out at a profit.

With all that in mind, ministers have been changing the rules to encourage smaller and more innovative firms. New licences allow companies to explore patches of ocean before they have finance arranged, and to hold on to difficult areas for six years instead of four. New rules prevent companies from sitting on unexploited discoveries for years at a time. And changes to the code of practice on access to pipelines (which are often owned by big oil companies) ensure that smaller companies can get their oil to market.

The new rules have proved popular. The latest licensing round, held in the summer of 2005, was the most successful in years. A total of 152 licences were offered to 99 companies, many of them in the frontier areas around northern Scotland and the Shetlands. A quarter of the companies were new to the North Sea.

But government can hinder as well as help, and not all its policies are so popular. The oil industry's relations with the Treasury have been poisoned by a series of sudden tax changes.

The first came in 2002, when Gordon Brown, the chancellor of the exchequer, raised the corporation tax for oil firms to 40% (most companies pay 30%). In November last year, he bumped it up to 50%. Furious oilmen accused the chancellor of risking the North Sea's future. UKOOA says that the changes create uncertainty, threatening future investment, and that they will do the most harm to the small firms that the government wants to attract. In its defence, the Treasury points to record oil company profits and insists that its only aim is "a fair deal for the taxpayer".

"The new taxes will probably bump the North Sea a few notches down the competitiveness ladder," says Geoff Gillies, an analyst at Wood Mackenzie, an energy consultancy. "But at today's oil price, the impact on development will be minimal." The danger will come if prices start to slip, as Wood Mackenzie thinks they will do over the next few years. Kieron McFadyen, a director at Shell UK, says that if expensive oil justifies higher taxes, then cheaper oil ought to bring tax cuts to compensate.

The death of the North Sea has been predicted many times before, points out Melfort Campbell, the head of the Scottish branch of the Confederation of British Industry. Yet technological advances have always confounded the gloom-mongers. The region will be even more dependent on innovation in its old age than it was in its youth. Most of the government's reforms reflect that. It would be a shame to see them undone by another tax grab.

Repeal Severance Tax Breaks for Oil and Gas

By Sarah Gorin, Equality State Policy Center

June 12, 2000

Since the beginning of fiscal year 1994, the people of Wyoming have lost over \$48 million dollars in severance tax breaks granted to our state's oil and gas industry on promises of greater - or at least sustained - production and employment. A new University of Wyoming study shows these promises were empty.

Over the past 15 years, the Wyoming Legislature has approved severance tax breaks - ranging from 33% to 75% - for several categories of oil production. Since 1993, it has also enacted a 67% break for certain categories of natural gas production.

Proponents of the tax breaks asserted they would result in increased production and employment, or would help preserve existing production and jobs. But no data was ever presented to support these assertions. They were upheld entirely by the lobbying power of the oil and gas industry and the willingness of a majority of legislators to accept the industry's assurances without evidence.

Thanks to an effort led by Senator Cale Case (R-S25, Lander), the evidence is finally in. Case successfully amended the most recent severance tax break legislation to include funding for a study to ask: Did the tax breaks trigger the well-advertised effect?

Part of that study has just been completed and released by a team of University of Wyoming economists, and the answer for oil and gas is: No. (The remainder of the study, focusing on coal, is in progress and will be completed by year's end.)

The UW economists created a oil and gas industry model capable of predicting the effects of changing tax rates. The model showed that cutting Wyoming's oil severance tax from 6% to 4% reduces the present value of oil severance tax revenues by 14%, while generating an increase in production of less than one-half of one percent (compared to a long-term "base case" of what would likely happen without any changes).

Similarly, a percentage point increase in the tax rate would still reduce production by less than one percent, but boost oil and gas severance tax collections by 17% compared to the base case.

One of the main reasons behind the minimal effect on production is that state taxes are deductible from federal taxes. A state tax break just means the producer pays more to the federal government. Thus the Wyoming Legislature sent oil and gas revenues to Washington, D.C. instead of to Cheyenne and to Wyoming's cities, towns and counties.

Second, because severance taxes are paid on oil and gas coming out of the ground, a severance tax break provides little incentive for the exploration and drilling activities that must come first.

Wyoming needlessly sacrificed just under \$48 million in oil and gas tax revenues for fiscal years 1994-99. This amount understates the loss because it does not include prior years when the tax breaks were in place but there was no reporting.



April 12, 2006

The Honorable Lyda Green
Alaska State Senate
Alaska State Capitol
Juneau, AK 99801-1182

Dear Senator Green:

Thank you for the opportunity to express ConocoPhillips' views on SB 305 before your committee early this month. Below are our responses to the questions you posed in your April 5, 2006 letter:

- 1) The PPT rate in the bill as introduced was 20%, while the rate in the Senate Resources CS is 25%. The consultants retained by the Legislature advise that the rate could be 25% without materially affecting the industry's investment in oil and gas development in Alaska. Do you agree with this statement? In your opinion, what should the PPT rate be in order to increase industry's investment here and why? Furthermore, if you think the PPT rate should be less than 20%, why did your company agree to a 20% rate?*

No, we do not agree that a tax rate of 25% will have no material impact investment. Rather, our view is that a 25% tax rate will reduce capital available for re-investment, reduce the competitiveness of Alaska projects within ConocoPhillips' portfolio, adversely alter the risk/reward balance in Alaska and result in lower investment levels in Alaska.

The PPT base rate is the most important variable in determining the overall effect of the resulting production tax system on investment attractiveness in Alaska. The higher the base rate, the lower the attractiveness will be for future investment in oil and gas in Alaska. As long-term investors, we must consider all of the effects of the proposed changes together. The tax credits will certainly help, but their effect on investment attractiveness is strongly outweighed by the higher tax rate.

In order to *increase* the industry's investment in Alaska, we believe that a PPT rate of significantly less than 20% is required. Given Alaska's high operating and development costs and low prospectivity, Alaska should lower its production tax base rate if it wishes to set its level of government take

competitively with comparable international areas such as the US Gulf of Mexico and the United Kingdom.

ConocoPhillips has consistently testified that we need a fair and balanced tax system. Even though the PPT system proposed in the original bill represented a substantial tax increase (an additional \$1B per year for the industry at today's prices) and is expected to negatively impact the competitiveness of our Alaska projects with other projects around the world, ConocoPhillips was willing to accept this higher tax burden because of the overall balance in the bill when viewed in a larger context. That is, the expected higher tax burden and lower project economics were offset by our view that the bill provided significant additional short term revenues to Alaska, ensured a continued strong presence for ConocoPhillips in Alaska and facilitated an agreement to move forward on the ANS Gas Pipeline among the three producers and the State.

Ultimately, the Legislature will have to make the judgment call of what is the right choice for Alaskans. No consultant (ours or yours) can make that judgment for you. Each industry participant can tell you how they might react to a tax change, but only you can judge whether the final PPT bill will strike the right balance for Alaska among various factors including investment, long-term oil recovery, state revenue, job creation for Alaskans, the overall health of the state economy and the realization of a gas pipeline.

- 2) *The Senate Resources CS proposes a tax in addition to the regular PPT in order to make the system more progressive when prices are high for oil. The House Resources CS proposes similar progressivity of gas as well as oil. If we include some kind of progressivity feature to deal with exceptionally high prices, will this have a material effect on industry investment in Alaska? If so, please explain why, and how material the effect would be. Is there any price level above which the effects of progressivity on new investments would become immaterial?*

The PPT 20/20 as proposed in the original bill is already a progressive tax. Introducing progressivity above and beyond the already progressive PPT is essentially a windfall profits tax and will have a negative impact on investment and investment attractiveness in Alaska, particularly since the tax will reduce investors' exposure to upside price risk, without helping on the downside.

When we consider investment decisions, we evaluate investments over a wide range of oil prices. In addition to a central assumption, we will consider high price outcomes as well as low price outcomes. This approach reflects the uncertainties of investing in a commodity-based business where we have no influence on the price at which we sell our product. The upside potential of a venture is highly significant in itself. Gaining exposure to the effects of high oil

prices is an important reason why we invest in certain projects (including high-cost projects) and why shareholders buy our stock.

Progressivity in tax take will, therefore, always have some bearing on our investment decisions, if the increases in tax take are significant over the range of prices we consider. There is, of course, a level where this influence becomes immaterial. For example, if the higher tax take kicked in at an index-linked price of \$100/barrel, the effect would probably be immaterial.

Although our view is that it is unreasonable and inappropriate to add a windfall profits tax element on top of the original PPT formulation, if the Legislature still insists on some form of super progressivity, we believe the methodology should be based on the taxable value after expenditures for the producer and be triggered only at a level that does not impact our normal project evaluation price considerations.

- 3) *We have been told there is a trade-off between the tax rate in the PPT and the percentage for tax credits against the PPT, and that an increase of five percentage points in the credit percentage will approximately offset the effects of an increase in the tax rate of one percentage point. Do you agree a trade-off exists, and if so, is the 5-to-1 ratio correct? Is there a law of diminishing returns at work here that decreases the effect of a credit after it gets to a certain percentage?*

Tax rates in almost all cases have a higher value to an investor than tax credits. The trade-off in value between the tax rate and amount of credits is complex in that it varies according to assumptions about future oil prices, cost levels, capital spend and various other parameters associated with new oilfield investments. The 5-to-1 ratio is our estimation of the trade-off based on a \$40 West Coast ANS price. At current prices and the terms in the current Senate CS, the ratio of equivalence is closer to 12-to-1

Tax credits are helpful to investors in helping to secure a return on our risk capital, and in giving incentives for active pursuit of efficient and effective development of Alaska's natural oil and gas resources. But we believe that the State needs to exercise a degree of caution in how far you set the balance of the PPT system that is finally enacted between tax credits and tax rate to investors.

There is a risk to the State in enacting a fiscal structure for PPT that is too heavily dependent on tax credits. In effect, if Alaska does this, it will be offering a high fixed level of tax relief on each \$1 of investment we make, which will come directly out of Alaskan State funds. Our view is that Alaska should balance the production tax system towards a lower PPT tax rate. In other words, let the industry take most of the risk of new investment, in return for sharing in a higher proportion of the eventual rewards. As leading players in the

international oil and gas business, managing the risks and rewards of investment is what we do best, and what our shareholders expect from us in Alaska, or wherever else we operate in the world.

In response to your final question, yes, we are concerned that tax credits in excess of 50% may not lead to efficient investment decisions.

- 4) *The original version of the SB 305 provided three alternatives for determining the "gross value at the point of production" for taxable oil and gas: 1) using the royalty netback determined under the a royalty settlement agreement with the State, 2) using a "formula" prescribed by the DOR based on a netback value or netback methodology approved by the Government, and 3) using another "formula" by DOR that reasonably estimates a value for the oil or gas at a specific geographical location. The Senate Resources CS deletes the first alternative, but keeps the latter two unchanged. What specific issues or problems do you foresee because of this deletion?*

Since royalty settlement agreements are negotiated with the State, we do not understand why the Senate CS deleted this option. It would seem that if the Department of Natural Resources has entered into an agreement to value the royalty oil and gas for the state that the value prescribed would be a fair and reasonable valuation for the oil and gas and in the best interests of the state as defined under AS 38.05.

The royalty settlement agreements provide protection for both parties to determine a fair and reasonable valuation and through re-openers the DNR has the ability to ensure that the valuation methodology continues to be reasonable over time. Utilizing one valuation methodology for both state royalty and tax purposes seems to be a reasonable simplification (rather than having multiple netback calculations in determining the value at the point of production) and will be beneficial for the state and the taxpayer from an administration standpoint.

While utilizing a methodology under a government-approved royalty settlement agreement appears reasonable, we are unsure what "adjustments" will be deemed appropriate by the department under the Senate CS current language. We believe that such adjustments would be limited to locational differences, as the royalty settlements provide protection for all other necessary changes to various components in the calculation through contractual re-opener clauses.

ConocoPhillips would strongly recommend that the first alternative for determining the value at the point of production be reinstated. That alternative is the only one which provides sufficient certainty as to how the value would be determined; the other two allow too much discretion by the department.

5) *What do you think the effective date should be for the PPT and why?*

The State should not have an effective date that is retroactive, nor should it be effective prior to regulations being drafted, reviewed and promulgated. Companies need time to plan appropriately and both the State and companies need time to implement systems, processes and procedures to comply with the new law.

Given the significance of the proposed changes, it is likely that in excess of 6 months will be required to complete the regulations. Consequently, ConocoPhillips believes a January 1, 2007 effective date is appropriate and reasonable.

6) *The Senate Resources CS allows a credit for investments made during the five years preceding the effective date of the PPT, but limits the credit so that new capital investments will have to be twice as much as the old ones in order for the credit to be fully used. How will this two-for-one transitional credit make a difference in you company's investment decision-making? Is this approach fair to both major and independent producers?*

A transition plan is essential to ensuring fair treatment of historical investments and maintaining a perception for potential future investors of a reasonable approach to fiscal change in the State of Alaska. Without any transition plan, recent investments will pay the highest effective tax rate on the North Slope -- investors who have proactively pushed forward with development would be penalized, while delayed investments would benefit.

The transition plan should:

- Recognize at least five full years of historical upstream investments. North Slope projects have long lead times and it is not uncommon for project approval and investment durations to be 5 years or longer. (For example the Fiord satellite was discovered in 1992; initial project capital was spent in 2001 and the project will come on stream later this year)
- Acknowledge that recent satellite investments were often sanctioned based on letter rulings from the State's Department of Revenue indicating that the projects would be subject to stable and relatively low production taxes.
- Not a threshold price below which the transition deductions are disallowed. The new two-for-one proposal provides an incentive for long-term future investment; it is unreasonable and inappropriate to remove that incentive based on a short-term spot price threshold.

ConocoPhillips believes that both the transition concepts provided in the original bill and that Senate CS can work. With regard to the Senate CS, the current proposal enables a company to receive a \$1 deduction for historical investment for each \$2 of future investment. We believe that to ensure equitable treatment of historical investments and still incentivize higher future levels of investment the period for recovery of historical deductions should be extended to 9 years in the future rather than the current 7 years in the Senate CS.

We believe this two-for-one transitional credit approach provides fair and reasonable benefits for all industry participants.

- 7) *In committee, it was mentioned that the safe harbor provisions in the Senate Resources CS, requiring taxpayers to calculate their monthly tax payments to a 95% degree of accuracy, is a very difficult target to hit and unreasonable. Do you agree with this statement and if so, what do you consider reasonable? Do you feel the quarterly true-up provision is manageable or should it be any annual true-up as proposed in the original version of the bill? What is the traditional relationship in this regard between the oil and gas industry and tax collectors in other states?*

Yes, ConocoPhillips definitely agrees that the provision for monthly tax payments in the current Senate CS is unreasonable and impractical. Further, our view is that quarterly true up provision is also impractical and we do not see any significant benefit to the State from such a provision. Rather, we believe the provisions of the original bill, which contemplated a 90% year to date test for each month a return is filed, is practical because it allows the taxpayer enough time to gather and process all of the information needed to properly pay the tax. If the industry on average estimates the proper amount of tax, overpays in some months and underpays in others, then there is really no benefit to either party.

Generally, a tax that is required to be calculated and paid on a monthly basis requires much more time and effort than a similar tax that is calculated and paid on an annual basis. Under the original bill, twelve separate monthly tax calculations and payments would be required and then a final true up would occur some time after that fiscal year to ensure that all income and costs were properly included.

The complexity of quarterly true-ups over and above an annual true-up is compounded by the fact that much of the information is not available until later time periods. For example, ConocoPhillips cannot fully determine all of its qualified capital expenditures as calculated by IRS rules until all partnership and corporate tax returns are prepared.

To ensure that taxpayers are not substantially and habitually underpaying, most taxing jurisdictions, including the federal government, usually charge interest and penalties on substantial underpayments, that is payments less than the safe harbor.

The interest charged by those jurisdictions is typically tied to current market rates rather than at rates substantially higher than market rates. Therefore, we view the CS inclusion of a 5% civil penalty as duplicative because the interest rate, which is the higher of 5 percentage points for the 12th Federal Reserve District or 11%, already includes a punitive element. We also believe that the 5% civil penalty called for in the CS is duplicative to the administrative regulation penalty in AS 43.05.220.

As for the traditional relationship with other states, the proposed PPT tax is different than the gross income production tax levied by all the other states in the US. The amount of information and the time needed to properly file this tax is more akin to the annual filing of income taxes found in US federal and state statutes. For income or profit based taxes, all US states provide for:

- quarterly or annual estimated payment,
- annual true-ups,
- a safe harbor which generally requires taxpayers pay 90-100% of their taxes prior to final annual tax due date and apply interest, and
- penalties that only apply if the taxpayer does not meet the safe harbor for the entire year.

8) *Please take this opportunity to describe any other provisions of the Senate Resources CS to SB 305 that cause considerable concern for your company and deserve additional discussion by the Senate Finance Committee.*

The fundamental issues are PPT base tax rate, the windfall profits tax (increased progressivity at high prices), transitional credits, use of royalty settlement agreements and the effective date. In addition to these fundamental issues and those referred to in the prior questions, we have considerable concern over (A) the treatment of abandonment costs, and (B) artificial restrictions on lease expenditures.

(A) The Senate CS's treatment of abandonment costs is contrary to the state's goals of maintaining production and economic stewardship:

- Drilling costs should be immediately deductible. As has been discussed by the state's economic experts, Alaska has low prospectivity. Therefore, the state should not further discourage exploration by disallowing abandonment deductions for dry holes.
- Dismantlement costs for upstream facilities and drill sites are not recovered through a tariff, in contrast to TAPS. However, dismantlement is part of the lease life cycle and is required under the lease terms with the state. The timely, thorough, and safe dismantlement and removal of

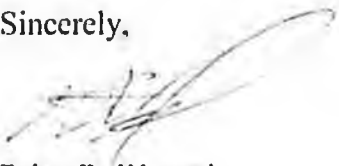
equipment should be promoted not discouraged.

- Many current capital projects in existing fields require removal or modification of existing facilities. It is unclear whether the Senate CS language is intended to disallow these costs.

(B) We believe that any lease expenditures that meet the stringent IRS requirements as ordinary and necessary and are in support of lease operations should be allowed as deductions under AS 43.55.160. For producers all costs paid on a joint venture bill are necessary costs of operating. The carving out of specific lease expenditures complicates the administration of the tax and will lead to unnecessary controversy and disputes. The restrictions seem excessive when considering what other jurisdictions would allow as ordinary and necessary costs and is allowable under federal regulations.

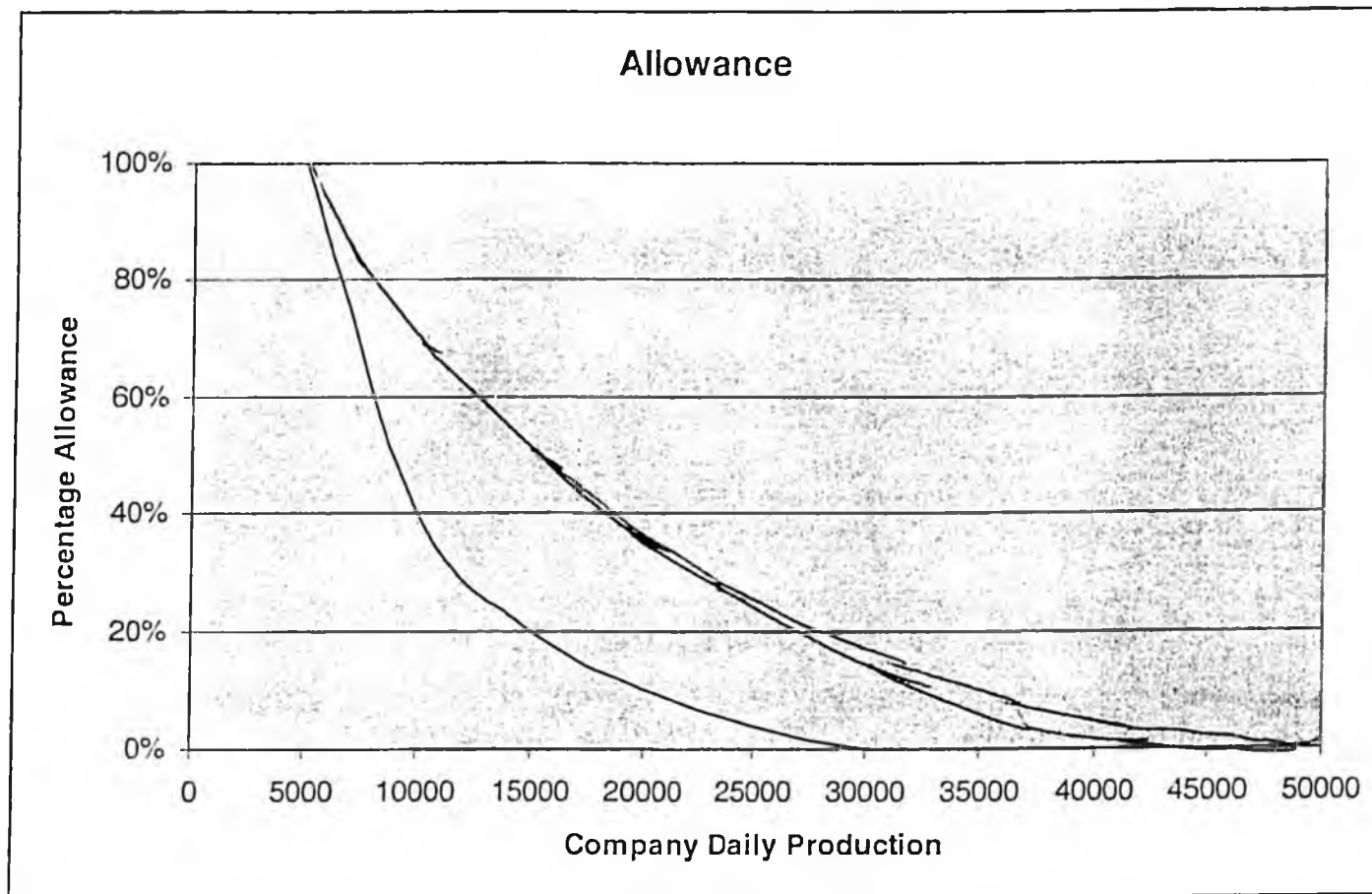
If you have any questions regarding this information, you may contact me at 907-265-1650 or make arrangements through our Juneau office at 907-586-3680.

Sincerely,



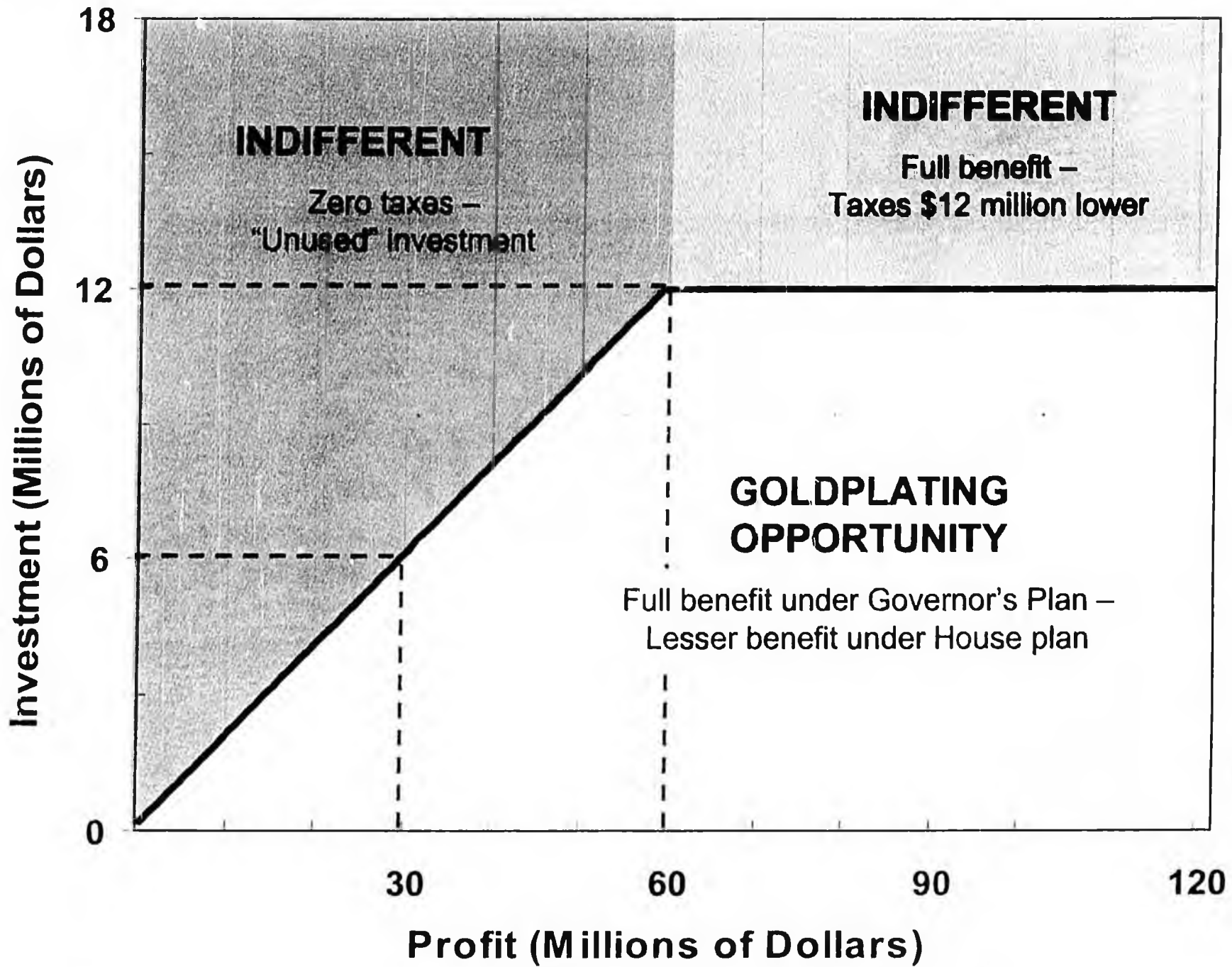
Brian R. Wenzel
Vice President, Finance & Administration
ConocoPhillips Alaska

FIGURE 2



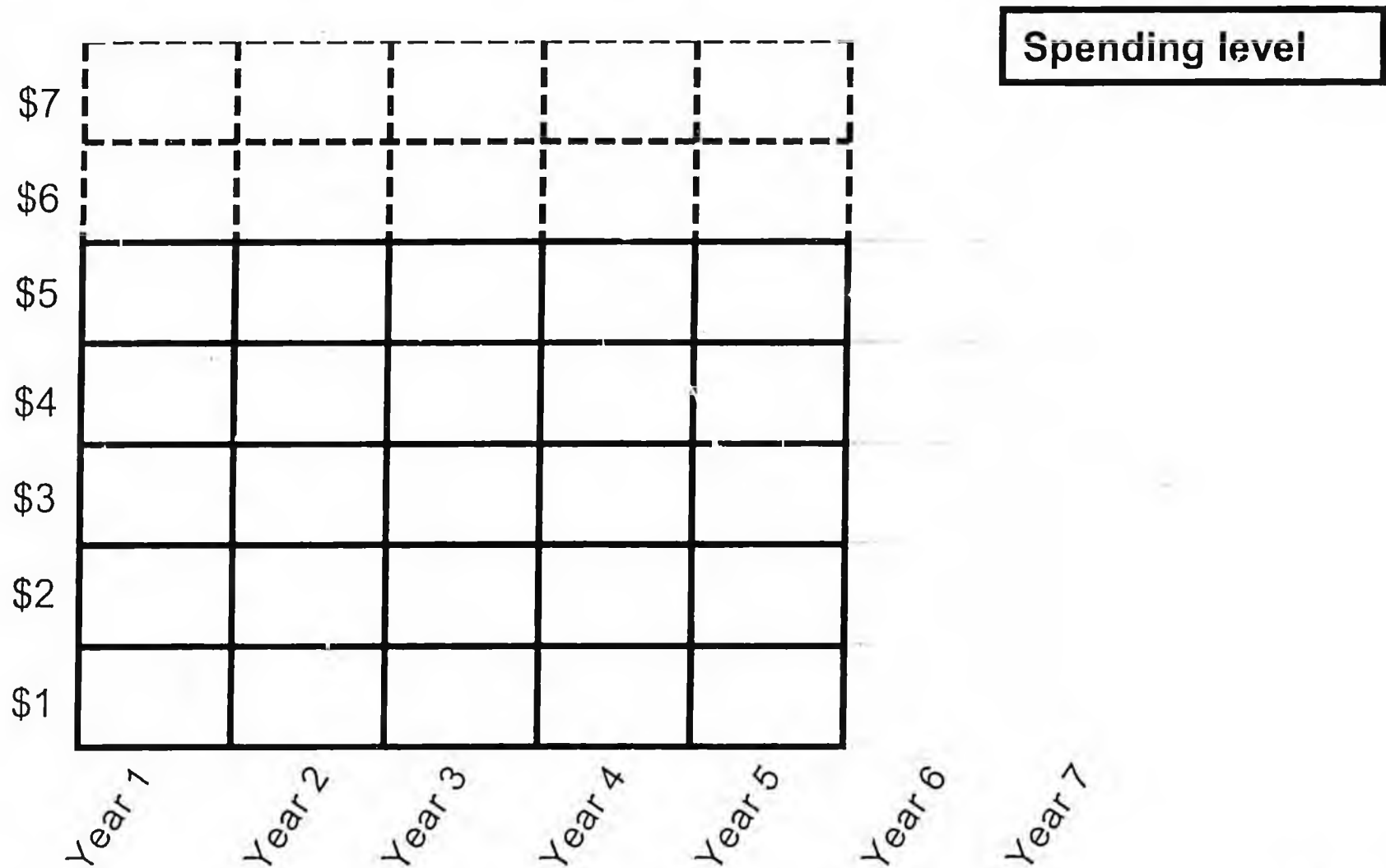
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Provided by
Dan Dickinson



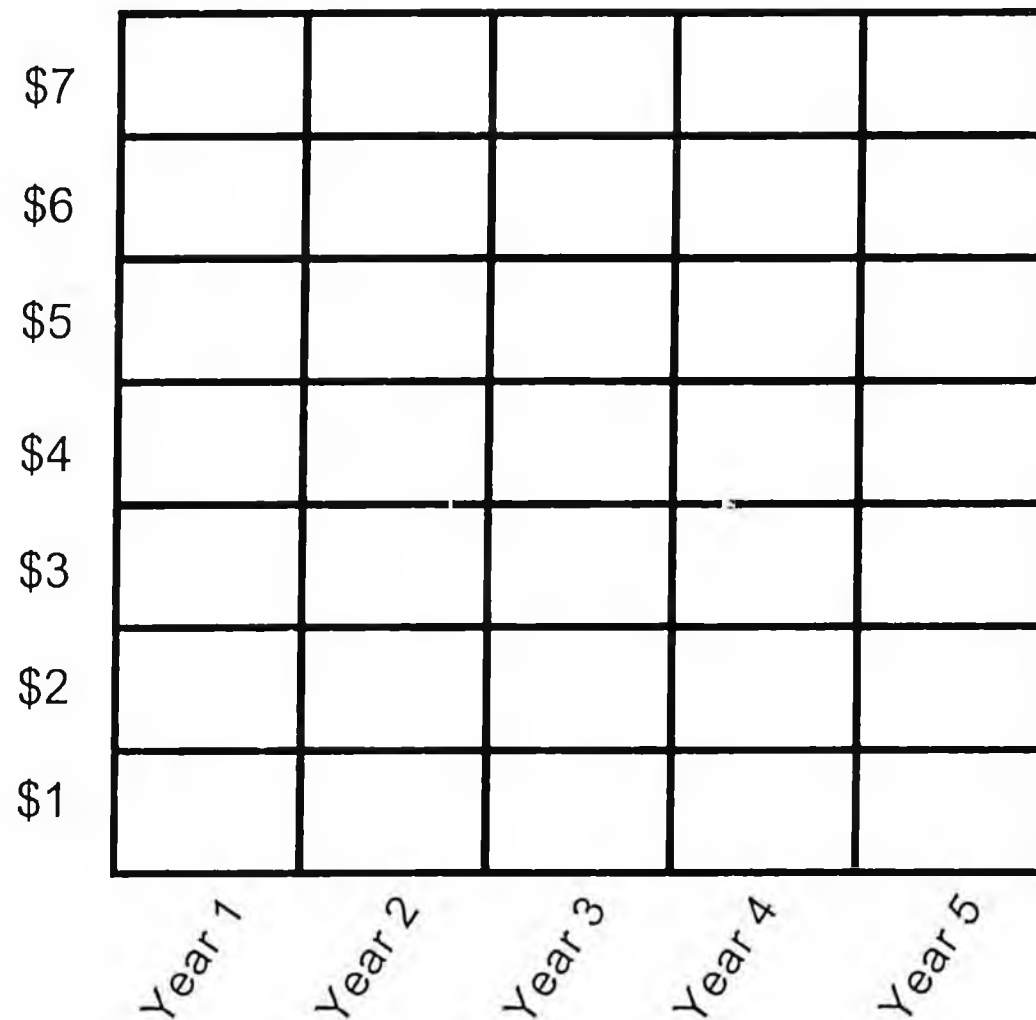
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Recovery of \$35 over 7 years 5 dollar a year
(One to One match would only require 5/7th of spend each year)



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Spending of \$35 in 5 years-
7 Dollars a year



Recovery of \$35 over 7 years: 5 dollar a year

(Two to One match would only require 40% increase in annual spending)

40%
increase
each
year

\$10

\$9

\$8

\$7

\$6

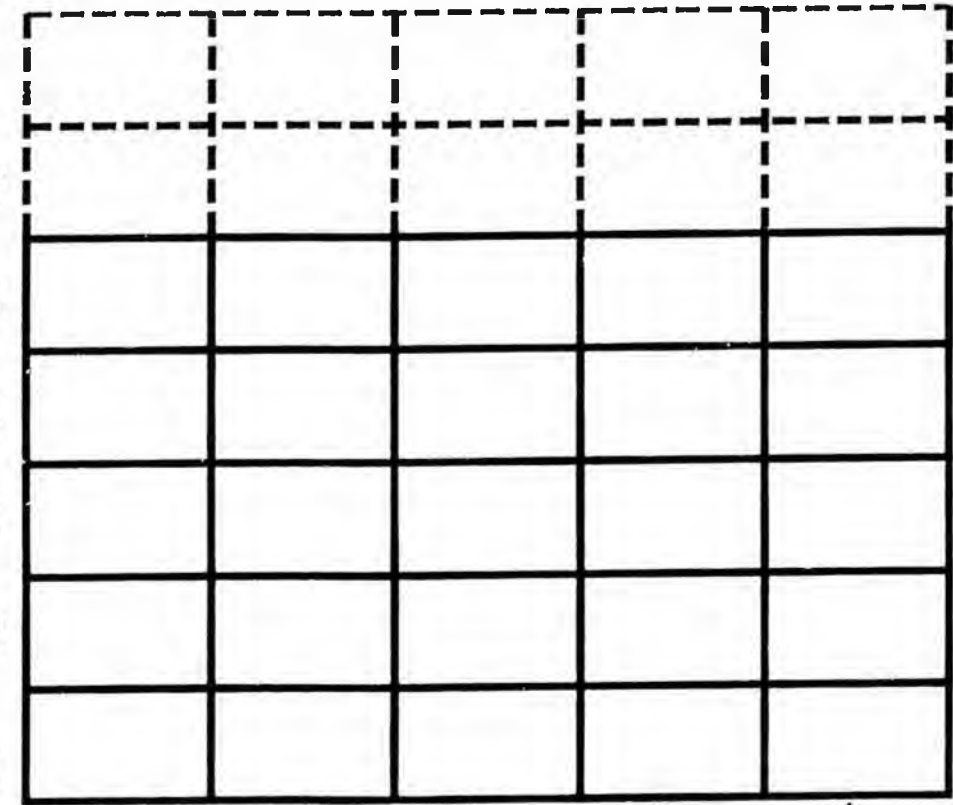
\$5

\$4

\$3

\$2

\$1



Year 1

Year 2

Year 3

Year 4

Year 5

Year 6

Year 7

Spending
level

4/3/2006

source: DOR

and 4/12/06

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

	governor's bill	House Resources CS Version L	Senate Resources CS Version C
tax rate	20% .011(a)--page 3	20% .011(a)--page 3	25% .011(e)--page 3
credit rate	20% .024(a)--page 5	20% .024(a)--page 8	20% .024(a)--page 7
private royalty tax rate	no special rate	5% .011(e)--page 3-4	1.5% (Cook Inlet), 5% other .011(f)--page 3
progressivity surcharge	none	over \$50/bbl WTI, (.3% x (WTI - \$50) x gross; <\$110 rate is 37.5% .011(f)--page 4	over \$40/bbl, (ANSwc - \$40) x .002 x ANSw h x .75 x bbls .011(g)--page 4
special gas progressivity?	n/a	yes .011(i)--page 4-5	no
progressivity deductible?	n/a	yes .160(a)--page 18	yes, but not clear
transition	5 yr lookback of capex .160(g)--page 15	3 mo. of capex & opex. ? Sec. 42 uncodified--page 30	5 yrs.lookback capex 2 for 1 recoupment .024(l)--page 10
transition treatment	deduction over 6 yr, if ANSwc >=\$40 .160(g)--page 15	deduction over 9 mo, no oil price test Sec. 42 uncodified--page 30	credit; no oil price test .024(i)--page 10
sunset of transition	no	n/a	3/31/2013 .160(i)--page 10
base allowance	\$73M deduction .160(i)--page 16	\$12M credit (equates to \$60M ded.) .170(a)--page 23	5000 bbl plan .160(g)--page 19--20
sunset of base allowance	none	3/31/2016 (exp incurred) .170(e)--page 24	12/31/2013 .160(h)--page 20
safe harbor	90%, annual true up, no interest .020(a)--page 3	90% with interest .020(g)--page 7	95% quarterly true-up, no interest .020(a)--page 5
pmt < safe harbor??	interest only .020(a)--page 3	5% penalty + interest .020(h)--page 7	interest only .020(a)--page 5
effective date	7/1/2006 page 20	4/1/2006 Section 45--page 30	4/1/2006 Sec. 38--page 28
transition payment	none	6 mos. pymt on old system; true-up in 7th mo. sec. 39--page 28	6 mos. pymt on old system; true-up in 7th mo. suc. 33--page 26
spill surcharge total	no change (5 cents)	no change (5 cents)	increase 1 cent, to 6 cents
spill surcharge split (.201/.300)	2/3	1/4	1/5
spill surcharge payable	no change	increase 1 cent page 24--25	increase 2 cents page 22-23
surcharge treatment	creditable against PPT page 17--18	not creditable, not ded. .160(d)(2)(L)--page 21	not creditable, not ded. .160(d)(2)(L)--page 17
SB 185 credit	no change	extends 10 years; only usable against PPT .025(b), .025(f)--page 11-12	no change
abandonment	no provision	no credit 024(i)(2)--page 11	partially deductible; no credit abandonment on old production 024(h)(2)--page 9
credits usable	against PPT only .024(a)--page 3	against PPT only .024(a)--page 8	against PPT only? .024(c)--page 8
credits transferable	yes--20% tax limit 024(d)--(e)--page 6	yes--20% tax limit 024(d)--(e)--page 8-9	yes--20% tax limit 024(d)--(e)--page 8-9
credits refundable?	no	up to \$10M depends on investment 024(f)(5)--page 9-10	no
credits for annual loss	yes, at 20% 024(b)--page 5	yes, at 20% 024(b)--page 8	yes, at 25% 024(b)--page 7
point of production	gas treatment upstream 900(7)--page 19	gas treatment upstream 900(7)--page 25-28	gas treatment upstream 900(7)--page 23
DNR royalty value	yes .150(d)--page 11	yes .150(d)--page 17-18	yes .150(d)--page 14
IRC sec. 482 as a tool	no	no	yes, including 5% penalty .160(l)--page 21
catastrophic oil spill deductible?	yes, if on lease (not precluded)	no 160(c)--page 19	yes, if on lease (not precluded)

Senate Finance CS

Per bbl cost/Price	Proposed Progressivity (\$ per barrel additional Tax)						
	50.00	55.00	60.00	65.00	70.00	75.00	80.00
5	0	0.25	0.55	0.90	1.30	1.75	(2.25)
6	0	0.20	0.49	0.83	1.22	1.66	2.15
7	0	0.14	0.42	0.75	1.13	1.56	2.04
8	0	0.09	0.36	0.68	1.05	1.47	1.94
9	0	0.05	0.31	0.62	0.98	1.39	1.85
10	0	-	0.25	0.55	0.90	1.30	1.75
11	0	-	0.20	0.49	0.83	1.22	1.66
12	0	-	0.14	0.42	0.75	1.13	1.56
13	0	-	0.09	0.36	0.68	1.05	1.47
14	0	-	0.05	0.31	0.62	0.98	1.39
15	0	-	-	0.25	0.55	0.90	1.30
16	0	-	-	0.20	0.49	0.83	1.22
17	0	-	-	0.14	0.42	0.75	1.13
18	0	-	-	0.09	0.36	0.68	1.05
19	0	-	-	0.05	0.31	0.62	0.98
20	0	-	-	-	0.25	0.55	0.90
21	0	-	-	-	0.20	0.49	0.83
22	0	-	-	-	0.14	0.42	0.75
23	0	-	-	-	0.09	0.36	0.68
24	0	-	-	-	0.05	0.31	0.62
25	0	-	-	-	-	0.25	0.55
26	0	-	-	-	-	0.20	0.49
27	0	-	-	-	-	0.14	0.42
28	0	-	-	-	-	0.09	0.36
29	0	-	-	-	-	0.05	0.31
30	0	-	-	-	-	-	0.25

Per bbl cost/Price	CSHB 488 (\$ per barrel additional Tax)						
	50.00	55.00	60.00	65.00	70.00	75.00	80.00
5	-	0.50	1.10	1.80	2.60	3.50	4.50
6	-	0.50	1.10	1.80	2.60	3.50	4.50
7	-	0.50	1.10	1.80	2.60	3.50	4.50
8	-	0.50	1.10	1.80	2.60	3.50	4.50
9	-	0.50	1.10	1.80	2.60	3.50	4.50
10	-	0.50	1.10	1.80	2.60	3.50	4.50
11	-	0.50	1.10	1.80	2.60	3.50	4.50
12	-	0.50	1.10	1.80	2.60	3.50	4.50
13	-	0.50	1.10	1.80	2.60	3.50	4.50
14	-	0.50	1.10	1.80	2.60	3.50	4.50
15	-	0.50	1.10	1.80	2.60	3.50	4.50
16	-	0.50	1.10	1.80	2.60	3.50	4.50
17	-	0.50	1.10	1.80	2.60	3.50	4.50
18	-	0.50	1.10	1.80	2.60	3.50	4.50
19	-	0.50	1.10	1.80	2.60	3.50	4.50
20	-	0.50	1.10	1.80	2.60	3.50	4.50
21	-	0.50	1.10	1.80	2.60	3.50	4.50
22	-	0.50	1.10	1.80	2.60	3.50	4.50
23	-	0.50	1.10	1.80	2.60	3.50	4.50
24	-	0.50	1.10	1.80	2.60	3.50	4.50
25	-	0.50	1.10	1.80	2.60	3.50	4.50
26	-	0.50	1.10	1.80	2.60	3.50	4.50
27	-	0.50	1.10	1.80	2.60	3.50	4.50
28	-	0.50	1.10	1.80	2.60	3.50	4.50
29	-	0.50	1.10	1.80	2.60	3.50	4.50
30	-	0.50	1.10	1.80	2.60	3.50	4.50

Distributed by Sen. Green

4/19/06 2:20 pm

Producer 2005 Daily Production (BOE Equivalents)

• Anadarko	27,801
• Aurora	1,543
• BP	354,670
• Chevron	44,757
• Doyon	27
• ExxonMobil	182,117
• Forest	7,004
• Marathon	27,705
• ML&P	2,572
• NANA	80
• ConocoPhillips	426,087
• XTOE Energy	3,345
• Kerr-McGhee**	20,000
• Pioneer**	<u>20,000</u>
• TOTAL	1,117,798

Time Stamp 2:08pm 4/12/04

Provided by
Senator Stedman.

Structure of the Senate Finance CS for SB 305

Calculate the tax base:

Calculate the gross value at the Point of Production
(May use a Royalty Settlement Agreement) (150 (d)) page 17
Take the Gas Revenue Exclusion (160 (a)) page 18
subtract lease expenditures including qualified capital expenditures to arrive at
the net "Production Tax Value" page 18

Apply the three tax rates:

Base PPT rate: 22.5 % applied against the Production Tax Value (.011 (e)) page 3
Private Royalty Rate applied against gross value at the point of production (.011 (f)) page 3
Progressivity: .001 * index applied against the Production Tax Value (.011 (g)) page 4
index= ((Production Tax Value/Barrel of oil Equivalents) - 45) (.011 (h)) page 4

To arrive at tax liability before credits

Apply the five credits

5,000 a day barrel equivalent credit, capped at \$14,000 million (non transferable) (.170) page 23
TIE credit equal to 1/2 of current investment (with other limits) (.024 (i)) page 10
Alternative Exploration Credit of up to 40% (SB 185 extended) (.025) page 11
Qualified Capital Expenditure of 25% (.024(a)) page 7
Any loss at the end of the year converted to a Carry Forward Credit (.024 (b)) page 8

To arrive at tax liability after credits

Estimated monthly payments, must be true up for prior year in by 3/31 of each year (.020 (a)) page 5
If any month is estimated at less than 95%, interest due. (.020 (a)) page 5
Taxpayer can either use annualized or monthly actual costs, and can opt for the whole year
at any time - however - must be one way or the other for all effects. (.024 (a)) & (160) page 7 & 22

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

4/19/2006

source: DOR

	governor's bill	House Resources CS Version L	Senate Resources CS Version C	Senate Finance CS draft
tax rate	20% .011(a)-page 3	20% .011(a)-page 3	25% .011(e)-page 3	22.5% .011(e)-page 3
credit rate	20% .024(a)-page 5	20% .024(a)-page 8	20% .024(a)-page 7	25% .024(a)-page 6
private royalty tax rate	no special rate	5% .011(e)-page 3-4	1.5% (Cook Inlet), 5% other .011(i)-page 3	5% oil & 1.67% gas Report from Commish .011(f)-page 3 & 28
progressivity surcharge	none	over \$50/bbl WTI, (.3% x (WTI - \$50) x gross; <\$110 rate is 37.5% .011(f)-page 4	over \$40/bbl, (ANSwc - \$40) x .002 x ANSwb x .75 x bbls .011(g)-page 4	over \$45/bbl, (net value/boe) x .001 x net value (net value= production tax value) .011(g) and (h)-page 4
special gas progressivity?	n/a	yes .011(i)-page 4-5	no	no
progressively deductible?	n/a	yes .160(e)-page 18	yes, but not clear	no
transition	5 yr lookback of capex .160(g)-page 15	3 mo. of capex & opex. ? Sec. 42 uncodified-page 30	5 yrs lookback capex 2 for 1 recoupment .024(i)-page 10	5 yrs lookback capex 2 for 1 recoupment .024(i)-page 9-10
transition treatment	deduction over 6 yr, if ANSwc >=\$40 .160(g)-page 15	deduction over 9 mo, no oil price test Sec. 42 uncodified-page 30	credit; no oil price test .024(i)-page 10	20% credit; no oil price test .024(i)-page 9-10
sunset of transition	no	n/a	3/31/2013 .024(i)-page 10	6/30/2013 .024(i)-page 10
base allowance	\$73M deduction .160(i)-page 16	\$12M credit (equates to \$60M ded.) .170(a)-page 23	5000 bbl plan .160(g)-page 19-20	Revised 5000 bbl equivalent credit capped at 14 million .170(a)-page 23-24
sunset of base allowance	none	3/31/2016 (exp incurred) .170(a)-page 24	12/31/2013 .160(h)-page 20	6/30/2016 w/commissioner report .170(b)-page 24 & 28
safe harbor	90%, annual true-up, no interest .020(a)-page 3	90% with interest .020(g)-page 7	95% quarterly true-up, no interest .020(a)-page 5	95%, annual true-up, no interest .020(a)-page 4-5
pmt < safe harbor??	interest only .020(a)-page 3	5% penalty + interest .020(h)-page 7	interest only .020(a)-page 5	interest only .020(a)-page 4-5
effective date	7/1/2006 page 20	4/1/2006 Section 45-page 30	4/1/2006 Sec. 38-page 28	7/1/2006 Sec. 43-page 31
transition payment	none	6 mos. pymt on old system; true-up in 7th mo. sec. 39-page 28	6 mos. pymt on old system; true-up in 7th mo. sec. 33-page 26	6 mos. pymt on old system; true-up in 7th mo. sec. 38(g)-page 30
spill surcharge total	no change (5 cents)	no change (5 cents)	increase 1 cent, to 6 cents	no change (5 cents)
spill surcharge split (2011-2001)	2/3	1/4	1/5	1/4 *Sen Wilken researching
spill surcharge payable	no change	increase 1 cent page 24-25	increase 2 cents page 22-23	increase 1 cent page 24-25
surcharge treatment	creditable against PPT page 17-18	not creditable, not ded. .160(d)(2)(L)-page 21	not creditable, not ded. .160(d)(2)(L)-page 17	not creditable, not ded. .160(d)(2)(L)-page 21
SB 185 credit	no change	extends 10 years; only usable against PPT .025(b), .025(f)-page 11-12	no change	extends 10 years; fixes \$20 m issue .025(b), .025(f)-page 11-14
abandonment	no provision	no credit .024(i)(2)-page 11	no credit; no deduction for abandonment on old production .024(h)(2)-page 9	no provision
credits usable	against PPT only .024(a)-page 3	against PPT only .024(a)-page 8	against PPT only? .024(c)-page 8	against PPT only .024(a)-page 3
credits transferable	yes-20% tax limit .024(d)-(e)-page 6	yes-20% tax limit .024(d)-(e)-page 8-9	yes-20% tax limit .024(d)-(e)-page 8-9	yes-20% tax limit .024(d)-(e)-page 8-9
credits refundable?	no	up to \$10M depends on investment .024(i)(5)-page 9-10	no	no
credits for annual loss	yes, at 20% .024(b)-page 5	yes, at 20% .024(b)-page 8	yes, at 25% .024(b)-page 7	yes, at 22.5% .024(b)-page 7
point of production	upstream of gas treatment upstream 900(7)-page 19	upstream of gas treatment upstream 900(7)-page 25-26	upstream of gas treatment upstream 900(7)-page 23	upstream of gas treatment upstream 900(7)-page 26-27
DNR royalty value	yes .150(d)-page 11	yes .150(d)-page 17-18	yes; after determination .150(d)-page 14	yes revised determination .150(d)-page 17
IRC sec 482 as a tool	no	no	yes, including 5% penalty .160(i)-page 21	no
catastrophic oil spill deductible?	yes, if on lease (not precluded)	no .160(c)-page 19	yes, if on lease (not precluded)	yes, if on lease (not precluded)
DNR gets exploration data				yes .024(a) page 6-7
020 (f) Sales Language				yes .020(f) page 6
NPSL reqs after industry practice				yes .160C page 10-20
Gas				Gas Revenue Exclusion in 160 equivalent to rate approximating 7% (also applies to private royalty rate creating equivalent rate below 1.5%) .160 (a) page 18

4/19/06

Oil Production January 2000 - January 2006

Cook Inlet

Barrels

% Volume by Ownership

CY	Barrels			Total	% Volume by Ownership				
	Federal	Other	State		Federal	Other	State	Total	
2000				9,988,509	9,988,509	0.0%	0.0%	100.0%	100.0%
2001				10,810,856	10,810,856	0.0%	0.0%	100.0%	100.0%
2002				10,726,968	10,726,968	0.0%	0.0%	100.0%	100.0%
2003				9,592,727	9,592,727	0.0%	0.0%	100.0%	100.0%
2004				7,844,470	7,844,470	0.0%	0.0%	100.0%	100.0%
2005				6,720,610	6,720,610	0.0%	0.0%	100.0%	100.0%
2006				515,470	515,470	0.0%	0.0%	100.0%	100.0%
Grand Total				56,199,610	56,199,610				

North Slope

Barrels

% Volume by Ownership

CY	Barrels			Total	% Volume by Ownership				
	Federal	Other	State		Federal	Other	State	Total	
2000			724,621	364,358,661	365,083,282	0.0%	0.2%	99.8%	100.0%
2001	201,261		3,101,570	358,201,110	361,503,941	0.1%	0.9%	99.1%	100.0%
2002	2,847,059		1,904,824	359,749,776	364,501,659	0.8%	0.5%	98.7%	100.0%
2003	3,925,374		818,505	357,020,139	361,764,018	1.1%	0.2%	98.7%	100.0%
2004	4,474,000		827,413	335,986,410	341,287,823	1.3%	0.2%	98.4%	100.0%
2005	3,999,993		1,075,535	319,222,132	324,297,660	1.2%	0.3%	98.4%	100.0%
2006	272,983		161,875	26,224,551	26,659,409	1.0%	0.6%	98.4%	100.0%
Grand Tot.	15,720,669		8,614,343	2,120,762,780	2,145,097,792				

Alaska

Barrels

% Volume by Ownership

CY	Barrels			Total	% Volume by Ownership				
	Federal	Other	State		Federal	Other	State	Total	
2000		0	724,621	374,347,170	375,071,791	0.0%	0.2%	99.8%	100.0%
2001	201,261		3,101,570	369,011,966	372,314,797	0.1%	0.8%	99.1%	100.0%
2002	2,847,059		1,904,824	370,476,745	375,228,627	0.8%	0.5%	98.7%	100.0%
2003	3,925,374		818,505	366,612,866	371,356,745	1.1%	0.2%	98.7%	100.0%
2004	4,474,000		827,413	343,830,880	349,132,292	1.3%	0.2%	98.5%	100.0%
2005	3,999,993		1,075,535	325,942,742	331,018,270	1.2%	0.3%	98.5%	100.0%
2006	272,983		161,875	26,740,022	27,174,879	1.0%	0.6%	98.4%	100.0%
Grand Tot.	15,720,669		8,614,343	2,176,962,389	2,201,297,402				

Gas Production January 2000 - January 2006

Cook Inlet

MCF

% Volume by Ownership

CY	MCF			Total	% Volume by Ownership				
	Federal	Other	State		Federal	Other	State	Total	
2000	18,066,841		6,054,171	138,044,334	162,165,346	11.1%	3.7%	85.1%	100.0%
2001	21,392,099		8,080,068	140,768,365	170,240,531	12.6%	4.7%	82.7%	100.0%
2002	22,903,938		7,102,043	131,237,625	161,243,606	14.2%	4.4%	81.4%	100.0%
2003	29,739,607		10,108,745	124,130,393	163,978,744	18.1%	6.2%	75.7%	100.0%
2004	28,557,450		11,954,668	124,123,550	164,635,708	17.3%	7.3%	75.4%	100.0%
2005	27,719,991		16,950,210	126,997,447	171,667,648	16.1%	9.9%	74.0%	100.0%
2006	2,800,687		1,659,284	11,315,525	15,775,496	17.8%	10.5%	71.7%	100.0%
Grand Tot.	151,180,612		61,909,189	796,617,279	1,009,707,079				

North Slope

MCF

% Volume by Ownership

CY	MCF			Total	% Volume by Ownership				
	Federal	Other	State		Federal	Other	State	Total	
2000				9,738,215	9,738,215	0.0%	0.0%	100.0%	100.0%
2001				11,756,645	11,756,645	0.0%	0.0%	100.0%	100.0%
2002				30,618,276	30,618,276	0.0%	0.0%	100.0%	100.0%
2003				45,503,013	45,503,013	0.0%	0.0%	100.0%	100.0%
2004				42,994,549	42,994,549	0.0%	0.0%	100.0%	100.0%
2005				39,857,452	39,857,452	0.0%	0.0%	100.0%	100.0%
2006				2,553,090	2,553,090	0.0%	0.0%	100.0%	100.0%
Grand Total				183,021,240	183,021,240				

Note: Excludes properties without any state or federal interest

Incentives & Credits

Exploration Incentive Credit and Tax Credit Programs

AS 38.05.180(i): Exploration Incentive Credits (EIC)

This EIC is included as a term of every lease. AS 38.05.18(i) provides for a system in which a lessee of State land drilling an exploratory well may earn credits depending on the footage drilled and the region in which the well is located. The statute also provides for an EIC for geophysical work on State land if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area. The geophysical information obtained is made public following the sale. Information is held confidential for two years, but confidentiality may be extended if the lessee meets certain requirements. The Department of Natural Resources Commissioner grants credits as high as 50 percent of the costs. Credits may be applied against State royalty and rental payments or taxes, or they may be assigned. Since the State began offering this program, lessees have earned \$54.7 million in credits for exploratory drilling.

AS 41.09.010: Exploration Incentive Credits

This EIC, adopted in 1994 under AS 41.09.010, allows the Natural Resources Commissioner to grant an EIC for exploratory drilling, the drilling of a stratigraphic test well, and for geophysical work on land in the State, regardless of whether the minerals are State-owned. This program is designed to encourage oil and gas exploration within remote parts of the State and to provide a means for the State to obtain exploration data from federal, private, and Native Corporation lands. As with the Title 38 program, the credits may be applied against oil and gas royalties, rentals, lease sale bonus bids and taxes, or they may be assigned. Drilling data will be kept confidential for two years, with no extension of this period. Copies of geophysical data may be shown to interested parties by the State, but may not be transferred to third parties. Credits may be as high as 50 percent of eligible costs if performed on State land, and as high as 25 percent when performed on federal or private land. A credit may not exceed \$5 million per eligible project, and the total of all credits may not exceed \$30 million. Drilling credits are based upon the footage (measured depth) drilled. All activity qualifying for this EIC must be completed by July 1, 2007.

AS 43.55.025: Oil and Gas Exploration Tax Credit

This program, adopted in 2003, allows for a production tax credit of 20 percent of the cost of an exploratory well if the bottom hole location is three or more miles from the bottom hole location of a preexisting well that was spud more than 150 days, but less than 35 years, prior to the spud date of the eligible exploration well. The program also allows for a production tax credit of 40 percent of the cost of an exploratory well if the bottom hole location is 25 miles or more from the boundary of any unit under a plan of development as of July 1, 2003. The program also offers seismic exploration tax credits of 40 percent of eligible costs for those portions of activities outside of a unit that is under a plan of development or plan of exploration. Seismic data qualifying for this credit will be held confidential for 10 years and 30 days. This tax credit is transferable. This program only applies to wells drilled between July 1, 2003 and July 1, 2007.

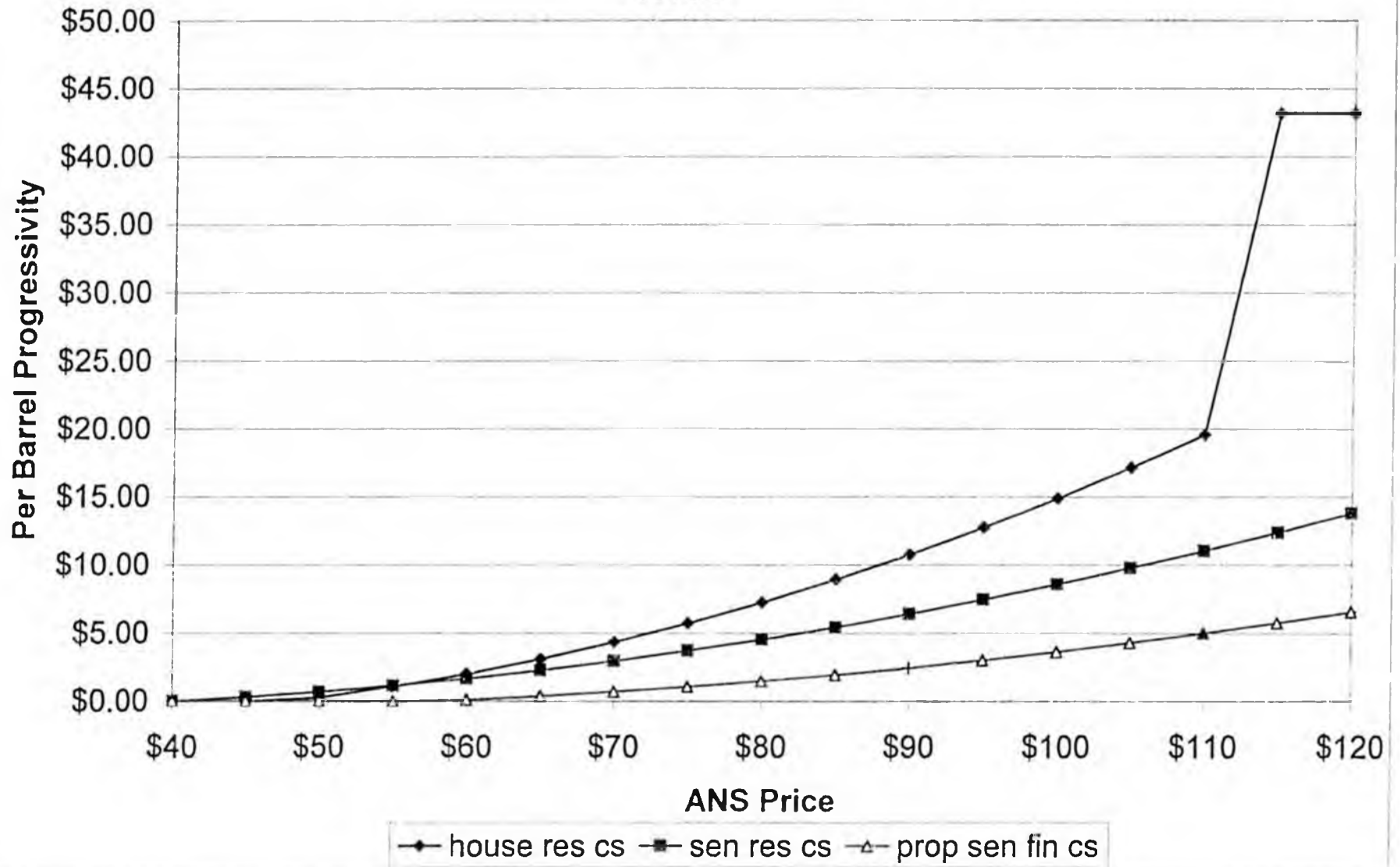


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AS 43.20.043: Gas Exploration and Development Tax Credit

This program, adopted in 2003, is applicable only to operators and working interest owners engaged in exploration for and development of gas resources and reserves south of 68 degrees North latitude (excludes North Slope and Beaufort Sea). The program allows for a 10 percent tax credit equivalent of qualified capital investments made after June 30, 2003, and 10 percent of the annual cost of activity in the State during each tax year. The total allowable yearly tax credit may not exceed 50 percent of the taxpayer's total tax liability. Unused tax credits may be carried forward for up to five years. Credit is

Per Barrel Progressivity Surcharge 2010



"Production Tax Value" under 180

	CI Boe 2005	NS BOE 2005	Total BOE 2005	30.00 (22.50)	40.00 (22.50)	50.00 (22.50)	60.00 (22.50)	70.00 (22.50)
				7.50	17.50	27.50	37.50	47.50
Doyon		27.0	27.0					
Nana		80.0	80.0					
Forest		95.0	95.0					
Aurora	1,543.0		1,543.0					
ML&P	2,572.0		2,572.0					
XTO	3,268.0	47.0	3,345.0					
Forest	6,909.0		6,909.0					
Marathon	27,705.0		27,705.0					
Anadarko		27,801.0	27,801.0					
Chevron	27,344.0	17,413.0	44,757.0					
Exxon	1,111.0	181,006.0	182,117.0					
BP		354,670.0	354,670.0					
Conoco	27,942.0	388,145.0	426,087.0					
	98,424.0	979,284.0	1,077,708.0					

Senate Finance

Doyon	100%	100%	100%	100%	100%
Nana	100%	100%	100%	100%	100%
Forest	100%	100%	100%	100%	100%
Aurora	100%	100%	100%	100%	100%
ML&P	100%	100%	100%	100%	100%
XTO	100%	100%	100%	100%	100%
Forest	72%	72%	66%	52%	43%
Marathon	18%	18%	16%	13%	11%
Anadarko	18%	18%	16%	13%	11%
Chevron	11%	11%	10%	8%	7%
Exxon	3%	3%	2%	2%	2%
BP	1%	1%	1%	1%	1%
Conoco	1%	1%	1%	1%	1%
Total	4%	4%	4%	3%	3%

Governor's Bill

Doyon	100%	100%	100%	100%	100%
Nana	100%	100%	100%	100%	100%
Forest	100%	100%	100%	100%	100%
Aurora	100%	100%	100%	100%	100%
ML&P	100%	100%	100%	100%	100%
XTO	100%	100%	77%	81%	50%
Forest	41%	26%	19%	15%	13%
Marathon	41%	26%	19%	15%	13%
Anadarko	26%	16%	12%	9%	8%
Chevron	6%	4%	3%	2%	2%
Exxon	3%	2%	2%	1%	1%
BP	3%	2%	1%	1%	1%
Conoco	3%	2%	1%	1%	1%
Total	8%	5%	4%	3%	3%

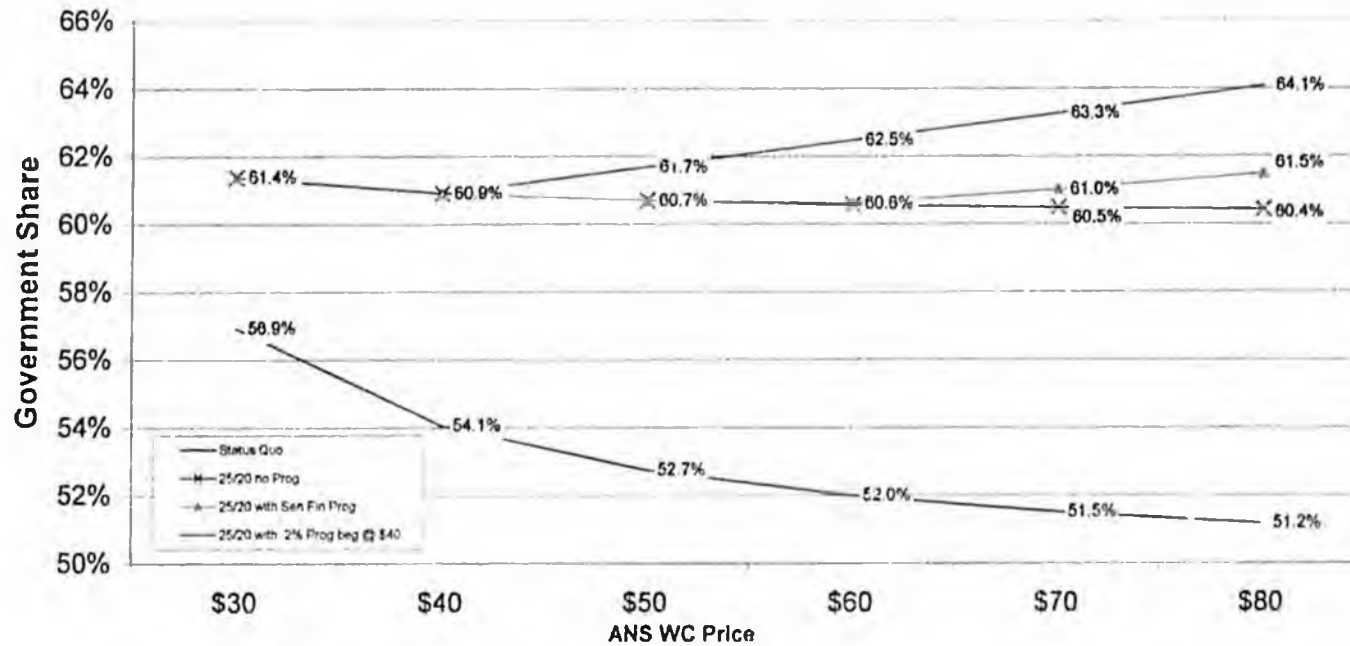
Senate Resources

Doyon	100%	100%	100%	100%	100%
Nana	100%	100%	100%	100%	100%
Forest	100%	100%	100%	100%	100%
Aurora	100%	100%	100%	100%	100%
ML&P	100%	100%	100%	100%	100%
XTO	100%	100%	100%	100%	100%
Forest	67%	67%	67%	67%	67%
Marathon	2%	2%	2%	2%	2%
Anadarko	2%	2%	2%	2%	2%
Chevron	0%	0%	0%	0%	0%
Exxon	0%	0%	0%	0%	0%
BP	0%	0%	0%	0%	0%
Conoco	0%	0%	0%	0%	0%
	1%	1%	1%	1%	1%

Distribution of Future Cash Flows Under SQ and Variations of the Senate Resources CS PPT Proposal* FY 2007-2030				
ANS WC \$/bbl	Status Quo	25/20 no Prog	25/20 with Sen Fin Prog	25/20 with .2% Prog beg @ \$40
\$30	56.9%	61.4%	61.4%	61.4%
\$40	54.1%	60.9%	60.9%	60.9%
\$50	52.7%	60.7%	60.7%	61.7%
\$60	52.0%	60.6%	60.6%	62.5%
\$70	51.5%	60.5%	61.0%	63.3%
\$80	51.2%	60.4%	61.5%	64.1%

*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Sen Fin

Distribution of Future Cash Flows Under SQ and Variations of the Senate Resources CS PPT Proposal* FY 2007-2030



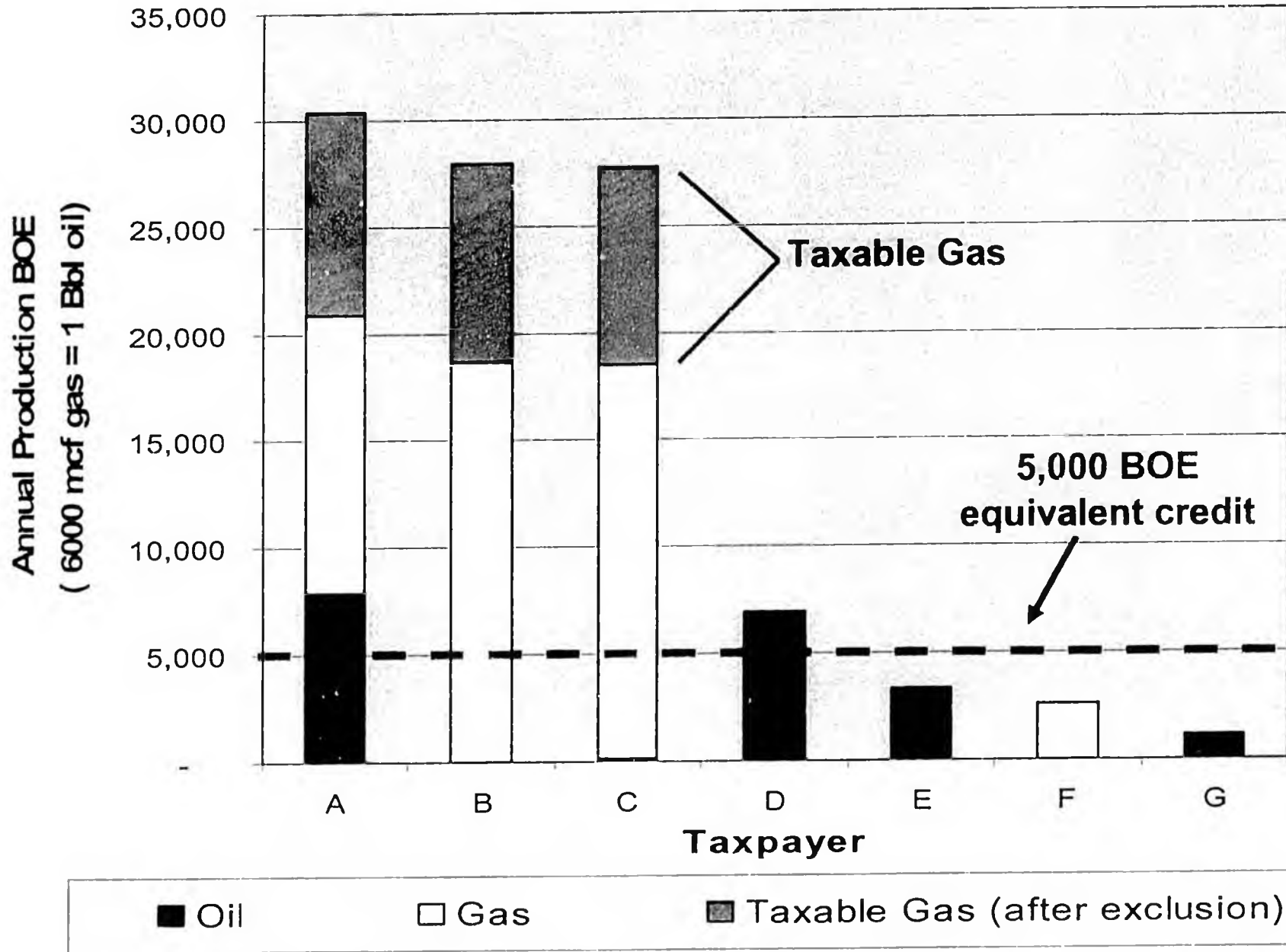
*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Sen Fin

PPT Revenue Studies

Senate Finance Committee

April 20, 2006

Cook Inlet



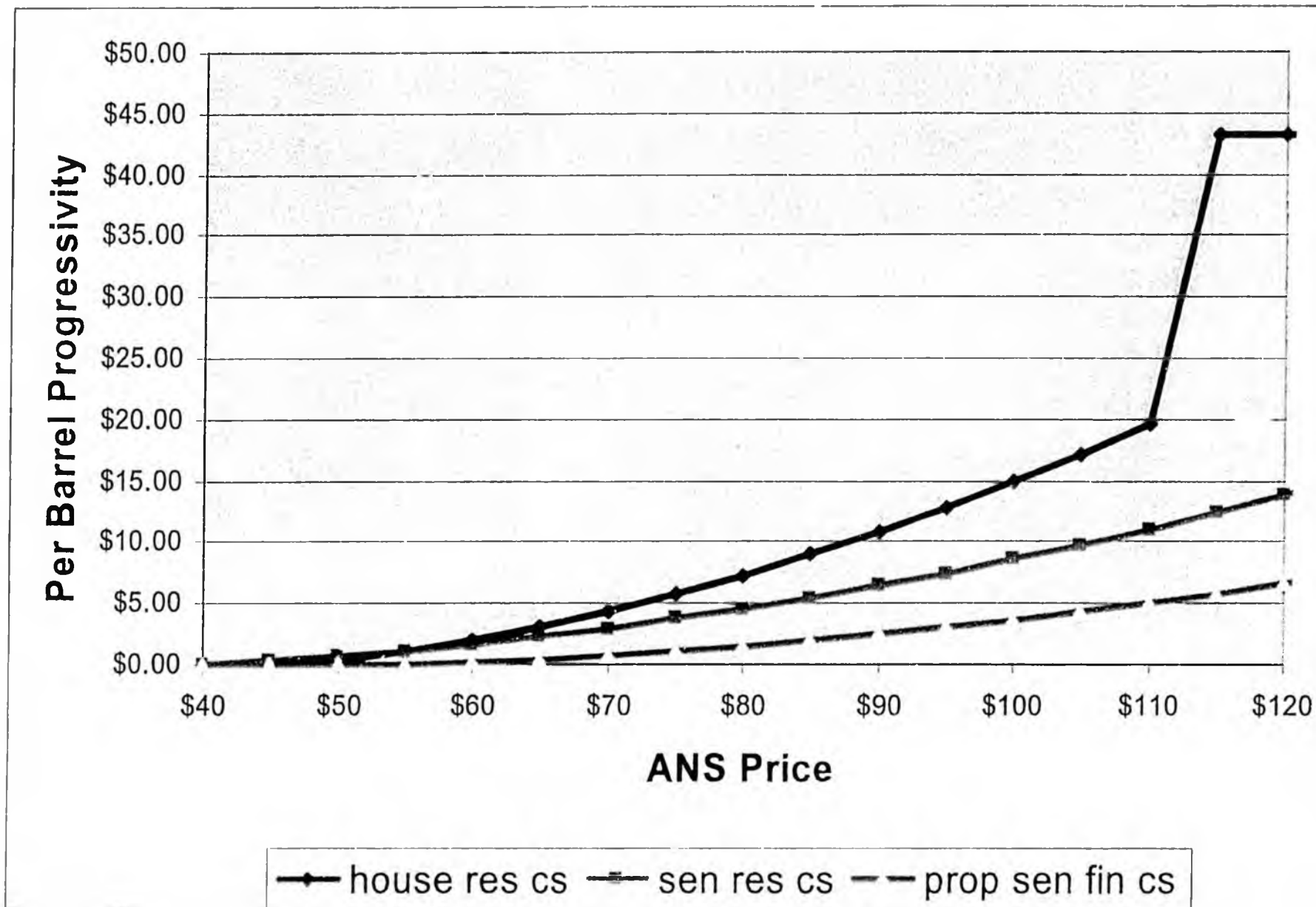
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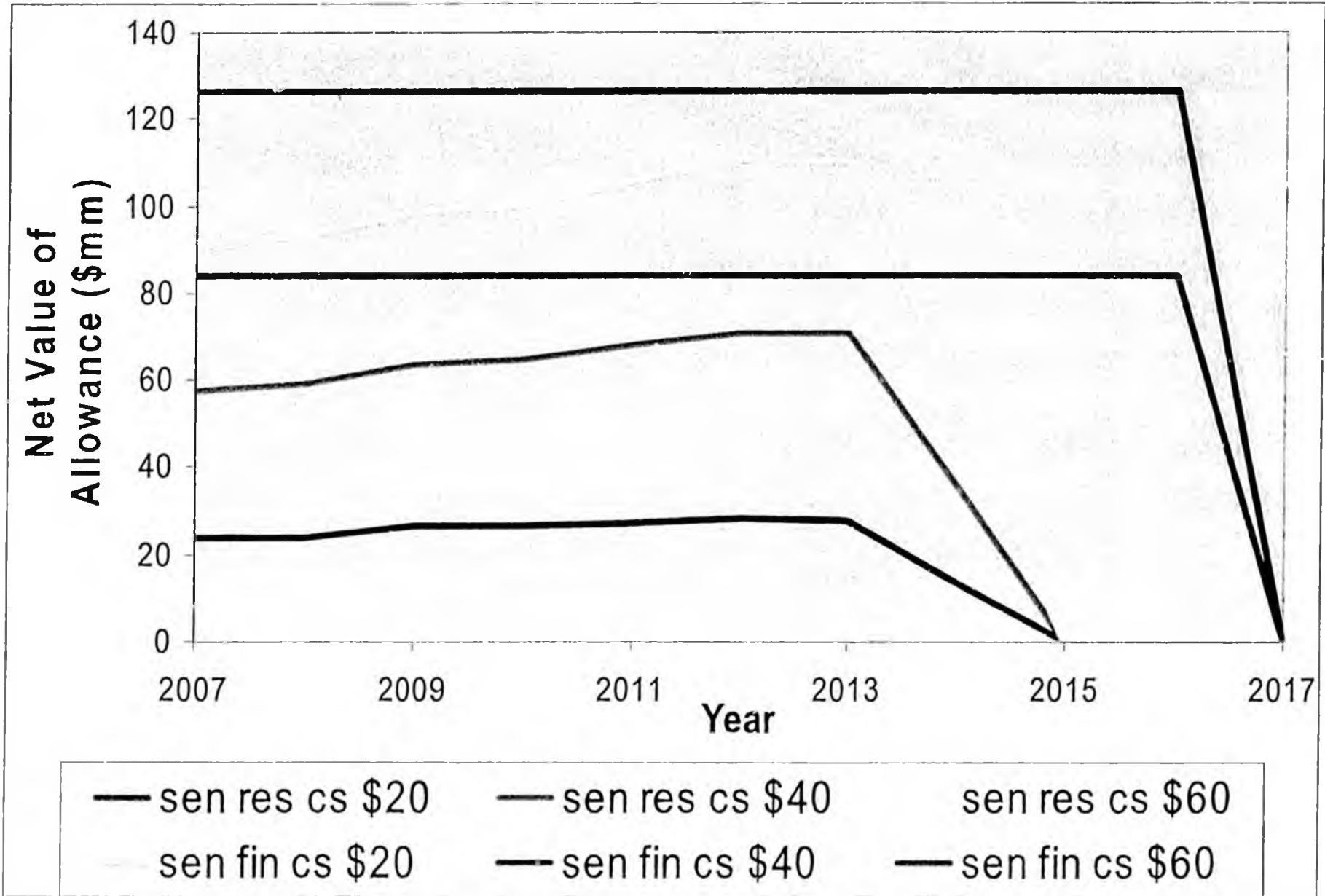
Per Barrel Progressivity Surcharge 2010



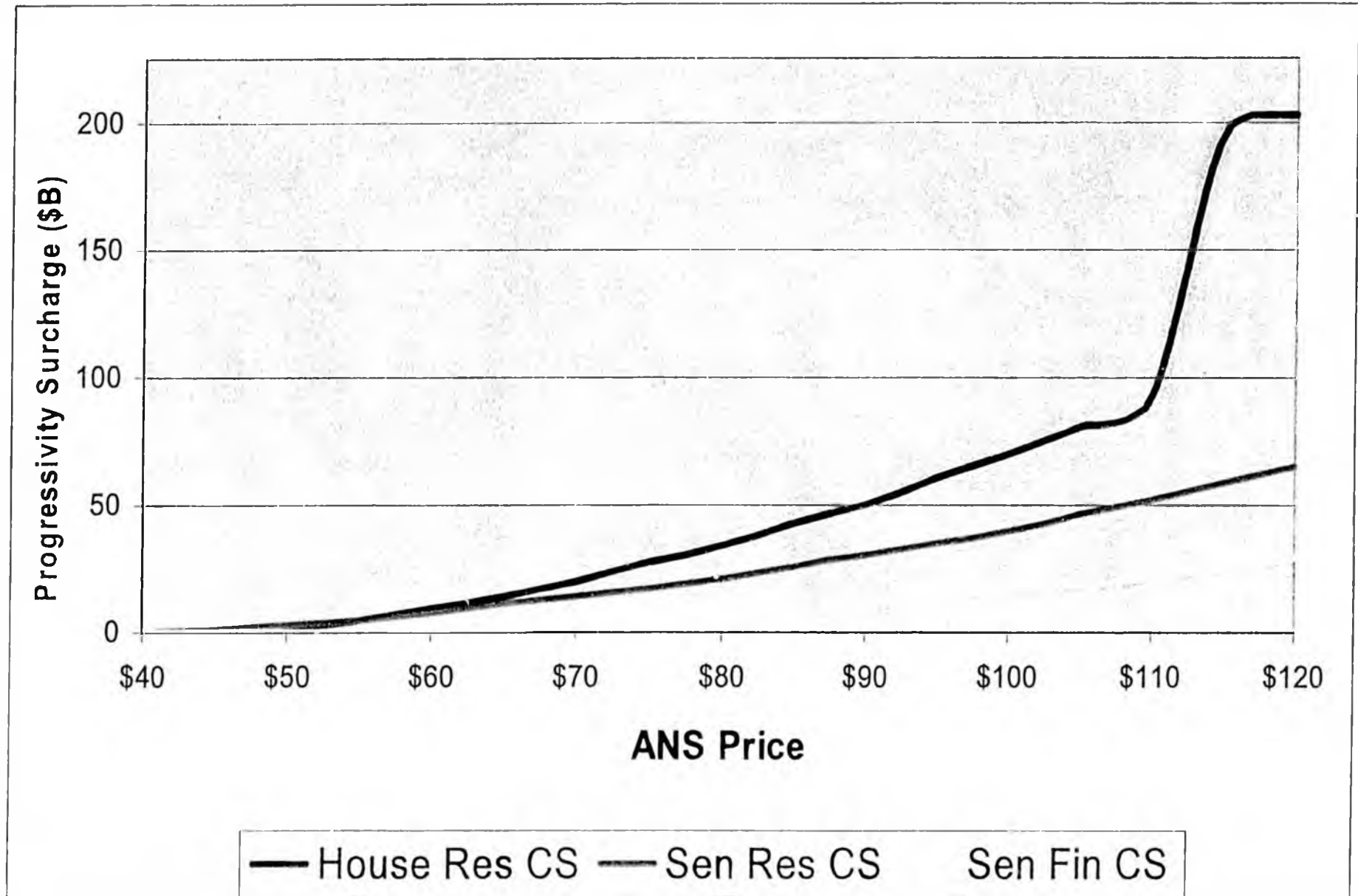
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Net Allowance Comparisons (\$millions)



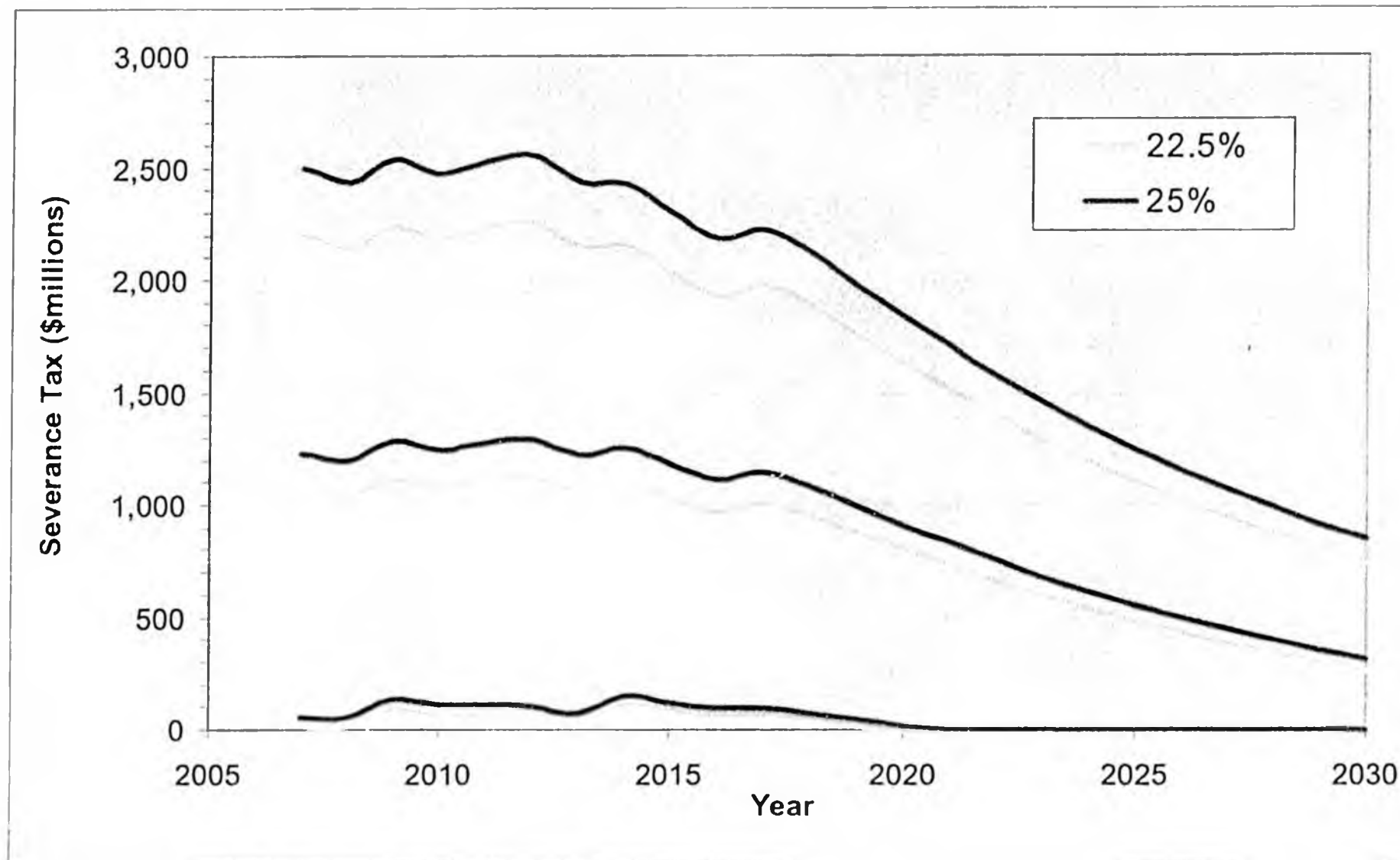
Total Progressivity Surcharges 2006-2030 (\$B)



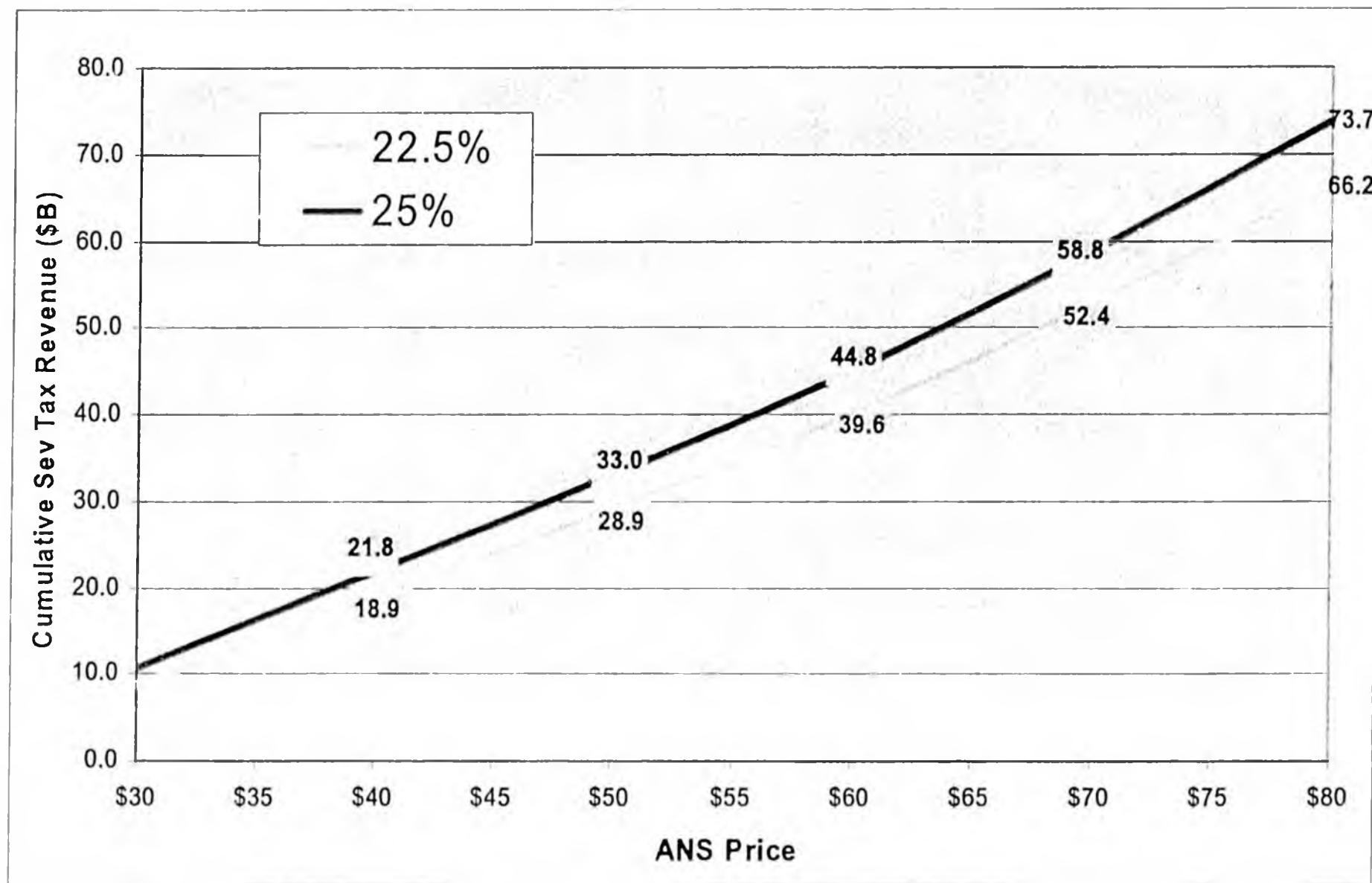
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Effect of Tax Rate: Annual Oil Severance Tax (\$Millions) Senate Finance CS with 22.5% and 25% Tax Rate at \$20, \$40, and \$60 per bbl, Low Volume Scenario



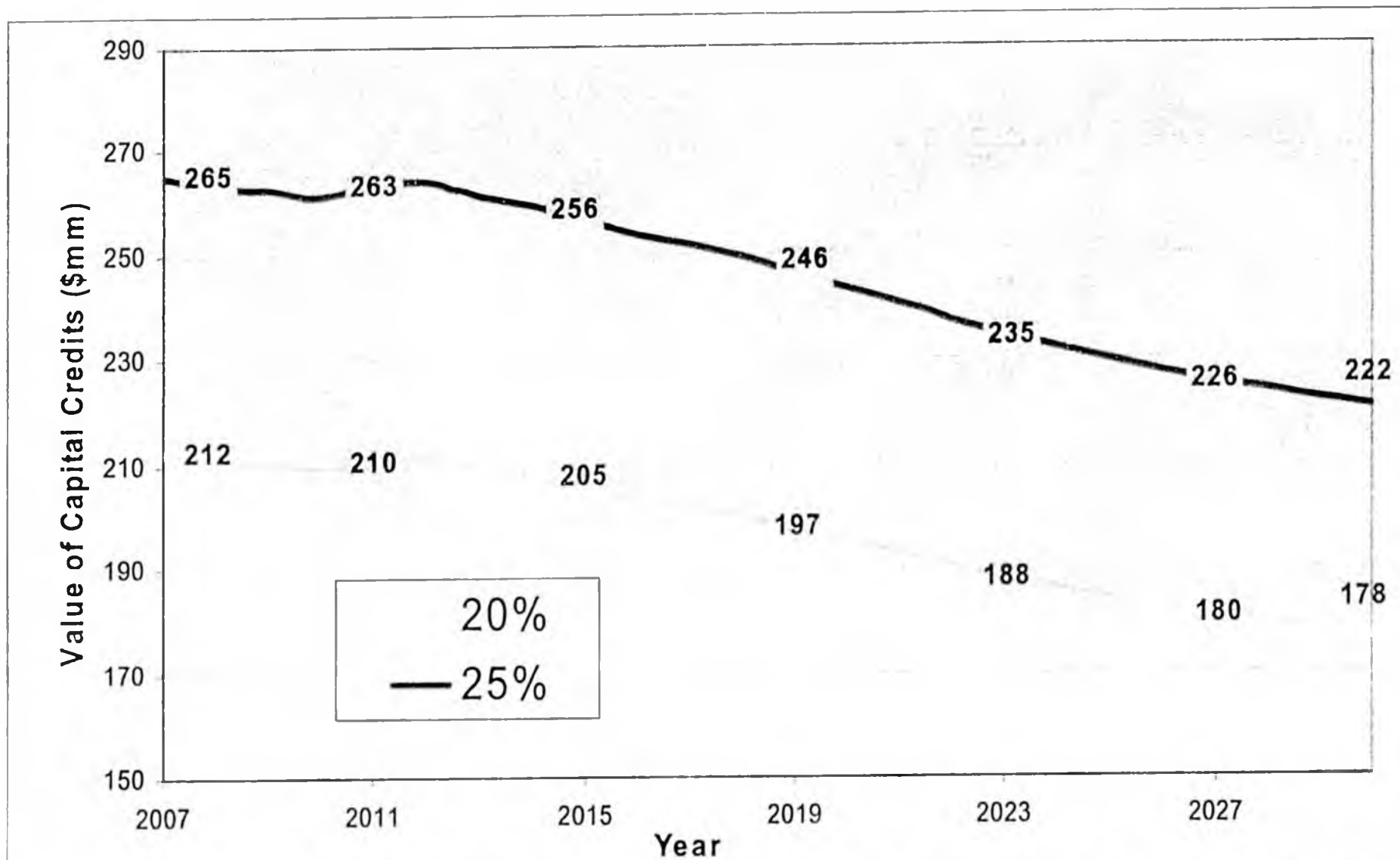
Cumulative Severance Tax Revenue, Senate Finance CS, with Tax Rates of 22.5% and 25%, 2007-2030 (\$B), Low Volume



4/20/06

4:06:22 pm

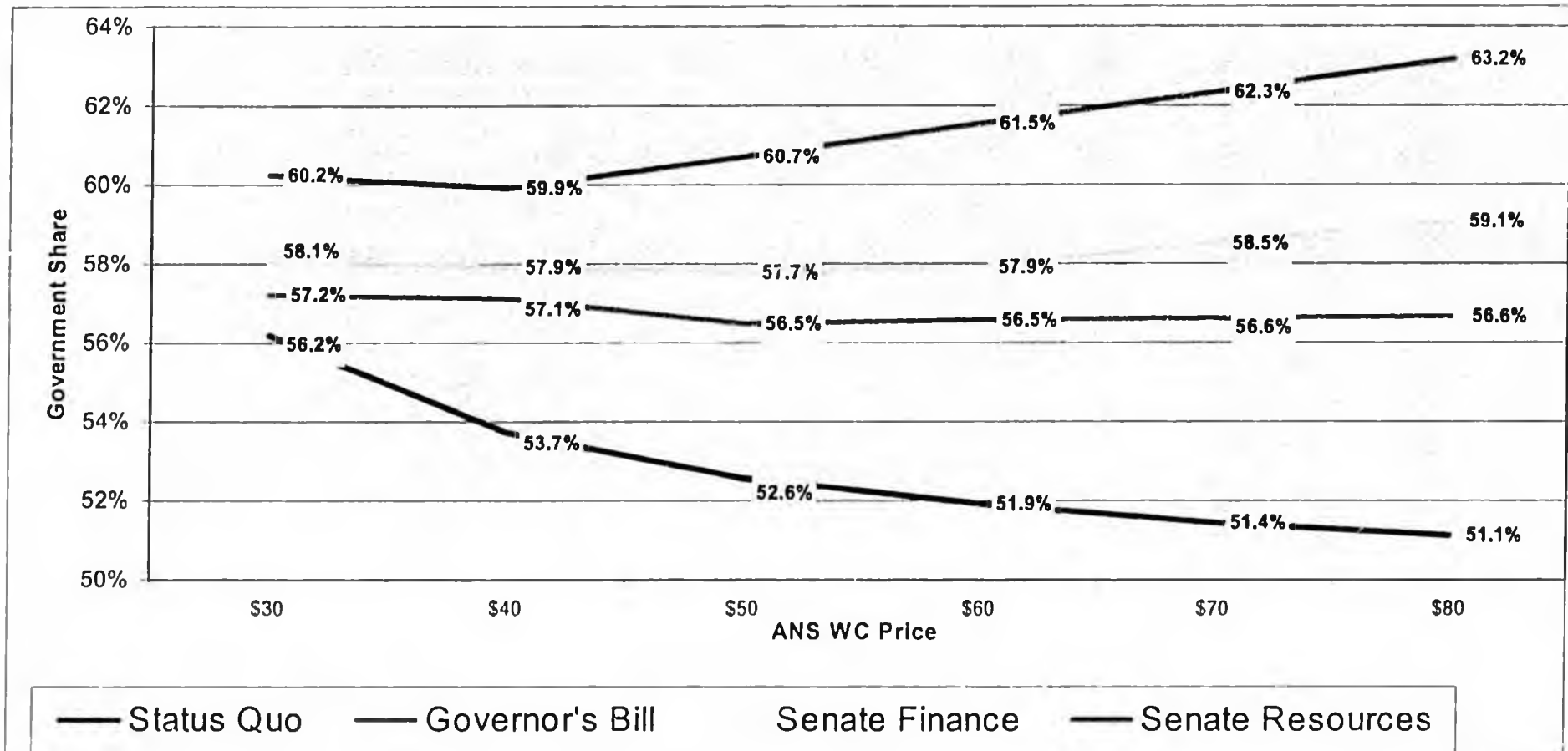
Value of Credits against Capital Expenditures Under Senate Finance CS, at 20% and 25% Credit Rates, 2007-2030, Low Volume



Average annual credit value is \$50 million greater under 25% credit rate than under 20% credit rate.

Distribution of Future Cash Flows Under SQ, Gov's Bill, Sen Res and Proposed Sen Fin CS* FY 2007-2016

ANS WC \$/bbl	Status Quo	Governor's Bill	Senate Finance	Senate Resources
\$30	56.2%	57.2%	58.1%	60.2%
\$40	53.7%	57.1%	57.9%	59.9%
\$50	52.6%	56.5%	57.7%	60.7%
\$60	51.9%	56.5%	57.9%	61.5%
\$70	51.4%	56.6%	58.5%	62.3%
\$80	51.1%	56.6%	59.1%	63.2%



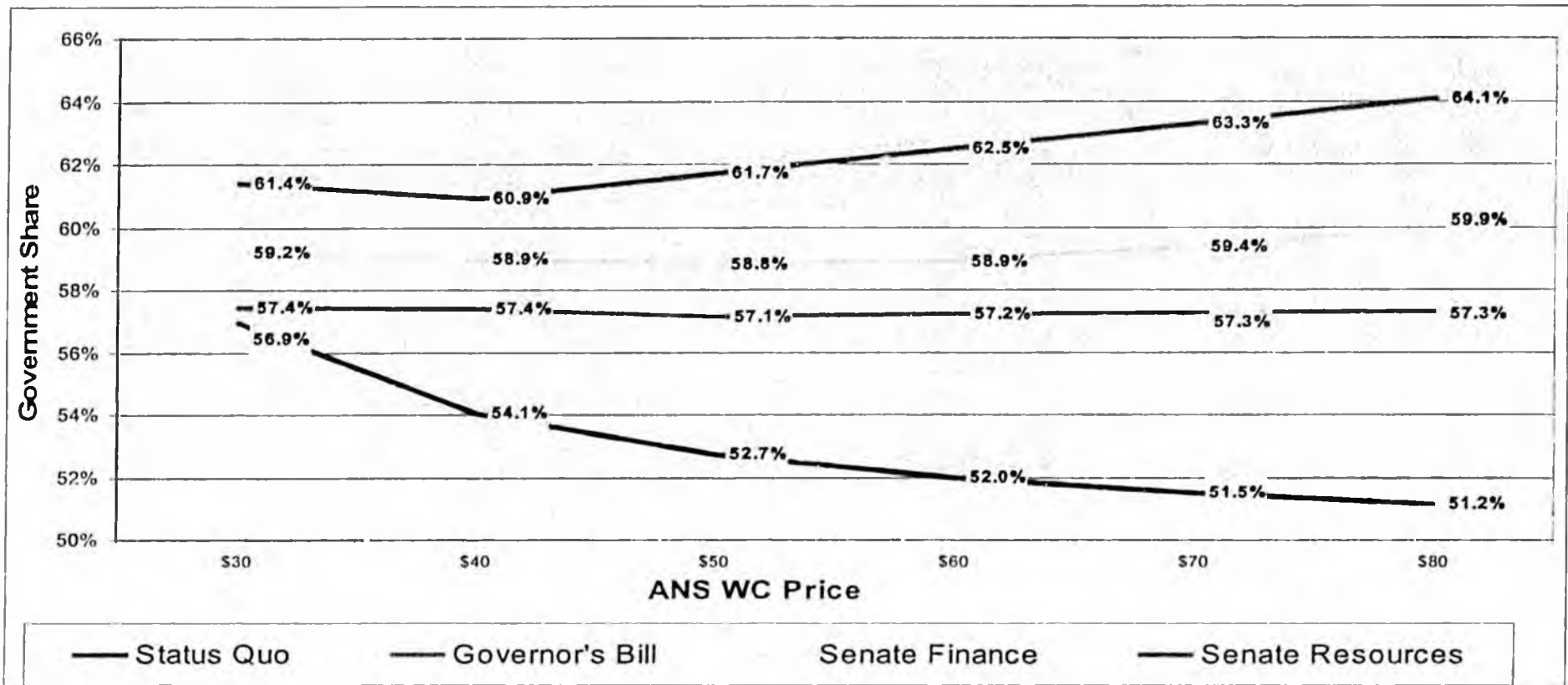
*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; It is not deductible for Finance CS.

4/29/06

3:50:49 pm
3:50:49 pm

Distribution of Future Cash Flows Under SQ, Gov's Bill, Sen Res and Proposed Sen Fin CS* FY 2007-2030

ANS WC \$/bbl	Status Quo	Governor's Bill	Senate Finance	Senate Resources
\$30	56.9%	57.4%	59.2%	61.4%
\$40	54.1%	57.4%	58.9%	60.9%
\$50	52.7%	57.1%	58.8%	61.7%
\$60	52.0%	57.2%	58.9%	62.5%
\$70	51.5%	57.3%	59.4%	63.3%
\$80	51.2%	57.3%	59.9%	64.1%



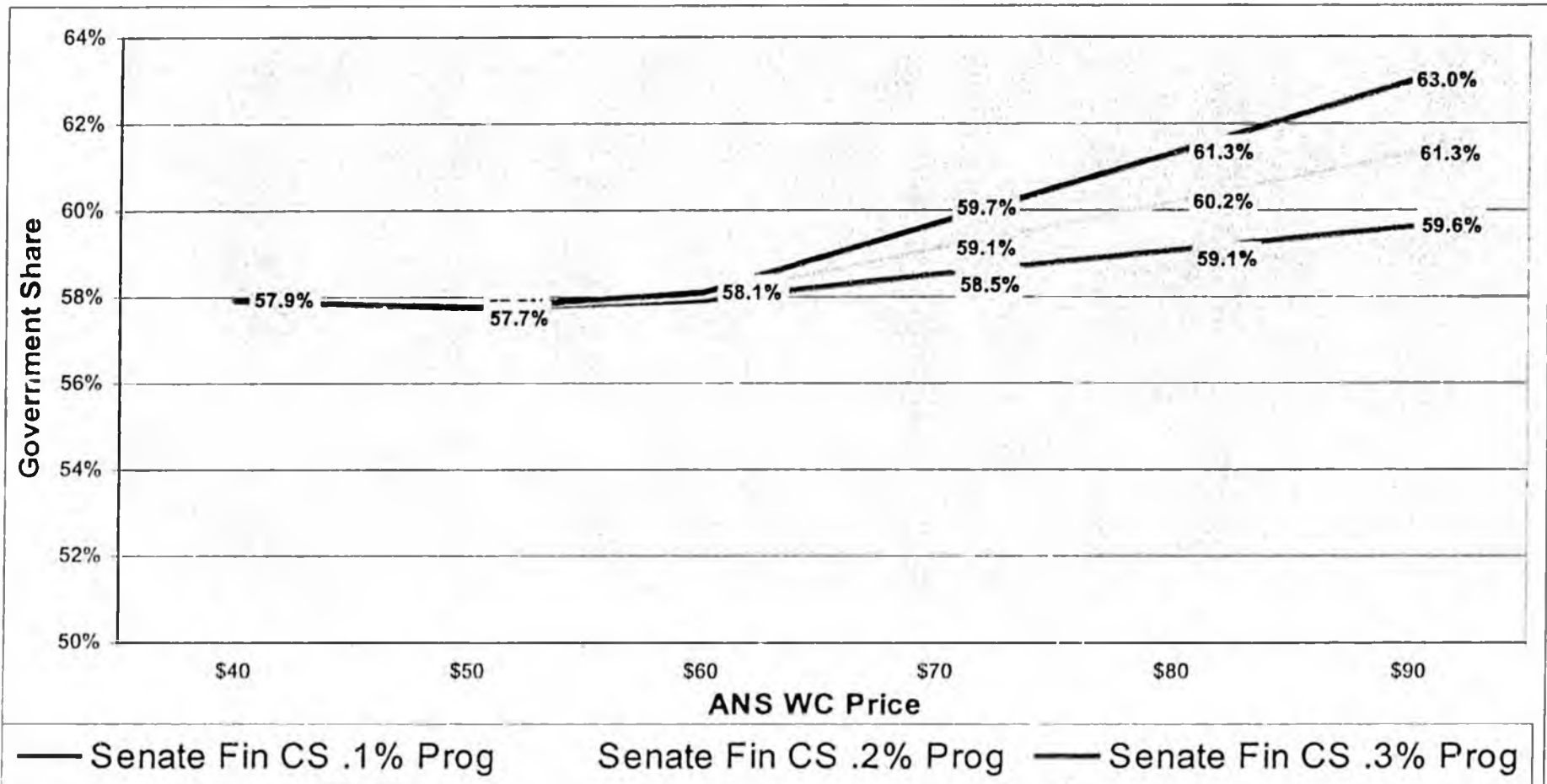
*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Finance CS.

4/20/06

4:15:44 PM

Distribution of Future Cash Flows Under Sen Fin CS with .1%, .2% and .3% Progressivity FY 2007-2016

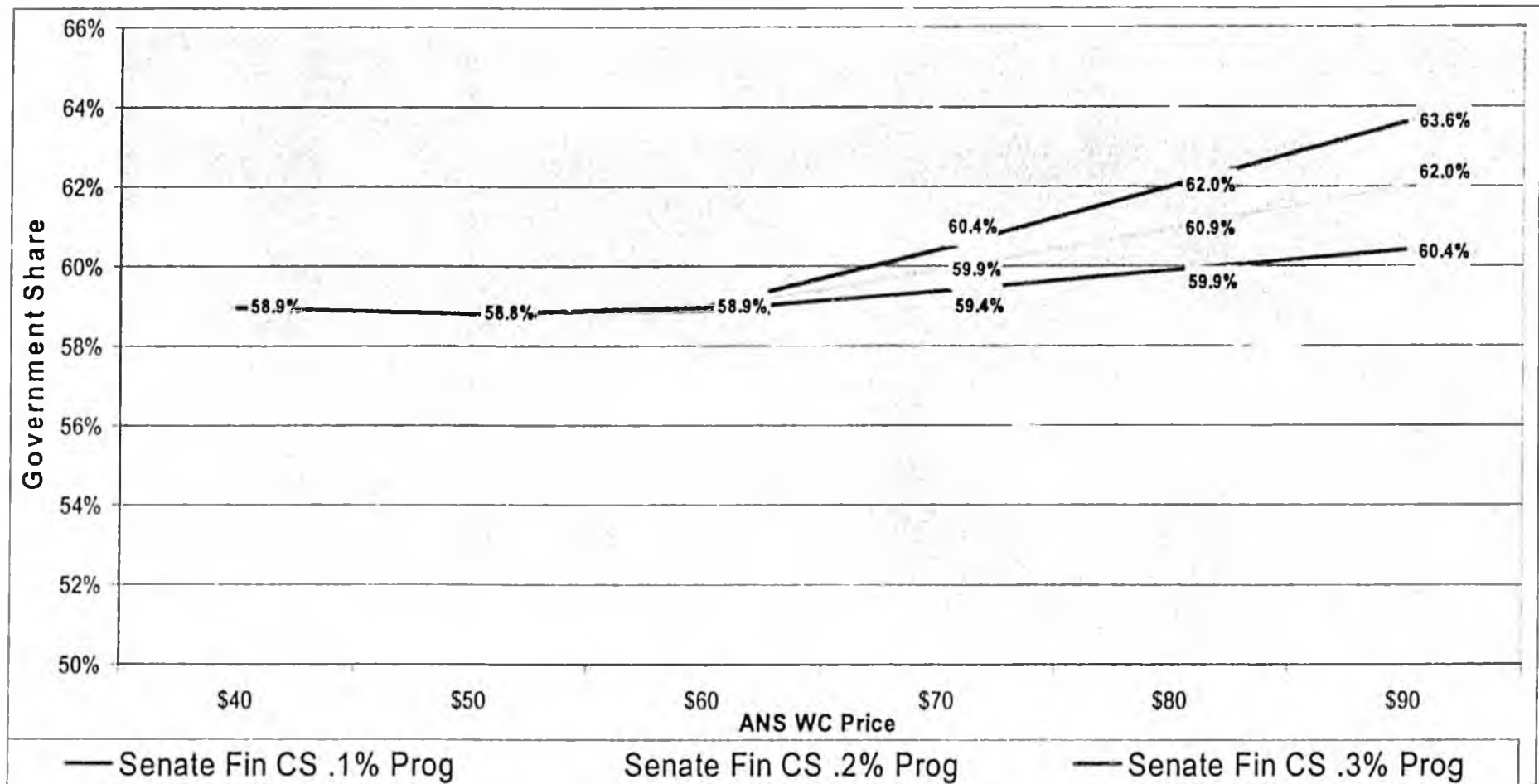
ANS WC \$/bbl	Senate Fin CS .1% Prog	Senate Fin CS .2% Prog	Senate Fin CS .3% Prog
\$40	57.9%	57.9%	57.9%
\$50	57.7%	57.7%	57.7%
\$60	57.9%	58.0%	58.1%
\$70	58.5%	59.1%	59.7%
\$80	59.1%	60.2%	61.3%
\$90	59.6%	61.3%	63.0%



4/20/06 4:00:24 pm
3:56:49 pm

Distribution of Future Cash Flows Under Sen Fin CS with .1%, .2% and .3% Progressivity FY 2007-2030

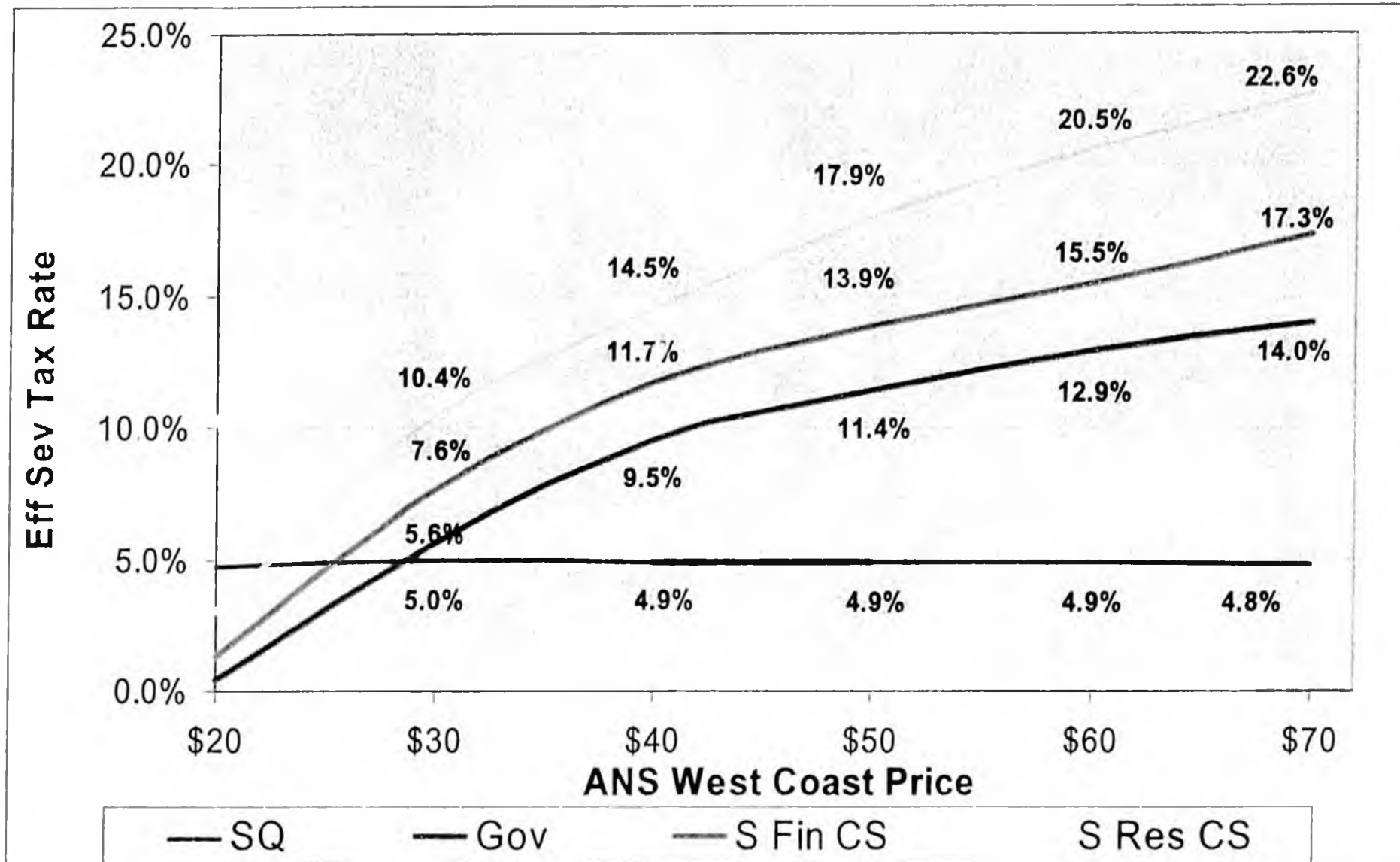
ANS WC \$/bbl	Senate Fin CS .1% Prog	Senate Fin CS .2% Prog	Senate Fin CS .3% Prog
\$40	58.9%	58.9%	58.9%
\$50	58.8%	58.8%	58.8%
\$60	58.9%	58.9%	58.9%
\$70	59.4%	59.9%	60.4%
\$80	59.9%	60.9%	62.0%
\$90	60.4%	62.0%	63.6%



Effective Severance Tax Rate

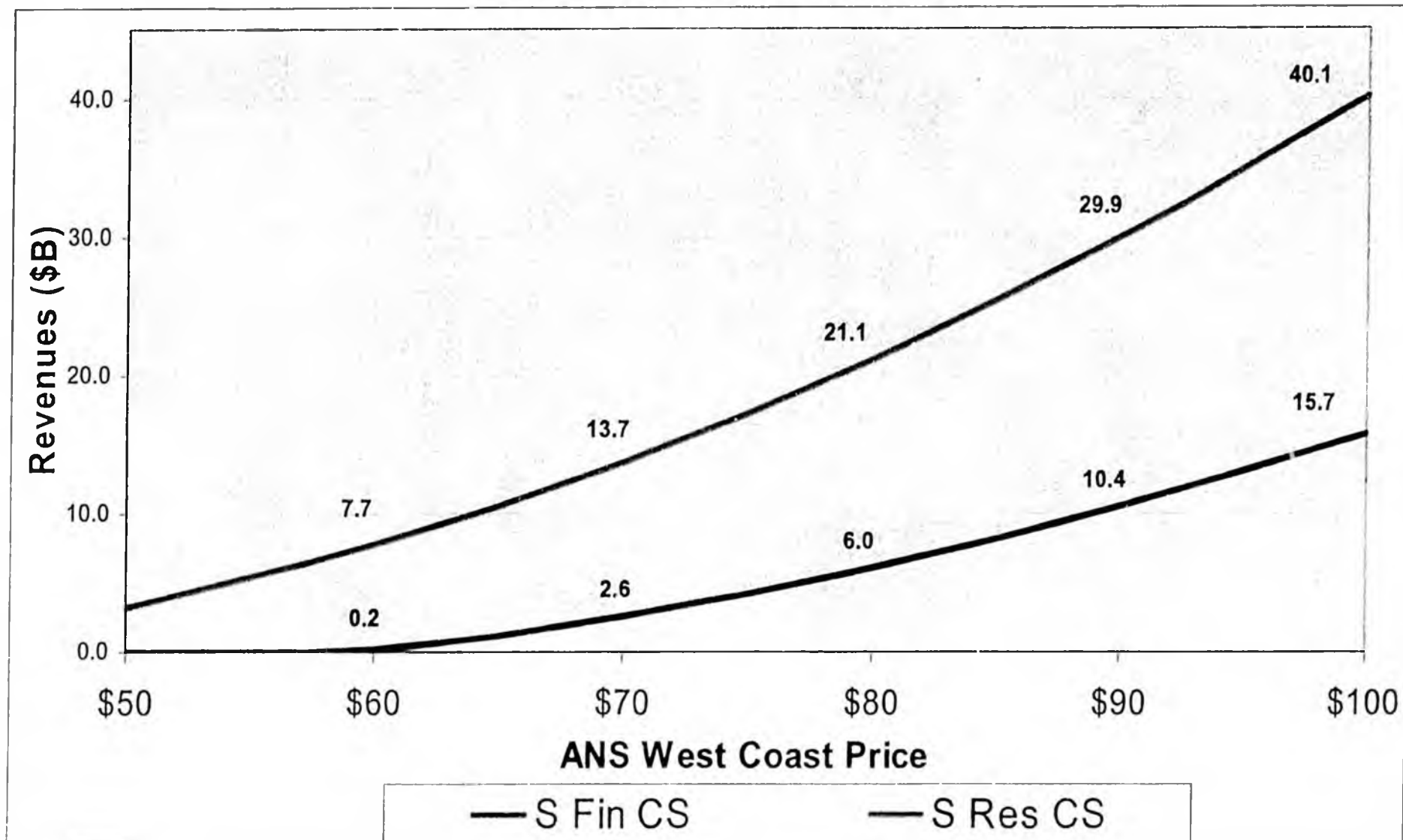
Sev Tax / Wellhead (less royalty)

Low Volume Scenario

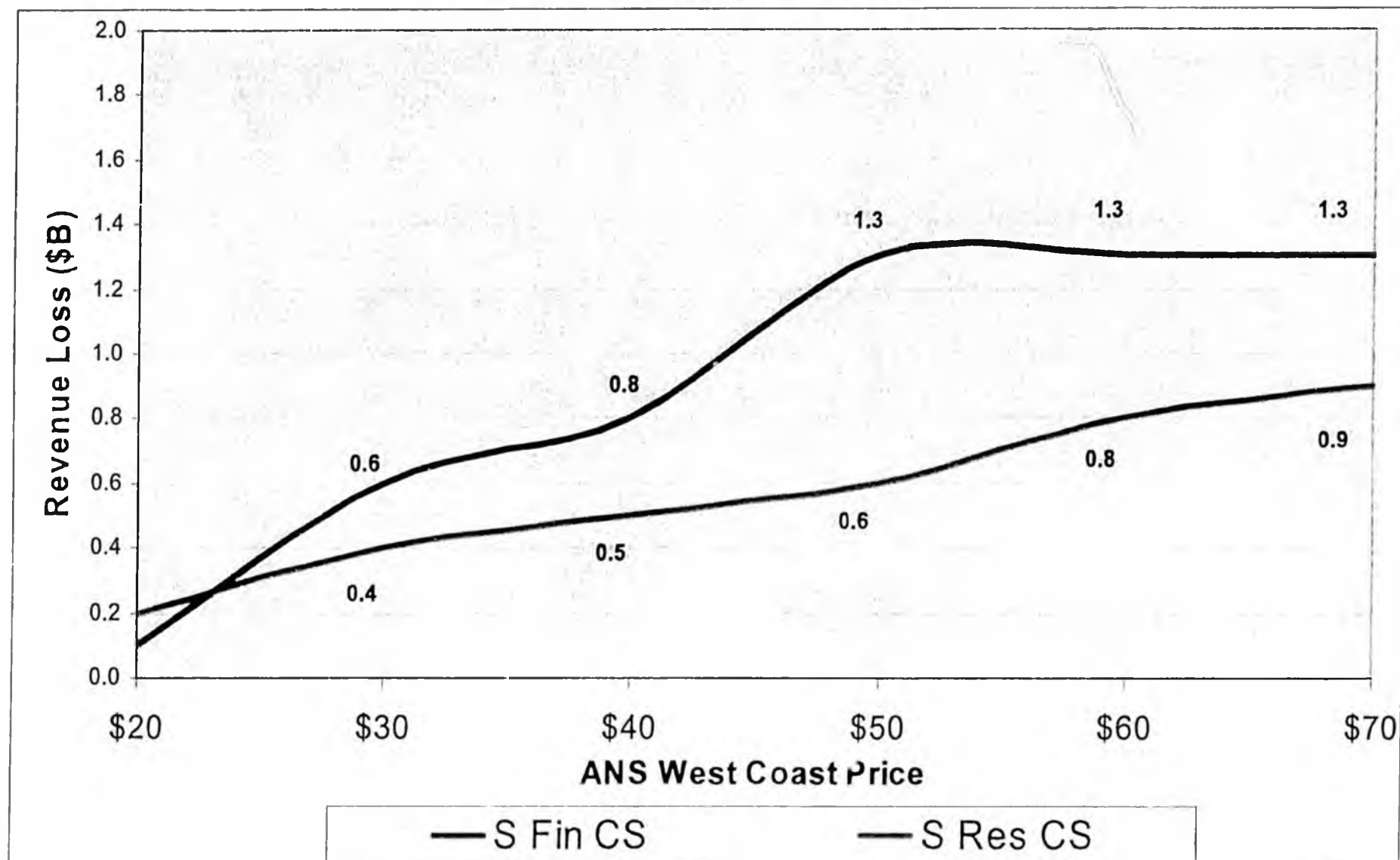


4/20/06 4:20:19 pm

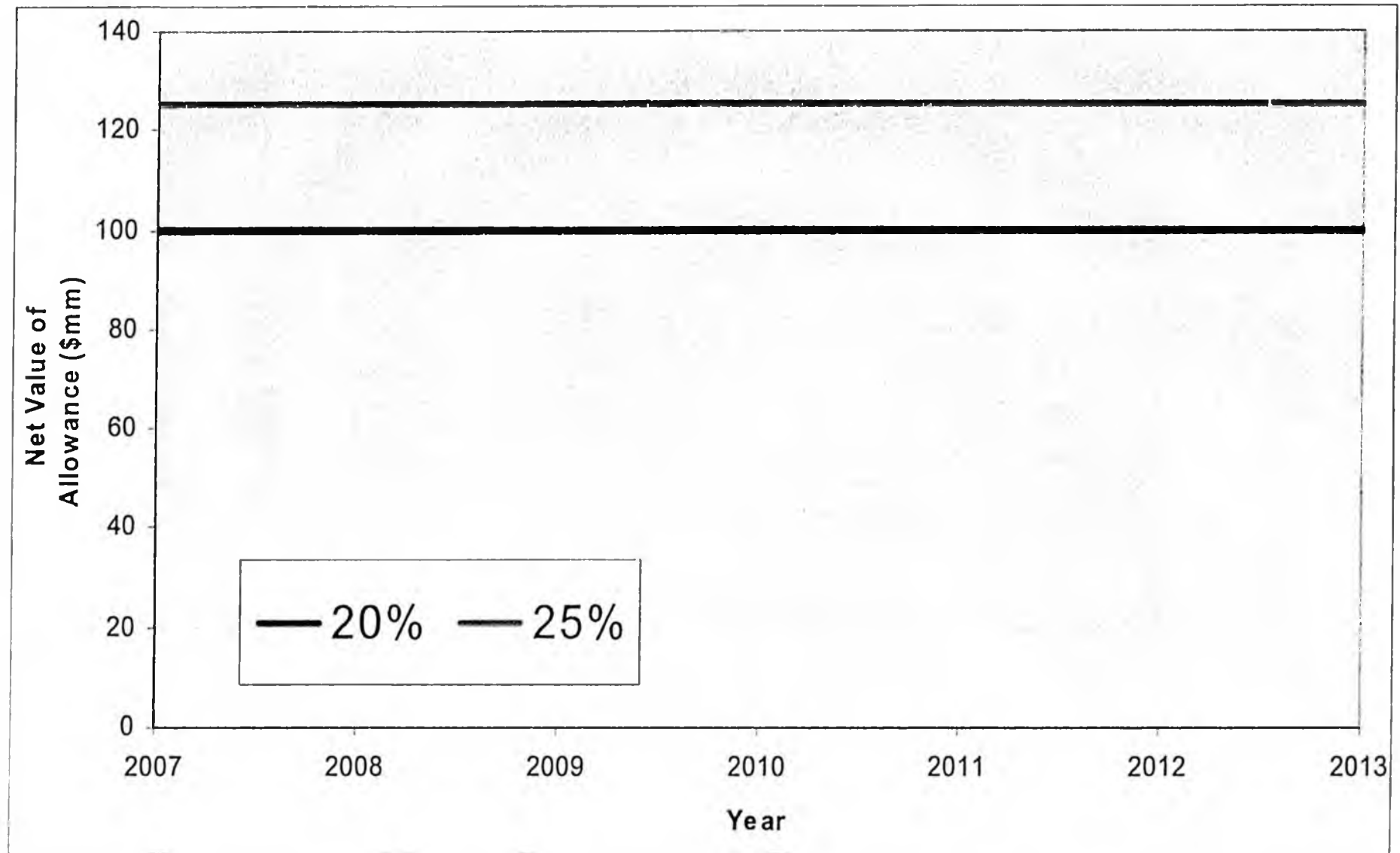
Cumulative Revenues Attributable to Progressivity Sen Fin CS and Sen Res CS, 2007-2030 Low Volume Scenario



Cumulative Revenue Loss Attributable to 5000 Bbl Mechanism Sen Fin CS and Sen Res CS, 2007-2030 Low Volume Scenario

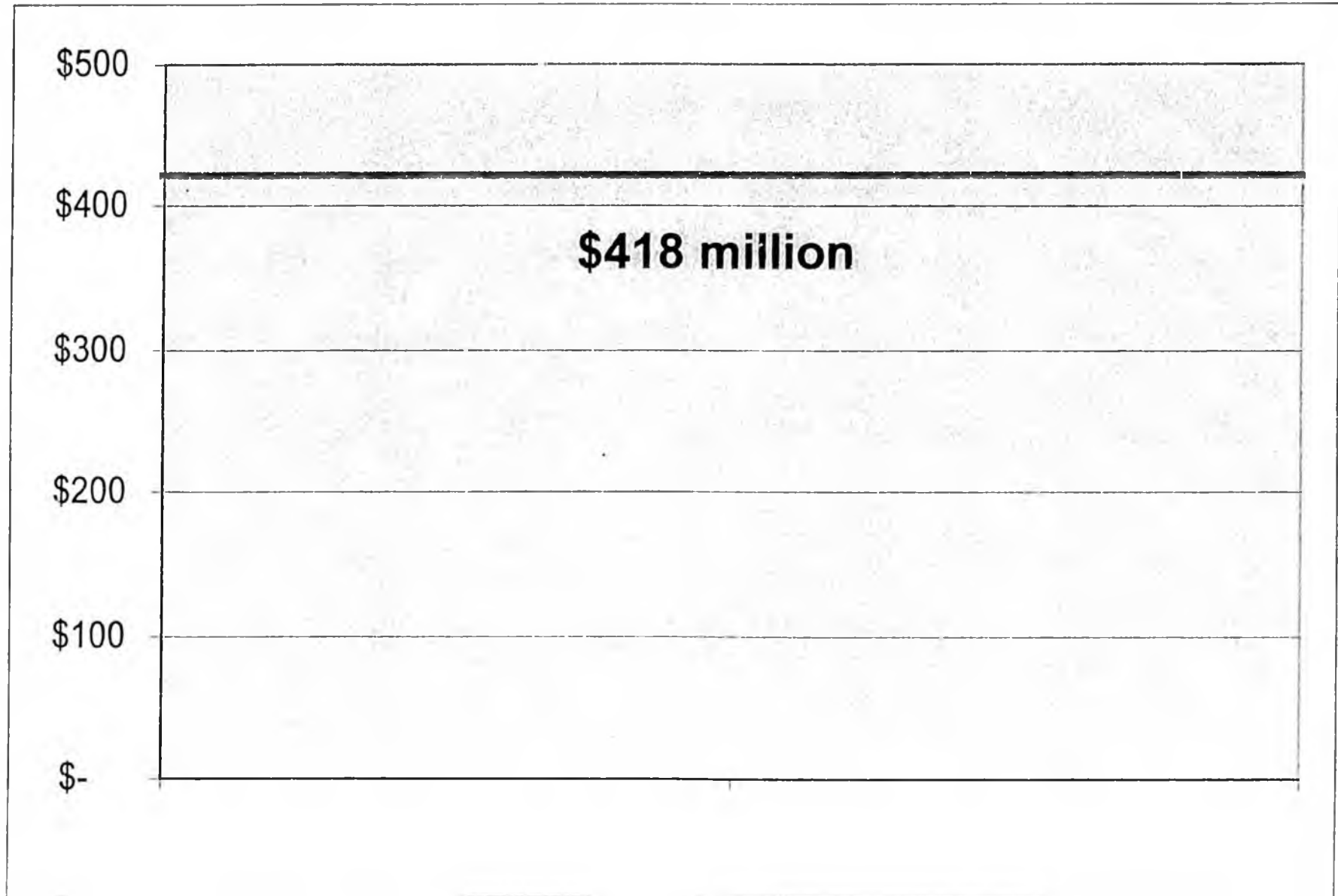


Senate Finance CS Transition at 20% and 25%, Annual Revenue Loss, 2007-2013



4/20/06 4:23:40pm

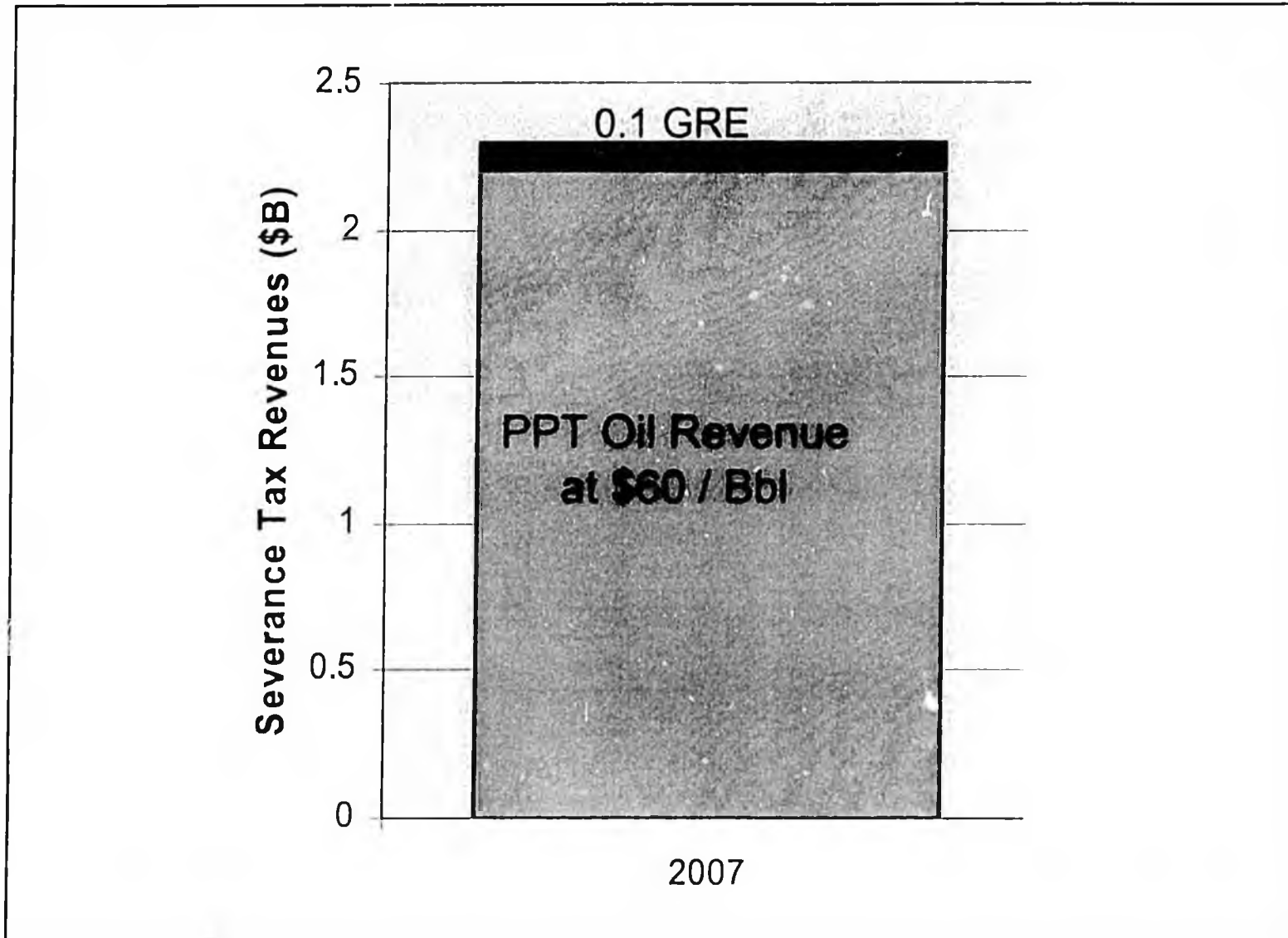
Effective Date Change From 04/01/2006 to 07/01/2006
at \$60 per Barrel Oil



4/21/06 11:21 AM

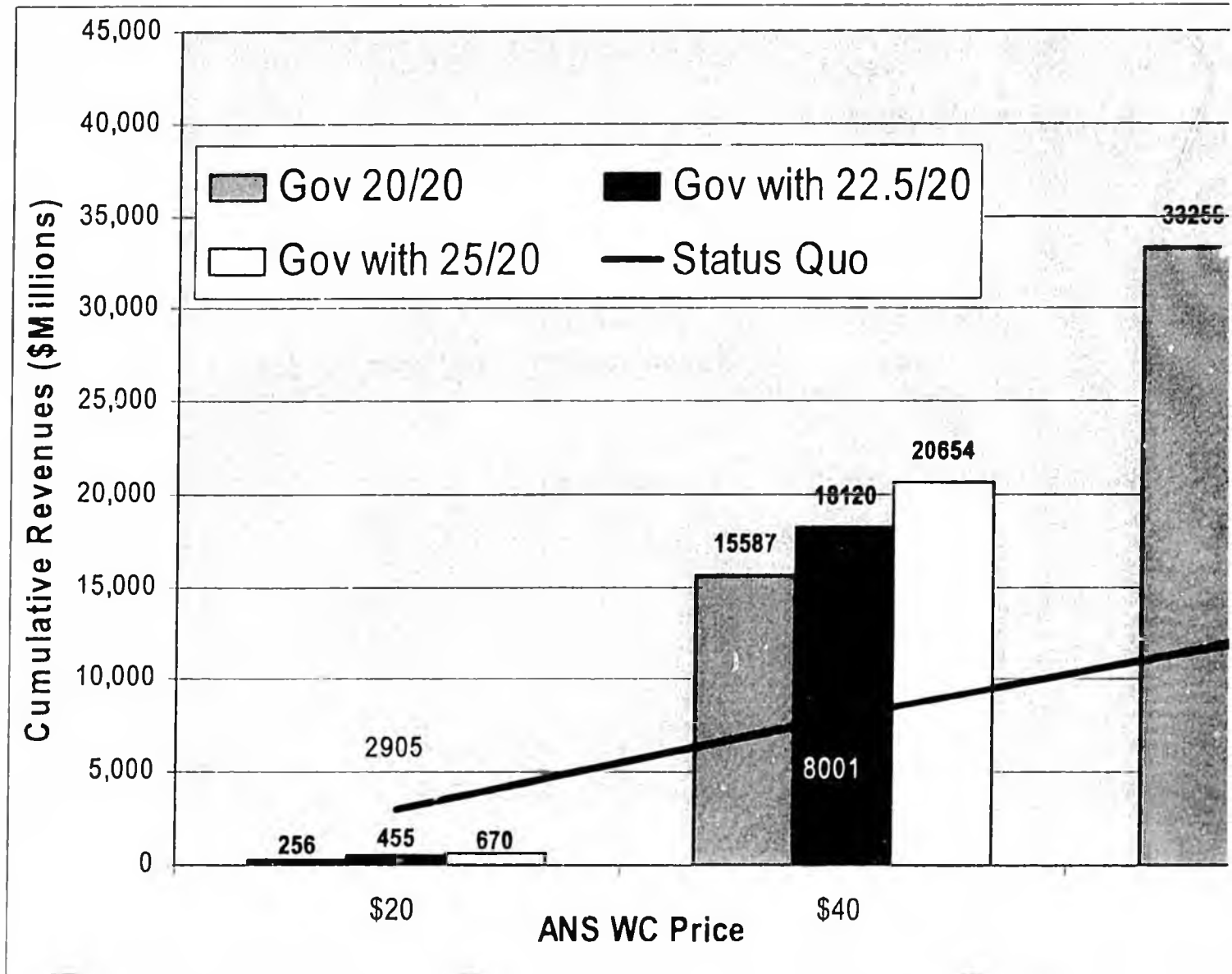
4/20/06 4:25:45 pm

PPT and GRE Revenue in FY 2007 at \$60 per Barrel Oil

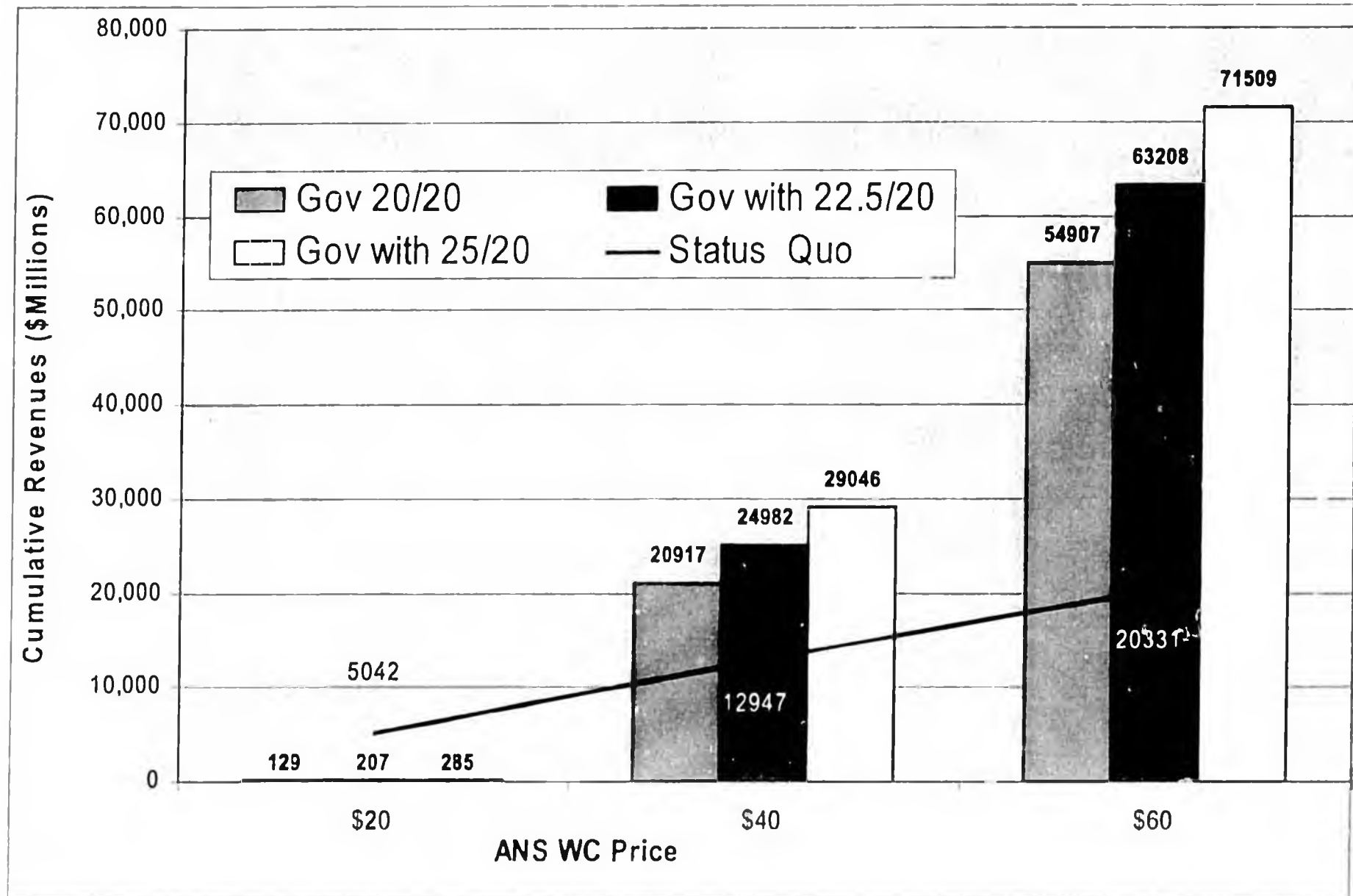


4/20/06 4:26:23pm

Cumulative Severance Tax Revenues under Governor's Bill with 22.5/20, and with 25/20, Low Volume Scenario 200



Cumulative Severance Tax Revenues under Governor's Bill as Written, with 22.5/20,
and with 25/20, High Volume Scenario 2006-2050



4/20/06 4:28:30pm

APR 20 2006

The logo for ConocoPhillips, featuring the company name in a bold, sans-serif font with a stylized oil drop icon above the 'o' in Phillips.

April 19, 2006

The Honorable Lyda Green
Alaska State Senate
Alaska State Capitol
Juneau, AK 99801-1182

Dear Senator Green:

In response to the invitation from the Senate Finance Committee, we would like to submit the below comments on the CS for Senate Bill No. 305 (FIN) (Work Draft P). We recognize the difficult task before your committee and the Legislature in terms of weighing the tradeoff between near term tax revenues and long term investment incentives. Consequently, we were impressed at how efficiently the Senate Finance Committee was able to conduct its hearings and produce a CS which is responsive to some of the concerns raised by the other legislators, industry and various consultants.

During our testimony before your committee and others, ConocoPhillips provided data and testimony showing that a 20% base production tax rate is high when compared to other OECD countries around the world. In terms of investment attractiveness, the proposed CS with a 22.5% base tax rate and an additional progressivity tax will place Alaska in an even more disadvantaged position. Ultimately, this a policy call for the Legislature in terms of how best to balance the state's desire for greater investment and resource development with near term tax revenue increases.

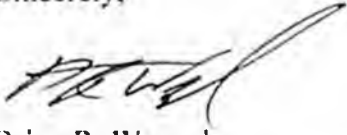
Consistent with our prior testimony, ConocoPhillips' view is that even with the 5% increase in the tax credit rate, the total production tax system proposed in the current Senate Finance CS will not deliver the increases in investment or resource development that you are seeking. While it might initially seem like small change, a 2.5 percentage point increase in the base rate, even if offset by a 5% increase in the tax credit rate, will still result in increased taxes payable by the industry of \$230 million in 2007 beyond what would have been payable under the original bill. Over 10 year period, this is an additional \$2.4 billion *above* the level of increased taxes already represented by the 20/20 original bill.

Finally, on April 13, AOGA addressed several concerns with the language of the prior CS and submitted suggested amendments. We don't believe any of those areas of concern have been adequately addressed by the Senate Finance CS and would request that you consider those suggestions.

COP Response to Questions on SB 305 (April 5, 2006 Letter from Senate Finance Committee)
April 12, 2006
Page 2 of 2

Please contact us if you have other questions or would like to further discuss the above.

Sincerely,

A handwritten signature in black ink, appearing to read "BWenzel", written in a cursive style.

Brian R. Wenzel
Vice President, Finance & Administration

Angus J. Walker
Commercial Vice President



BP Exploration (Alaska) Inc.
P.O. Box 196612
900 East Benson Boulevard
Anchorage, Alaska 99519-6612
(907) 564-4761
(907) 561-5111
Fax (907) 564-5599
WalkerA4@BP.com

April 20, 2006

The Honorable Lyda Green, Co-Chair
Senate Finance Committee
State Capitol
Juneau, AK 99801

Dear Senator Green:

Thank you for this opportunity to comment on draft "P" (4/16/06) of the proposed Senate Finance Committee Substitute for SB 305. We recognize significant effort has gone into this CS and thank you, your staff and the committee for their continued efforts. We offer the following comments for your consideration:

PPT Rate.

Oil: The proposed rate of 22.5% is an improvement from the 25% rate in the Resources CS, but it is still higher than the 20% in the original bill and considerably higher than the rate which we believe would be best for Alaska. Significant additional investment is urgently required to stem North Slope production decline. More investment, more production, more jobs, and the resulting benefits to the state economy are better for Alaska than short term increases in revenue. And more investment promises greater total state revenue in the long run. We therefore urge the Legislature to adopt an oil tax rate which is less than the 20% the Governor proposed.

Gas: A PPT tax rate of 1/3 that proposed for oil is appropriate for gas.

Progressivity. We remain firmly of the belief that progressivity, over and above that already provided by the PPT structure, is not appropriate for Alaska. However, should the Legislature insist progressivity be part of the solution, a structure based on net "production tax value" as proposed in the draft has merit and is better than those previously proposed which were based on gross value. The \$45/BOE trigger point should escalate annually for inflation.

The Honorable Lyda Green, Co-Chair
Senate Finance Committee
April 20, 2006
Page -2-

PPT Credit. The proposed 25% credit for capital expenditures is an improvement from the 20% in the previous versions of the bill. Increased credits will increase reinvestment in Alaska and is consistent with the need for significant additional investment urgently required to stem North Slope production decline.

Transitional Investment Expenditure (TIE) Credits (clawback). The 2-for-1 provision introduces a hurdle which the producers must overcome before they can take the benefit of the TIE credit. Nevertheless, we recognize this is consistent with the need for significant additional investment being urgently required to stem North Slope production decline and understand the driver behind the 2-for-1 provision. In order that we can reasonably expect to receive the benefit of the provision, we would request that you consider either lengthening the seven-year period or lowering the 2:1 investment ratio.

We also have two technical comments to simplify and clarify the administration of the PPT. We believe they are important because they will significantly reduce or avoid unnecessary disputes in the future about how it is supposed to work.

Definition of deductible "direct, ordinary, and necessary costs". PPT deductions under AS 43.55.160(c)(1) must be "direct, ordinary, and necessary costs" for exploration and production, but nowhere is this phrase defined. Parts of it are defined — "direct costs" in AS 43.55.160(d)(1) and (2), and "ordinary and necessary" in AS 43.55.160(j)(2) — but these fragmentary definitions do not necessarily add up to define the whole. The lack of a definition for the whole phrase would leave a loophole for taxpayers or DOR to try to interpret it differently from the definitions of its individual parts.

Clarification of deductible costs "upstream of the point of production". AS 43.55.160(c)(1) also specifies that deductible lease expenditures are "total costs upstream of the point of production" of oil or gas. As AOGA recommended, this should be "total costs in support of activities upstream of the point of production" in order to avoid uncertainty and disputes over the deductibility of field costs not directly tie-able to any specific point or location along the flow of oil and gas from the reservoir to the point of production, such as helicoptering crew out to the platforms in Cook Inlet or lodging workers on the North Slope.

I hope these comments are clear and helpful in your deliberations. We remain available if we can be of any further assistance to the committee.

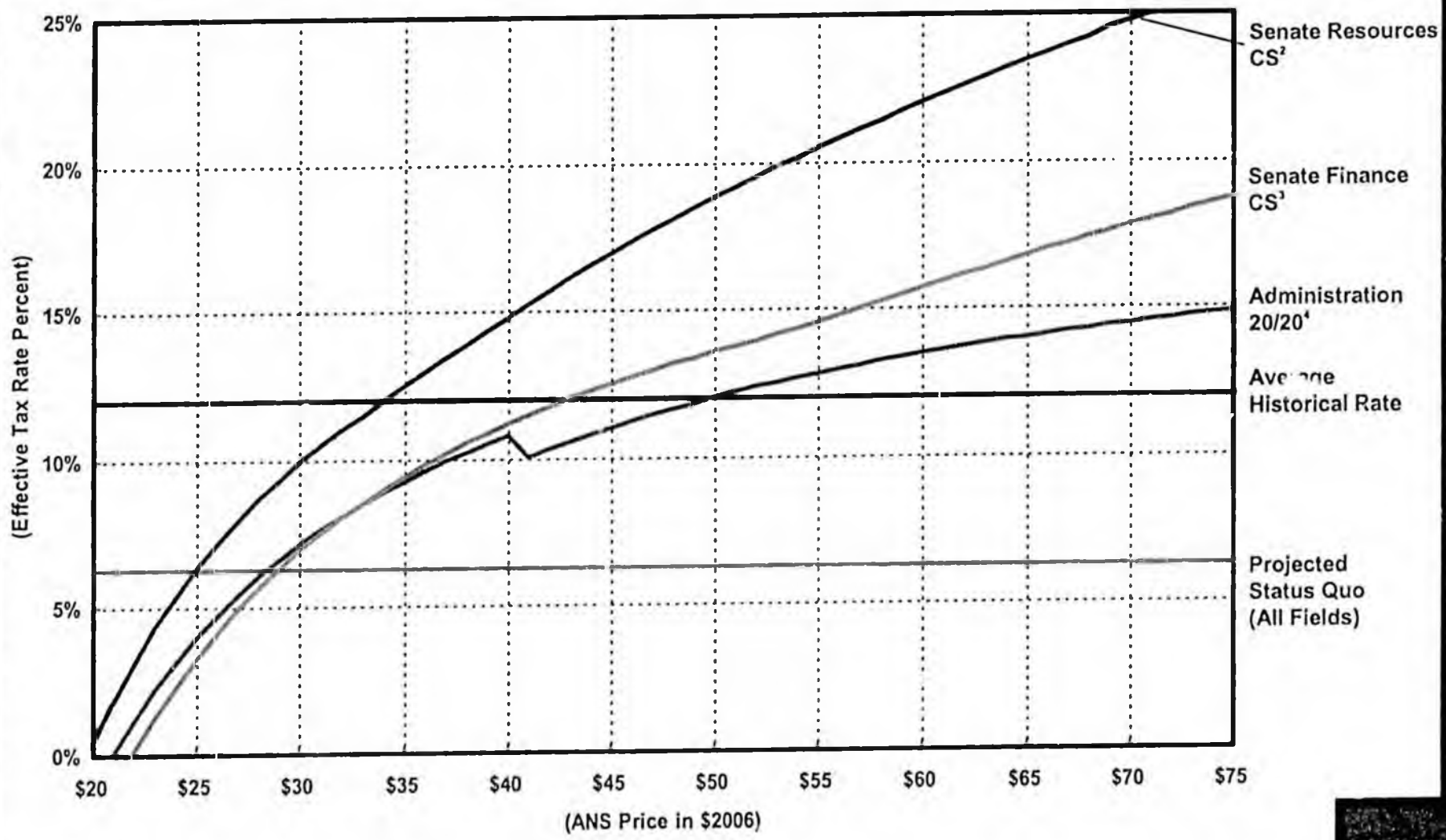
Yours Sincerely,

Angus J. Walker



Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)



¹ Assumes no major gas sale.
² Calculated from April 2006; includes transition (10% of capex over 1st 7 years to maximum of \$4 Billion) and \$5 MBO assumption; volumes per DOR Fall 2005 Forecast with Ooquruk projection.
³ Calculated from July 2006; includes transition (50% of capex over 1st 7 years to maximum of \$3 Billion) and revised \$ MBO assumption; volumes per DOR Fall 2005 Forecast with Ooquruk projection.
⁴ Calculated from July 2006; includes 5-year transition (100% 2007-2011) and \$73 million assumption over 7 companies; volumes per DOR Fall 2005 Forecast with Ooquruk projection.
 Source: Historical: Alaska Department of Revenue.



4/22/06

11:20 AM

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

<i>Effective Tax Rate (Percent)</i>							
Administration 20/20 ²	0.0%	7.1%	10.8%	12.0%	13.5%	14.5%	15.2%
Senate Resources CS ³	0.5%	9.9%	14.8%	18.8%	22.0%	24.8%	27.2%
Senate Finance CS ⁴	0.0%	6.9%	11.2%	13.6%	15.7%	17.8%	19.6%

<i>Alaska Government Take (Percent)</i>							
Administration 20/20 ²	32.8%	31.3%	31.5%	30.9%	31.0%	31.1%	31.2%
Senate Resources CS ³	33.5%	34.7%	35.8%	37.7%	39.3%	40.9%	42.5%
Senate Finance CS ⁴	32.8%	31.1%	31.9%	32.3%	33.2%	34.3%	35.4%

<i>Total Government Take (Percent)</i>							
Administration 20/20 ²	62.9%	58.9%	58.1%	57.3%	57.2%	57.1%	57.1%
Senate Resources CS ³	63.4%	61.1%	60.9%	61.7%	62.5%	63.4%	64.3%
Senate Finance CS ⁴	62.9%	58.7%	58.4%	58.3%	58.6%	59.1%	59.7%

<i>Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)</i>							
Administration 20/20 ²	(\$256)	\$55	\$416	\$683	\$1,044	\$1,405	\$1,766
Senate Resources CS ³	(\$238)	\$240	\$787	\$1,489	\$2,280	\$3,160	\$4,126
Senate Finance CS ⁴	(\$256)	\$42	\$453	\$865	\$1,364	\$1,972	\$2,639

Assumes no major gas sale.
 Calculated from July 2006. Includes 6-year transition (100% 2007-2008) and \$73 billion exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oqoguruk projection.
 Calculated from April 2006. Includes transition (100% of cases over 1st 7 years to maximum of \$3 billion) and 15 MBD exemption; volumes per DOR Fall 2005 Forecast with Oqoguruk projection.
 Calculated from July 2006. Includes transition (100% of cases over 1st 7 years to maximum of \$3 billion) and revised 9 MBD exemption; volumes per DOR Fall 2005 Forecast with Oqoguruk projection.
 Source: Historical, Alaska Department of Revenue.

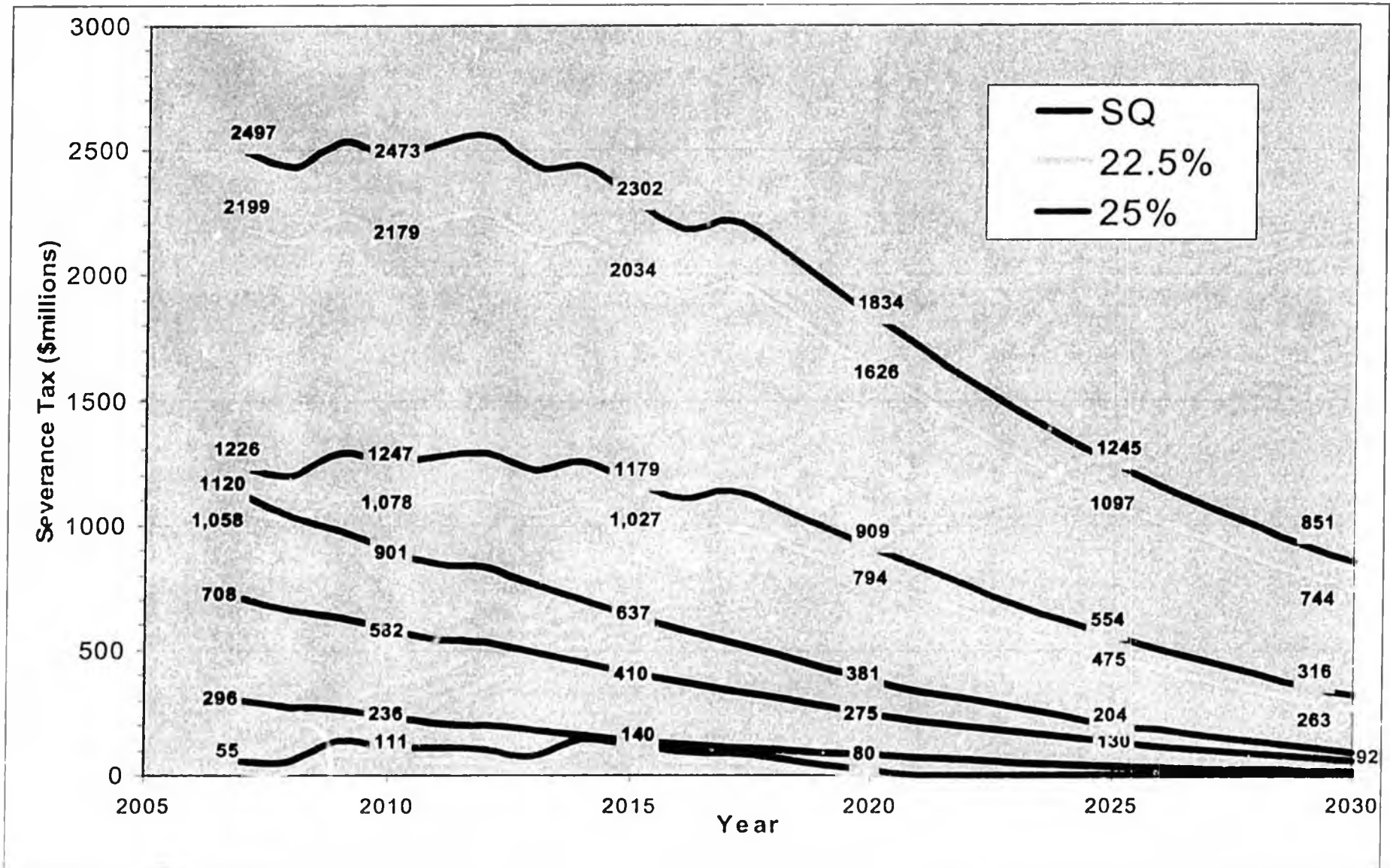


PPT Revenue Studies

Senate Finance Committee

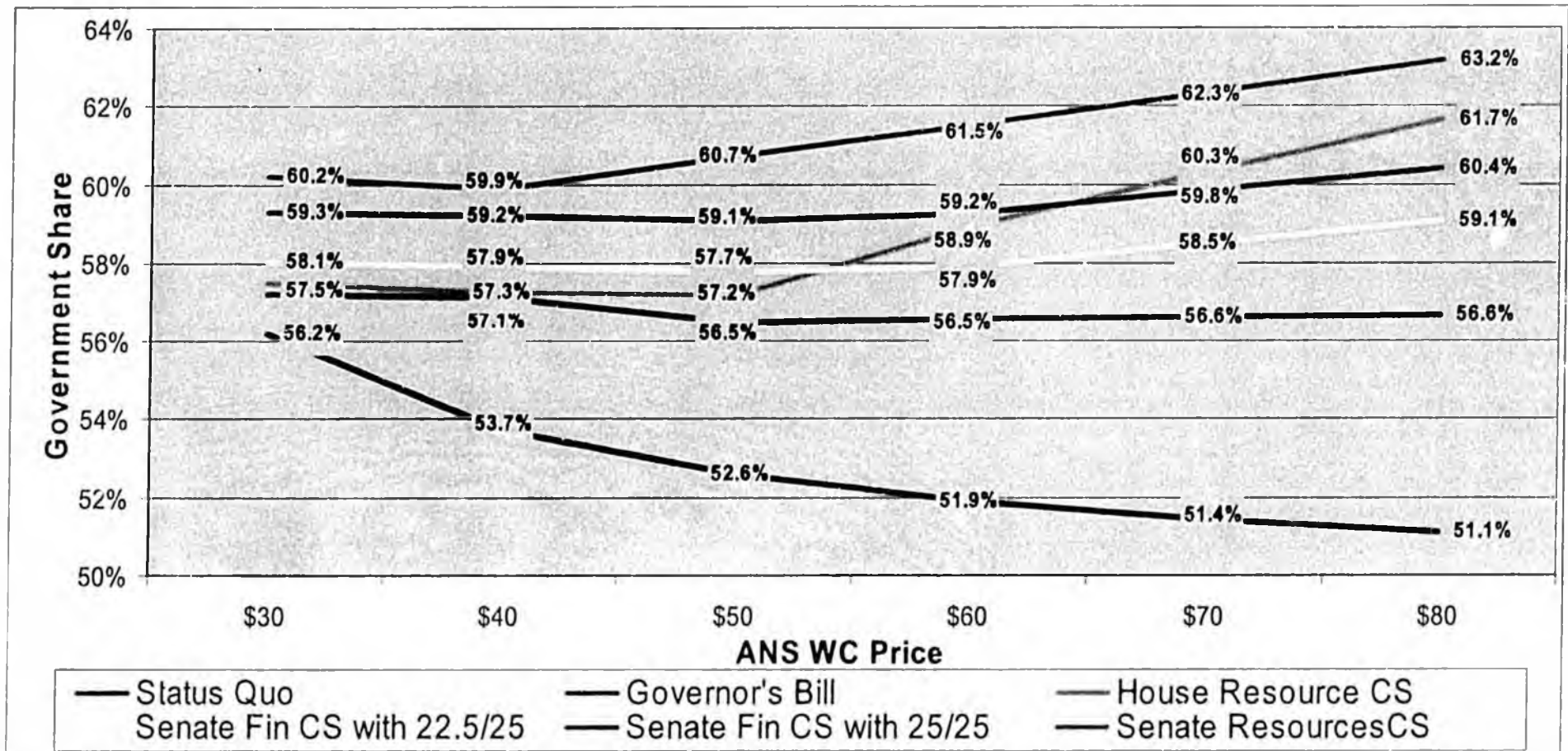
April 21, 2006

Effect of Tax Rate: Annual Oil Severance Tax (\$Millions) Status Quo and Senate Finance CS with 22.5% and 25% Tax Rate at \$20, \$40, and \$60 per bbl, Low Volume Scenario



Distribution of Future Cash Flows Under SQ, Gov's Bill, House Res, Sen Res* and Proposed Sen Fin CS at 22.5/25 and at 25/25, FY 2007-2016

ANS WC \$/bbl	Status Quo	Governor's Bill	House Resource CS	Senate Fin CS with 22.5/25	Senate Fin CS with 25/25	Senate Resources CS
\$30	56.2%	57.2%	57.5%	58.1%	59.3%	60.2%
\$40	53.7%	57.1%	57.3%	57.9%	59.2%	59.9%
\$50	52.6%	56.5%	57.2%	57.7%	59.1%	60.7%
\$60	51.9%	56.5%	58.9%	57.9%	59.2%	61.5%
\$70	51.4%	56.6%	60.3%	58.5%	59.8%	62.3%
\$80	51.1%	56.6%	61.7%	59.1%	60.4%	63.2%

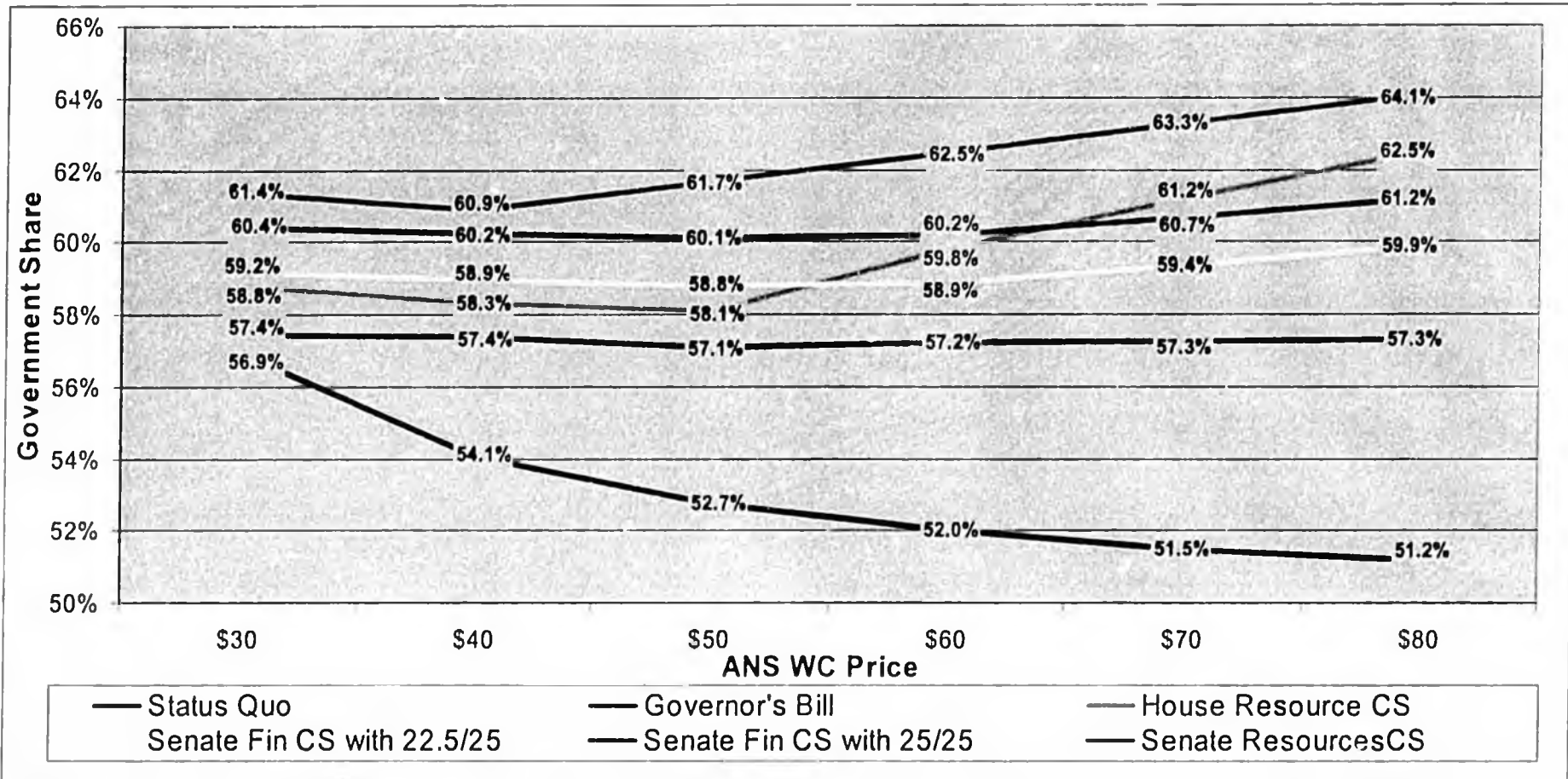


*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Finance CS.

4/21/04 11:06 AM

Distribution of Future Cash Flows Under SQ, Gov's Bill, House Res, Sen Res* and Proposed Sen Fin CS at 22.5/25 and at 25/25, FY 2007-2030

ANS WC \$/bbl	Status Quo	Governor's Bill	House Resource CS	Senate Fin CS with 22.5/25	Senate Fin CS with 25/25	Senate ResourcesCS
\$30	56.9%	57.4%	58.8%	59.2%	60.4%	61.4%
\$40	54.1%	57.4%	58.3%	58.9%	60.2%	60.9%
\$50	52.7%	57.1%	58.1%	58.8%	60.1%	61.7%
\$60	52.0%	57.2%	59.8%	58.9%	60.2%	62.5%
\$70	51.5%	57.3%	61.2%	59.4%	60.7%	63.3%
\$80	51.2%	57.3%	62.5%	59.9%	61.2%	64.1%

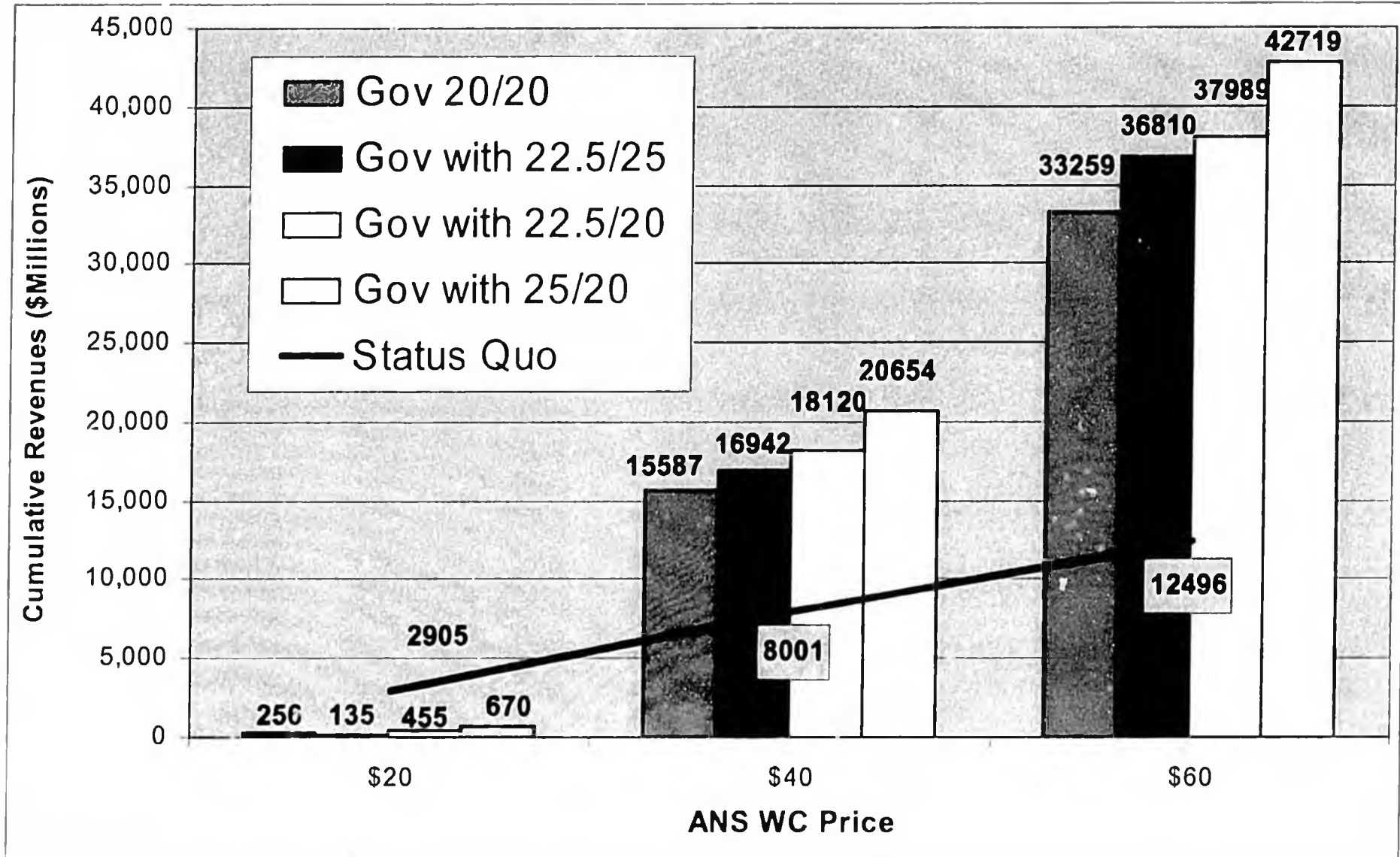


*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Finance CS.

4/21/06

11:08 AM

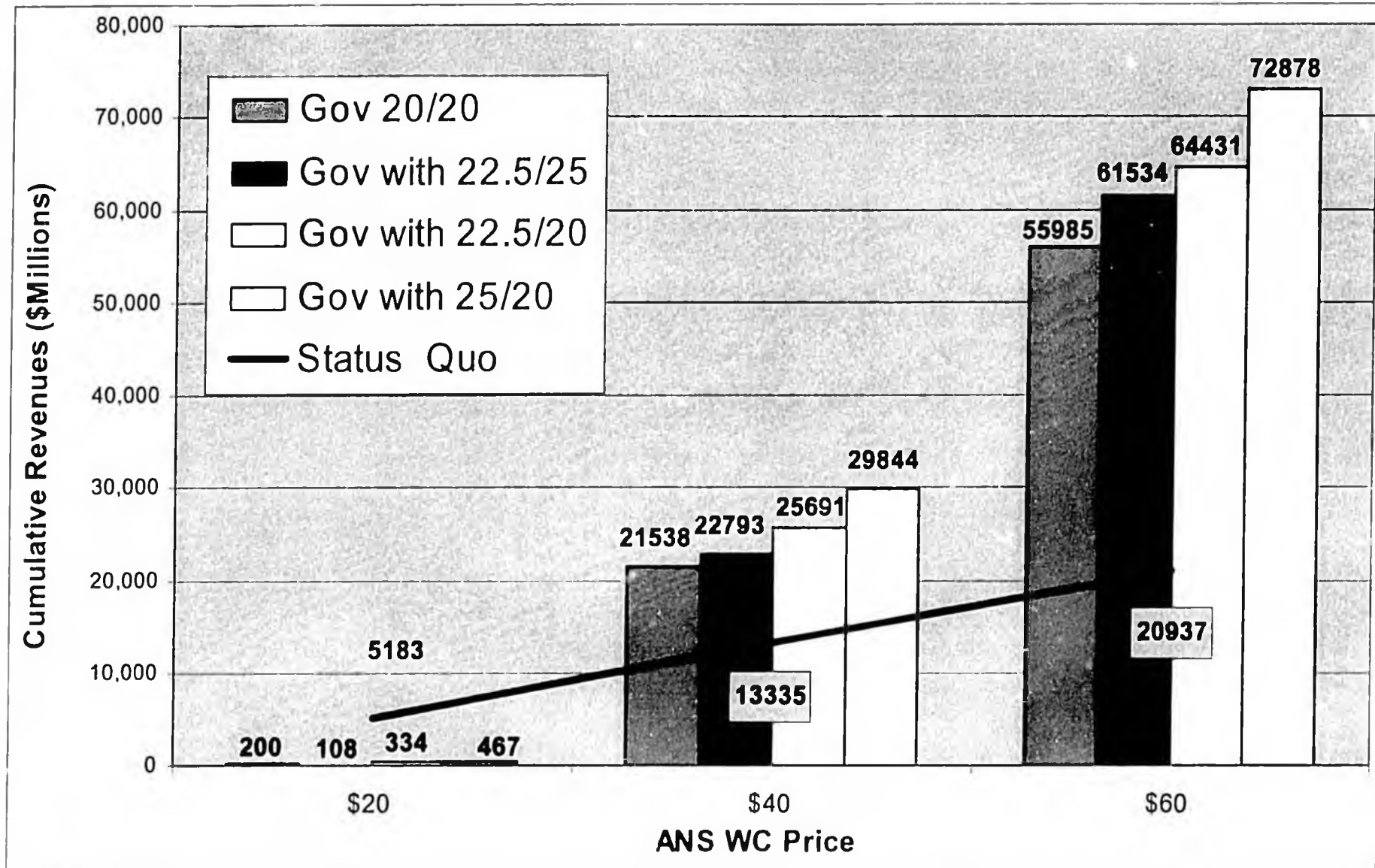
Cumulative Severance Tax Revenues under Governor's Bill as Written, and with 22.5/25, 22.5/20, and 25/20, Low Volume Scenario 2006-2030



4/21/06

11:10 AM

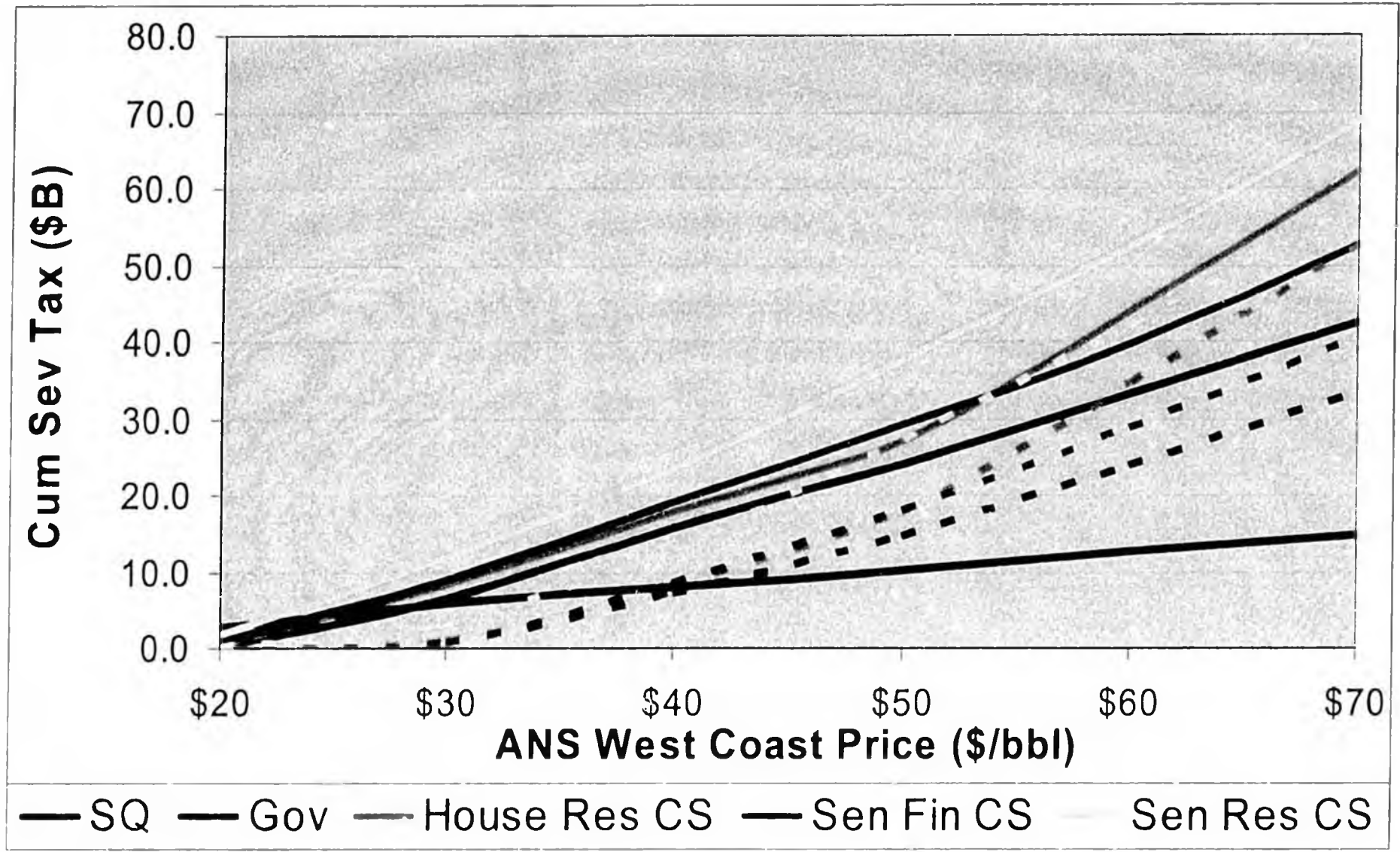
Cumulative Severance Tax Revenues under Governor's Bill as Written, with 22.5/20, and with 25/20, High Volume Scenario 2006-2050



4/21

11:10 AM

Cumulative Severance Tax with Estimated Capital Costs and with Double Est. Capital Costs(\$B) 2006-2030, Low Volume Scenario



4/21/06 11:16 AM

**Comparing CSSB 305 (RES)
to CSSB 305 (FIN) (version P)**

**Before the Senate Finance
Committee**

April 20, 2006

Robert E. Mintz, Department of Law

Dan E. Dickinson, C.P.A.

RES, Section 32

FIN, Section 37

New production tax provisions apply to oil
and gas produced on or after:

April 1, 2006 (RES)

(FIN)

RES, Section 5

AS 43.55.011(e)

There is levied upon the producer . . . a tax
for all produced . . .
[except for] a lessor's royalty interest. . . .
The tax is equal to 25 of the
production tax . . . under AS 43.55.160.

FIN, Section 5

AS 43.55.011(e)

There is levied upon the producer . . . a tax
for all produced . . .

[except for] a lessor's royalty interest. . . .

The tax is equal to of the
production tax . . . under AS 43.55.160.

RES, Section 5 (cont.)

AS 43.55.011(f)

There is levied upon the producer . . . a tax for all oil and gas produced each month . . . the ownership or right to which constitutes a lessor's royalty interest The tax is equal to five percent of the gross value at the point of production [for existing leases]

- BUT . . .

RES, Section 5 (cont.)

AS 43.55.011(f) (cont.)

The tax is equal to 1.5 percent of the gross value at the point of production [for existing *COOK INLET BASIN* leases]

- AND . . .

RES, Section 6 (cont.)

AS 43.55.011(f) (cont.)

The commissioner shall recommend to the legislature the rate of tax [for FUTURE leases]

FIN, Section 5 (cont.)

AS 43.55.011(f)

There is levied upon the producer . . . a tax for all oil and gas produced each month . . . the ownership or right to which constitutes a lessor's royalty interest

five percent of the gross value at the point of production . . .

FIN, Section 36

RES, Section 5 (cont.)

AS 43.55.011(g) – (h)

[When West Coast ANS is above \$40/Bbl]
there is levied upon the producer of oil a tax
... equal to.

(West Coast ANS – 40) * .2 % *

(ANS Prevailing Value) * 75% *

(amount of oil production)

FIN, Section 5 (cont.)

AS 43:55.011(g) – (h)

When
upon the producer of oil
of
index

there is levied
a tax equal to
times price

So . . .

The Resources CS has three production tax components:

- (1) 25% of net value (now called “production tax value”) *except* for lessor royalty share
- (2) 5% or 1.5% of gross value for lessor royalty share
- (3) A progressive-rate tax on prevailing value of *oil* only, including lessor royalty share

And . . .

The _____ also has three production tax components:

- (1) _____ of net value (now called “production tax value”) *except* for lessor royalty share
- (2) 5% of _____ gross value and _____ for lessor royalty share
- (3) a progressive-rate tax on _____ of oil
_____ ,
lessor royalty share

RES, Section 22

AS 43.55.160(a)

production tax . . . is the total of the
of . . .
oil and gas . . . from in
the state,
less . . . as

FIN, Section 26

AS 43.55.160(a)

production tax . . . is the total of the
of . . .

oil and

. . . from

in the state,

less

. . . as

RES, Section 28

FIN, Section 32

AS 43.55.900(7)

“gross value at the point of production”

means

for , the value . . . at the . . . meter . . . in .

..

for . . . the value . . . where . . . metered

[]

RES, Section 20
FIN, Section 24

AS 43.55.150(a)

... gross value at the point of production is
calculated using the reasonable

...

RES, Section 21

AS 43.55.150(d)

if the commissioner completes a detailed fiscal analysis and determines . . . the long-term fiscal interests of the state [would be served] . . . the department. . . . gross value [to be calculated based upon

] royalty . . . valuation [or] another a value

FIN, Section 25

AS 43.55.150(d)

... the department
. gross value [to be calculated based upon
] royalty ... valuation [or]
another a
value

RES, Section 22

FIN, Section 26

AS 43.55.160(c)

... lease expenditures ... are the costs
of the point of production ... on
or after April 1/ , 2006 ... that are the
costs of
oil
or gas ... in the state.

RES Section 22

AS 43.55.160(c) (continued)

In determining . . . [. . .] costs . . . the department shall give substantial weight . . . to typical . . . as to [billable] costs . . . under . . . and [. . .].

FIN Section 26

AS 43.55.160(c) (continued)

This CS gives to industry practices and standards. DNR's net profit share lease regulations are looked to only if industry practices and standards

or

Section 22/26

AS 43.55.160(d) provides specific examples of, and exclusions from, “direct costs”

- FIN CS adds “ ” to exclusion of depreciation/amortization
- FIN CS clarifies language of several exclusions
- FIN CS deletes RES CS exclusion for “disuse,” dismantlement, restoration, etc.

Section 22/26 (cont.)

- FIN CS retains RES CS fair market rule for non-arm's length transactions but RES language referring to IRS provisions
- Note: fair market rule for *adjustments* to lease expenditures is moved from subsec. (A) to
- FIN CS deletes RES CS treatment of

RES, Section 22

AS 43.55.160(g)

... a producer that is ... and produces
under 55,000 BOE/day may reduce the net value
by ... equal to the
following fraction of the production tax value:

$$(5,000 - 0.2 * [\text{average daily production} - 5,000]) \div$$

average daily production

RES, Section 22

AS 43.55.160(h) – producer's qualification for an allowance. Expires 12/31/2013.

This is an anti-splitting provision to prevent abuse of the *per producer* allowance under AS 43.55.160(g).

It is essentially the same anti-splitting provision that is in sec. 21 of the original bill, for the \$73 million *per producer* allowance.

FIN, Sec. 26 (cont.)

Allowance provision in RES CS version
(AS 43.55.160(g) & (h)) is replaced with a new
provision in FIN CS (AS 43.55.170)

Credit = _____ of up
to _____ of production

Up to \$14 million/yr, non-transferable, not
carried forward, expires 2016.

FIN, Sec. 26 (cont.)

Credit provision of AS 43.55.170
has essentially the same *anti-*
splitting provision as the
Governor's bill and the RES CS

AS 43.55.170(c)

FIN, Section 36

Department of Revenue is directed to the effects of the AS 43.55.170 credit on exploration, encouraging new entrants, etc., and by 2015, including recommending whether to extend credit provision.

RES, Section 13

AS 43.55.024(a)

... a producer ... that incurs a
... may ... elect ... to
take a ... in the amount of
of that expenditure.

FIN, Section 12

AS 43.55.024(a)

... a producer ... that incurs a
... may ... elect ... to
take a ... in the amount of
of that expenditure.

[

]

Section 12/13 (cont.)

AS 43.55.024(h)(2)

“qualified capital expenditure” does not include an expenditure incurred . . . for . . . an extended period of disuse, dismantlement, removal . . . or abandonment . . . or for the restoration of a lease, field, [etc.]

Section 12/13 (cont.)

AS 43.55.024(b)

A producer . . . may elect to take a . . . of 25 / . . . of a carried-forward [which is the amount of a previous year's that were because they would have reduced the production tax value of the oil and gas below zero].

Section 12/13 (cont.)

AS 43.55.024(d) – (f)

A producer entitled to a tax credit may apply to the Dep't of Revenue for a Once issued, a certificate may be used for its face value, but a transferee may not apply a certificate to reduce its tax liability by more than during a calendar year.

Section 12/13 (cont.)

AS 43.55.024(i) (cont.)

- a producer may . . . take a tax credit . . . of 20 percent of the producer's [TIE] but only [up to] one-half of the producer's qualified capital expenditures . . . during the month
- credits are non-transferable
- credit provision expires April 1 [], 2013

FIN, Sections 13-17

AS 43.55.025 (from SB 185)

The FIN CS

- extends the sunset for these exploration credits to
- fixes an ambiguity re: \$20 million cap for Cook Inlet
- makes conforming amendments

RES, Sections 7, 12

AS 43.55.020(a) and (g)

- 95 percent of principal production tax (AS 43.55.011(e)), net of credits, due each month. Remaining portion due at end of next calendar quarter.
- 100 percent of tax on lessor royalty interest (AS 43.55.011(f)) due each month.
- Bill does not specify payment of progressive-rate oil tax (AS 43.55.011(g)).

FIN, Section 7

AS 43.55.020(a)

95 percent of production tax (AS 43.55.011(e)-(g)), net of credits, due each month. Remaining portion due

FIN, Section 11

AS 43.55.020(f) - "Prevailing value"

The Governor's bill clarified that prevailing value applies where there is of oil or gas. The FIN CS also clarifies that where there is a sale, prevailing value may be calculated for the when that makes more sense than the month during which the oil or gas was produced.

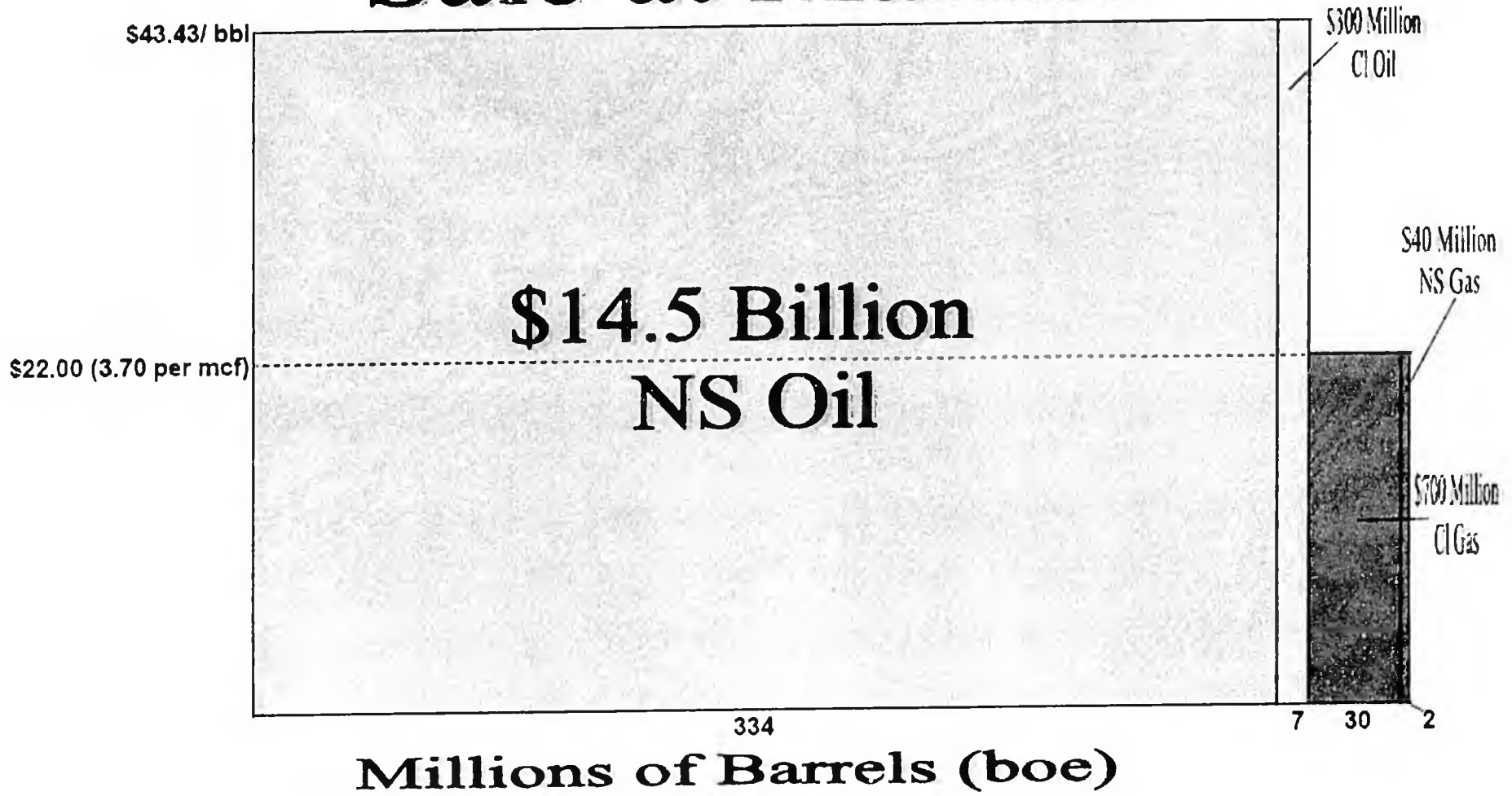
And finally . . .

RES Section 25, FIN Section 29

The RES CS increased the oil conservation surcharge under AS 43.55.300 from 3 cents per barrel to 5 cents.

The FIN CS increases it from 3 cents per barrel to

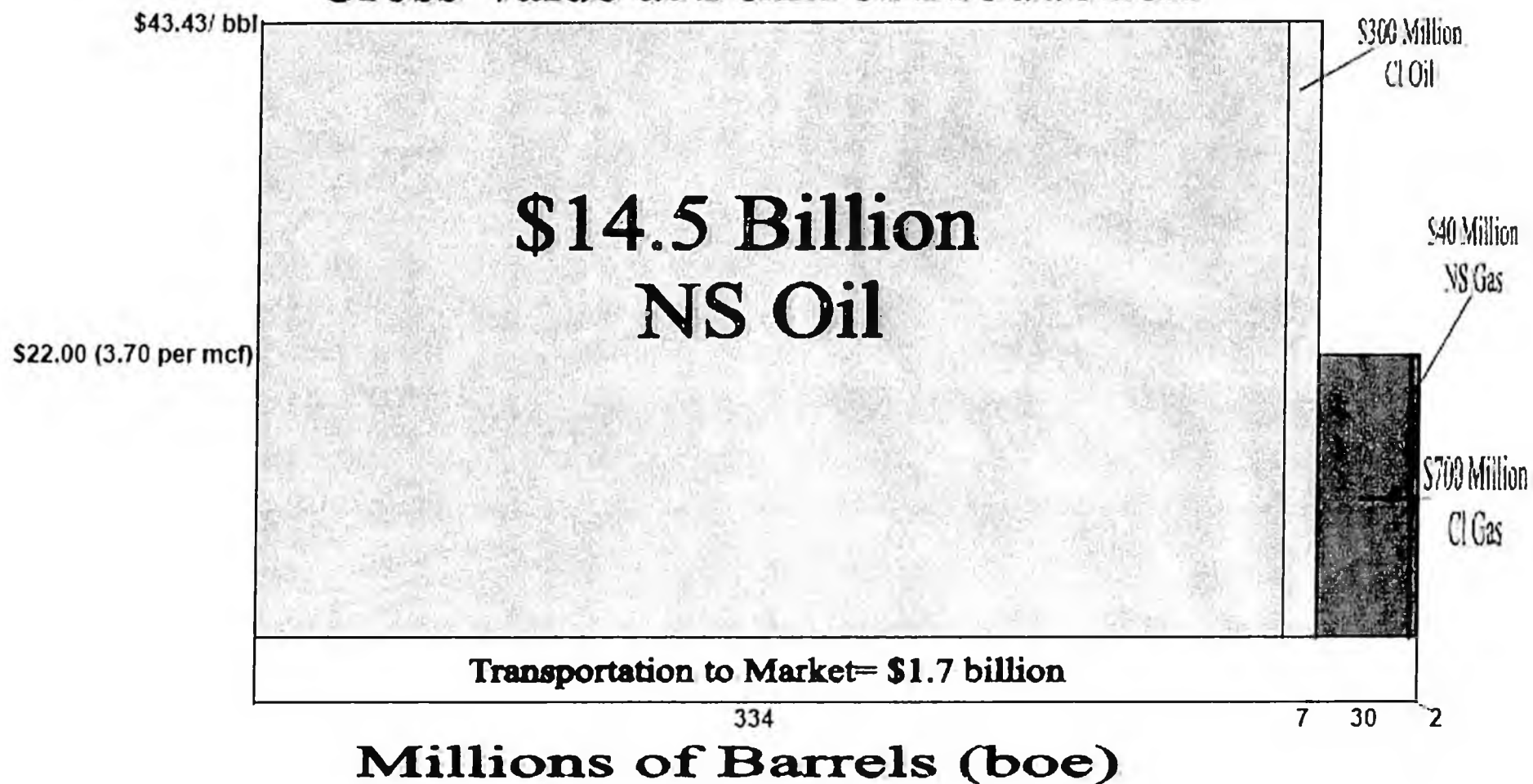
Sale at Market



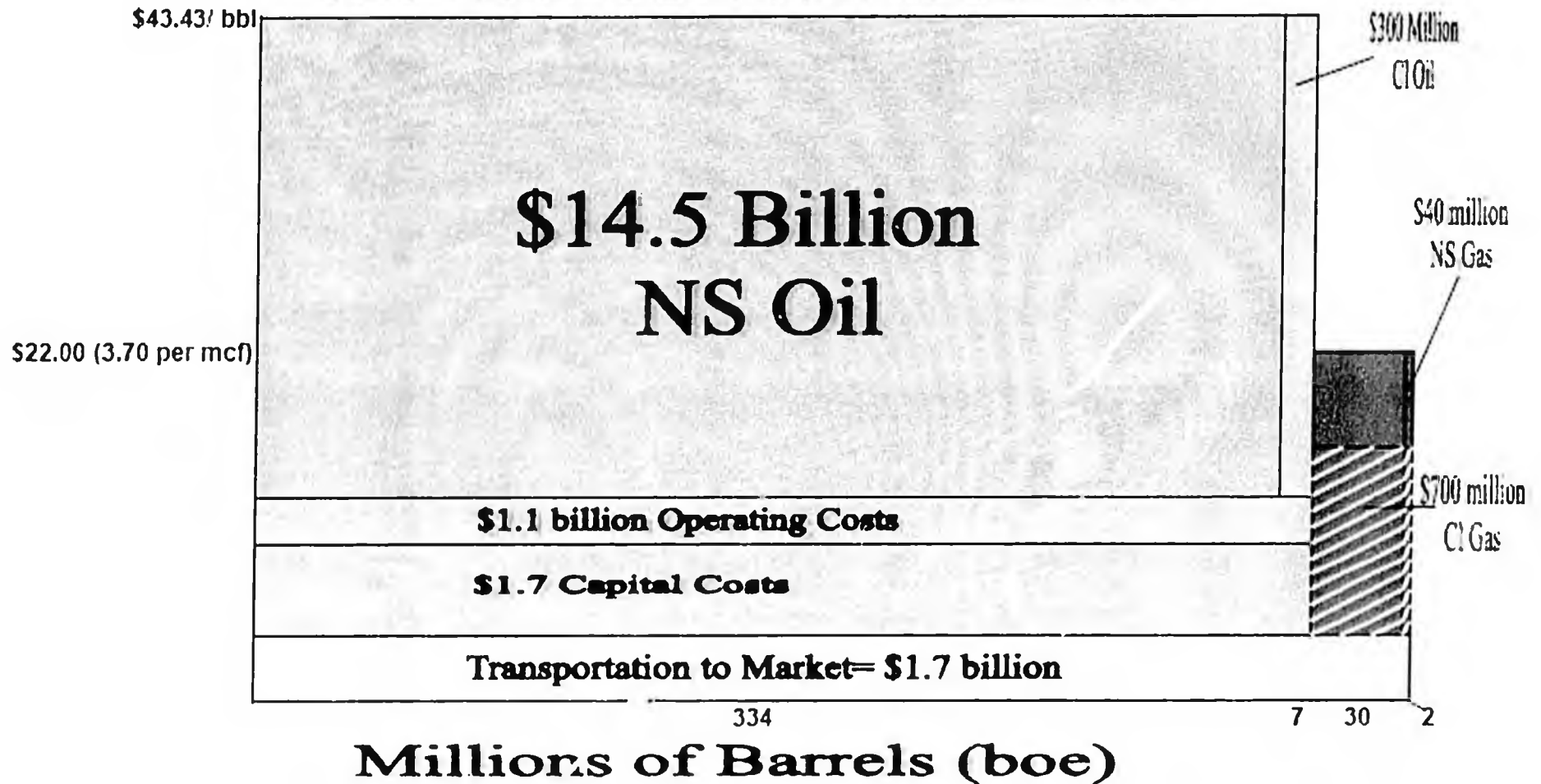
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provided by Dept. Revenue

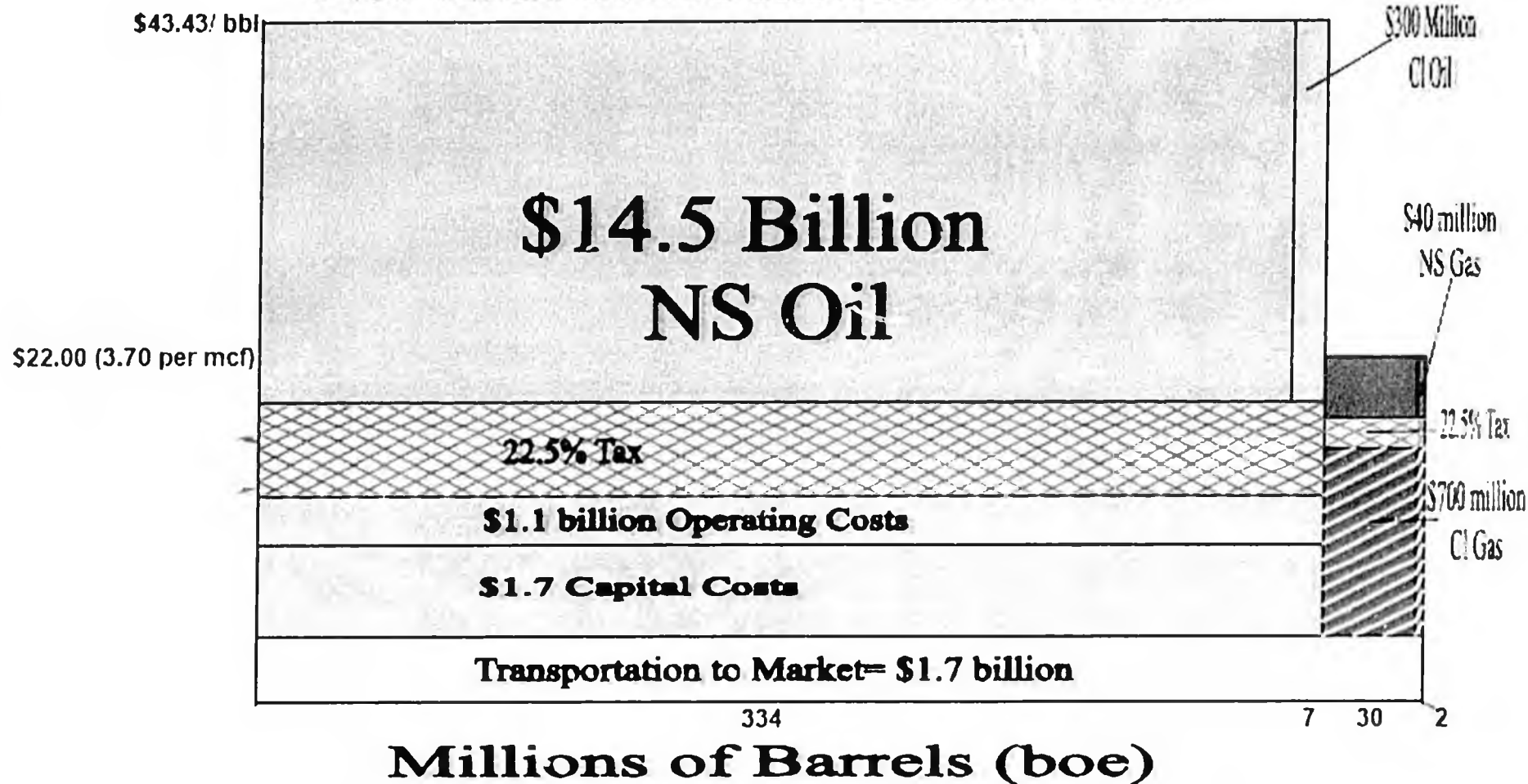
Gross Value at Point of Production



Net Value or Production Tax Value



Net Value or Production Tax Value



Tax Before Credits

2.4 billion

Tax After Credits

Tax After Credits 1.7 billion

5,000 bbl equivalent credit 8 users at max of 14 million = 112 million

TIE credit $1.7 \times .5 \times .2 = 170$ million

$1.7b \times .25 = 425$ million Qualified Capital Expenditure Credits

Tax After Credits

Tax After Credits 1.7 billion

5,000 bbl equivalent credit 8 users at max of 14 million = 112 million

ITB credit $1.7 \times .5 \times .2 = 170$ million

$1.7b \times .25 = 425$ million Qualified Capital Expenditure Credits

Tax Under Status Quo ~ .9 billion