

ALASKA LEGISLATURE

HOUSE and SENATE FINANCE COMMITTEE FILES, 2005-2006 3104

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

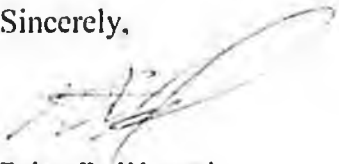
equipment should be promoted not discouraged.

- 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.

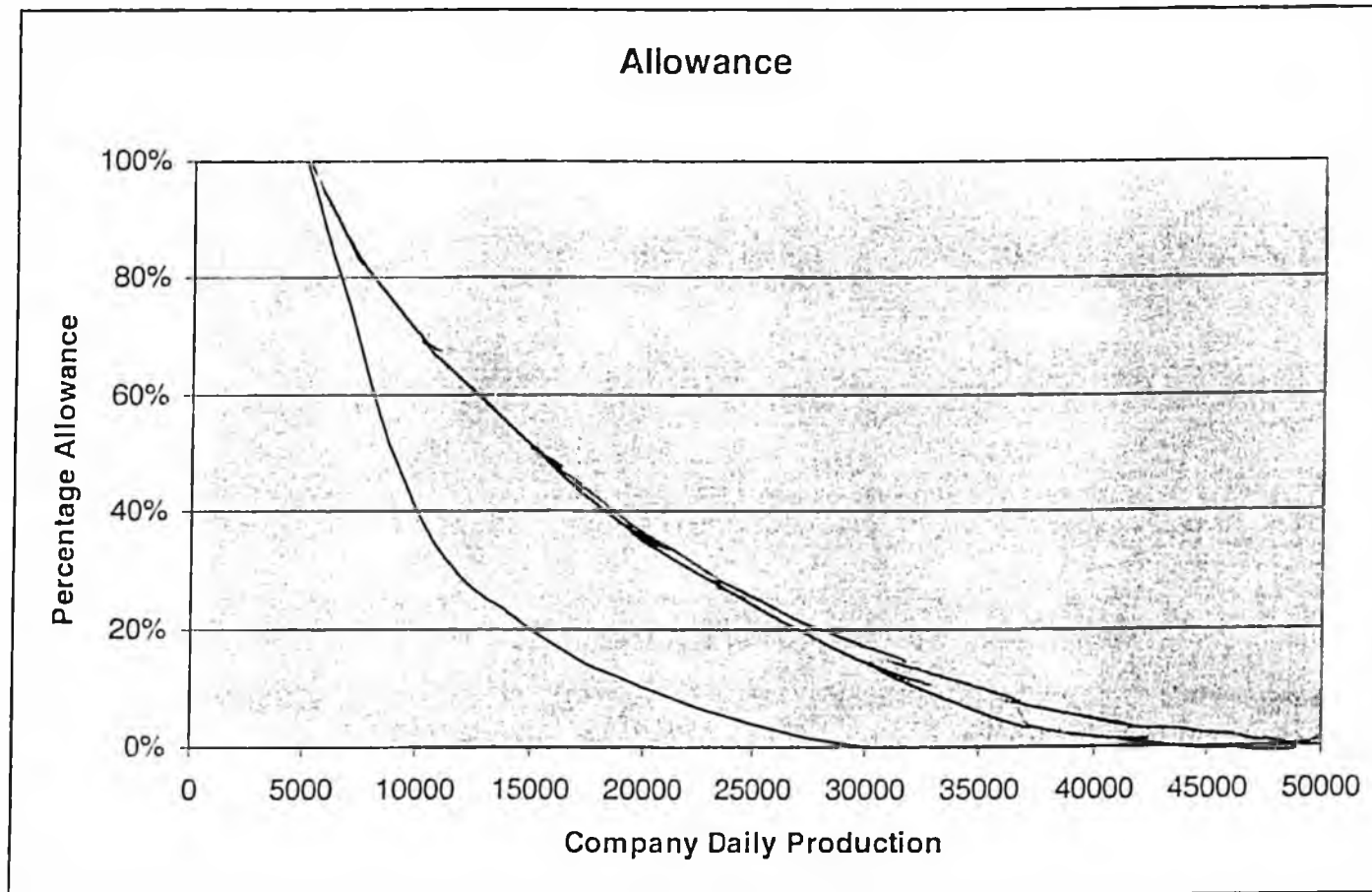
If you have any questions regarding this information, you may contact me at 907-265-1650 or make arrangements through our Juneau office at 907-586-3680.

Sincerely,



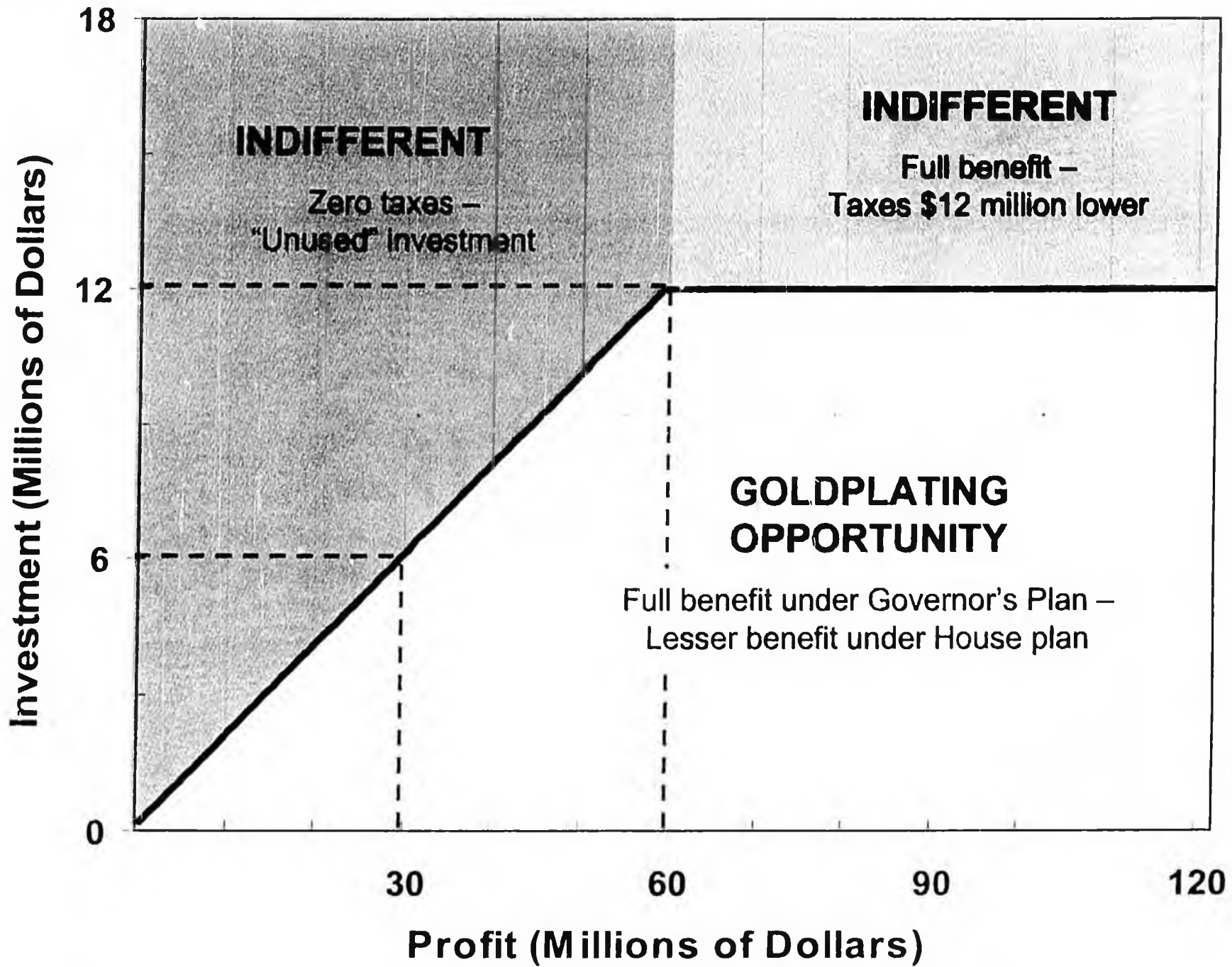
Brian R. Wenzel
Vice President, Finance & Administration
ConocoPhillips Alaska

FIGURE 2



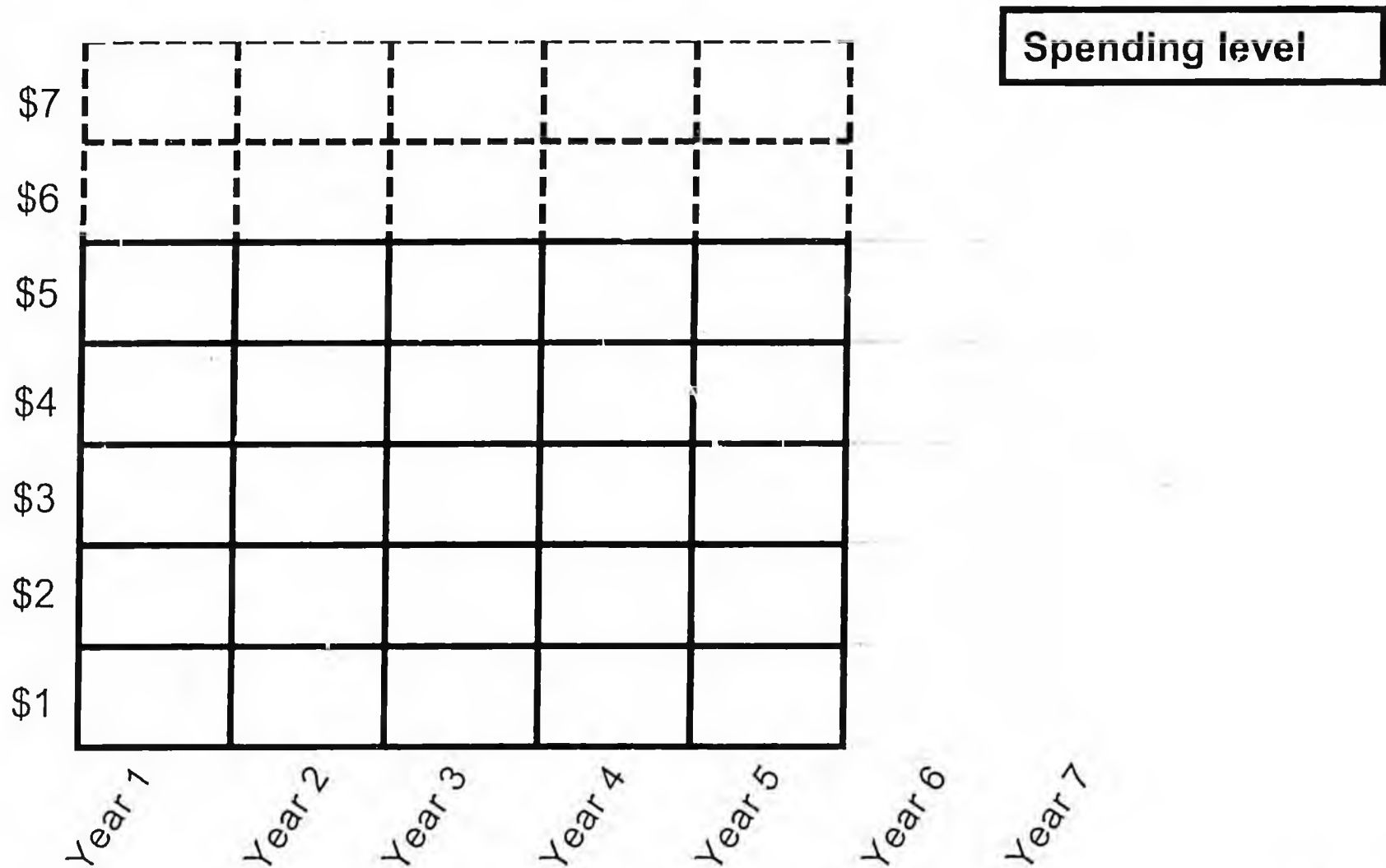
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Dan Dickinson



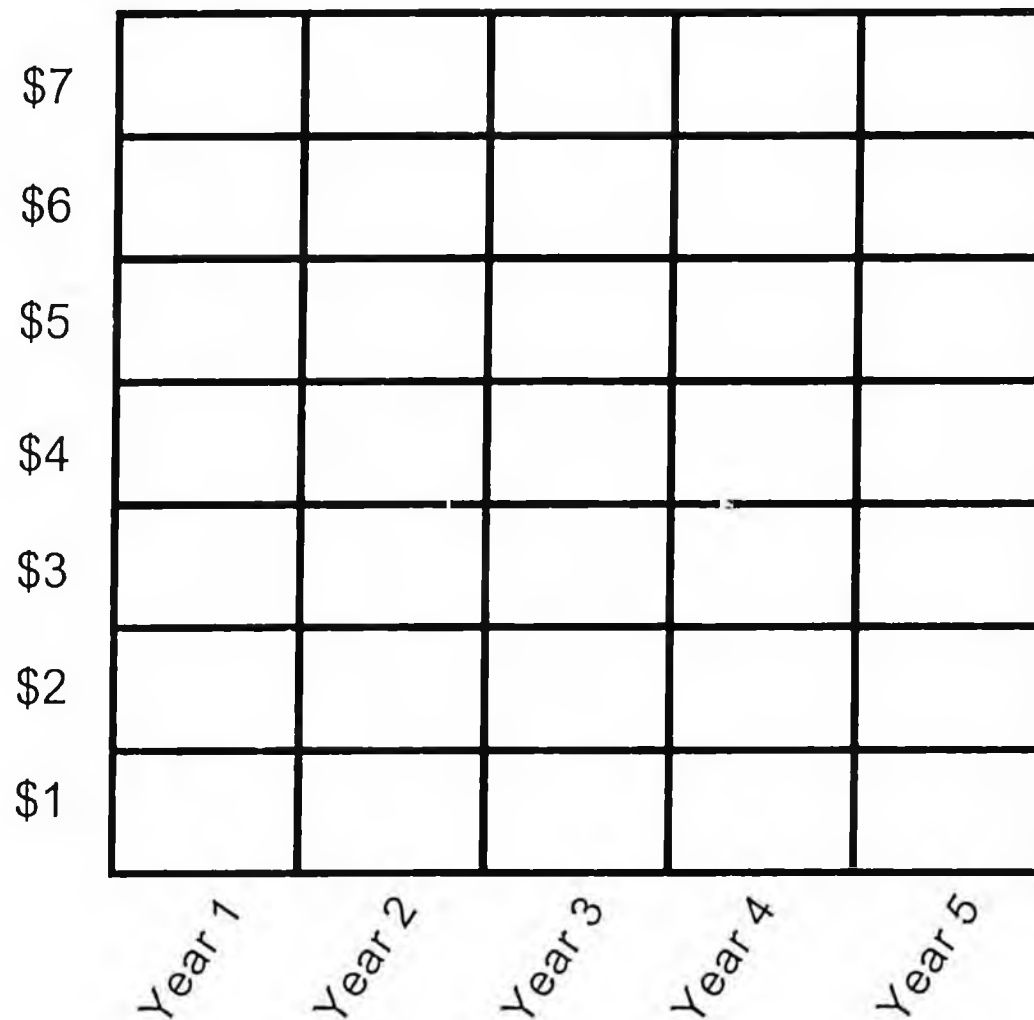
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Recovery of \$35 over 7 years 5 dollar a year
(One to One match would only require 5/7th of spend each year)



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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

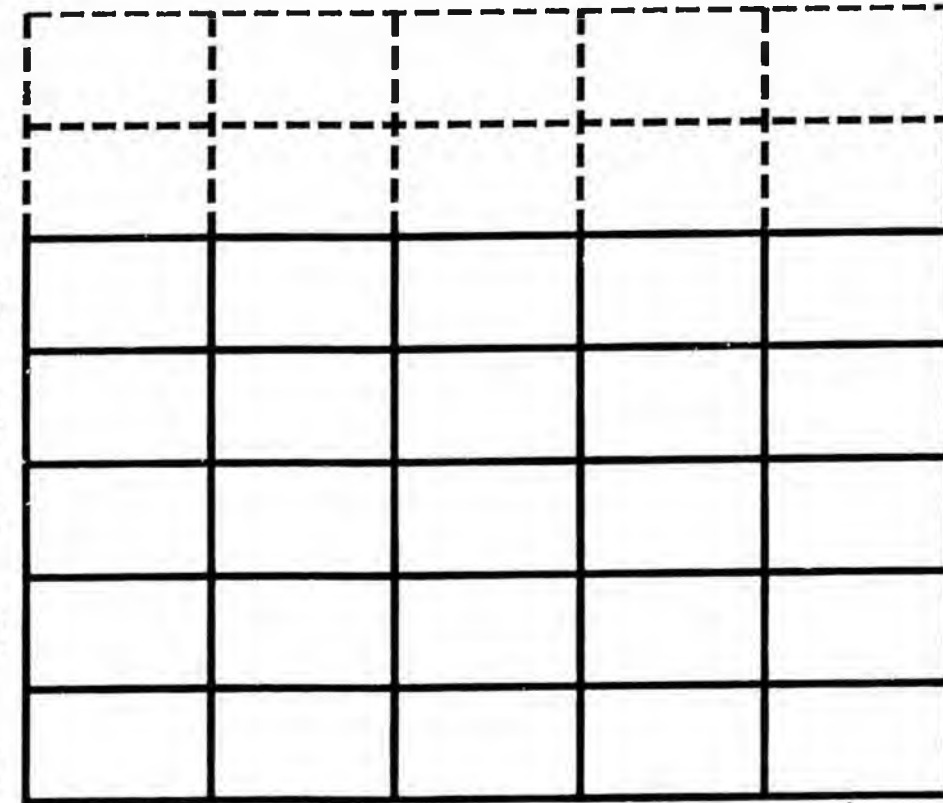
\$5

\$4

\$3

\$2

\$1



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	Federal	Other	State	Total	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	Federal	Other	State	Total	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	Federal	Other	State	Total	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	Federal	Other	State	Total	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	Federal	Other	State	Total	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.

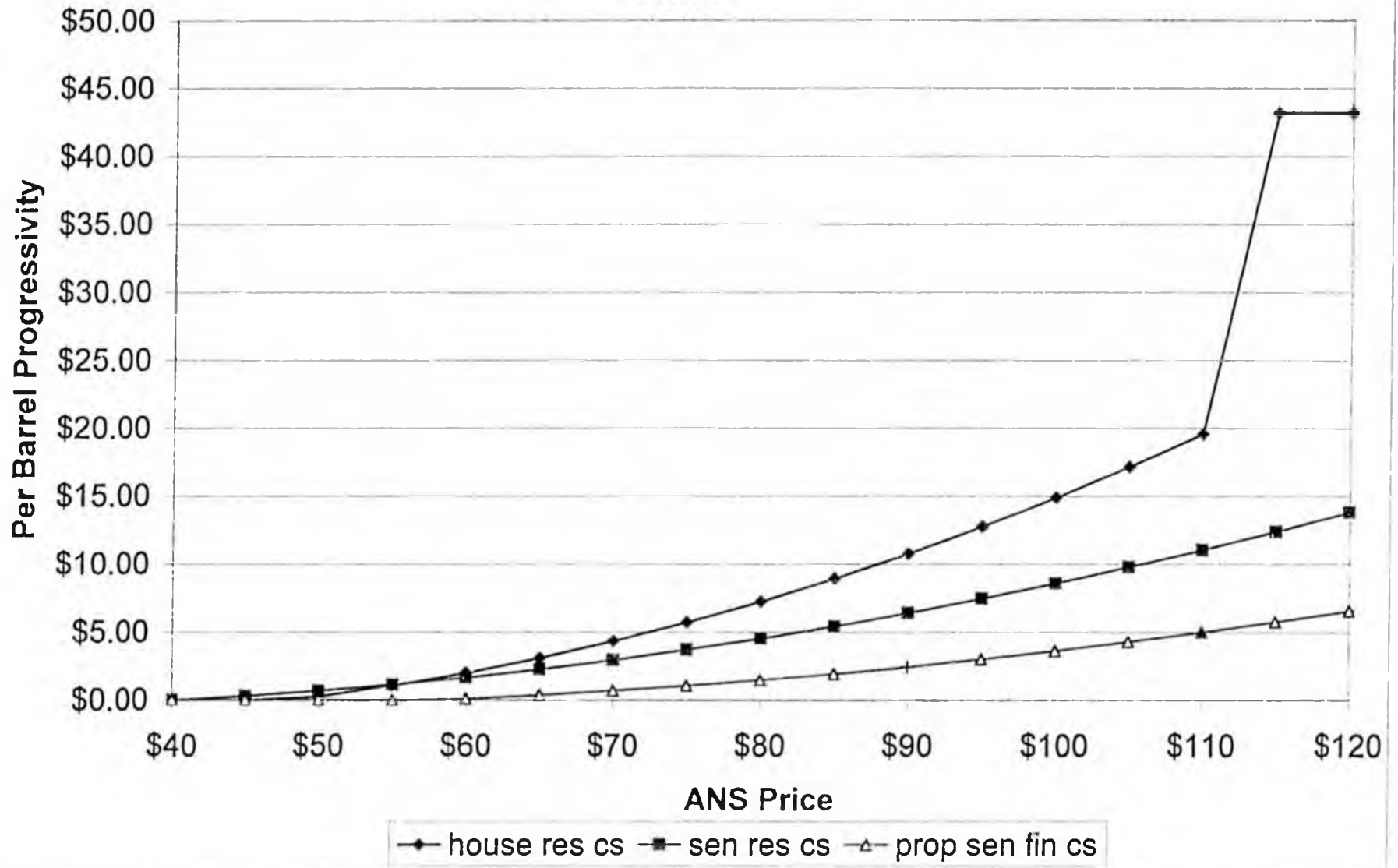


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AS 43.20.043: Gas Exploration and Development Tax Credit

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%

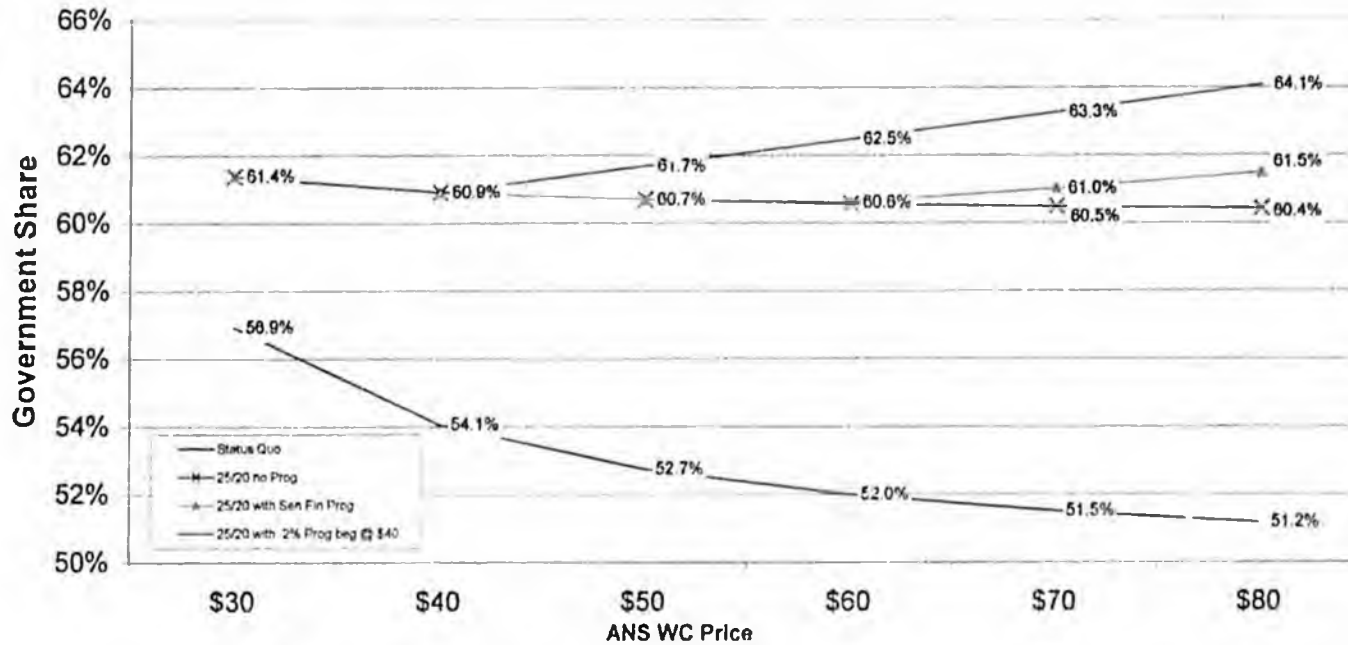
Senate Resources

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



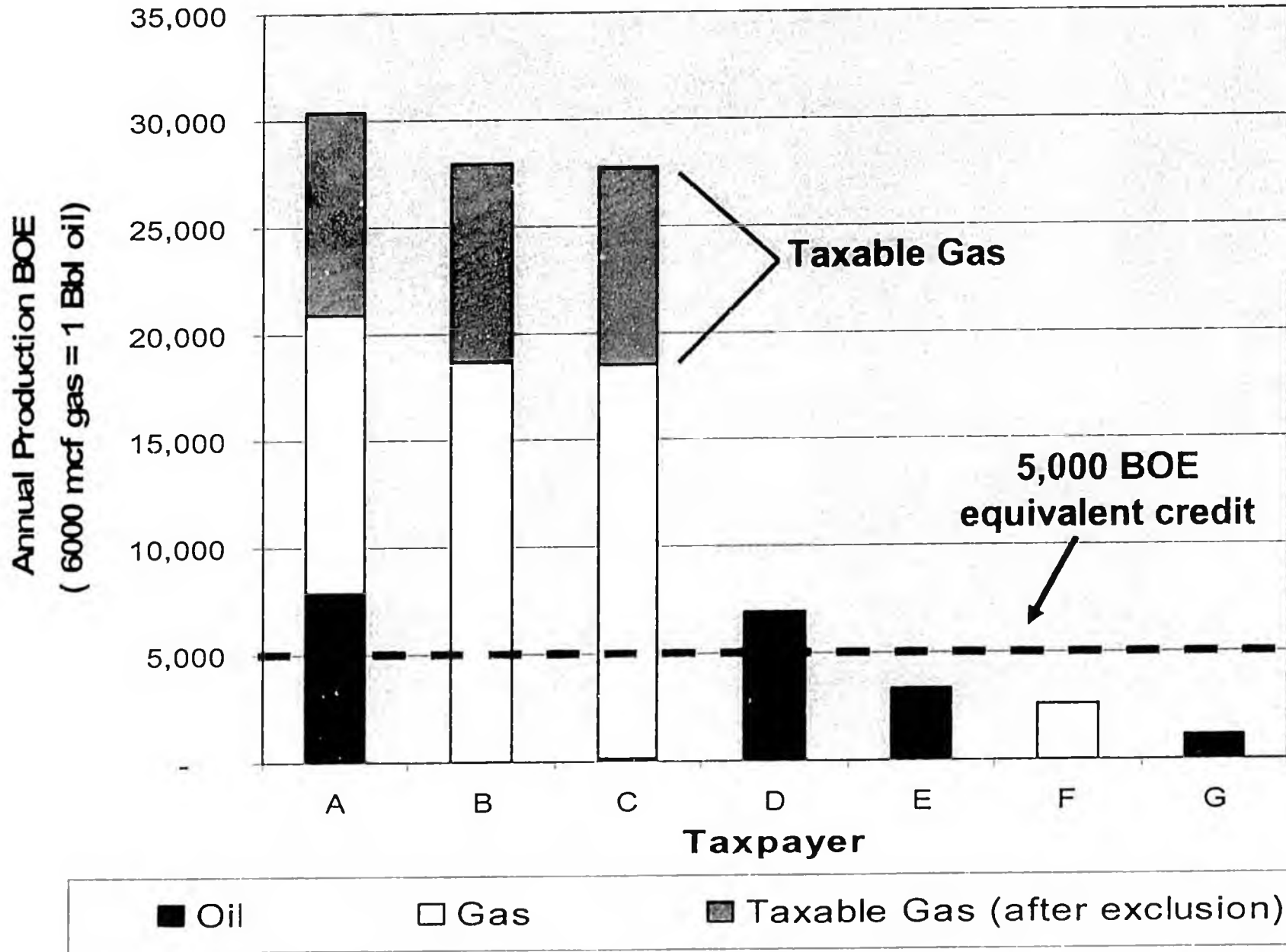
*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Sen Fin

PPT Revenue Studies

Senate Finance Committee

April 20, 2006

Cook Inlet



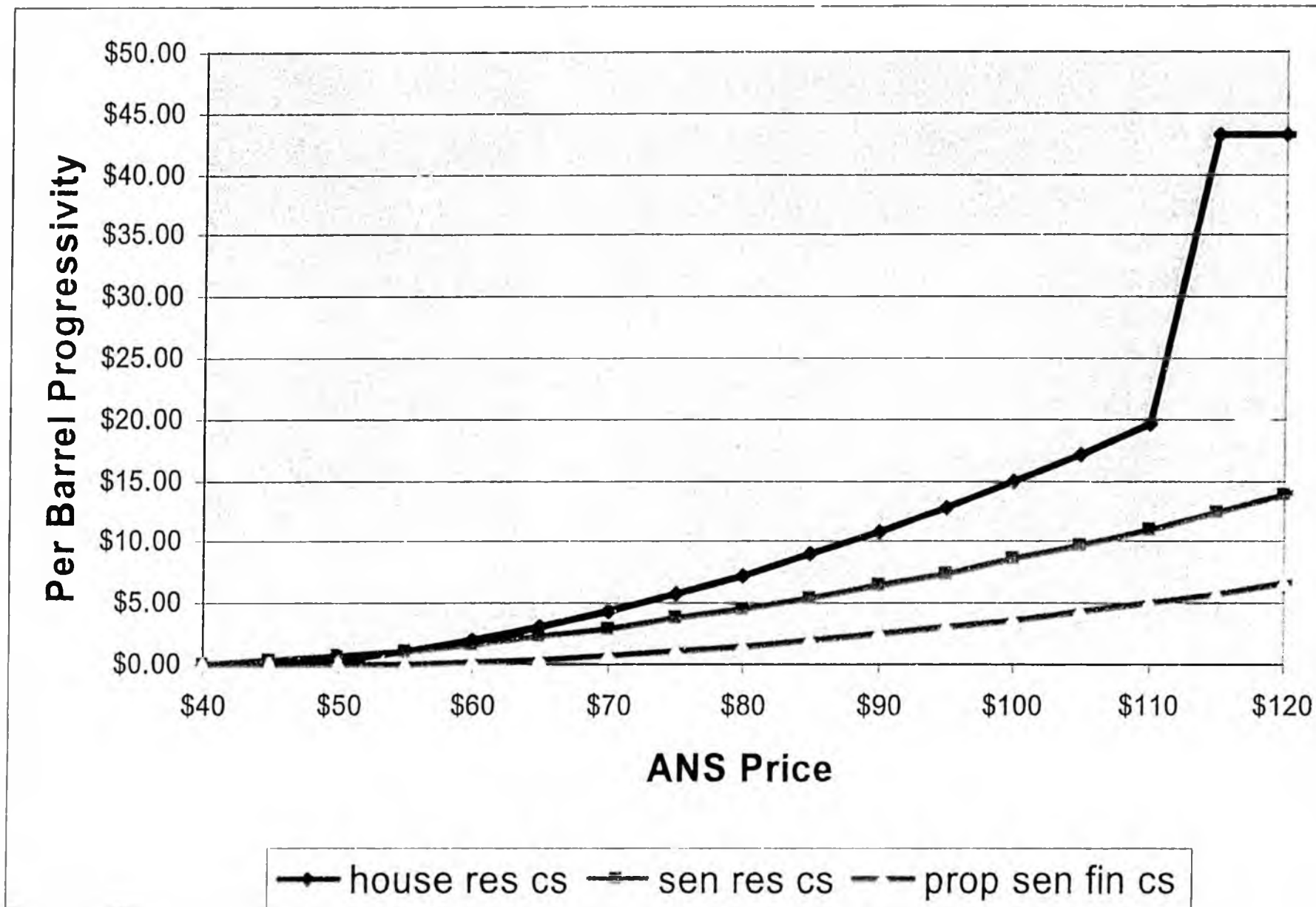
4/21/06

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10:52am

4/20/06

Timestamp

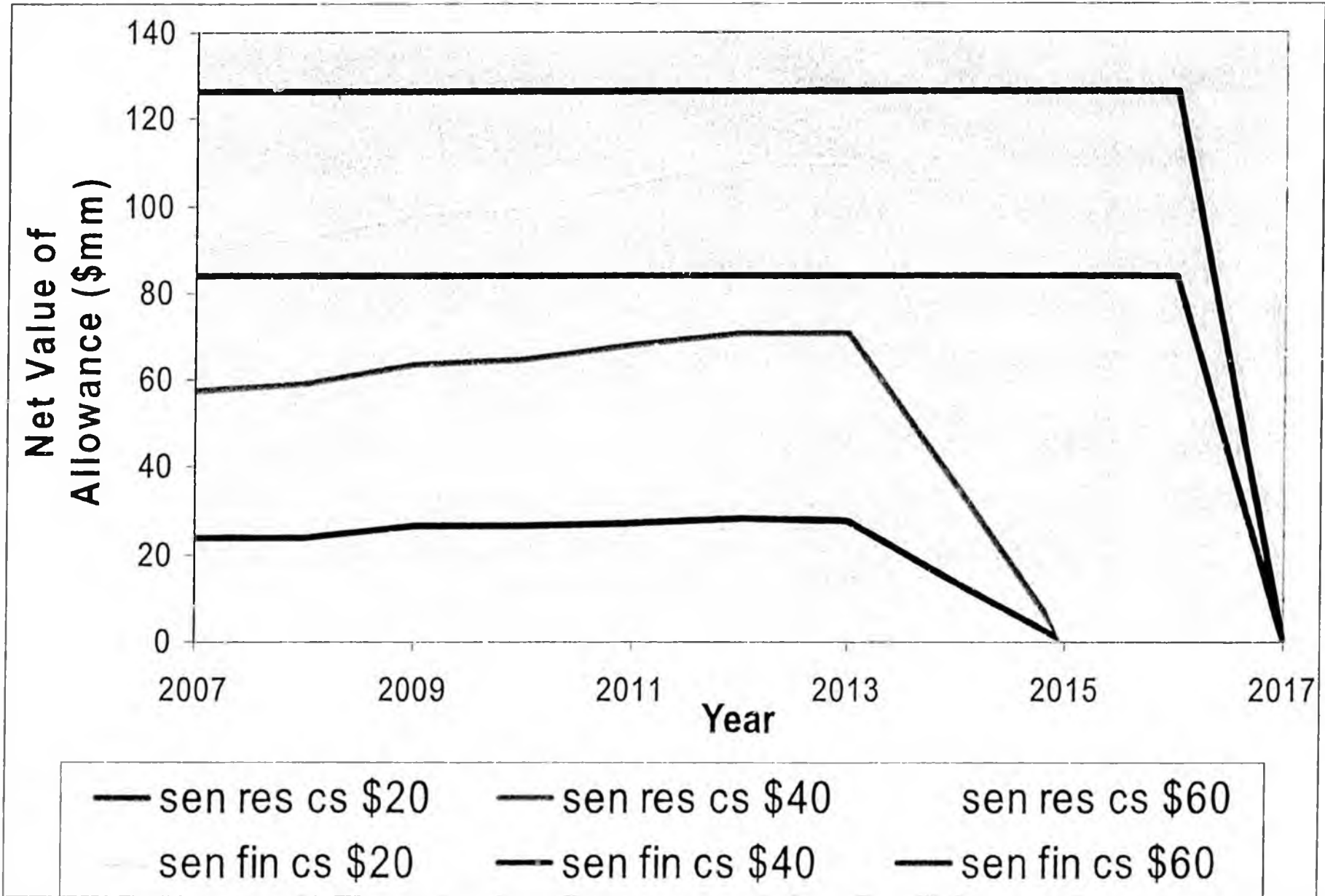
Per Barrel Progressivity Surcharge 2010



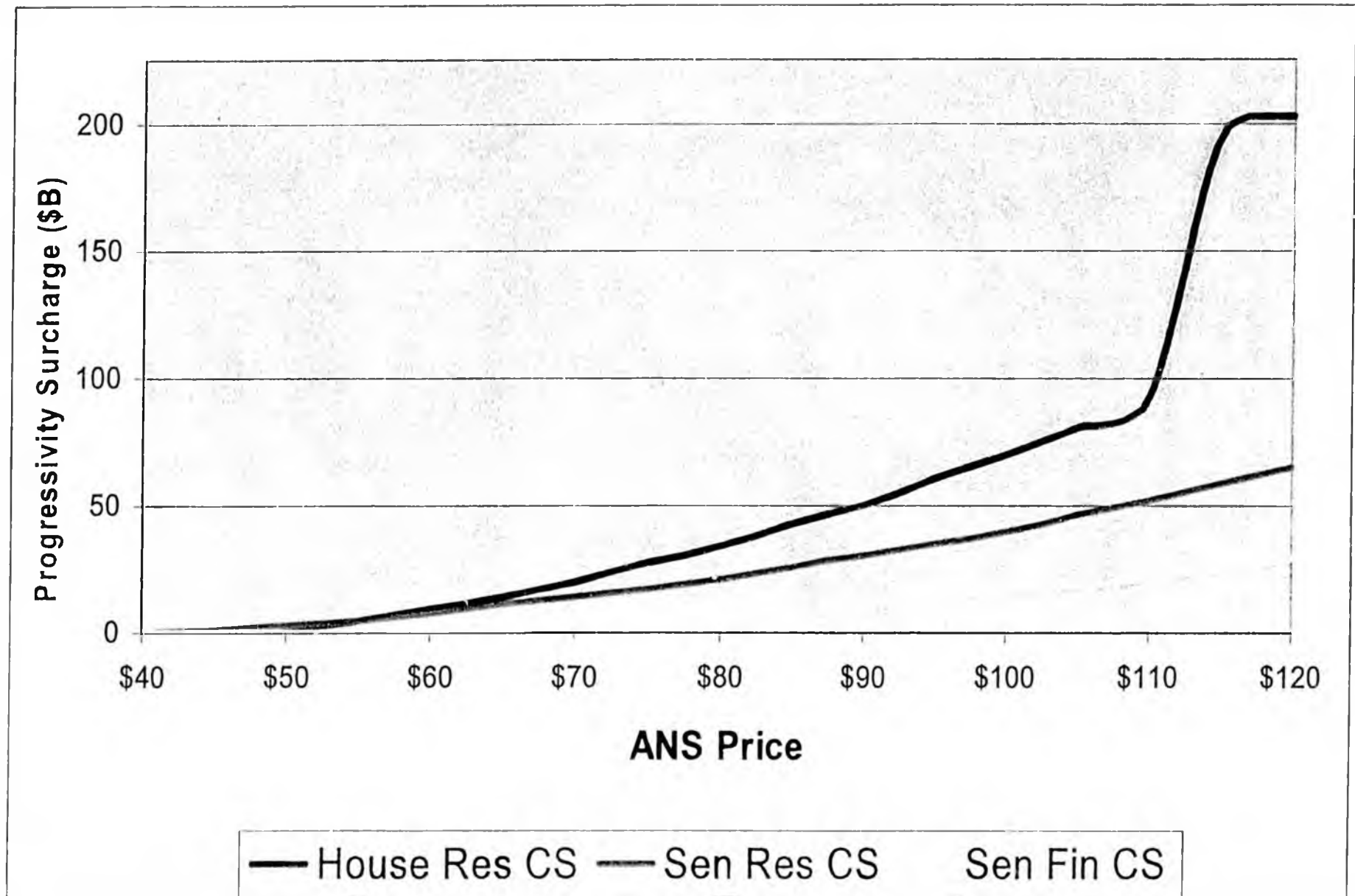
4/29/06

3:54:25 PM

Net Allowance Comparisons (\$millions)



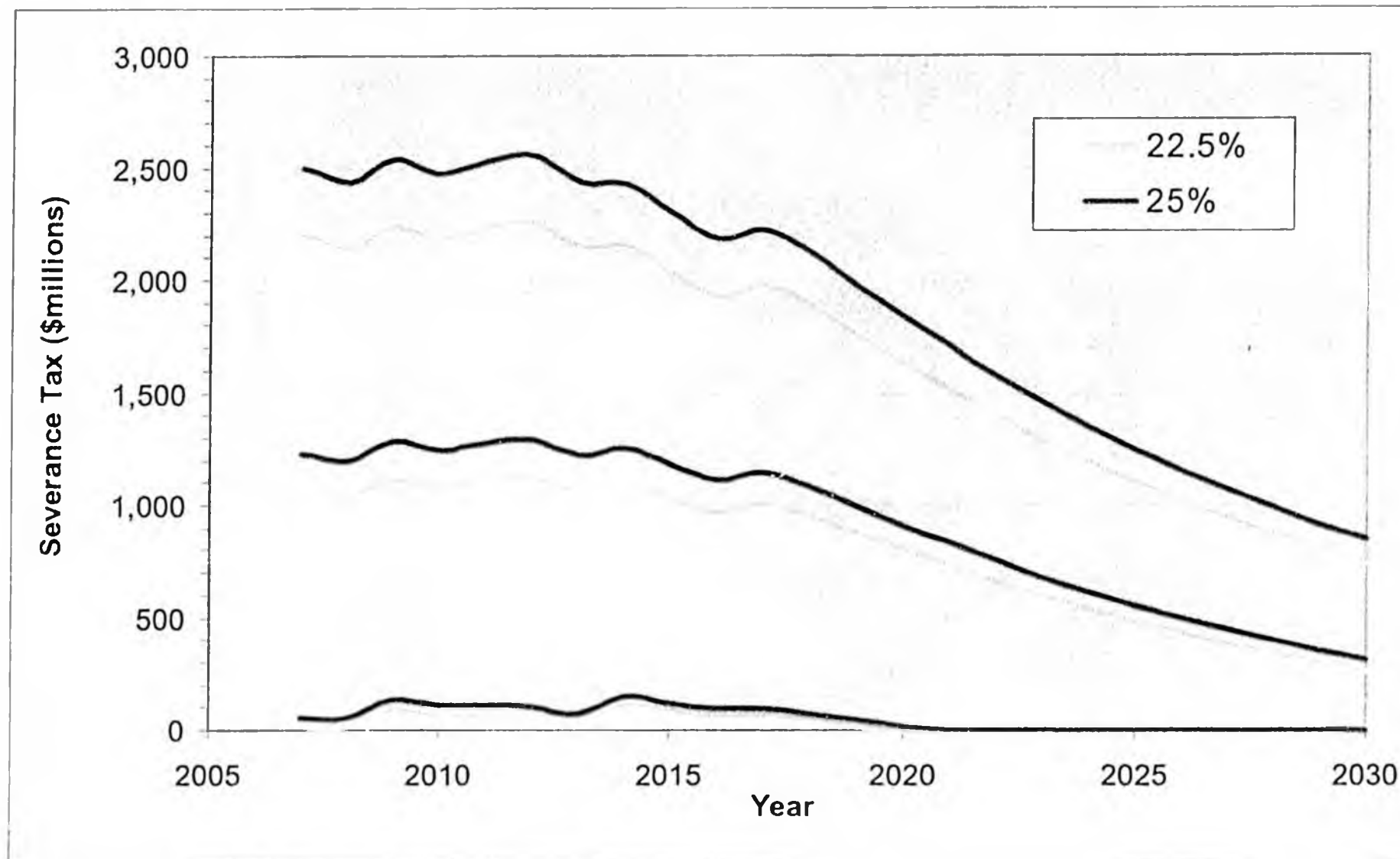
Total Progressivity Surcharges 2006-2030 (\$B)



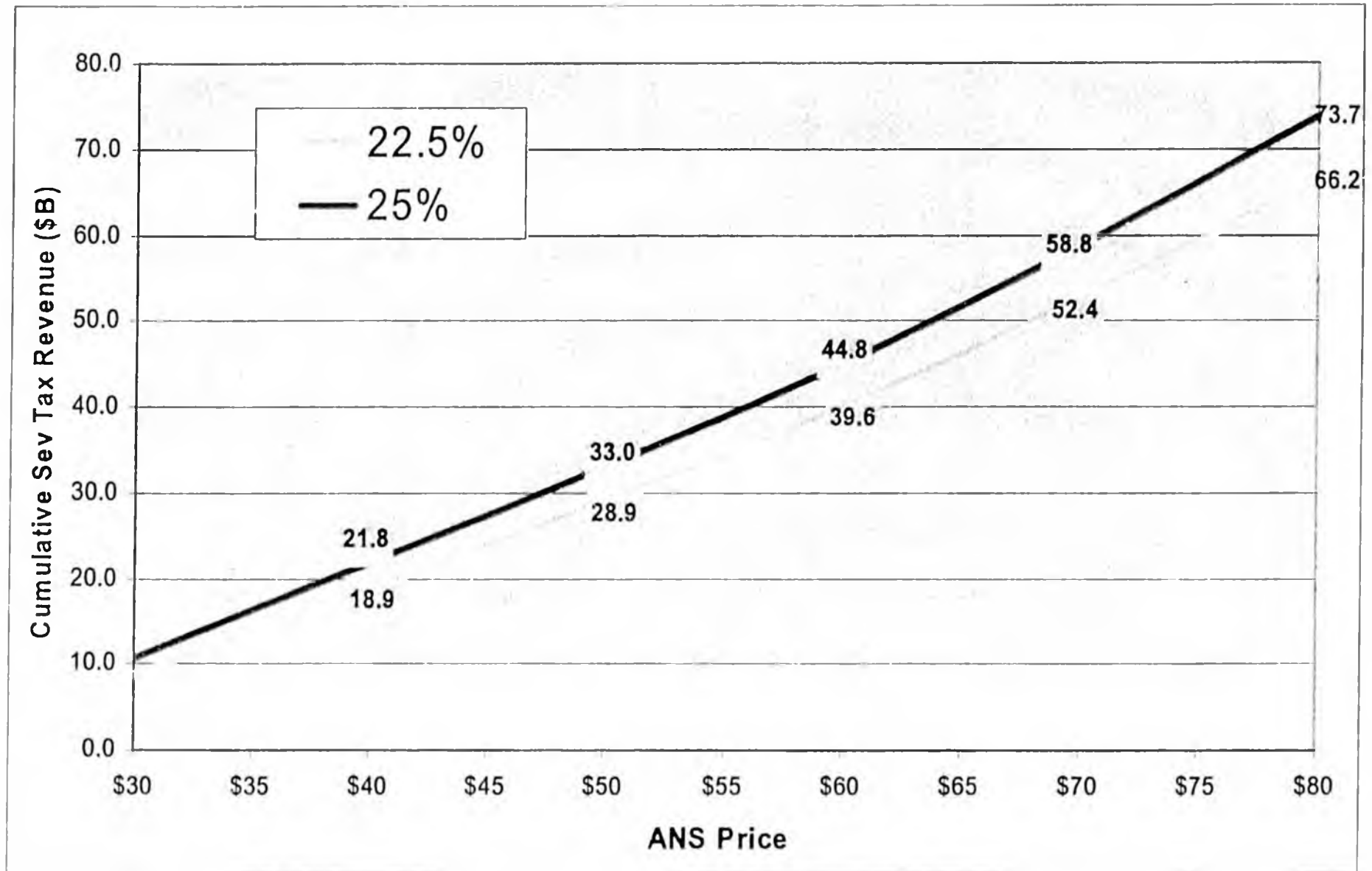
4/20/06

3:54:44 Pm

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



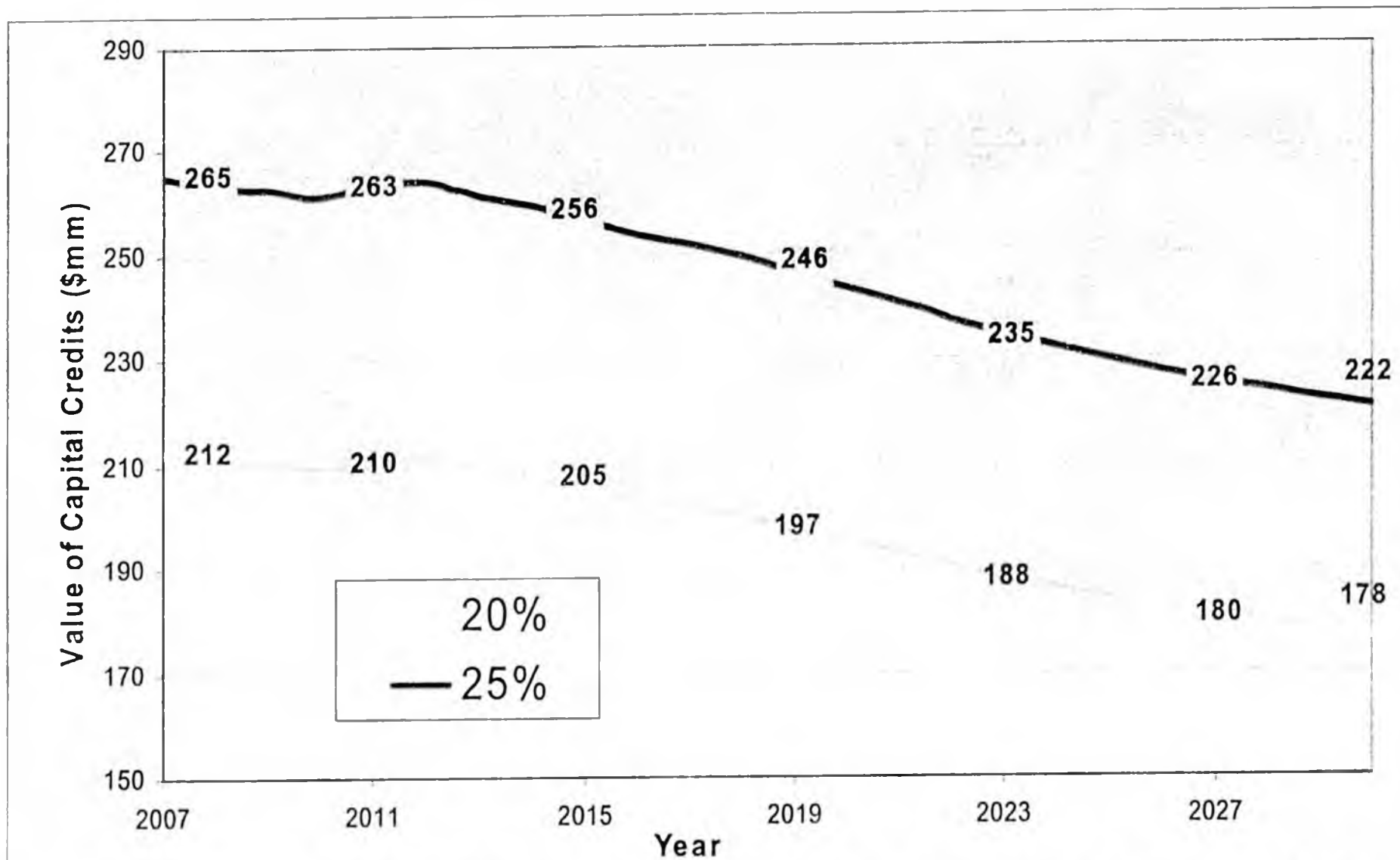
Cumulative Severance Tax Revenue, Senate Finance CS, with Tax Rates of 22.5% and 25%, 2007-2030 (\$B), Low Volume



4/20/06

4:06:22 pm

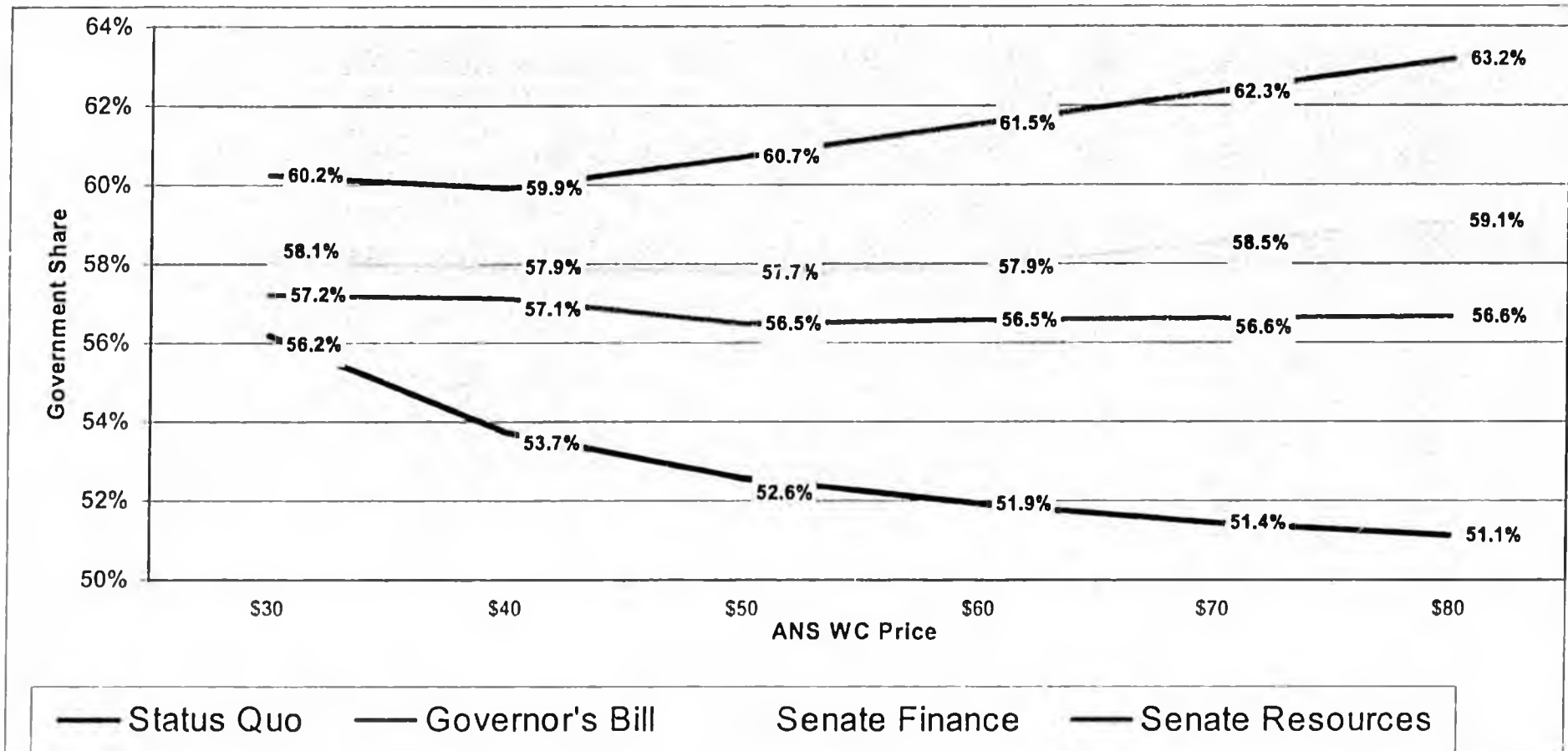
Value of Credits against Capital Expenditures Under Senate Finance CS, at 20% and 25% Credit Rates, 2007-2030, Low Volume



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%



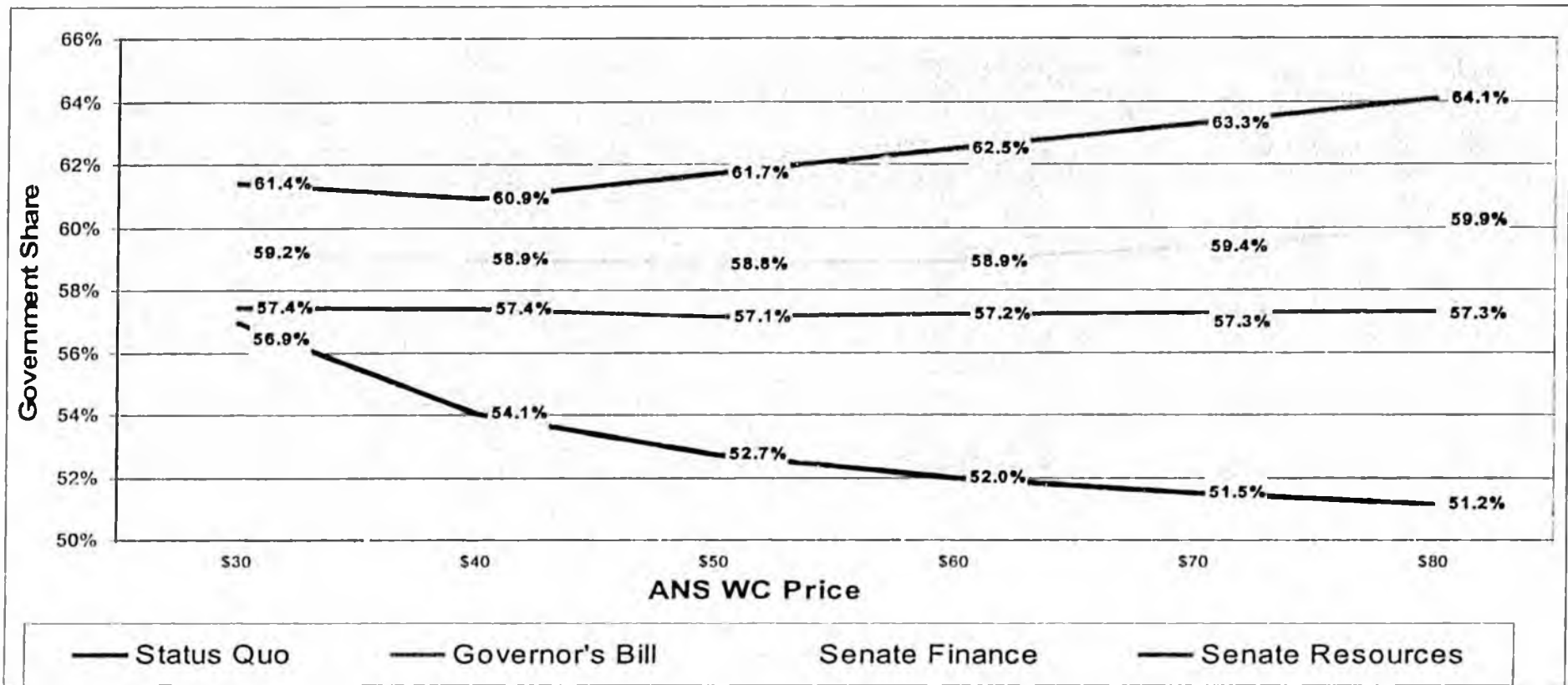
*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; It is not deductible for Finance CS.

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%



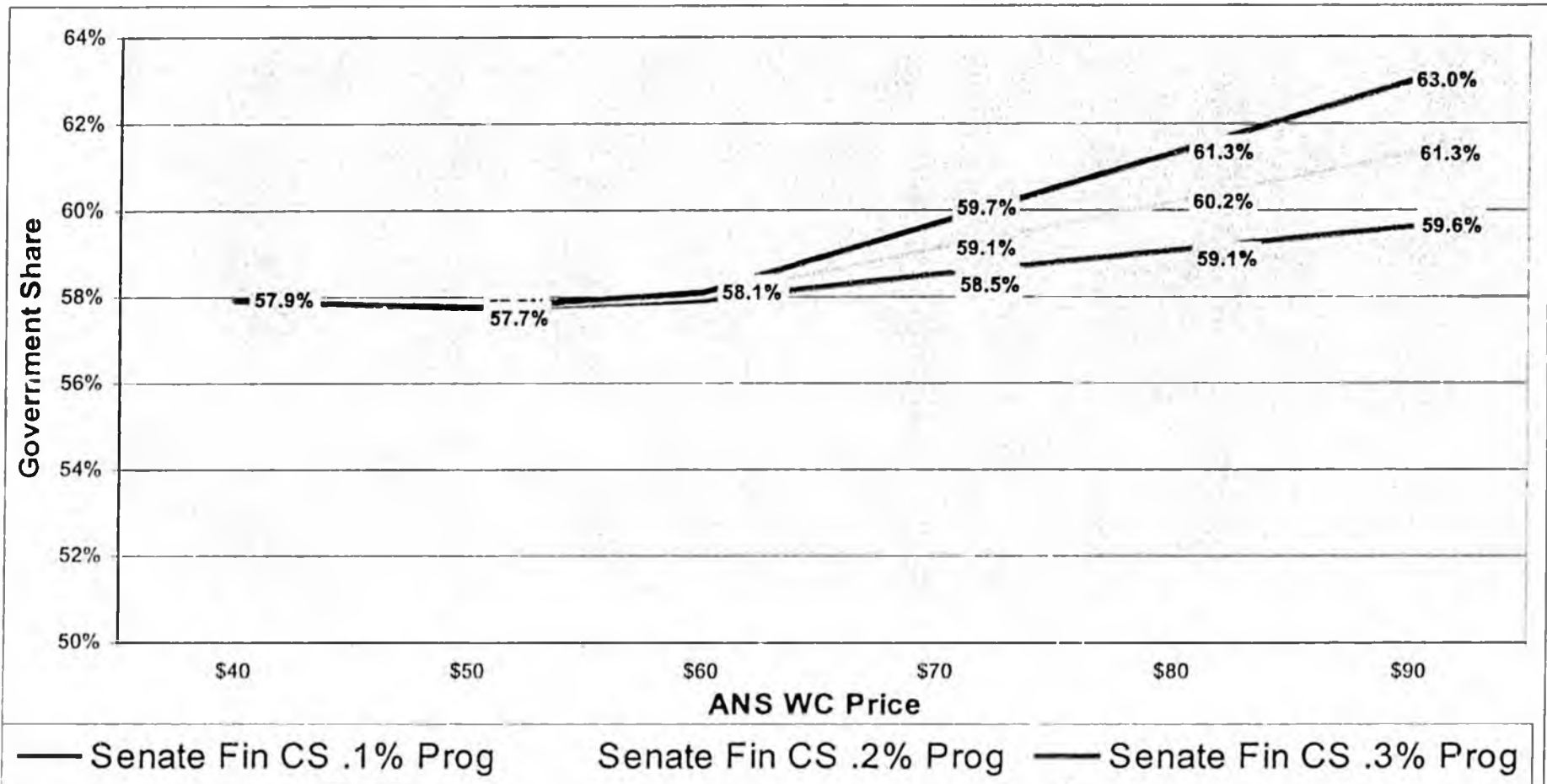
*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Finance CS.

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

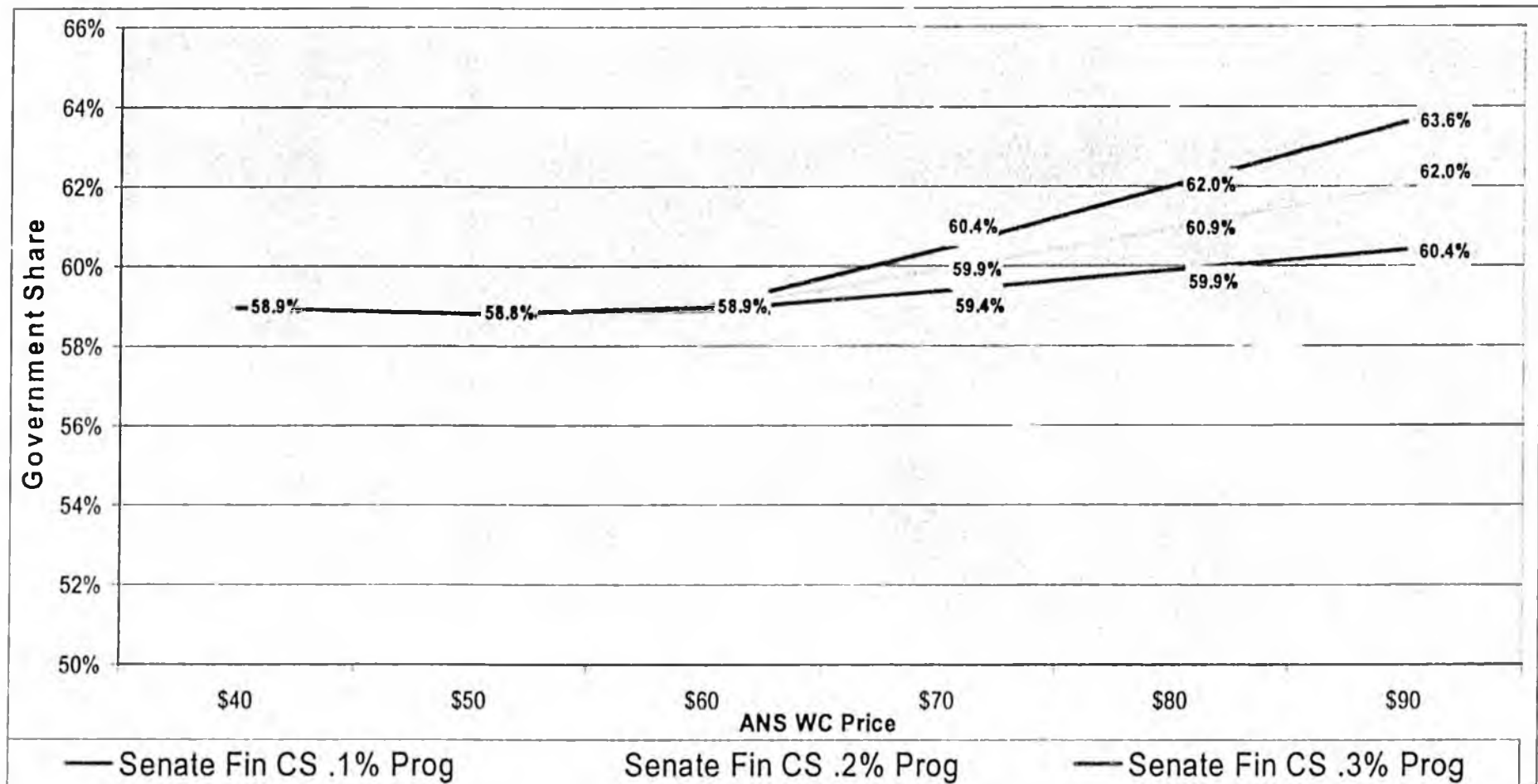
ANS WC \$/bbl	Senate Fin CS .1% Prog	Senate Fin CS .2% Prog	Senate Fin CS .3% Prog
\$40	57.9%	57.9%	57.9%
\$50	57.7%	57.7%	57.7%
\$60	57.9%	58.0%	58.1%
\$70	58.5%	59.1%	59.7%
\$80	59.1%	60.2%	61.3%
\$90	59.6%	61.3%	63.0%



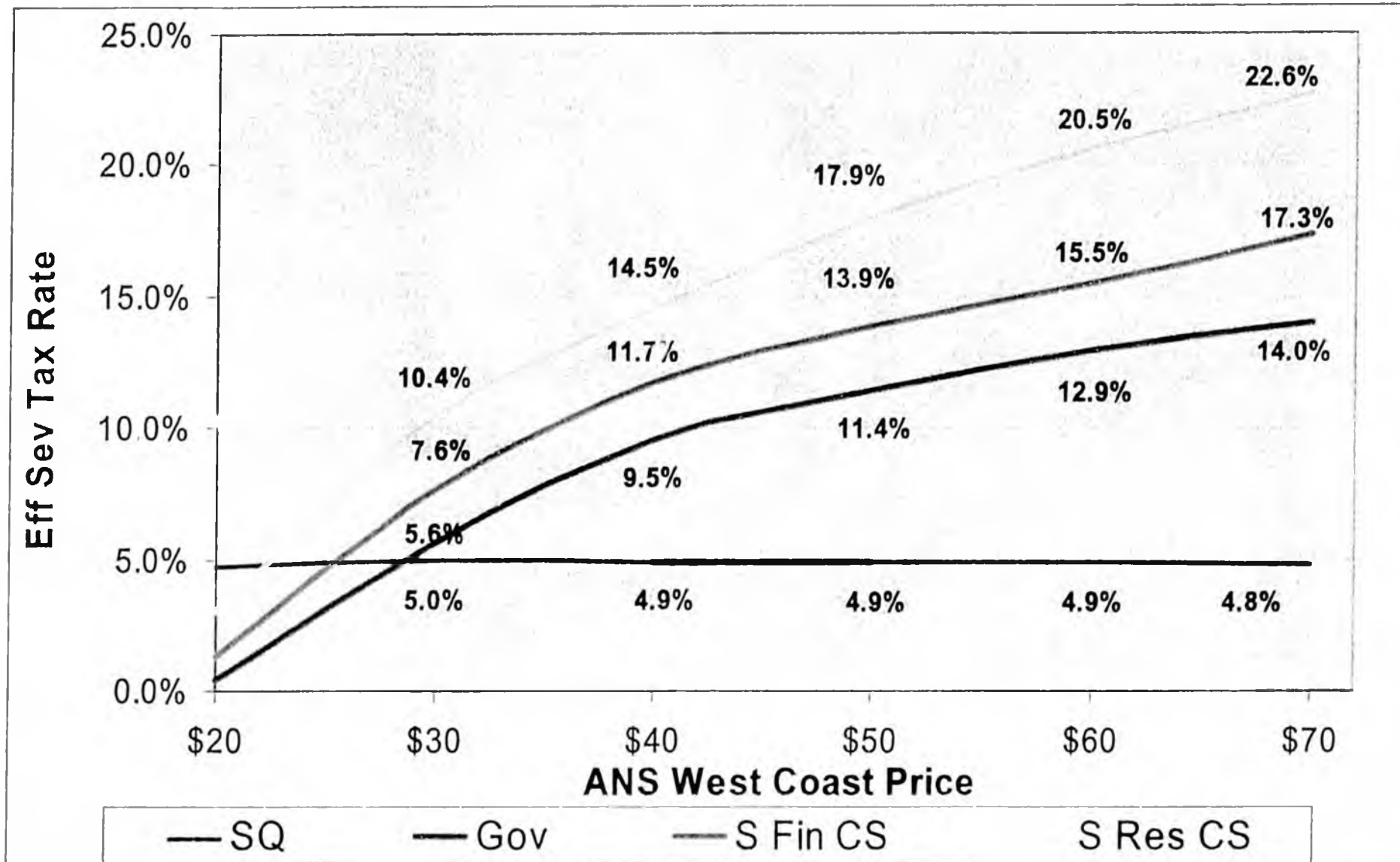
4/20/06 4:00:24 pm
 B. B. 4:49 pm

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%

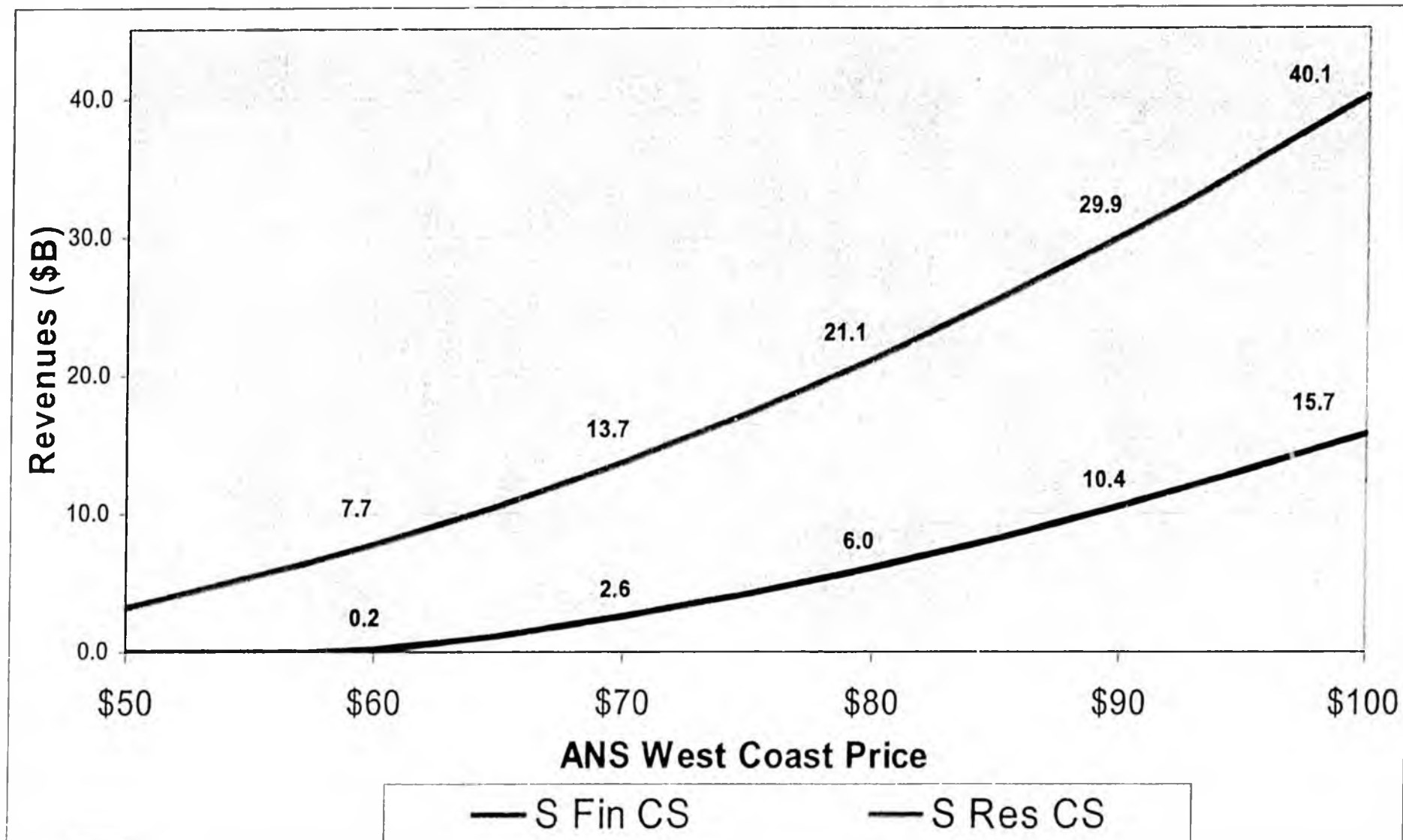


Effective Severance Tax Rate Sev Tax / Wellhead (less royalty) Low Volume Scenario

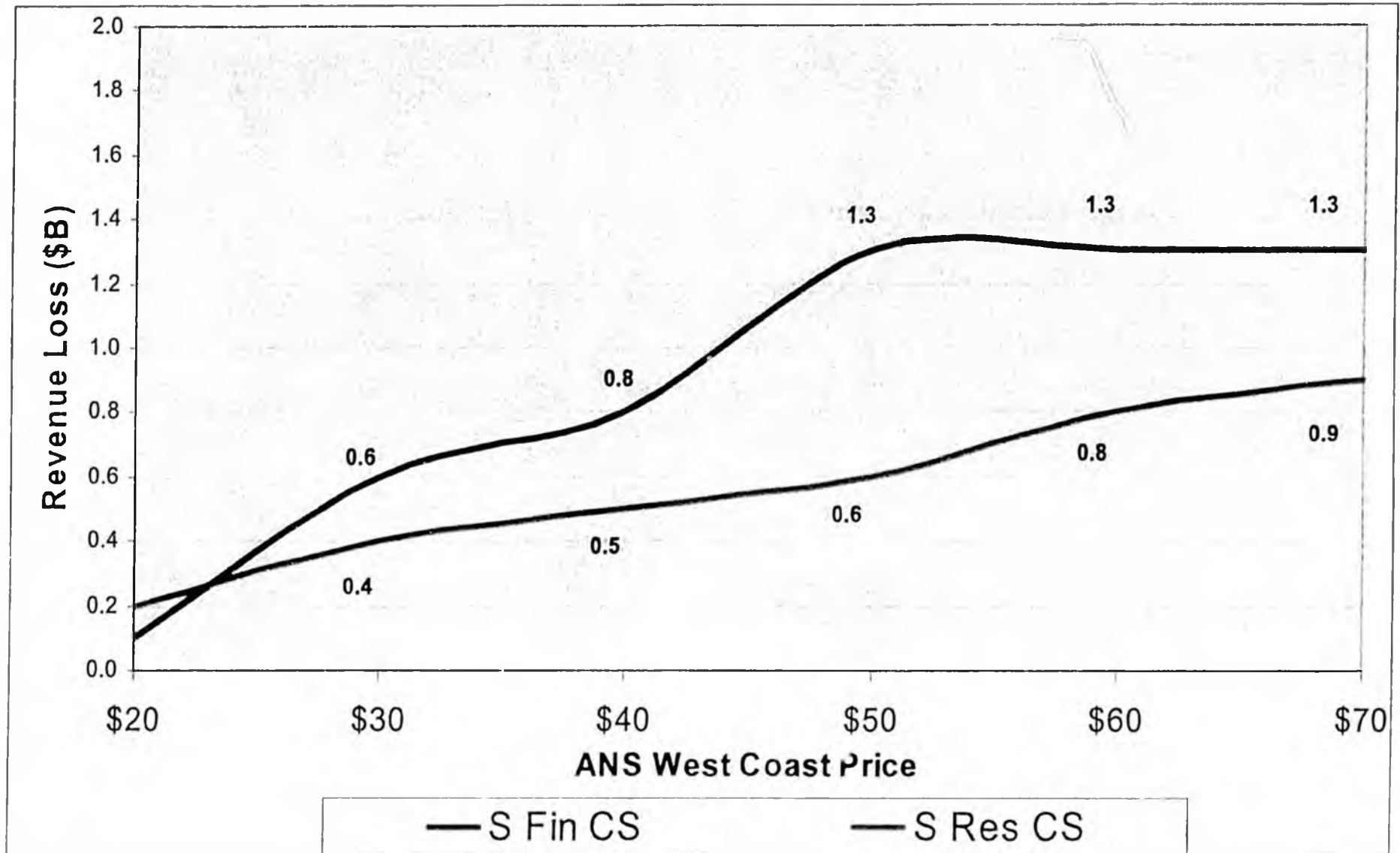


4/20/06 4:20:19 pm

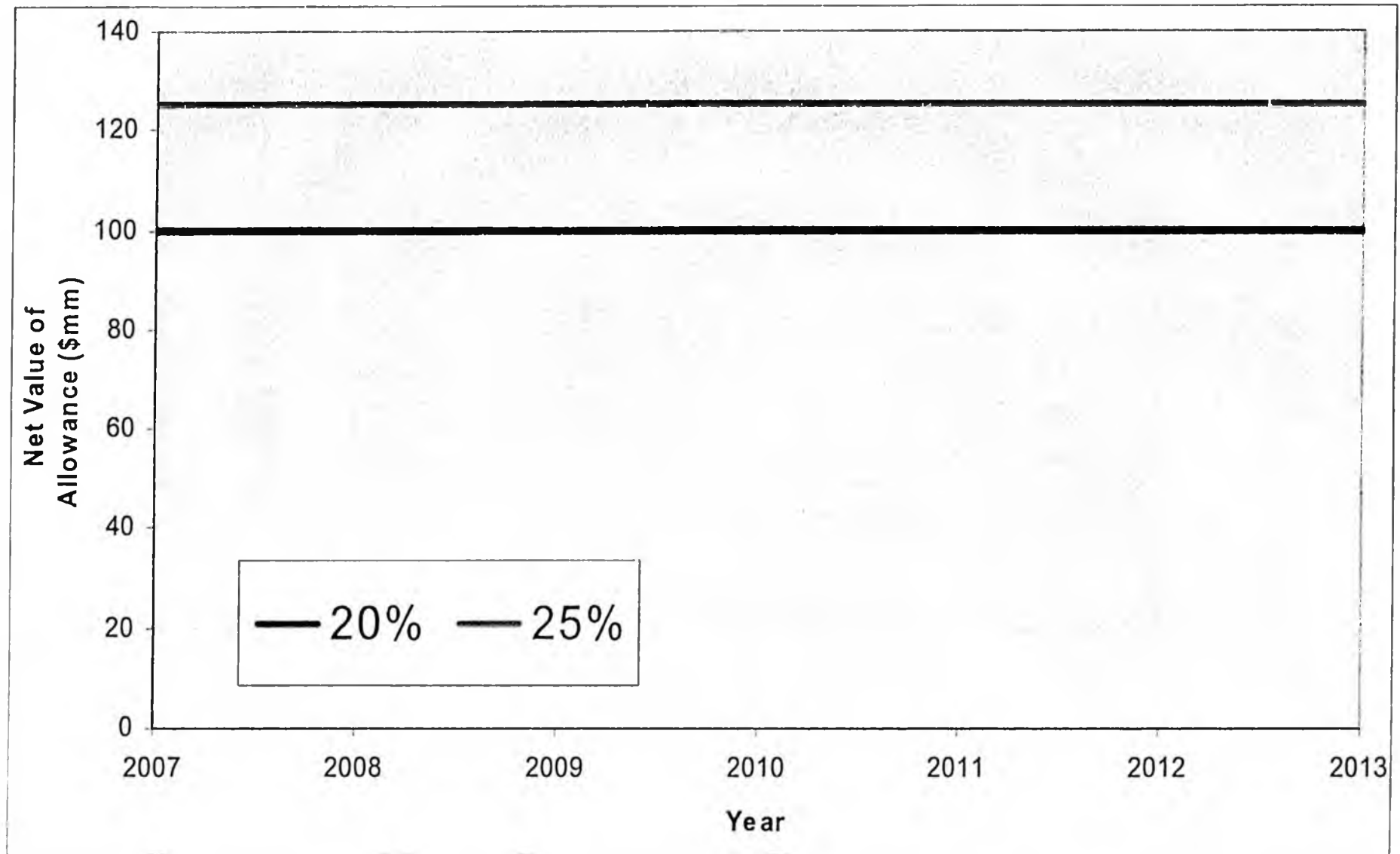
Cumulative Revenues Attributable to Progressivity Sen Fin CS and Sen Res CS, 2007-2030 Low Volume Scenario



Cumulative Revenue Loss Attributable to 5000 Bbl Mechanism Sen Fin CS and Sen Res CS, 2007-2030 Low Volume Scenario

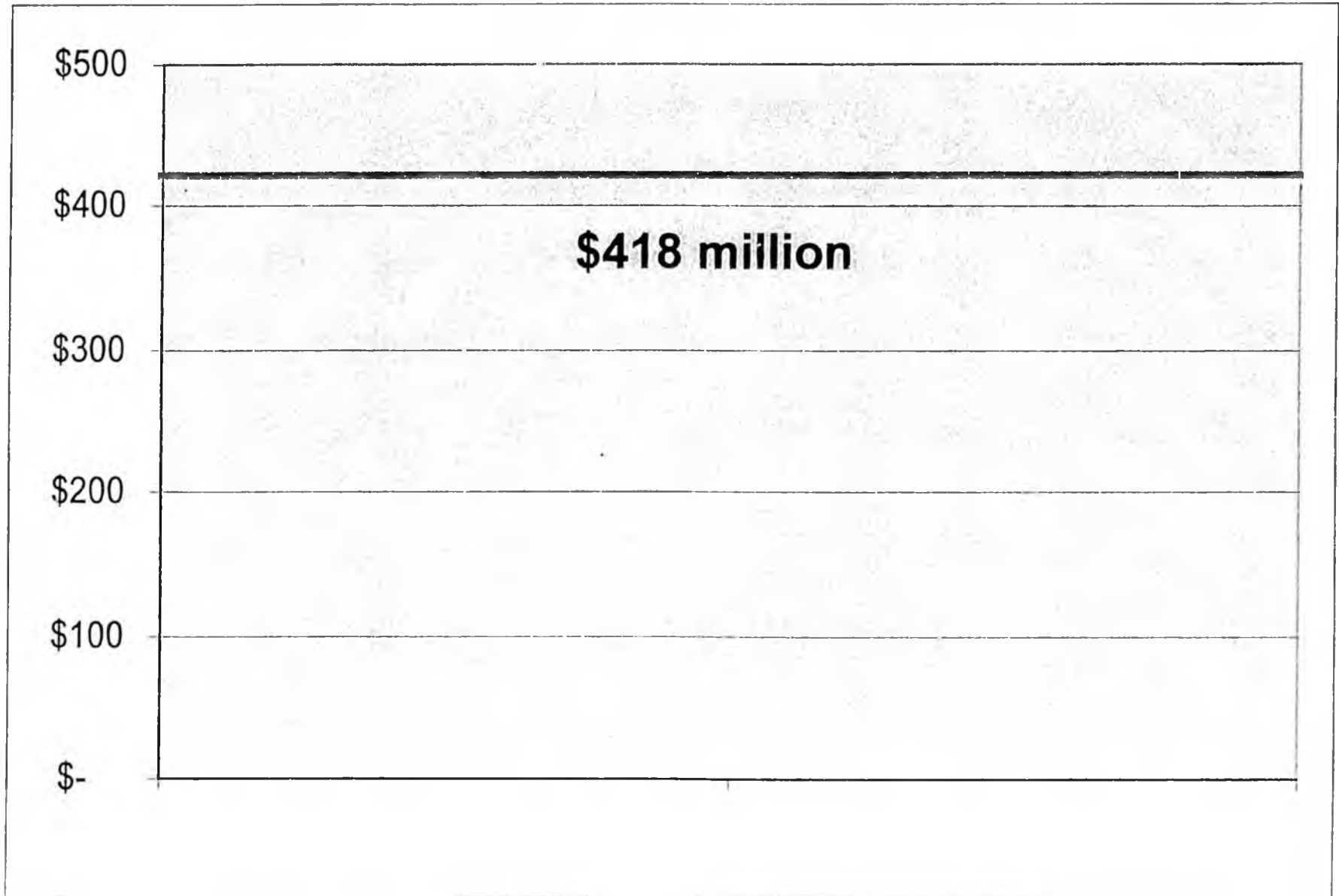


Senate Finance CS Transition at 20% and 25%, Annual Revenue Loss, 2007-2013



4/20/06 4:23:40pm

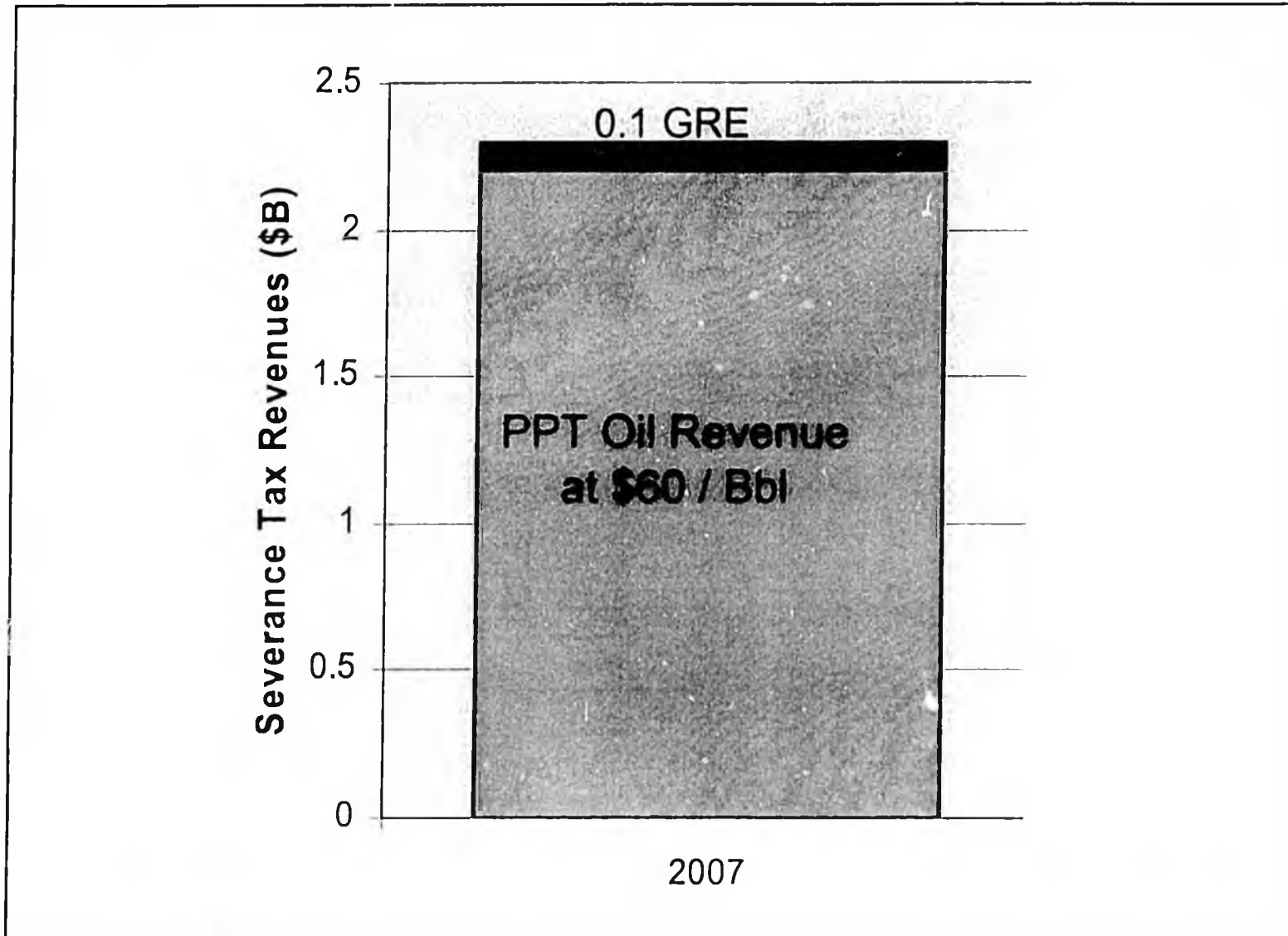
Effective Date Change From 04/01/2006 to 07/01/2006
at \$60 per Barrel Oil



4/21/06 11:21 AM

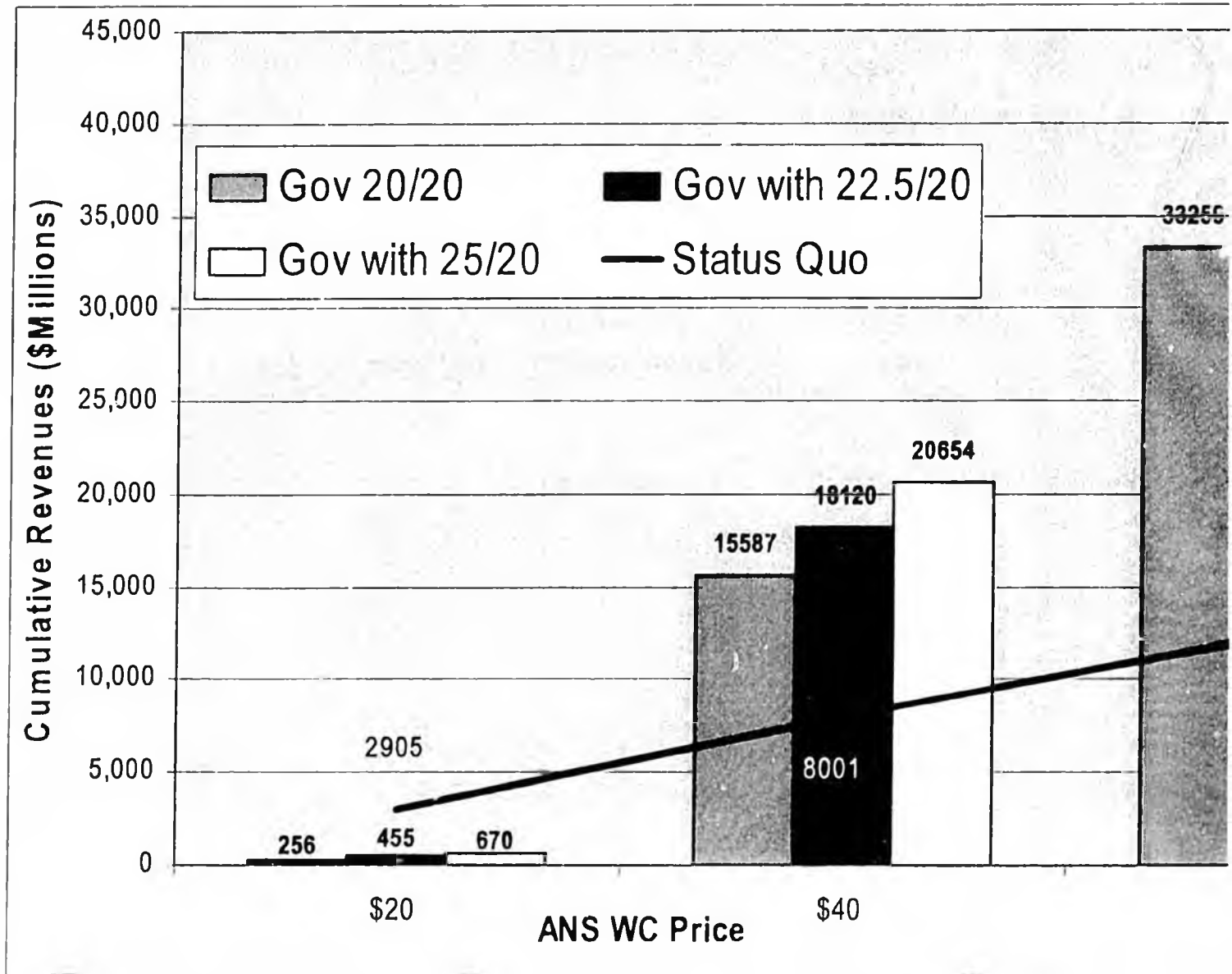
4/20/06 4:25:45 pm

PPT and GRE Revenue in FY 2007
at \$60 per Barrel Oil

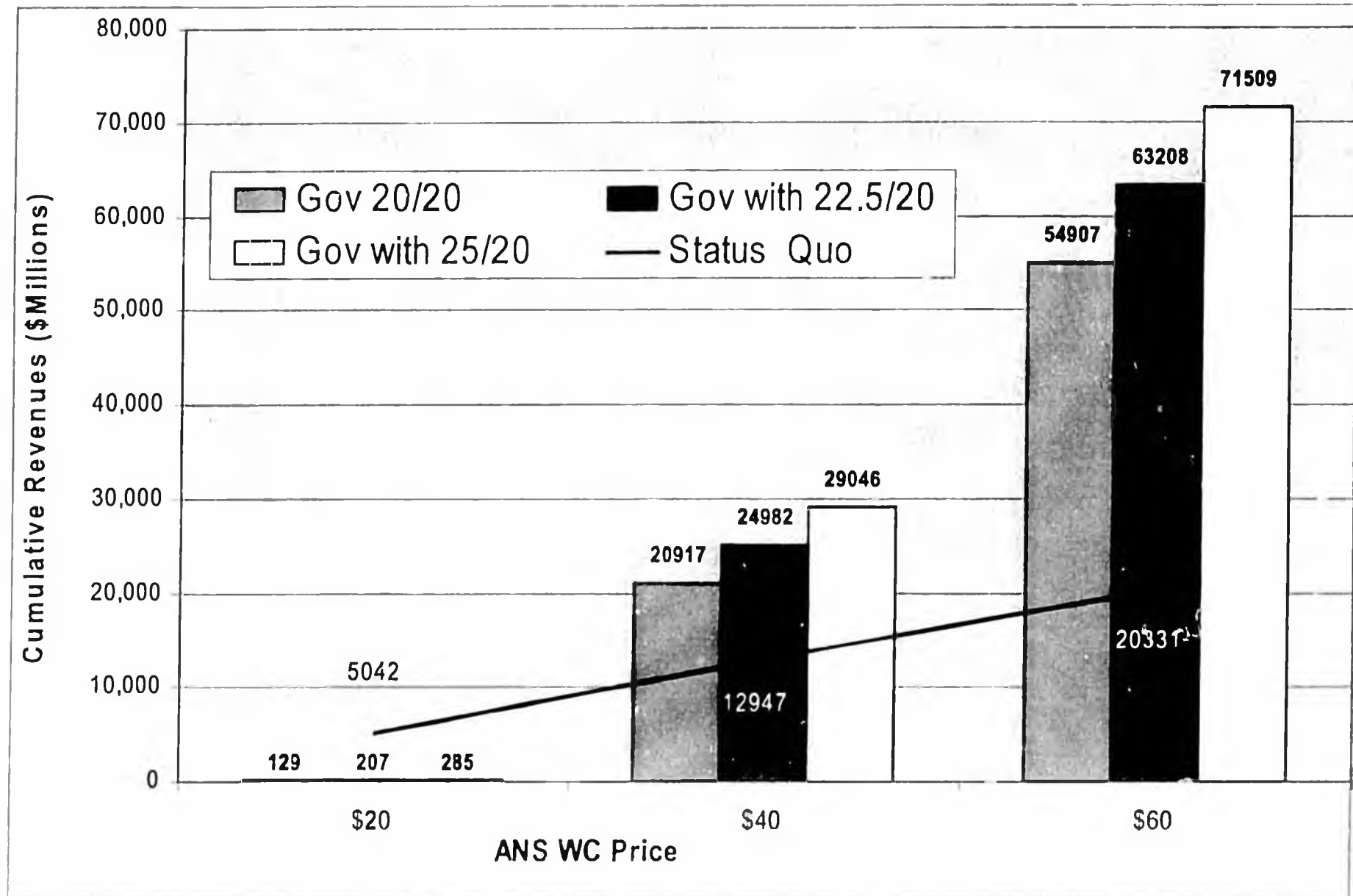


4/20/06 4:26:23pm

Cumulative Severance Tax Revenues under Governor's Bill with 22.5/20, and with 25/20, Low Volume Scenario 2000



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 a stylized black triangle above the word "ConocoPhillips" in a bold, sans-serif font.

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.

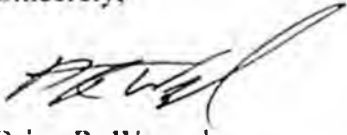
Consistent with our prior testimony, ConocoPhillips' view is that even with the 5% increase in the tax credit rate, the total production tax system proposed in the current Senate Finance CS will not deliver the increases in investment or resource development that you are seeking. While it might initially 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 "B. Wenzel", 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.

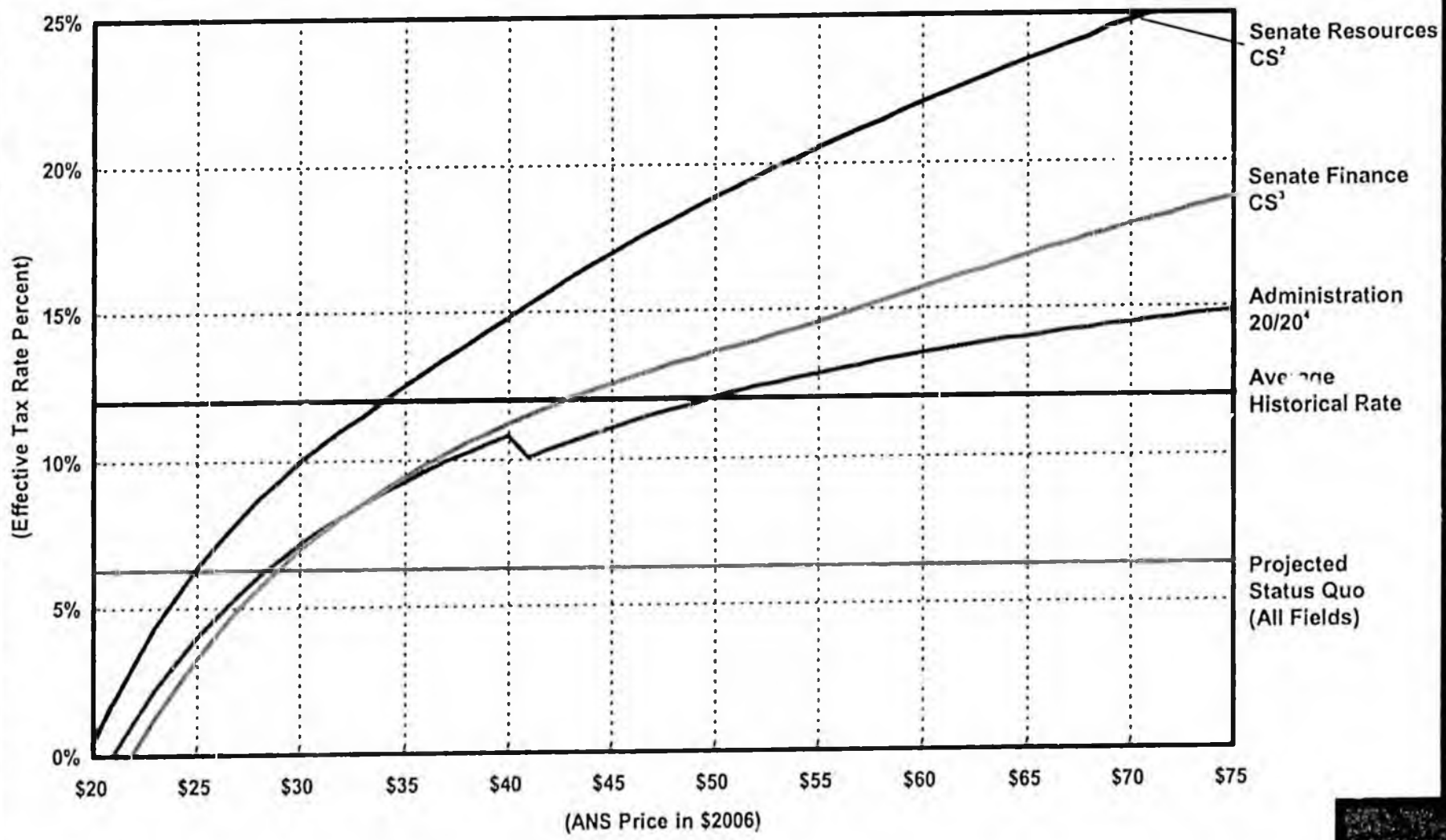
Yours Sincerely,

Angus J. Walker



Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)



Assumes no major gas sale.
 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.
 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.
 Calculated from July 2006; includes 5-year transition (100% 2007-2011) and \$73 billion assumption over 7 years; 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.

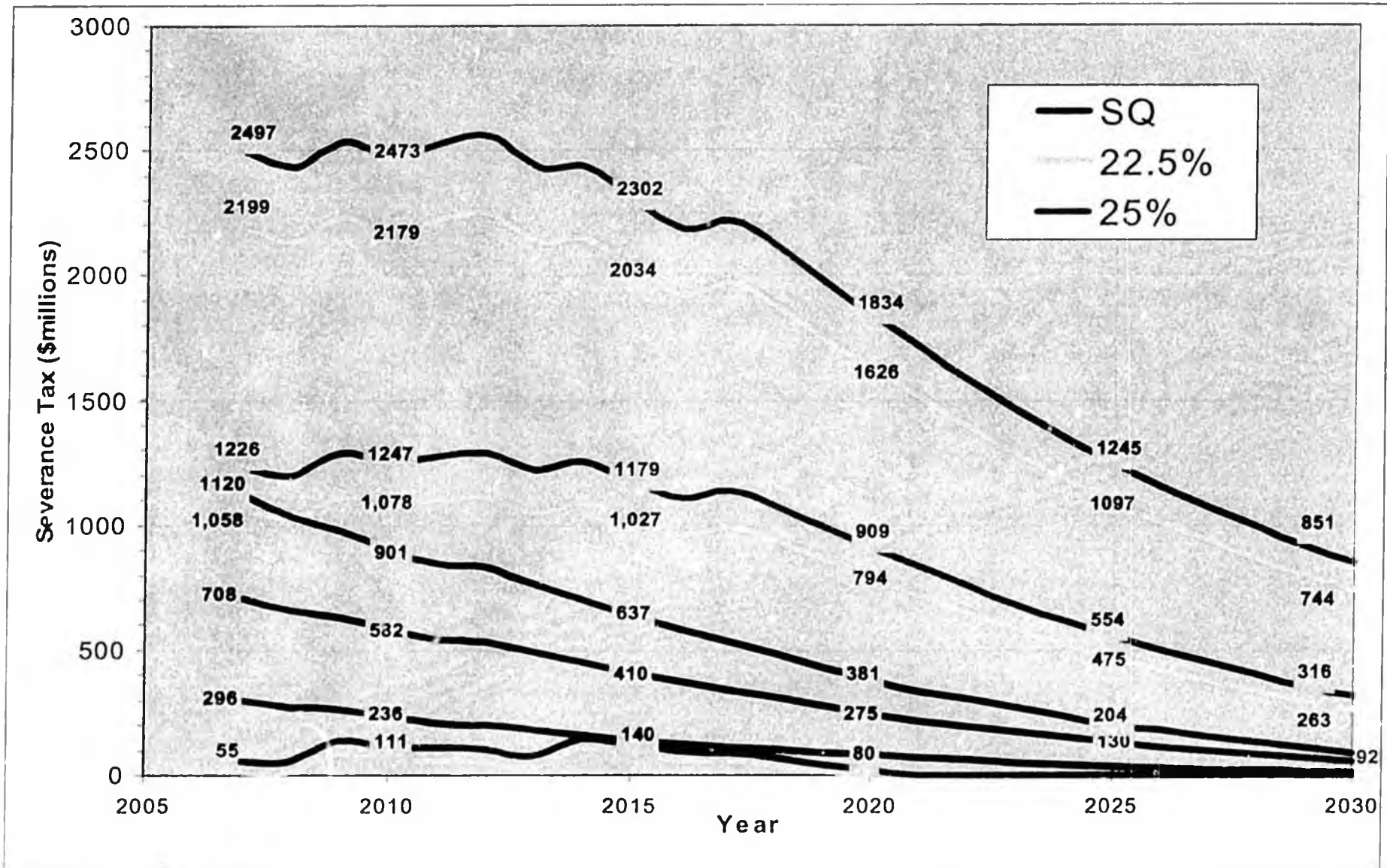


PPT Revenue Studies

Senate Finance Committee

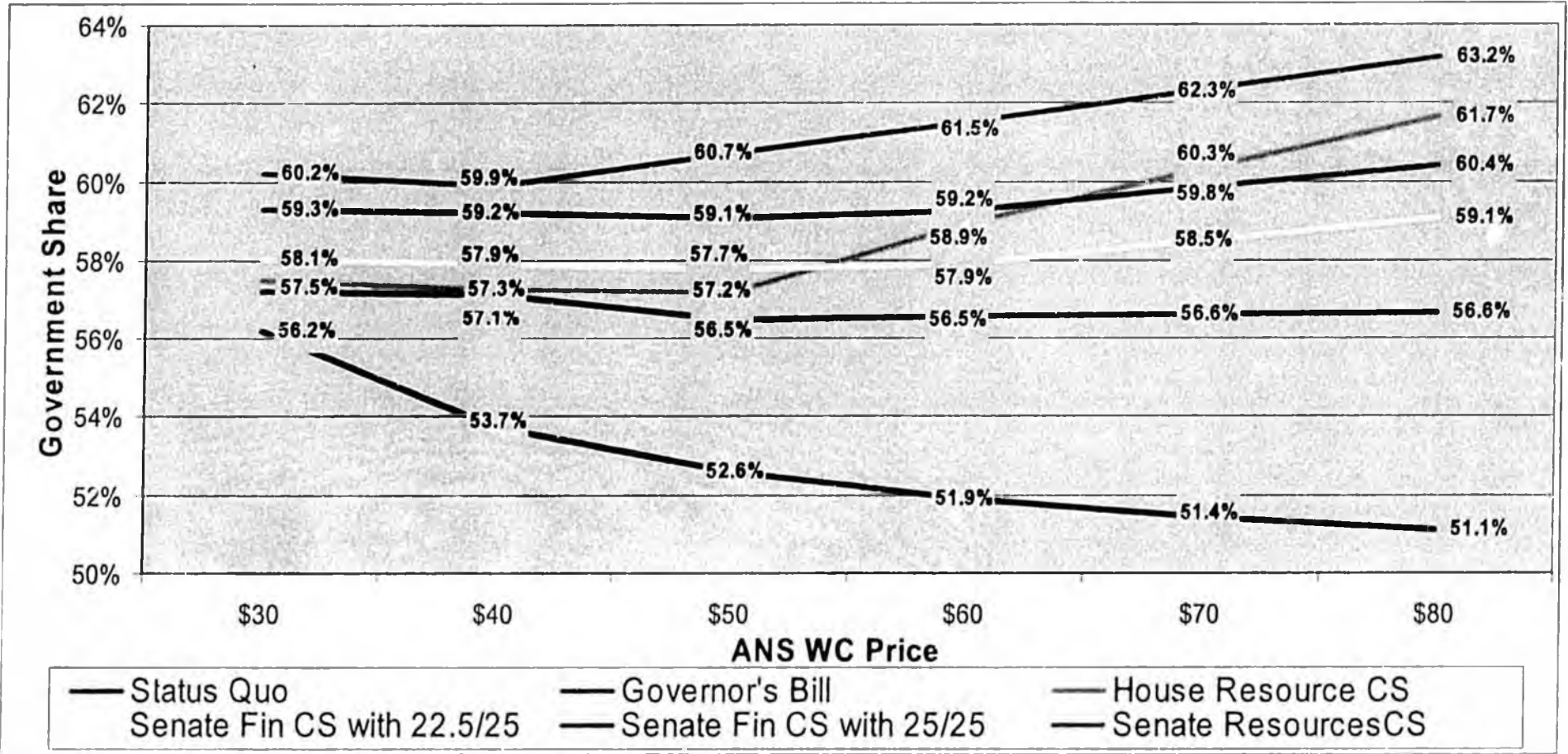
April 21, 2006

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%

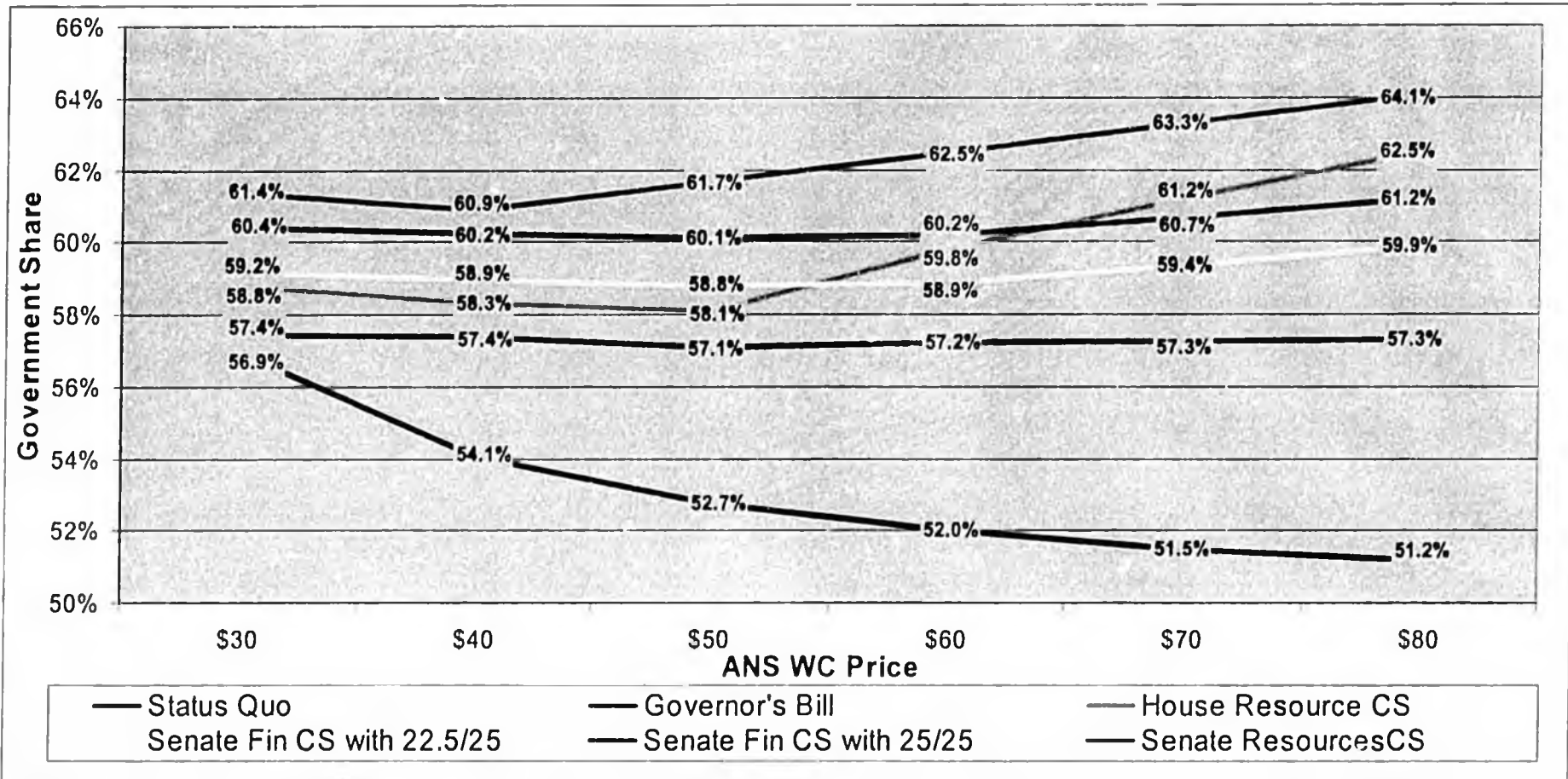


*Assumes the Progressive tax is deductible only once from the PPT calculation for Resources CS; it is not deductible for Finance CS.

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

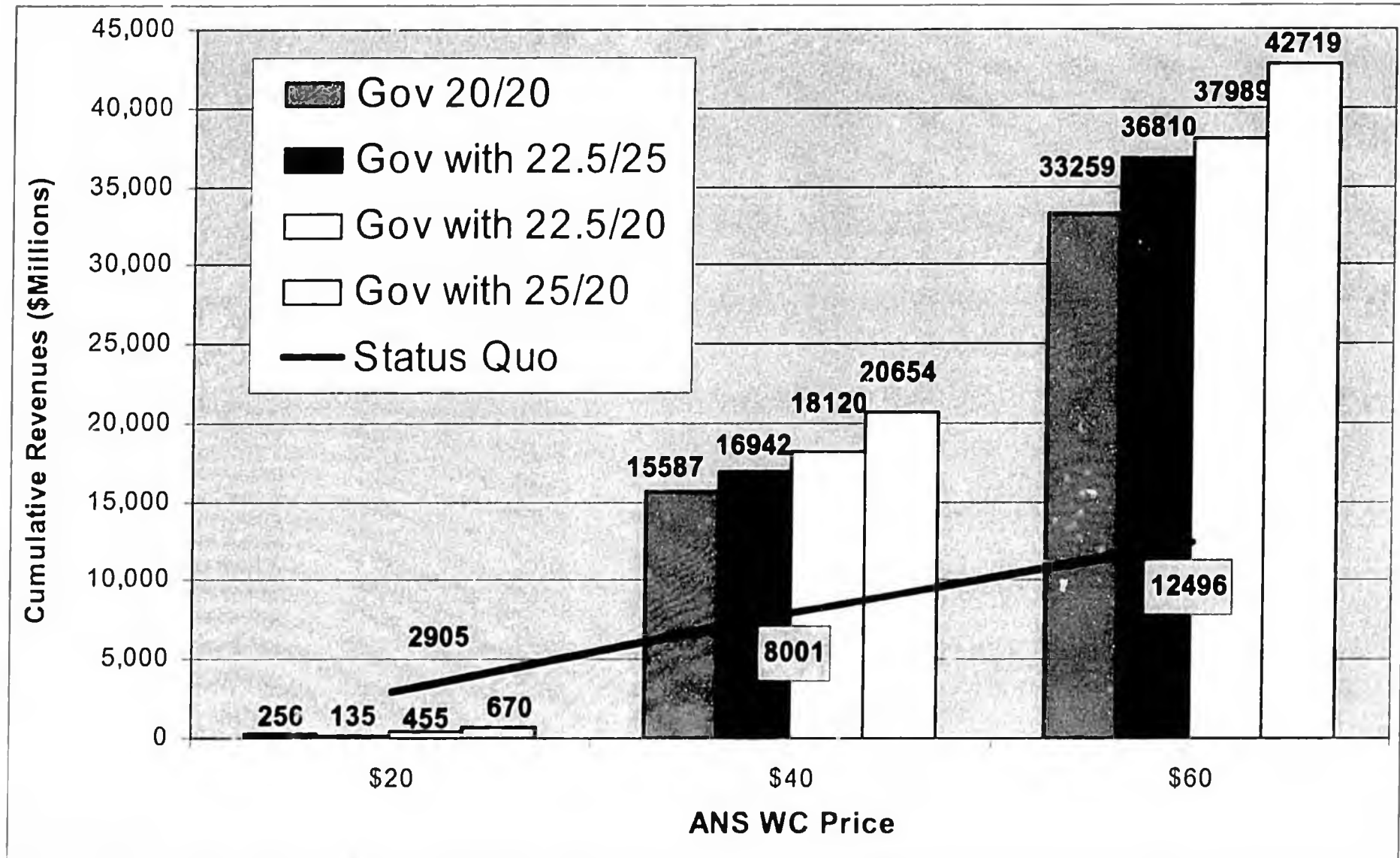
ANS WC \$/bbl	Status Quo	Governor's Bill	House Resource CS	Senate Fin CS with 22.5/25	Senate Fin CS with 25/25	Senate ResourcesCS
\$30	56.9%	57.4%	58.8%	59.2%	60.4%	61.4%
\$40	54.1%	57.4%	58.3%	58.9%	60.2%	60.9%
\$50	52.7%	57.1%	58.1%	58.8%	60.1%	61.7%
\$60	52.0%	57.2%	59.8%	58.9%	60.2%	62.5%
\$70	51.5%	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

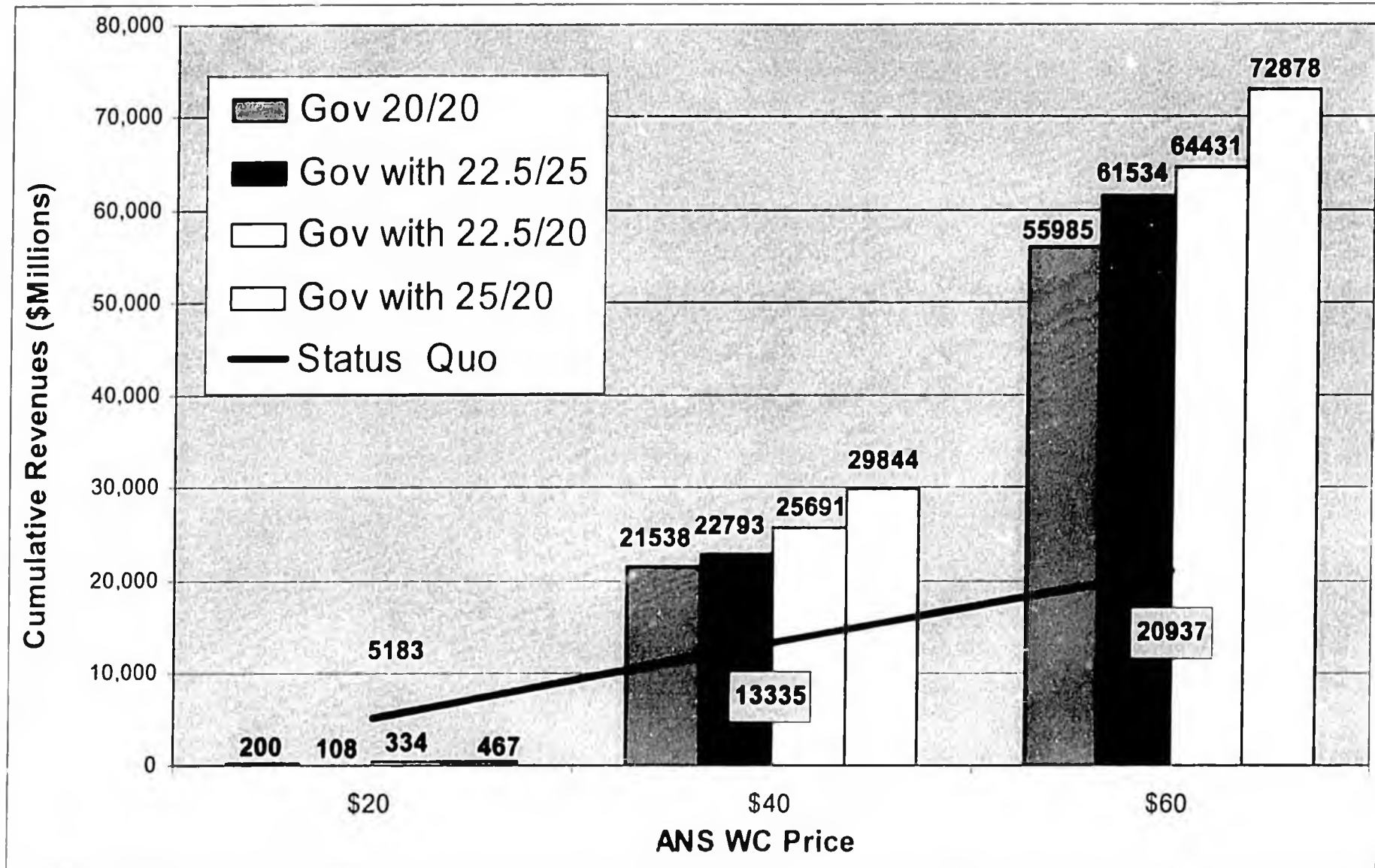
Cumulative Severance Tax Revenues under Governor's Bill as Written, and with 22.5/25, 22.5/20, and 25/20, Low Volume Scenario 2006-2030



4/21/06

11:10 AM

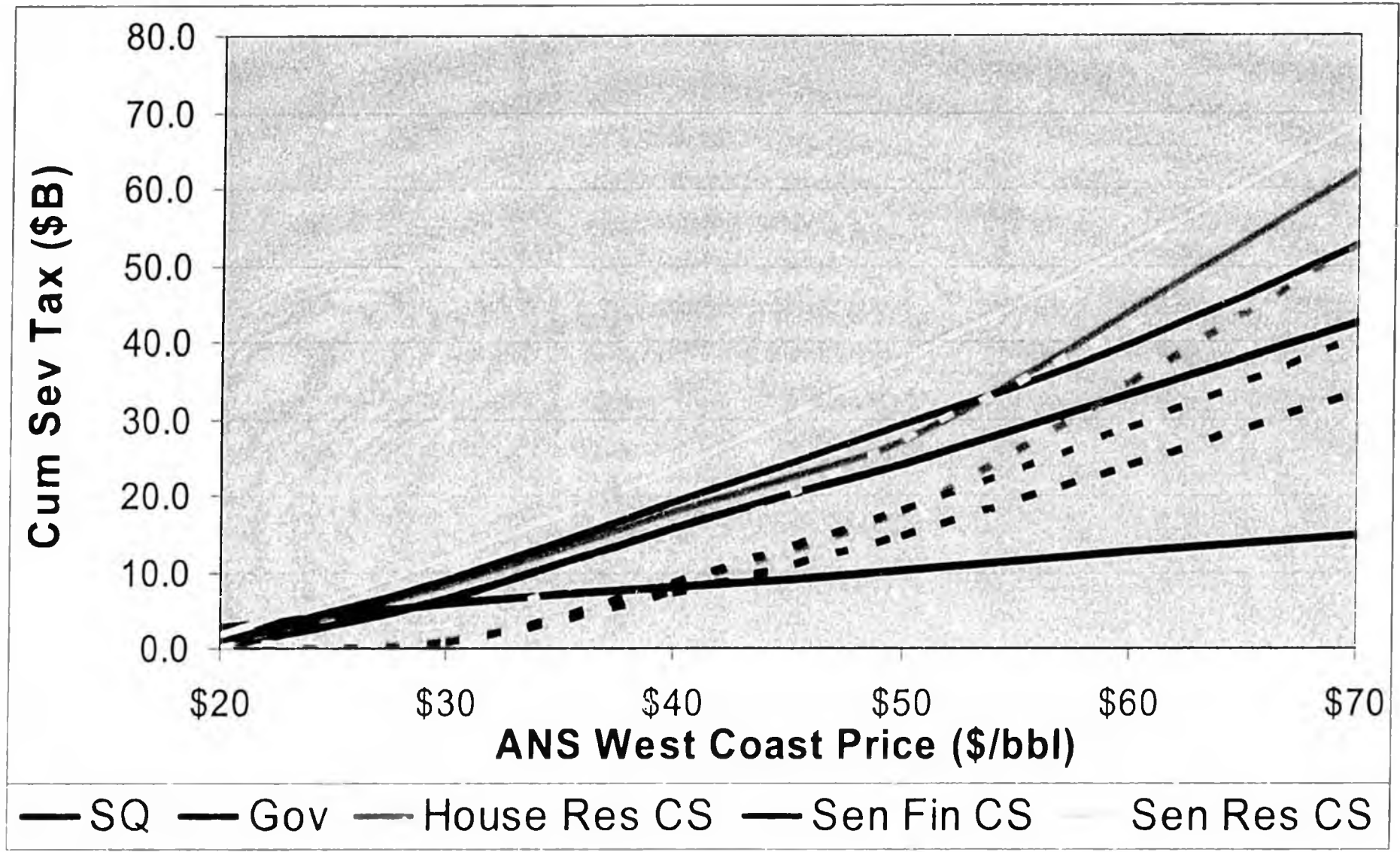
Cumulative Severance Tax Revenues under Governor's Bill as Written, with 22.5/20, and with 25/20, High Volume Scenario 2006-2050



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
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