

ALASKA LEGISLATURE

HOUSE and SENATE FINANCE COMMITTEE FILES, 2005-2006 3088

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

DRAFT 5/4/06 4:00pm.

5/4/2006

source: DOR

	governor's bill	House Resources CS Version L	SENATE (page refs = S. Fin. CS)	House Finance CS Version
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. 37(g)--pages 31-32	6 mos. pymt on old system; true-up in 7th mo. Sec. 36(h)--page 34
spill surcharge total spill surcharge split (.201/.300) spill surcharge payable	no change (5 cents) 2/3 no change	no change (5 cents) 1/4 increase 1 cent page 24-25	increase 1 cent, to 6 cents 1/5 increase 2 cent .201, .300 pages 27-28	no change (5 cents) 1/4 increase 1 cent pages 28-29
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 22	not creditable, not ded. .160(d)(2)(L)--page 23
SB 185 credit	no change	extends 10 years; only usable against PPT .025(b), .025(f)--page 11-12	extends 10 years; fixes \$20 m issue .025(b), .025(f)--page 12-14	extends 10 years; fixes \$20 m issue .025(b), .025(f)--pages 13-14
abandonment	no provision	no credit .024(i)(2)--page 11	no deduction or credit for abandonment on old production .160(d)(2)(P) page 22	no deduction or credit for abandonment on old production (improved language) .160(d)(2)(P)--page 22
credits usable	against PPT only .024(a)--page 3	against PPT only .024(a)--page 8	against PPT only .024(a)--page 7	against PPT only .024(a)--page 7
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 9-10
credits refundable?	no	up to \$10M depends on investment .024(f)(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 22.5% .024(b)--page 8	yes, at 20% .024(b)--page 8-9
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)--pages 28-29	upstream of gas treatment upstream (definition added) .900(7)--page 29-30
DNR royalty value	yes .150(d)--page 11	yes .150(d)--page 17-18	no	yes .150(d)--page 19
IRC sec. 482 as a tool	no	no	yes (incl. §6662) .160(i)--page 24	yes (w/ §6662) <i>ITB</i> .160(i)--page 26 <i>note</i>
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) <i>removed</i>
DNR gets exploration Data			yes .024(a) page 8	yes .024(a)--page 7
020 (f) Sales Language			yes .020(f) page 7	yes .020(f)--page 7
NPSL regs after industry practice			yes .160(c)(1)(B) page 20	yes .160(c)(1)(B)--page 21

from 3/6/06

exploration credit

yes treatment redifined

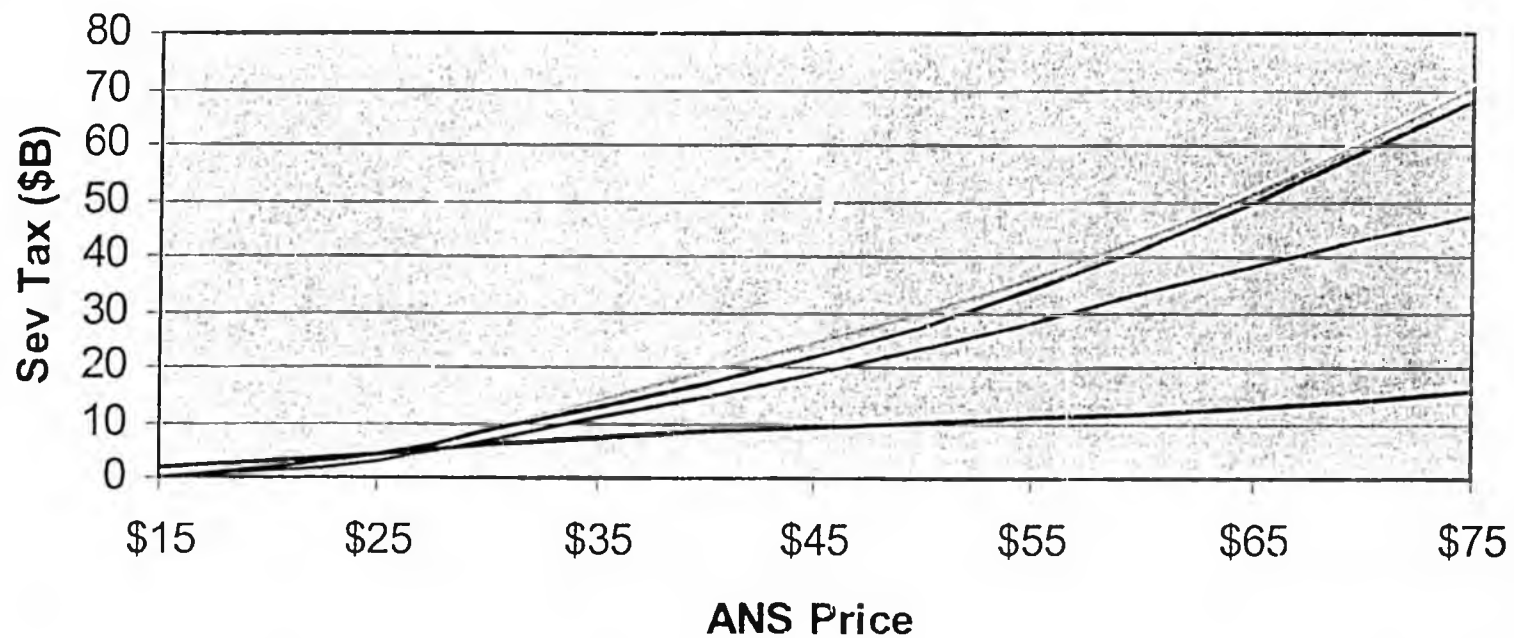
investing in local production

removed

clarified

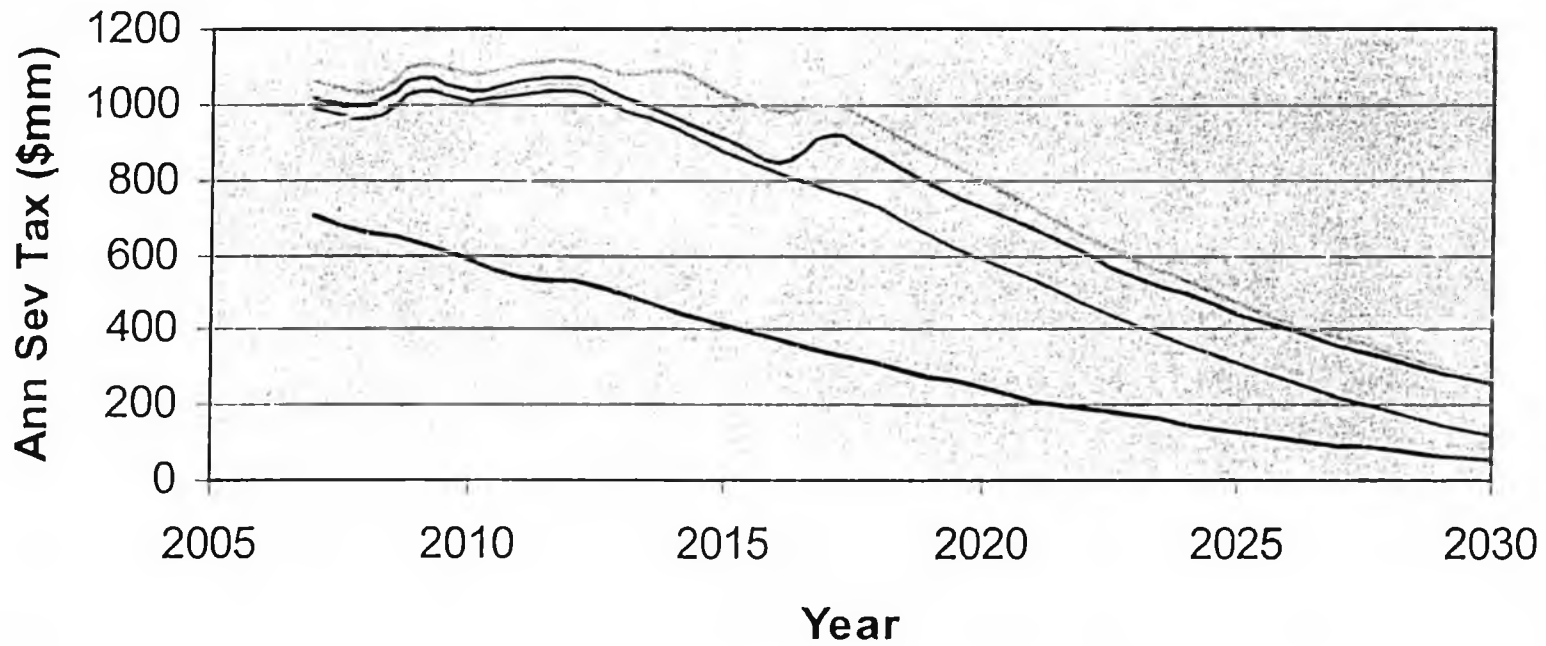
DRAFT
HB 488 House Finance CS
Comparative Revenues
Alaska Department of Revenue
May 5, 2006

Cumulative Severance Tax 2007-2030 (\$Billions)



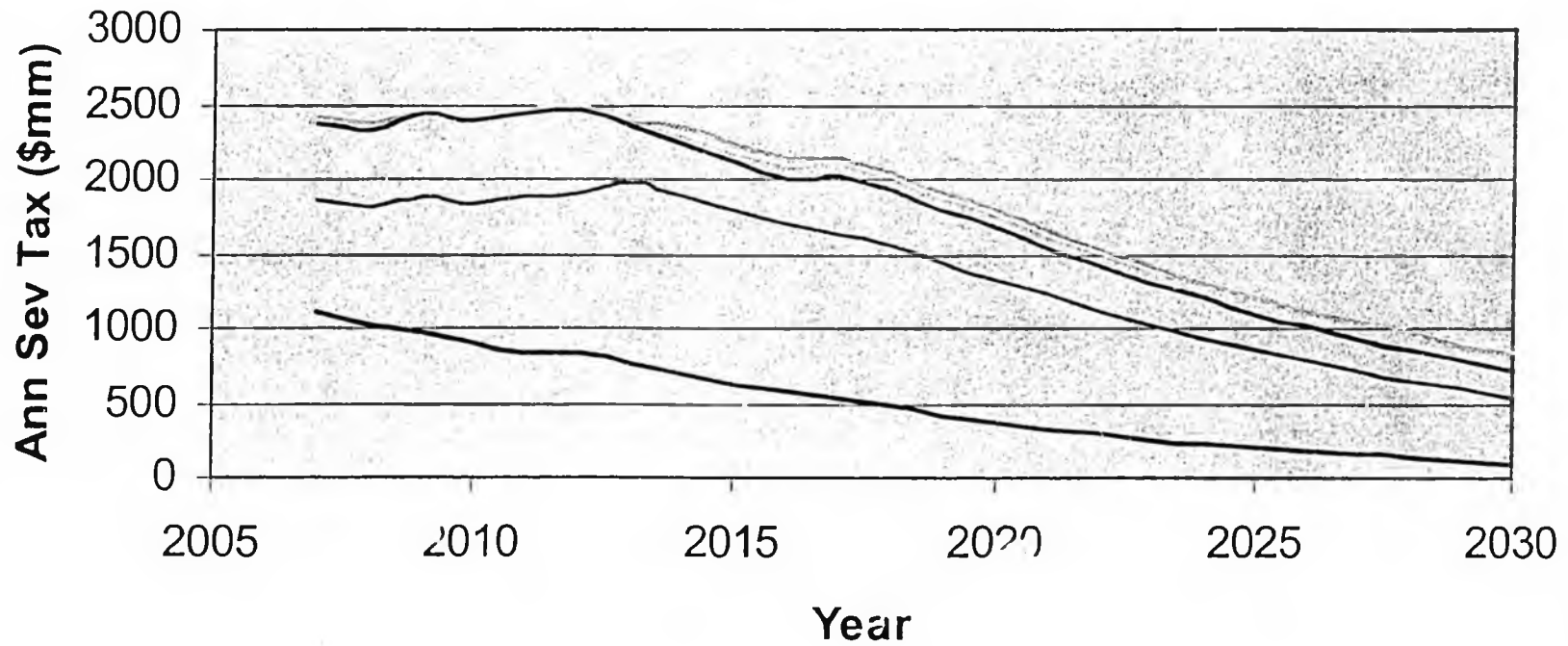
— sq — gov house res cs — sb 305 — house fin cs

Annual Severance Tax @ \$40 2007-2030 (\$Millions)



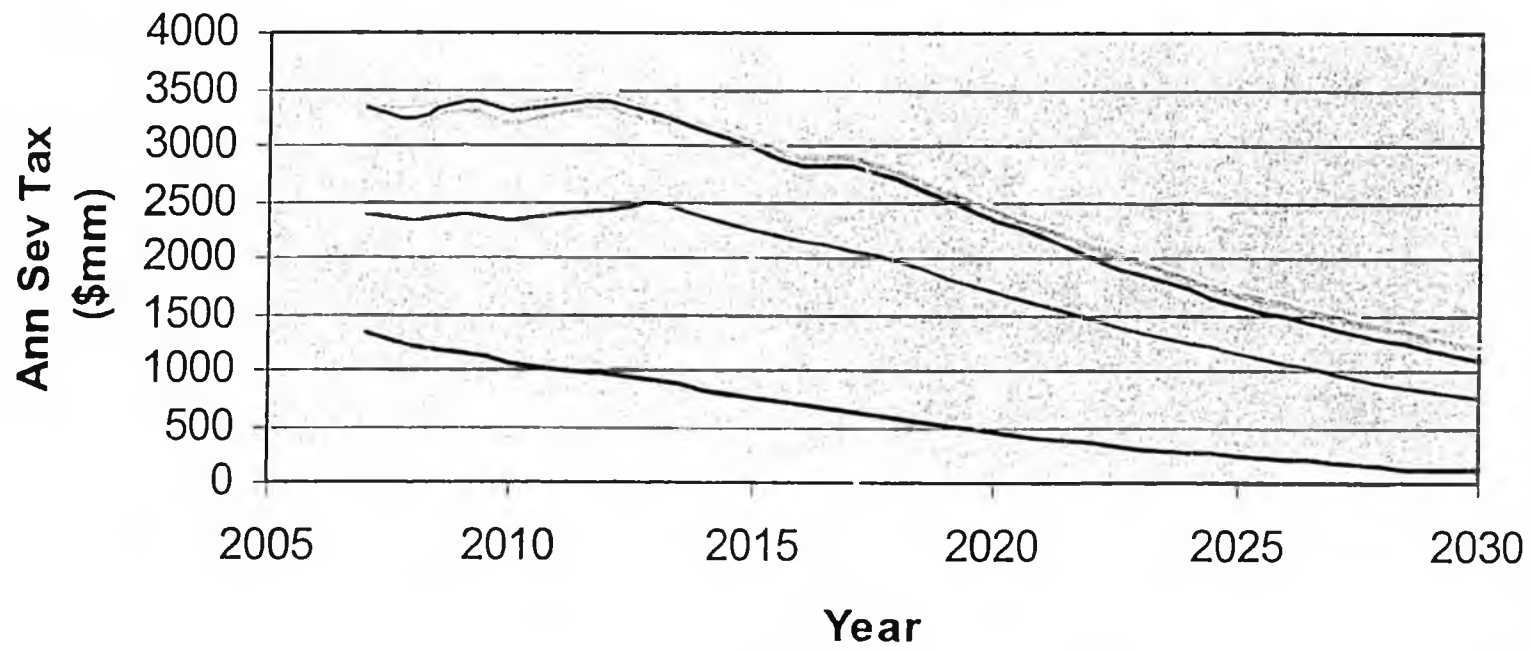
— sq — gov house res cs sb 305 — house fin cs

Annual Severance Tax @ \$60 2007-2030 (\$Millions)



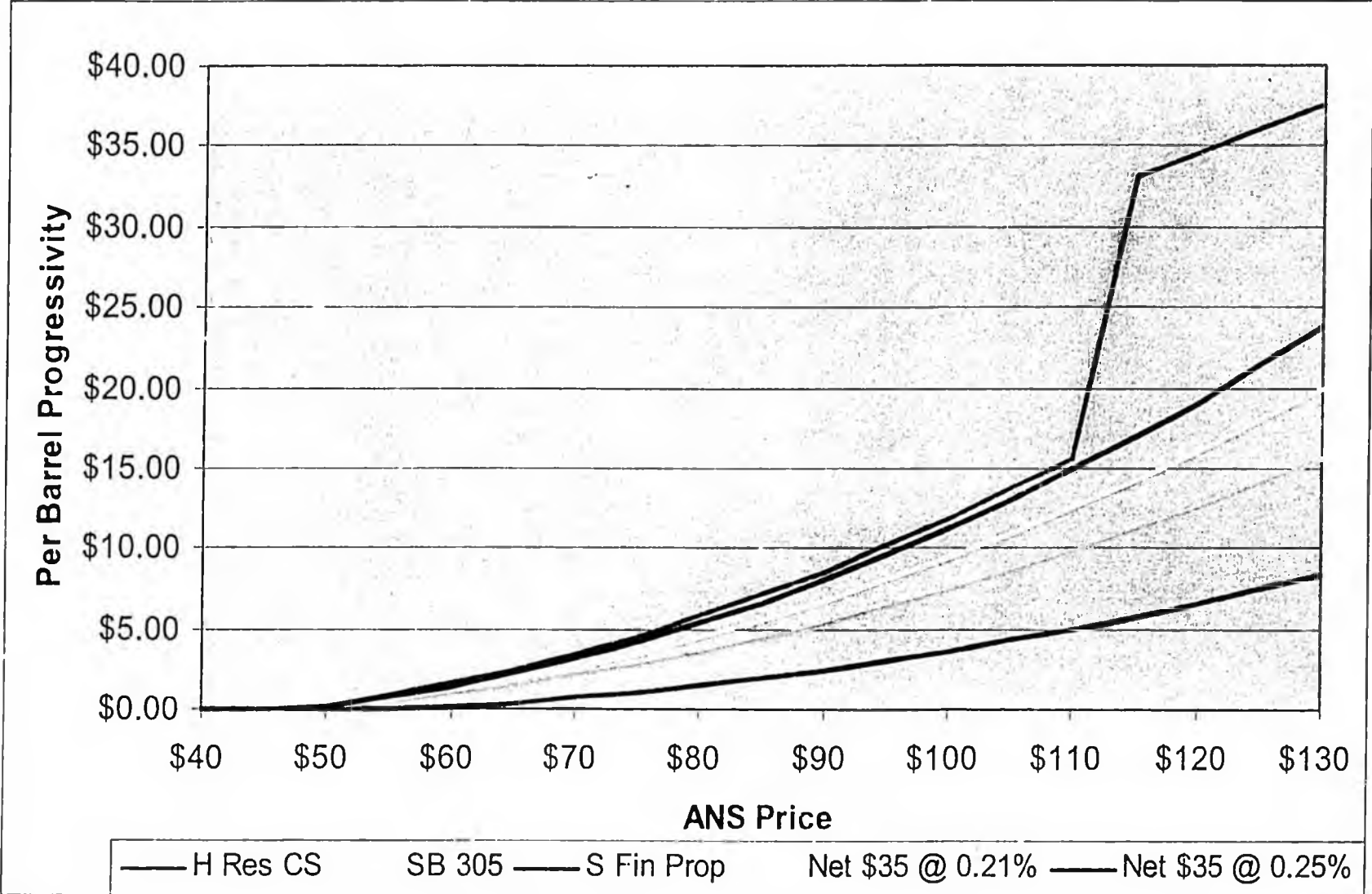
sq
 gov
 house res cs
 sb 305
 house fin cs

Annual Severance Tax @ \$70 2007-2030 (\$Millions)



— sq — gov house res cs - - - sb 305 — house fin cs

Per Barrel Progressivity Surcharge on Net \$35 at 0.21% and 0.25%



SB

305

(FILE 2)

HFIN

FILE

PPT Issues

Presentation to
House Finance Committee

April 29, 2006

Pedro van Meurs

Attachment
4/29/06
avm

HEAVY OIL

There could be 2 – 4 billion of viscous and heavy oil on the North Slope that might be recoverable at prices of about \$ 35 per barrel WTI.

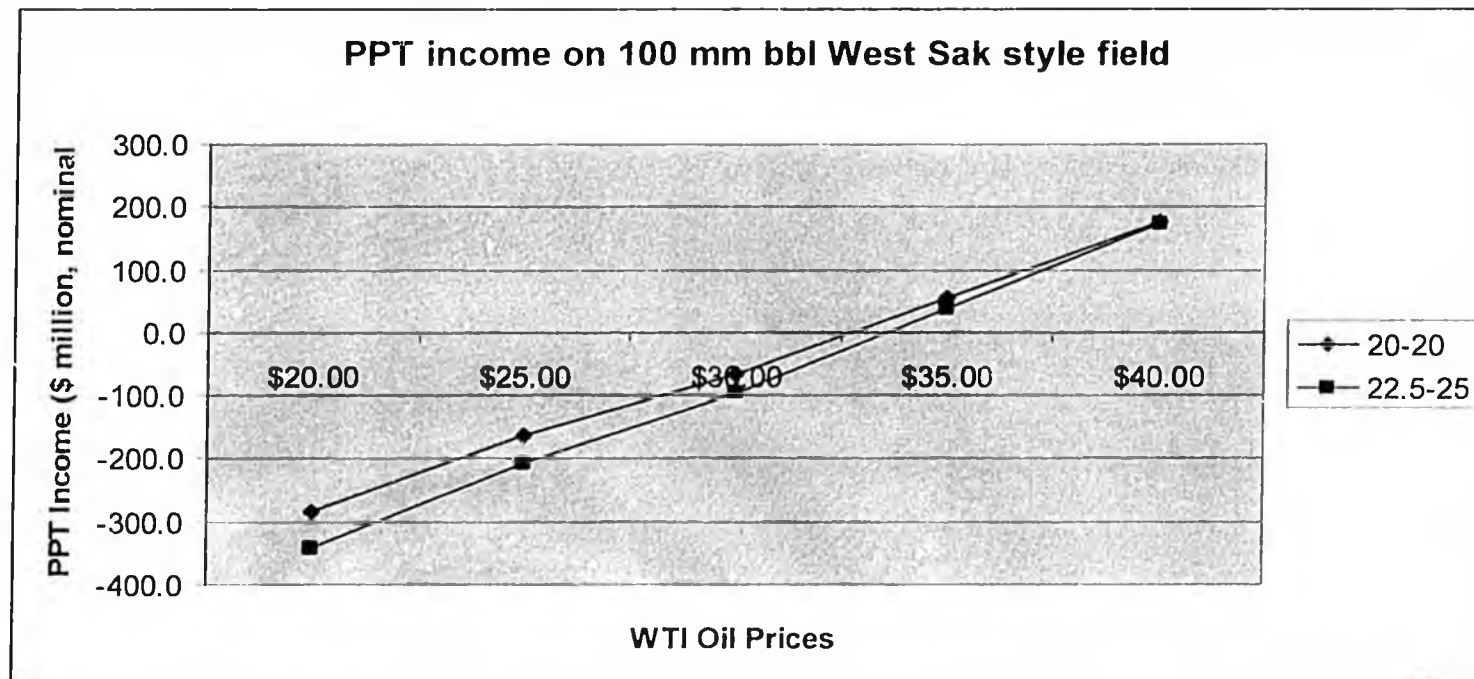
Heavy oils have much lower well head values depending on API gravity which could range from 25 to 10 degrees.

Heavy oil have much higher production costs

Therefore heavy oils were actively considered for a 25% PPT tax credit.

My recommendation was against such a credit in view of the considerable downside price risk that this would pose for the State.

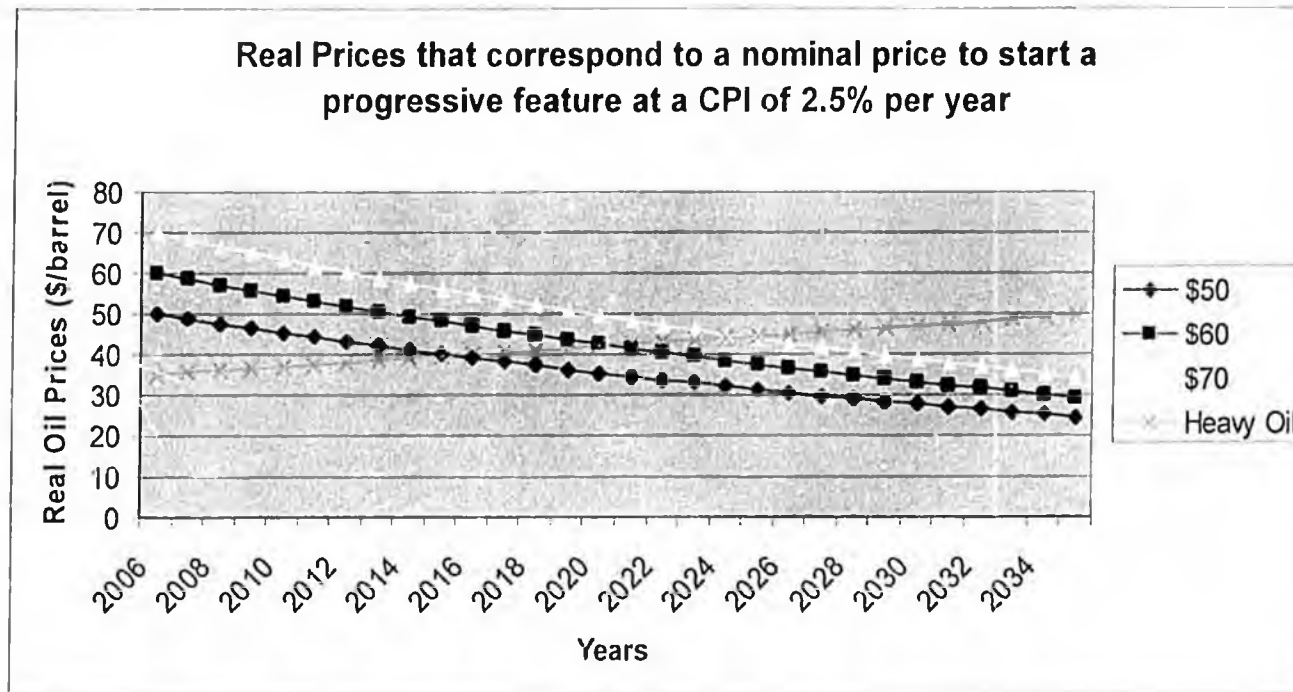
WEST SAK PPT ECONOMICS



As can be seen the State will receive **less** PPT from a 22.5-25 system than from a 20-20 system up to a price of \$ 40 WTI.

The downside exposure with a 22.5% - 25% system would be considerable.

Oil Price level for progressive feature



The starting oil price for progressive feature in nominal terms will rapidly erode in real value over time. This may affect seriously heavy oil development towards lower API gravities if price is established too low. It also indicates that it may be useful to use the actual gross value at the point of production rather than WTI or ANS.

Level of activity and tax rate

Large Companies

	\$26 20-20-0	\$36 20-20-0	\$26 25-20-0	\$36 25-20-0
Alaska Current	196	161	193	158 regressive
Alaska PPT	154	147	158	153 neutral
Norway	182	214	181	214 progressive
UK	68	63	68	63 neutral
US GOM	27	25	27	25 regressive
Nigeria	80	92	80	92 progressive
Alberta-Oil Sands	80	74	80	74 neutral
Angola	151	160	151	158 progressive
Russia-Sakhalin	214	226	214	226 progressive
Azerbaijan	168	158	168	157 U-shape

22.5% -25% strategy

A general strategy to increase tax rates to 22.5% and have a 25% tax credit in order to maintain the level of activity at the same level as a 20-20 system increases the risk to the State considerably.

Under downside price conditions tax loss carry forward + investment credits now add up to 47.5% rather than 40%.

Gas Gross Revenue Exclusion

Generally governments that face long distance gas transport to market fix government takes for gas that are 5% – 30% in government take below those for oil (Indonesia, Malaysia, Qatar, Oman, Libya, Trinidad, Venezuela).

Therefore, there is a good logic for establishing a GRE as proposed.



INTERNATIONAL

4/29/06 am

Prepared For:

State of Alaska House and Senate Legislators, at
the request of ConocoPhillips Alaska

CRA International Analysis of Oil and Gas Fiscal Proposals Alaska House and Senate

Prepared By:

David Bramley

CRA International

1 Undershaft

London EC3A 8EE, United Kingdom

Date: 29 April 2006

CRA Project No. D09110

EXECUTIVE SUMMARY

The key points in CRA's analysis of the Original bill, and the House and Senate Finance CS bills, are as follows:

- The balance of Alaska's fiscal strategy, even under the terms of the Original bill, favors short term revenue gain over promotion of new investment in oil production, and the jobs and economic activity that would go with it
- CRA's view is fundamentally different from that of others who have submitted testimony on the legislation, because we believe there will be a reduction in investment levels due to the higher taxes:
 - Compared to international peer group competitors, Alaska's levels of government take are already high under the existing fiscal system, and this provides a strong explanation of the relatively low levels of current investment
 - The new Alaskan legislation (Original bill, 20/20) would increase state-wide government take by around 4%, and the increase for new investments will be significantly more than that (typically around 8%).
 - The Senate Resources CS 25/20 proposal would increase government take by at least a further 3%
 - In our view, each of these increases will have a significant downward impact on new investment in Alaskan oil production
 - There will be an inevitable trade-off between the short term gain for Alaska in tax revenues and the impact of lower investment through steeper production decline, fewer jobs and lower economic activity in the State.
 - Oil investments of all kinds – exploration, development, in-field drilling and heavy oil – are likely to be lower than they would have been under the existing terms
 - The link between higher taxes and lower investment is founded in the competitive nature of global project opportunities available to oil companies; higher oil prices will not remove this link
 - There is no global trend towards tougher oil and gas tax terms: more countries have relaxed their terms than have tightened them over the past 2-3 years
 - Neither is there a global trend towards progressive tax regimes for oil and gas: most regimes are either broadly neutral or regressive, and countries with significantly progressive regimes tend to either have high prospectivity or (more commonly) low levels of investment
 - In instigating a progressive system, driven by price alone, Alaska would be taking a highly unusual fiscal stance, particularly in combination with the strong regressiveness that will remain at lower prices, driven by the State royalty provisions

For each of these points the main body of this letter provides a fuller explanation.

1. 'THE APPROPRIATE TAX RATE FOR ALASKA'

The choice of the 'appropriate rate' is a political one and will reflect an inherent fiscal strategy on the part of the State's Legislature and Administration. It is not in CRA's remit to say what that fiscal strategy should be.

However, CRA's views do differ in some important respects from those of others who have provided testimony to the Legislature. We have put forward the case that there is an inevitable trade-off for Alaska between short-term revenue and investment attractiveness. If Alaska's tax take on the profits from new investment goes up, new investment will be reduced compared to what it would otherwise have been, and vice versa. In our view, ignoring the effect of higher taxes on investment is no less of a flaw in the overall analysis than would be ignoring considerations of what is a 'fair share' of the profitability of oil extraction for Alaska: not taking account of either one of those things would be to overlook something that is fundamental to the interests of the State.

Thus, we do not believe it is enough to judge what oil companies 'could live with' or might 'be acceptable' to them. The real questions around securing future investment relate to Alaska's global competitiveness and how much capital is attracted into the industry. These questions are significantly harder to answer than those that relate to short term revenues, but that does not make them any less real.

In the discussion that follows, we will lay out CRA's thinking on why there will be a significant downward impact on new investment because of the higher taxes, and what the consequences of that are likely to be.

In terms of the inherent fiscal strategy that will emerge from the new legislation, our view is that it will clearly favour short term revenue gain over investment and job creation.

2. ALASKA'S COMPETITIVENESS FOR OIL AND GAS INVESTMENT

2.1 Alaska's taxes on new investment already look high under ELF

CRA's analysis showed that Alaska's existing ELF regime gives levels of government take on new investment that already look high compared to other OECD oil and gas producing countries, in the context of Alaska's high cost base and low prospectivity. This provides a better explanation of the relatively low levels of exploration and development investment in Alaska than the undoubted structural problems of the ELF mechanism.

Table 1: OECD Producing Areas: Techno-economic and fiscal attractiveness

Area	Average New Filed Size, mmb ¹	Typical Technical Cost \$/bo ²	Government Take on New Investment ³
Alaska ELF	34	15	52%
Australia NWS	59	9.5	59%
Canada Oil Sands	1,195	10	49%
Norway	162	13	73%
UK	45	11.5	50%
US GoM ⁴	91	7.5-9.5	41-48%

(1) Average new field size developed 2001-04

(2) CRA estimate of typical capital and operating costs for new field developments

(3) Government take on net cash flow from new developments. Note Alaska figure reflects relatively low ELF Severance tax on a typical new development

(4) Ranges are for US GoM shallow and deep water situations

Extending the comparison group does not change this conclusion. Despite the wide range of countries that have been suggested for comparison, no-one has put forward an area with similar prospectivity and costs to Alaska, but the same (or higher) taxes, and good investment levels.

2.2 Alaska's new regime will increase tax take and reduce investment

Total state-wide government take under the new Alaskan proposals goes up to around 57.5% (original 20/20 bill) and 61% (Senate CS), from its level under ELF of around 54%.

The effective rise in taxes on new investment will be larger than these numbers suggest, since typical new fields would have paid less than the average current rate of Severance Tax. In terms of government take, the impact of the Senate CS 25% rate for PPT over

the 20% in the Original bill is an increase of more than 3%, rather than the 2% claimed by others who have submitted testimony.

These increases have a direct impact on investor share of profitability and therefore on Net Present Values – the most fundamental criterion an investor will consider in ranking and screening opportunities. In CRA's view the conclusion that there will be a direct downward impact on investment attractiveness is inescapable: the situation is not unlike putting up prices in a competitive market: some buyers (investors) will accept the change, but others will take their custom (capital) elsewhere.

Although the impact of these effects is hard to quantify, this is very conventional economics – much more conventional in our view than the assertion that companies will simply 'live with' a significant change in the prevailing tax rate and not change their investment behavior.

The arguments that have been put forward that exploration attractiveness may actually improve under the new system are, in our view, misleading. A full discussion of the impact of the higher taxes on different types of investment is laid out in Appendix A.

CRA put forward 'illustrative estimates' of what the impact of the original bill may be in reality, taking into account lower investment levels and the consequent increase in decline in Alaska's future production. A reduction of 20% in investment levels might increase Alaska's overall production decline by 2%. Tax revenues to the State would go up in the short term, but by 2012 the additional production decline would be the dominant effect, and tax revenues would be lower thereafter than under ELF. Additionally, the reduced investment would lead to 3000-4000 job losses, and a reduction of at least \$1 billion in GDP in the State.

We readily acknowledge that others may put different numbers on these things, and it may have been a helpful contribution to the debate for them to do that, although it would be surprising if anyone expects the overall level of investment to either go up or remain unchanged as a result of the higher taxes.

2.3 Capital discipline is the reason investment will be reduced, and global trends won't remove the problem

Our model of oil company investment behavior is founded on the idea that companies will always be obliged to exercise capital discipline amongst a portfolio of competing opportunities. Even small changes in tax take will affect Alaskan competitiveness. Some Alaskan investments will take place despite the higher taxes, some will be deferred, and some will be lost altogether.

In reality, the supply of capital for new investment is not the limiting resource. It is much more likely that the supply of qualified technical and project management staff will be the limiting factor for the foreseeable future: oil companies will only apply their scarce human resources to the best projects, and this is the mechanism through which higher tax rates will be damaging to Alaskan competitiveness.

It has been suggested that high oil prices will mitigate the effect of Alaska's tax rises on new investment, but this ignores the competitive aspect of the situation. Higher oil prices will be a benefit to opportunities in all areas, and therefore will offset only a fraction of the competitive disadvantage of higher taxes.

It has also been suggested that Alaska is not alone in putting up its tax rates in the current environment, but in reality there is no great move in the world towards higher oil and gas taxes. Most countries have not adjusted their terms one way or the other. Amongst the countries that have made changes in the past 2-3 years, there are more examples of improved terms than of tougher terms:

Table 2: Examples of countries which have changed oil and gas taxation terms since 2002

Tougher Terms	Improved Terms
UK*	Indonesia
Venezuela	India
Bolivia	Peru
China	New Zealand
	Colombia
	New Zealand
	Papua New Guinea
	Italy
	Syria

- * UK terms for new investments shifted from 30% government take to 50%, with full depreciation of all costs in one year.

2.4. Profit-based progressivity remains a feature of only a minority of international oil and gas tax regimes

It has been suggested that:

'[Alaska's] system simply must be progressive. This has been a strong trend around the world...'

And that:

'A typically progressive system (at a minimum) would increase Government Take by 5 percentage points with oil prices going from \$20/bbl to \$40/bbl.'

In fact, the real situation is quite different:

- A recent industry survey showed that out of a total of 64 oil and gas producing areas, only 7% of them have progressivity to price increases of more than 5 percentage points
- The great majority of regimes – over 85% in the 2005 study – were either broadly neutral (less than 2% progressivity) or regressive
- Amongst Alaska's peer group of OECD oil and gas producers, only Norway's system is mildly progressive
- The majority of the countries with significantly progressive regimes are either highly prospective, or – more commonly – have low levels of investment activity
- There is no particular evidence of any major trend over time towards more progressivity in significant oil and gas producing countries

Additionally, the international regimes that are significantly progressive are almost all based on profitability measures such as Rate of Return thresholds or 'R factors', rather than the simple oil price thresholds, as proposed in some of the committee substitute bills. The key difference is that progressivity linked to profitability takes account of costs, whereas progressivity linked to oil prices does not. This is particularly significant in the high cost Alaskan environment.

In instigating a progressive system, driven by price alone, Alaska would be taking a highly unusual fiscal stance, particularly in combination with the strong regressiveness that will remain at lower prices, driven by the State royalty provisions.

APPENDIX A:

IMPACT OF NEW TAXES ON DIFFERENT KINDS OF INVESTMENT

A.1 Alaska's future is strongly dependent on the big legacy fields

Alaska is very reliant on ongoing investment in its legacy fields, Prudhoe Bay and Kuparuk in particular, to offset future production decline. Capital spending on Prudhoe Bay and Kuparuk represented around 60% of the total of all capital spent in Alaska over the past 5 years, whereas new exploration was only 10%.

Investment in legacy fields will be directly affected by the new taxes, and it is simply wrong to contend that the lower risks of secondary investment compared to exploration will offset the impact.

The history of investment patterns in Kuparuk and Prudhoe Bay over the past 5 years shows a strong correlation between spending and Severance Tax rates.

If the future impact of PPT follows these trends, the reduction in investment from even the original bill would be significantly more than the 20% loss in CRA's 'illustrative estimate'.

A.2. Exploration is important for Alaska, but not the central investment issue

It has been suggested that the new taxes will help investment levels in Alaska through support to exploration, by new entrants to the State in particular. CRA's view is that this is at best misleading, for the following reasons:

- Exploration investment is only around 10% of total spending in Alaska, success rates are low (16% during 2000-04) and new field sizes are small (average 34 mmboe). Unless newly prospective areas such as ANWR become available, new exploration will never contribute more than a fraction of the growth needed to offset Alaska's production decline
- The new taxes will reduce the fundamental attractiveness of exploration success in a similar way to their impact on development economics. It is true that tax credits on dry holes will mitigate this effect in certain situations – but does Alaska wish to use its own revenues to offset part of the risk of marginal exploration ventures?
- New company entrants to the State can provide future growth, but there are issues of scale and sustainability. The four biggest companies already present in Alaska have provided over 95% of investment over the past 5 years: even if there is dramatic growth in the share of smaller players, it is unlikely they will become the dominant investors in future. And the allowances against PPT that will help small players in their first developments will become significantly less effective for subsequent investments.

A.3. Heavy oil may be an opportunity seriously deferred by the new taxes

Alaska's heavy oil is a huge, known resource, but very difficult to develop technically: to date there has been very little development or production compared to heavy oil resources in other OECD areas. In technical and economic terms, Alaska's heavy oil position has significant resemblances to the Canada Oil sands in the early 1980s: a very large, but disadvantaged resource, requiring significant learning and advances in technology to make it economic.

There is a restricted set of heavy and viscous oil capabilities in the world, and demand for this expertise is growing very strongly. The effect of higher taxes on Alaskan heavy oil will be to disadvantage its access to these limited resources, and delay the development and application of heavy and viscous oil technologies in the State. This could be a significant factor in Alaska's future: not only would new heavy oil production be deferred, but the additional effect of lowering unit costs of conventional oil, by utilising existing facilities and the TAPS pipeline would also be delayed.

DISCLAIMER

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April 5, 2006

Questions for Finance Panel/or later

Hi Sharon – Some of these questions should work for tomorrow, but others I know will take some time. Just wanted to get them to you now, but I don't expect them all to get answered tomorrow. Beth

1. Can you suggest a progressive PPT that would not take all profit at extremely high prices (this is the question I asked of ECON One on 4/5/06)?
2. Taking into account just cash expenses related to production, removing exploration costs, depreciation, amortization and depletion, along with any other non-cash expenses, what would the state have received in total for 2005, from all sources of revenue from oil companies under a progressive severance tax structure where the tax is 25% at \$40 per barrel, 30% at \$50 per barrel, and 35%, at \$60 per barrel? What would the producers have kept?
3. What oil or gas that is currently taxable would be exempt from tax under the amendment to AS 43.55.020 (e)? What is the revenue impact? Is oil or gas expended in lease operations also a deductible lease expenditure under the PPT? If so, did you intend that oil and gas used in lease operations would

be both exempt from tax and also form the basis for a deduction and credit? If so, please explain the rationale.

4. AS 43.55.160 provides that direct costs do not include "(B) royalty payments" Did you mean to limit the exclusion to just "royalty payments"? Would production payments, overriding royalty payments and other types of similar payments be deductible as direct costs?

5. What is your opinion of why, given high oil prices and the current tax regime, Alaska has not seen more exploration? In your opinion, what are the best ways to incentivize exploration in general?

6. Given the differences in the older, "legacy" fields and new fields, do you think a greater tax on the legacy fields is justifiable? How would you devise such a tax?

4-6-06

Co Chair

April 6, 2006
Questions for PPT Panel

General

1. Legislators took an oath to maximize the return on resources for the benefit of Alaskans. What do you believe is the best proposal to maximize this return while at the same time encouraging investment and exploration to extend the production life of our oil/gas resources?
2. Econ One stated that 25/20 was better in a low rate environment. What tax/credit rate best meets the balance between government and industry and high and low prices? Should we be considered a two-tiered system dependent on price?

Progressivity

3. Substantial discussion has occurred over the progressivity surcharges in the House and Senate bills. Outstanding issues of concern include inflation, the slope, and the cap. What do you consider to be a reasonable way to address these issues?
4. What issues are different when considering a progressivity surcharge on gas?
5. Are you aware of any other elements used by governments world wide that we should be aware of? Is our system too complex?

Transition

6. What does the State give away (monetarily) with the Senate version on transition? Is there some balance of 2 for 1 and the look back period? Is a sunset for transition needed?

Payment of Taxes

7. What is the benefit of a quarterly true up versus an annual true up? State and Industry perspectives.
8. What is the potential loss of revenue to the State of delaying implementation of PPT by a three-month period? What is the estimated time needed to write the regulations?

Conico

Questions for House Finance Panel Discussion – April 6, 2006

- 1) How much of the future production is likely to come from exploration versus known fields versus heavy oil?
- 2) How will PPT impact these three (exploration, known fields, heavy oil) differently?
- 3) What mean field size is the likely expectation of explorers in Alaska?
- 4) Do you agree that for the existing players, the original bill, the House CS and the Senate CS will result in a greater tax burden relative to the current system?
- 5) Can you explain again how an explorer can be better off under 25% rather than 20%?
- 6) What do you think will be the result of PPT with respect to investment, and how would that impact production?
- 7) What is your view of the most likely price forecast (including low and high prices as well as type of distribution of prices) used by existing investors in Alaska when evaluating projects in Alaska?

Ruth

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April 6, 2006

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Progressivity

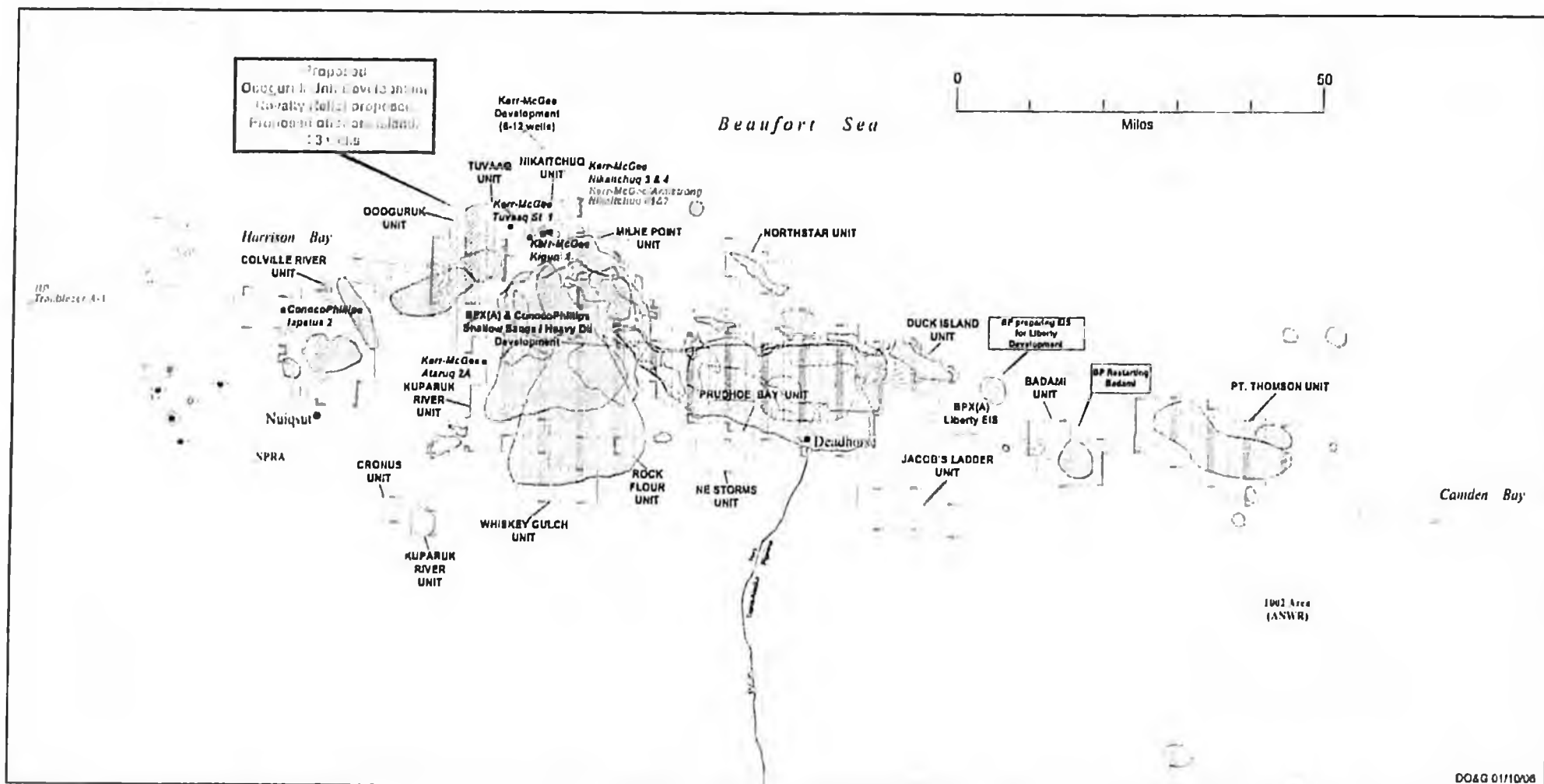
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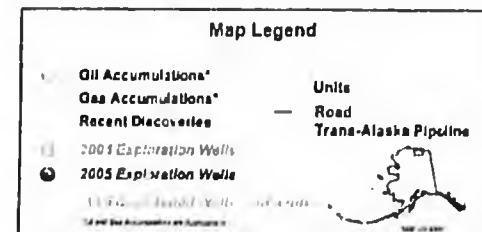
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DO&G 01/1006

North Slope Oil & Gas Activity & Discoveries January 2006



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

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 – **NOT** 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

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

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

Questions for House Finance Panel Discussion – April 6, 2006

- 1) How much of the future production is likely to come from exploration versus known fields versus heavy oil?
- 2) How will PPT impact these three (exploration, known fields, heavy oil) differently?
- 3) What mean field size is the likely expectation of explorers in Alaska?
- 4) Do you agree that for the existing players, the original bill, the House CS and the Senate CS will result in a greater tax burden relative to the current system?
- 5) Can you explain again how an explorer can be better off under 25% rather than 20%?
- 6) ~~What~~ What do you think will be the result of PPT with respect to investment, and how would that impact production?
- 7) What is your view of the most likely price forecast (including low and high prices as well as type of distribution of prices) used by existing investors in Alaska when evaluating projects in Alaska?

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ORIGINAL
COPIES

Co Chair

April 6, 2006
Questions for PPT Panel

General

- 1. Legislators took an oath to maximize the return on resources for the benefit of Alaskans. What do you believe is the best proposal to maximize this return while at the same time encouraging investment and exploration to extend the production life of our oil/gas resources?
- 2. Eeon One stated that 25/20 was better in a low rate environment. What tax/credit rate best meets the balance between government and industry and high and low prices? Should we be considered a two-tiered system dependent on price?

Handwritten notes:
1/25/06
1/25/06

Progressivity

- 2 3. Substantial discussion has occurred over the progressivity surcharges in the House and Senate bills. Outstanding issues of concern include inflation, the slope, and the cap. What do you consider to be a reasonable way to address these issues?
- 4. What issues are different when considering a progressivity surcharge on gas?
- 5. Are you aware of any other elements used by governments world wide that we should be aware of? Is our system too complex?

Transition

- 6. What does the State give away (monetarily) with the Senate version on transition? Is there some balance of 2 for 1 and the look back period? Is a sunset for transition needed?

Payment of Taxes

- 7. What is the benefit of a quarterly true up versus an annual true up? State and Industry perspectives.
- 8. What is the potential loss of revenue to the State of delaying implementation of PPT by a three-month period? What is the estimated time needed to write the regulations?

Conoco

Questions for House Finance Panel Discussion – April 6, 2006

- 1) How much of the future production is likely to come from exploration versus known fields versus heavy oil?
- 2) How will PPT impact these three (exploration, known fields, heavy oil) differently?
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- 7) What is your view of the most likely price forecast (including low and high prices as well as type of distribution of prices) used by existing investors in Alaska when evaluating projects in Alaska?

3

Ruth

April 5, 2006

Questions for Finance Panel/or later

Hi Sharon – Some of these questions should work for tomorrow, but others I know will take some time. Just wanted to get them to you now, but I don't expect them all to get answered tomorrow. Beth

1. Can you suggest a progressive PPT that would not take all profit at extremely high prices (this is the question I asked of ECON One on 4/5/06)?

2. Taking into account just cash expenses related to production, removing exploration costs, depreciation, amortization and depletion, along with any other non-cash expenses, what would the state have received in total for 2005, from all sources of revenue from oil companies under a progressive severance tax structure where the tax is 25% at \$40 per barrel, 30% at \$50 per barrel, and 35%, at \$60 per barrel? What would the producers have kept?


3. What oil or gas that is currently taxable would be exempt from tax under the amendment to AS 43.55.020 (e)? What is the revenue impact? Is oil or gas expended in lease operations also a deductible lease expenditure under the PPT? If so, did you intend that oil and gas used in lease operations would

be both exempt from tax and also form the basis for a deduction and credit? If so, please explain the rationale.

4. AS 43.55.160 provides that direct costs do not include "(B) royalty payments" Did you mean to limit the exclusion to just "royalty payments"? Would production payments, overriding royalty payments and other types of similar payments be deductible as direct costs?

5. What is your opinion of why, given high oil prices and the current tax regime, Alaska has not seen more exploration? In your opinion, what are the best ways to incentivize exploration in general?

6. Given the differences in the older, "legacy" fields and new fields, do you think a greater tax on the legacy fields is justifiable? How would you devise such a tax?

4/27/06 #2
PM bp


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) 564-5598
WalkerA4@BP.com

April 27, 2006

The Honorable Mike Chenault
Co-Chair, Committee on Finance
The Alaska House of Representatives
Alaska State Capitol, Room 505
Juneau, AK 99801-1182

The Honorable Kevin Meyer
Co-Chair, Committee on Finance
The Alaska House of Representatives
Alaska State Capitol, Room 501
Juneau, AK 99801-1182

Re: PPT Legislation

Dear Representatives Chenault and Meyer:

Thank you for the opportunity to comment on the proposed PPT legislation pending before the House Finance Committee. In my opinion, the greatest threat to Alaska's prosperity, jobs and economic well-being in the future is the ongoing decline of oil production. To counter this threat there must be a major increase – at least a doubling – of industry investment on the North Slope. The structure of the PPT has the potential to make Alaska more attractive to investors, but it will only serve Alaska well if the numbers are right and the mechanics are clear and workable. As drafted the bill threatens to frustrate this potential. Following is BP's view of the key provisions and recommendations for the committee's consideration:

PPT Rate.

- o Oil: 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 20 percent.**
- o Gas: **An effective PPT tax rate of 1/3 that proposed for oil is appropriate for gas.**

If there is a desire to tax gas or a particular category of oil at a different rate from the general one, the best way to do it is to exclude a portion of the value of that oil or gas from the PPT calculation instead of creating a separate PPT rate for it.

Progressivity. We remain firmly of the belief that **further progressivity above that provided by the PPT structure runs counter to Alaska's goal of maximizing benefits for its people.** We continue to hold that investment and economic growth provide more benefit and revenue than increased tax. Further, if one can justify, which we cannot, increasing the tax rate as the price of oil increases, then is it not equally justifiable to reduce it as the price of oil falls?

However, if the Legislature views progressivity as a necessary element of PPT, care should be taken to ensure the structure chosen is durable. Specifically we would contend:

- o It's preferable to **base progressivity on the net "production tax value"** as the Senate Finance CS did. To do otherwise would introduce a deterrent to investment as costs of production increase and consume a larger portion of the value of the oil.
- o The trigger point for progressivity must be **adjusted for inflation** or it will increasingly become unreflective of economic reality. It is worth recalling that the \$33 price for North Slope oil in 1980 is equivalent to more than \$71 today, solely because of inflation.

Capital Credits. Because of the design of PPT, a higher credit will increase reinvestment in Alaska and help meet Alaska's urgent need for significantly increased investment to counter North Slope production decline. The proposed **25% credit for capital expenditures in the Senate's version is superior** to the 20% credit in the House Resources CS.

Special Conditions on Using Capital Credits. This change was added to the PPT by a floor amendment in the Senate. Superficially it sounds like a good idea: requiring the producers to pass on the benefits of their PPT credits to third parties who are using the producers' production facilities and pipelines. This would be logical if the PPT were part of the costs that producers include in the tariffs and fees charged for using their facilities, but PPT won't be part of those costs any more than state royalties on the producers' production would be. Tariffs and fees are based on the operating and capital costs for the facilities, not on the obligations that fall on the producer as a result of producing its own oil or gas, such as royalty, PPT or something else like income tax.

CSSB 305(FIN)AM further provides that if the PPT-credit benefit is not passed on to third parties through the tariffs and fees producers charge for using their facilities, DOR can disallow the credit retroactively for the periods when it is found not to have been passed on. This would throw the value of a credit completely up in the air until DOR can audit and confirm that the benefit from it was passed on. The effectiveness of the credit as an incentive for investment will be all but lost because of the uncertainty caused by the unnecessary and ill-advised provisions in **AS 43.55.160(j) and (k) of the Senate's version, which should be deleted as bad policy acting directly against the intent of the PPT bill and the need to attract investments to Alaska.**

Transition (TIE) Credits. It is appropriate and common practice to allow transitional relief for investments made under the ELF-based production tax. When Alaska switched from separate-accounting to its present income tax at the end of 1981, it provided transitional relief even though, as in the past five years, oil prices had risen significantly while separate-accounting was in effect.

CSSB 305(FIN)AM recognizes capital investments during the five years before PPT, but limits the use of the credit according to how much new investments are being made. While this limitation introduces a hurdle which a producer must overcome before it can get the benefit of the TIE credit, we recognize it is consistent with addressing the need for significant additional investment that is so urgently

required to stem North Slope production decline, and so we accept the Senate-passed version as a reasonable resolution of the transition issue.

Effective Date. Retroactivity is both unfair and problematic and could lead to delays, disputes and litigation, particularly when it involves the complete restructuring of a major tax like the proposed transformation of the ELF-based production tax into the PPT. April 1st as an effective date already involves a degree of retroactivity, which becomes greater and more unfair with each day. **July 1, 2006 would be an acceptable effective date, provided there is a transitional provision allowing taxpayers to report initially on the basis of the present ELF-based tax for a reasonable time until they can adapt their computer systems and software to the new PPT, and then they would pay the difference.**

Use of Royalty Netbacks for PPT. The House Resources CS, like the original Bill, would authorize, but not require, DOR to let producers determine the "gross value at the point of production" of their taxable oil and gas on the basis of three alternative approaches: the netback determined under their royalty settlement agreements with the State, the netback determined on a basis acceptable to DNR in the case of production from state lands (to the U.S. Interior Department when state land is not involved but federal land is), and "another formula" adopted by DOR for determining the value of oil or gas "at a specific geographic location."

The version passed by the Senate deletes reference to these three netback approaches altogether. The resulting silence on the matter in the Senate version would not bar DOR from using either or both of the royalty-based approaches, nor from using some other royalty-based approach. Since the door for using them remains open, we believe it is better for the Legislature to clarify their intention and provide specific guidance permitting DOR to use royalty-based netbacks as the House Resources CS does.

Disallowance of "Abandonment" Costs. This is a feature of the Senate-passed Bill that is not in the House Resources CS. We also believe these provisions are unnecessary because of the already-existing provisions in all versions of the Bill that require costs to be "ordinary and necessary" costs of producing oil or gas from that field in order to be deductible.

Worse, the Senate's provisions are ill-drafted and overly broad. Every time we cement an existing well, it might arguably constitute an "abandonment" of that well, even though we cement it in order to redrill it to a different bottom-hole location. Similarly, any time we replace a worn-out or out-dated piece of equipment or hardware, the removal of the old one might arguably constitute an "abandonment" of it. Applied in this fashion, the current version of SB 305 would open up normal field operations to almost innumerable "mini-abandonments" on an practically everyday basis. And for each "abandonment" its costs would be partially disallowed in proportion to the ratio of cumulative production as of the PPT effective date to the cumulative production as of the date when the "abandonment" occurs. This scenario would make PPT almost impossibly complex for producers to comply with and for DOR to administer and enforce. **For these reasons we believe the "abandonment" cost provisions in the Senate version should not be included in the House Finance Committee's CS.**

90% vs. 95% "Safe Harbor". Whether at 90% or 95%, the present provisions do not account for practical limitations in the real world and thus are unduly harsh and unfair. Producers cannot know in the early months of the year what that year's capital expenditures are going to be, both in terms of how much of the budget will be spent and in terms of how much whatever is spent will end up being properly classifiable as "capital" expenditure, which generates a tax credit. If capital spending comes in below budget for a year, the deduction and the tax credit for it will be less than planned earlier in the year, which in turn will make the PPT for those early months higher than planned at the time the payments for those months were made. Coming in under budget is a good thing that the State should encourage, but as the PPT is drafted now, it will likely trigger penalties and interest the further below budget the expenses are.

A 95% figure could be used for the "safe harbor" if it is based on the cumulative PPT for the current and prior production months in the year, using the information currently available at the end of each month of production. The 95% PPT payment could continue to be "due" at the end of the month after the one when the oil and gas are produced, which will allow interest to accrue starting then on an underpayment that falls outside this "safe harbor." **The AOGA letter of April 13th included a proposal to achieve this fair result, and we endorse it.**

Definition of Deductible Costs. In both the House Resources CS and the Bill passed by the Senate, deductible costs are defined in AS 43.55.160(c)(1) as "direct, ordinary, and necessary costs" of exploring for, developing and production oil and gas. "Direct costs" are defined in the new statute, and so is the phrase "ordinary and necessary." The intent is clear that, taken together, these two partial definitions define the combined term, "direct, ordinary, and necessary costs" – they are simply costs that are both "direct" and "ordinary and necessary." But any experienced lawyer will tell you that, legally, this is not necessarily the result because the terminology is not exactly the same. To ensure that the intent is carried out, all that is needed is to add language explicitly saying that the combined term does equal the sum of these two individually-defined parts. **In its April 13th letter to you the Alaska Oil & Gas Association offered specific language to do this, which we endorse.**

The present definition of deductible cost also speaks in terms of "costs incurred upstream of the point of production" for the oil or gas. Many costs that are clearly "upstream" in nature – such as the cost of helicoptering crews out to platforms in Cook Inlet – cannot be tied directly to any particular point along the route of the oil and gas as it moves from the reservoir to its eventual "point of production." While we believe the Legislature's intent here is clear, the present Bill language opens the door for arguing that such upstream costs are not "upstream" for purposes of being deductible for PPT. **In its April 13th letter to you the AOGA also offered specific language to clarify this, which we endorse.**

Costs from Non-Arm's-Length Transactions. In order for PPT to work, it is essential that its two central elements – the "gross value" of oil and gas and the "lease expenditures" to be deducted from that gross value – be done right. It would be a serious mistake to define lease expenditures in a way that involves special books, records and accounting methods that are unique to PPT, nor is it necessary to create a unique system like that. For this reason all versions of the PPT Bill wisely direct DOR, for purposes of determining deductibility, to follow industry practice about billable costs and authorize DOR to approve the use of costs billed by the operator to partners as the deductible lease expenditures for that field or exploration prospect.

Representatives Chenault & Meyer
Re: PPT Legislation
April 27, 2006
Page 5

Within this framework, the Senate has introduced special provisions invoking the "concepts" of sections 482 and 6662(e) of the Internal Revenue Code to deal with the matter of costs arising under transactions at less than arm's length. In terms of providing clarity and simplicity for PPT, it should be noted that these federal statutes, particularly section 482, are among the most difficult, cumbersome and fought-over provisions of the Internal Revenue Code. When the IRS invokes section 482 against a taxpayer, it often entails a sustained effort lasting a decade or longer.

These new special provisions are unnecessary where there is one or more partners in a field or exploration prospect with a sufficient stake in the costs to police the operator's billings effectively, and they create potential ambiguity and conflict with the other PPT provisions that already deal appropriately with less-than-arm's-length costs. First, the operator's partners themselves are going to be particularly concerned to make sure a billed cost is appropriate when it arises from a such a deal, and so there will already be a strong element of self-policing by the partners. Moreover, the requirement that lease expenditures be "ordinary and necessary" costs, as defined for IRS purposes, allows DOR to police the costs arising under less-than-arm's-length transactions even if the operator's partners somehow failed to police those costs. This makes the use of "concepts" from federal sections 482 and 6662(e) unnecessary. Second, introducing those federal "concepts" will create ambiguity to the extent they might be inapplicable to, inappropriate for, or inconsistent with the framework the Legislature is creating for PPT.

Where there is only one company involved or where the partners lack a sufficient stake in the costs to police the operator's billings effectively, the federal "concepts" are still unnecessary because of the "ordinary and necessary" requirement for expenditures to be deductible.

For these reasons, we believe subsections (j) and (k) in AS 43.55.160 of the Senate-passed version of the Bill should be deleted.

If, however, it is considered prudent or necessary to include specific language to deal with less-than-arm's-length costs in this situation, the Senate Finances CS did this by simply prescribing that such costs are limited to the "fair market value" of the goods or services involved. This effectively reached the desired outcome under the "concepts" of the two federal statutes, but without the enormous complexity, time, effort and controversy which those statutes entail.

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
Commercial Vice President, BP Alaska

Key PPT Issues and Recommended Solutions



ITEM	CSHB 488 (RES)	CSSB 305 (FIN)am	OTHER
PPT Rate	20%	22.5%	<20%
Progressivity	0.3% per \$ WTI spot > \$50	0.2% per \$ ANS West Coast spot > \$50	NONE
Credit	20%	25%	
Special Conditions on Credit	NONE	3 rd party	
Transition (TIE) Credits	1Q06 only	Last 5 years: 2-to-1 new investments to old	
Effective Date	1 April 2006	1 April 2006	1 July 2006
Use of Royalty Netback	Allowed	Silent	
“Abandonment” Costs	Already Addressed	Overkill	
Safe Harbor	90% each month: interest + special penalty + reg penalty	95% each month: interest + regular penalty	95% due cumulatively during year, delinquent after 3/31 of next year
Deductible “lease expenditures”	Fragmented	Fragmented	Clarify definitions (AOGA proposal)
Non-Arm’s Length Costs	Addressed	Overkill (IRC 482)	Fair Market Value (as in CSSB 305 (FIN))

on file

4/27/06
PM

#1

**BP Presentation on PPT
(CSHB 488 RES & CSSB 305 FIN)**

**Alaska State Legislature
House Finance Committee
27th 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 again provide testimony on Committee Substitutes for House Bill 488 & Senate Bill 305.

I will not repeat our previous testimony, but would like to spend a few moments on the key issue for Alaska, production decline.

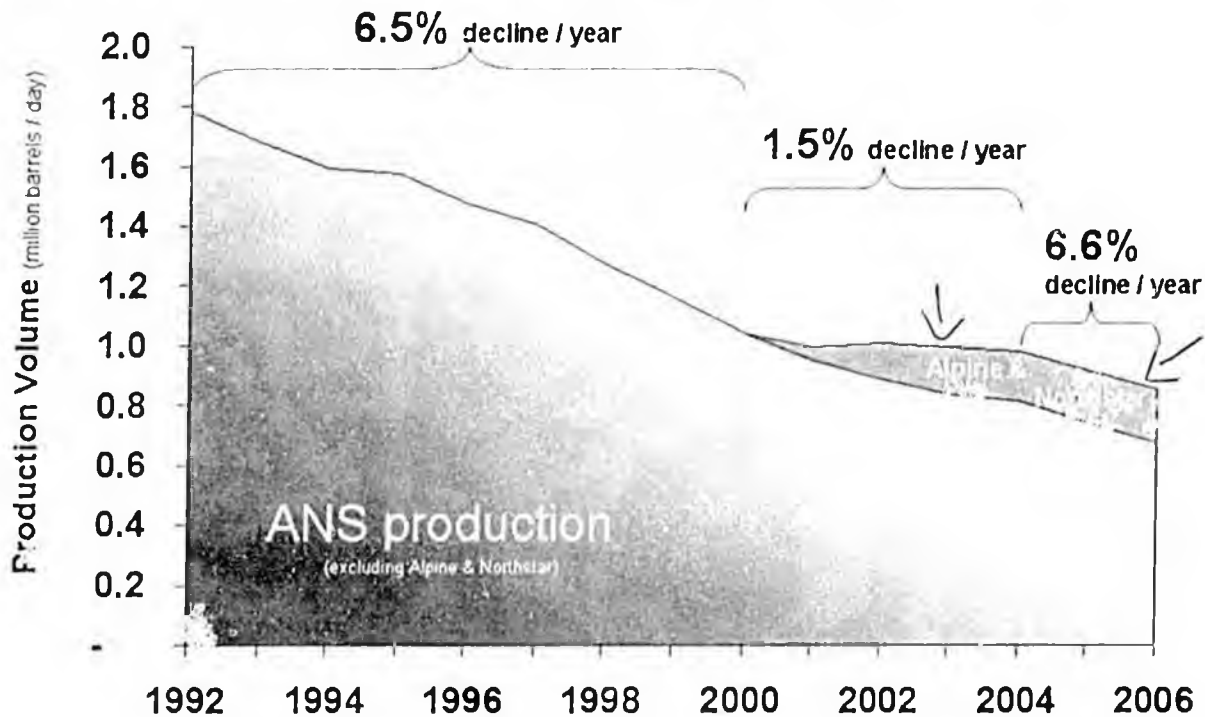
- **ANS production is declining rapidly, despite the current level of investment (circa 1 billion dollars per year).**
- **At the current rate of decline production will be about 450,000 barrels per day in 10 years.**
- **To achieve the DOR's latest production forecast, investment needs to be significantly higher than (at least twice) the current level of investment.**
- **The revenue projections provided to the Legislature by DOR & the consultants do not tell the whole story.**
 - **They rely upon production forecasts which require significantly more capital than is currently being invested.**
 - **They make no attempt to quantify the adverse impact that increased taxes will have on investment.**

Decline poses a serious risk to Alaska's future. And as such, it is essential that we carefully consider these factors. We believe that upon reflection you will agree a lower tax rate will reduce risk by attracting more investment and generate more production, more revenue, more jobs, more economic activity, more contributions to the Permanent Fund and more sustainable benefits for Alaskans. A lower tax rate will also mean a healthier oil business and stronger foundation on which to build the gas pipeline.

Alaska North Slope Production Decline

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 will be to you.

ANS production is declining rapidly, despite the current level of investment (approximately \$1 billion per year)

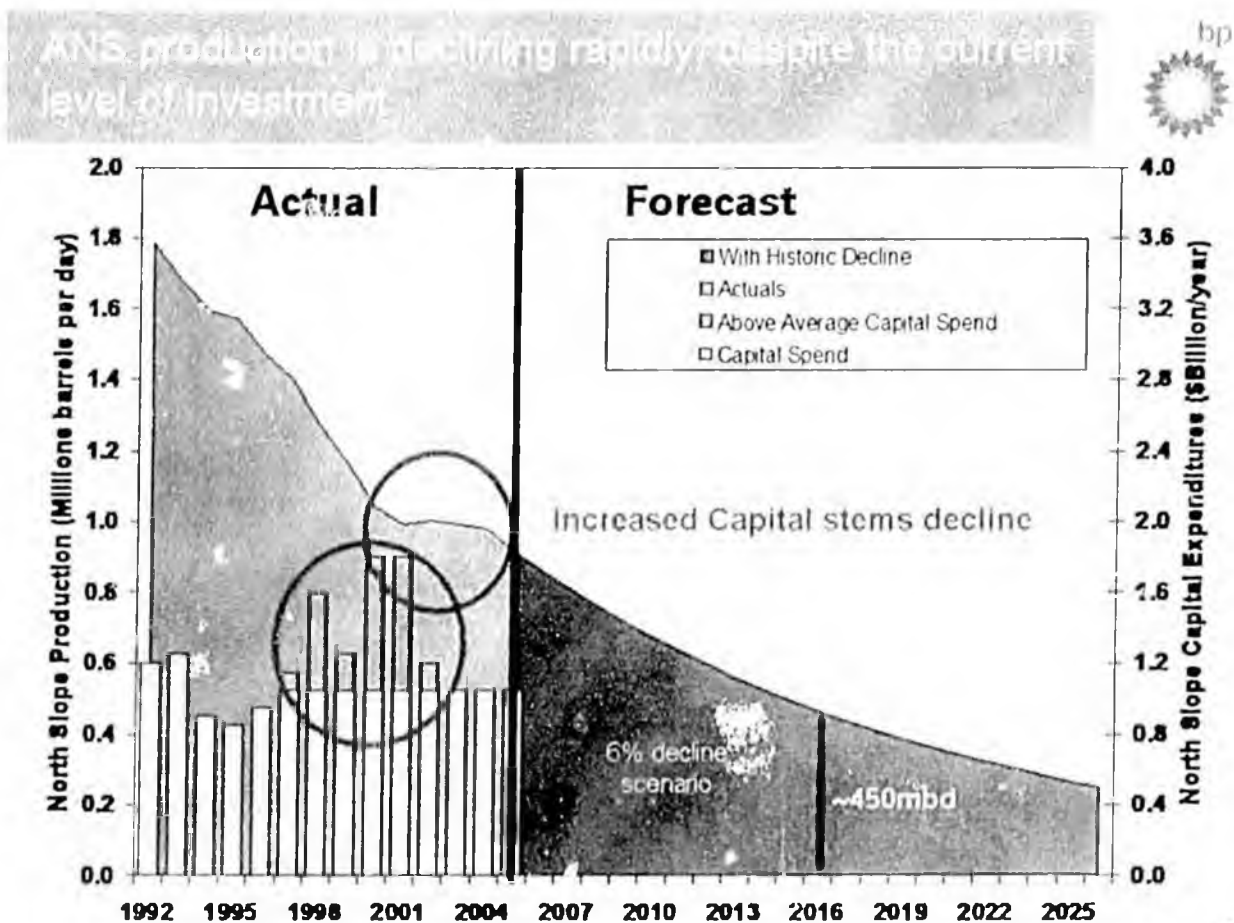


Many of you have heard us state that ANS production is declining at 6% per year. Why do we say that? For the eight years leading up to 2000, ANS production declined at a rate of about 6% per year. The development of Alpine, Northstar, and the Prudhoe Bay Satellites between 2000 and 2002 successfully stemmed North Slope decline for a number of years. However with NorthStar & Alpine on plateau or declining, 2005 saw a return to the 6% decline 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.

Investment leads to Production

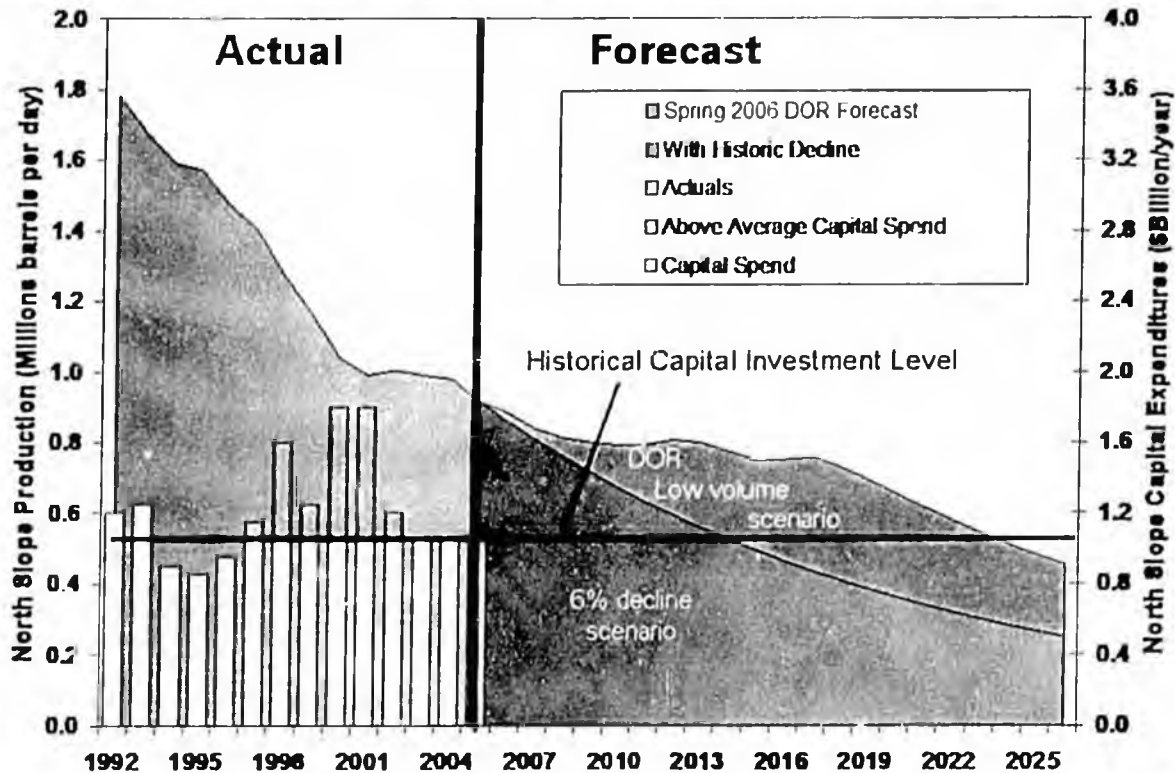
The decline abatement experienced about 2000 required investment levels above historical averages. This graph demonstrates the cause and effect relationship between investment and production.

This graph also extrapolates the 6% historical decline to demonstrate what will happen to production if investment remains at current levels. Within ten years ANS production will be approximately 450 mbd. This projection assumes investment stays at historic levels and is not adversely affected by increased taxation.



Significant additional investment is required to offset decline

To achieve the DOR's latest production forecast, investment needs to be significantly higher than (at least twice) the current level.



The latest DOR 2006 spring forecast is the line above the blue wedge. The wedge represents the difference between the Spring forecast and expected decline at current investment.

This cause & effect (investment and production) demonstrated in the 1998 to 2004 timeframe provide a vivid illustration of why significant investment is required to meet the DOR Spring forecast. This future can only be realized if Alaska also realizes a significant investment increase. It is unrealistic to assume that the tax increase contemplated by the current version of SB305 will lead to a significant investment increase – like the one Alaska needs tomorrow. We need to ask ourselves what we want? Unless those investments are made, decline will continue at the current rate and the DOR will be revising its production forecast down yet again.

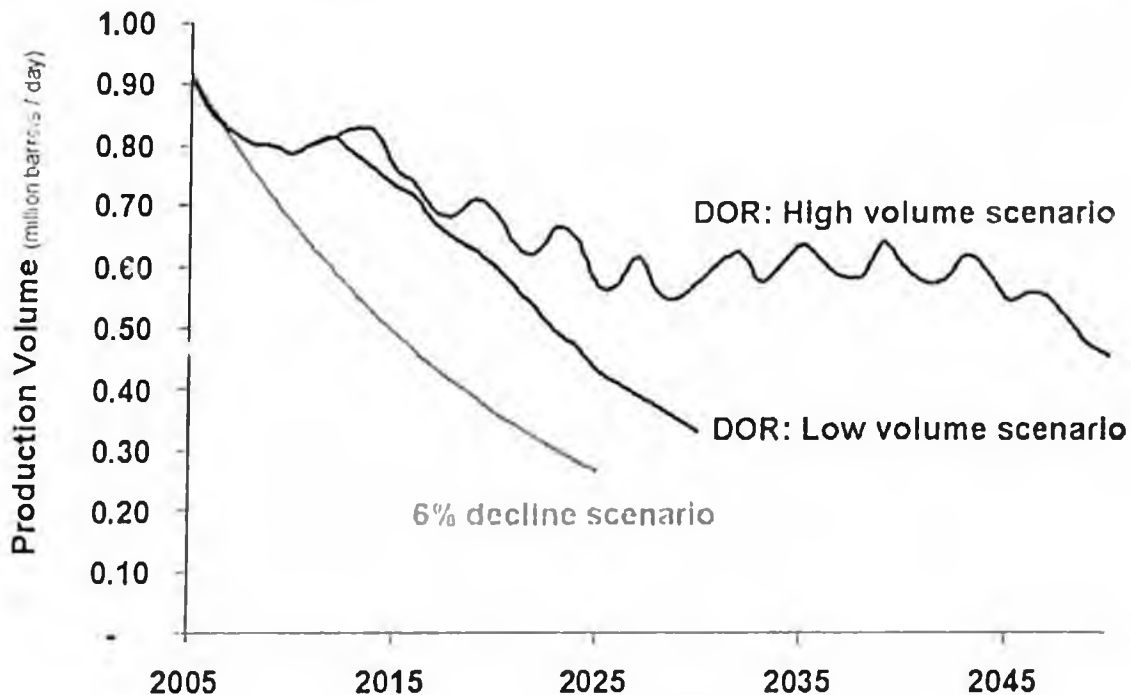
The blue wedge is 1.3 billion barrels of production over twenty years. At today's prices that represents tens of billions in state revenue lost because oil was left in the ground. This is before any consideration for the economic multiplier effect that the billions of investment would have created for the economy, for jobs, for Alaskans and for Alaskan businesses.

If the question is, "how do we maximize benefits for the people of Alaska?" We believe that the answer is not, "by increasing taxes on the oil industry."

Production Profiles

It is important to recognize that there is a big difference between production forecasts that have been used to demonstrate the mechanics of the PPT tax and Alaska's current reality. You will recognize the forecasts below. The key point here is that the DOR "low volume" and "high volume" production scenarios would necessitate significantly more investment than Alaska is attracting today. The "low volume" forecast would require at least twice the current level of investment (c. \$1 bn per year) and the "high volume" scenario, much-much more. Given this fact, we believe it is unreasonable to assume that these scenarios represent the future profile in Alaska after a tax increase like the one contemplated today.

To achieve either the low or the high volume scenarios, investment needs to be significantly higher than the current level.



Conclusion

- The decline of North Slope production is the most serious threat to Alaska's future.
- The tax regime you approve will directly impact how attractive Alaska is for investment and that will translate into a new investment and decline profile.
- The highest state revenue is derived from the greatest production not highest tax. And benefits are maximized when increased investment spurs economic activity, creates jobs, offsets decline and extends the life of Alaska's oil and gas businesses.

The 20 percent PPT tax would increase the marginal tax rate on our Alaska operations from 56% to about 61%. According to the DOR, this would generate an additional \$1 billion a year in state revenue at current oil prices and swell the state's substantial budget surplus.

BP agreed not to oppose this significant oil tax increase as a means of advancing the gas project. It was not an easy concession to make.

First, this increase in tax only makes sense if the future includes a gas pipeline. Without gas production, this tax increase – over time – will speed the decline and shorten the economic life of existing North Slope fields.

A lower tax rate will reduce risk by attracting more investment and generate more production, more revenue, more jobs, more economic activity, more contributions to the Permanent Fund and more sustainable benefits for Alaskans. A lower tax rate will also mean a healthier oil business and stronger foundation on which to build the gas pipeline.

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

Angus Walker
Commercial Vice President
BP Exploration (Alaska) Inc.

Note: BP has separately provided the committee written documentation summarizing the key issues relating to the proposed legislation and BP's specific recommendations and rationale for those recommendations for the committee's consideration. [Reference letter of April 27, 2006 from Angus Walker to House Finance Co-Chairs Chenault and Meyer]

Ken 907 317 5471

4/27/06 pm

TESTIMONY OF RICHARD OWEN
ON SB305 TO THE HOUSE FINANCE COMMITTEE

April 27, 2006

Co-Chair Chenault, Co-Chair Meyers, 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.

Thank you for the opportunity to provide our comments concerning the Committee Substitute to SB 305 now under consideration by the House Finance Committee. Significant work has been conducted by the Resources and Finance Committees in their analysis and deliberation of the PPT legislation. We appreciate your careful examination of the legislation to ensure the correct balance is struck between additional government take and maintaining an active and healthy oil and gas industry in Alaska.

Let me begin by reminding the committee that all of the different versions of the PPT legislation we have commented on over the past months have represented a significant tax increase on the oil and gas industry. Any change in Alaska's fiscal regime impacts how we view the stability and attractiveness of the Alaskan investment 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. To offset current

production decline, industry will need to make a significant increase in investments. We believe the focus of the tax bill should be on encouraging investment and growing production.

The version before you today increases the already high base tax rate contained in the original bills to 22.5% 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. The proposal to increase the already high tax rate as prices increase does reduce the upside potential and will result in Companies recalibrating investment decisions.

We urge the committee to reduce the tax rate from the 22.5% to the 20% contained within the original bill. We also urge the committee to eliminate the additional progressive feature that increases the tax further when prices are higher.

We are disappointed 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 Senate's final version of the bill. The PPT bill 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. The use of a producer's royalty settlement agreement establishes a methodology to determine the value for oil and gas that reflects current market conditions and includes a re-opener process for adjusting that methodology to keep it reflective of the market. The result of this re-opener process is a self-adjusting system for determining the value of oil and gas that remains representative of market conditions as those conditions evolve. This provision is important to industry and the State as it provides 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 which would allow the State to use the Royalty Settlement Agreement methodology for determining the value of product.

ExxonMobil supported CS 305/HB 488 as originally proposed since it sought to provide a balance of revenues to the state and producers across a range of prices, provided sufficient incentive for producers to undertake exploration and development risks and provided predictability and durability to gauge investment decisions. 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. While predictability and durability are important, their attractiveness is lost if it comes at too high a cost.

Any change to the PPT legislation as originally proposed could potentially jeopardize our ability to progress the gas pipeline and at a minimum would require a reexamination of the gas pipeline Fiscal Contract. We urge the committee to:

- Adjust the tax rate to 20%, with an investment tax credit rate of 20%
- Eliminate the additional progressive tax rate feature
- Provide language allowing the use of Royalty Settlement Agreements
- Make the effective date for the new system to July 1, 2006

I would like to thank the Co-Chairs and the Committee for the opportunity to testify today.

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

key differences from Senate
Version
minor differences

4/25/2006

source DOR

	governor's bill	House Resources CS Version L	Senate Resources CS Version C	Senate Finance CS Version R	SENATE (page refs = S Fin CS)	House
tax rate	20% .011(a)--page 3	20% .011(a)--page 3	25% .011(a)--page 3	22.5% general 5% on Cook Inlet oil .011(a)--pages 3-4	22.5% general 5% on Cook Inlet oil .011(a)--pages 3-4	
credit rate	20% .024(a)--page 5	20% .024(a)--page 8	20% .024(a)--page 7	25% .024(a)--page 7	25% .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	5% oil & 1.67% gas Report from Commish .011(f)--page 4 & 180 pg 26	5% oil & 1.67% gas Report from Commish .011(f)--page 4 & 180 pg 26	
Gas (GRE)	n/a		n/a	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 19	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 19	
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 ANSwl x .75 x bbls .011(f)--page 4	over \$50/bbl, (ANSwc - \$50) x .002 x ANSwl x .775 x bbls (oil only) .011(a) and (h)--pages 4-5	over \$50/bbl, (ANSwc - \$50) x .002 x ANSwl x .775 x bbls (oil only) .011(a) and (h)--pages 4-5	
special gas progressivity?	n/a	yes .011(i)--page 4-5	no	no	no	
progressivity deductible?	n/a	yes .160(a)--page 18	yes, but not clear	no .160(d)(2)(O)--page 22	no .160(d)(2)(O)--page 22	
transition	5 yr lookback of capex .160(a)--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)--pages 10-11	5 yrs lookback capex 2 for 1 recoupment .024(i)--pages 10-11	
transition treatment	deduction over 6 yr, if ANSwc >=\$40 .160(a)--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)--pages 10-11	20% credit, no oil price test .024(i)--pages 10-11	
sunset of transition	no	n/a	3/31/2013 .024(i)--page 10	3/31/2013 .024(i)--page 11	3/31/2013 .024(i)--page 11	
base allowance	\$73M deduction .160(a)--page 16	\$12M credit (equates to \$60M ded) .170(a)--page 23	5000 bbl plan .160(a)--page 19-20	Revised 5000 bbl equivalent credit capped at 14 million .170(a)--pages 25-26	Revised 5000 bbl equivalent credit capped at 14 million .170(a)--pages 25-26	
sunset of base allowance	none	3/31/2016 (exp incurred) .170(a)--page 24	12/31/2013 .160(h)--page 20	3/31/2016 w/commissioner report .170(a)--page 25, 180 pg 26-27	3/31/2016 w/commissioner report .170(a)--page 25, 180 pg 26-27	
safe harbor	90%, annual true-up, no interest .020(a)--page 3	90% with interest .020(a)--page 7	95% quarterly true-up, no interest .020(a)--page 5	95%, annual true-up, no interest .020(a)--pages 5-6	95%, annual true-up, no interest .020(a)--pages 5-6	
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)--pages 5-6	interest only .020(a)--pages 5-6	
effective date	7/1/2006 page 20	4/1/2006 Section 45--page 30	4/1/2006 Sec 38--page 28	4/1/2006 Sec 40--page 33	4/1/2006 Sec 40--page 33	
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 37(g)--pages 31-32	6 mos. pymt on old system, true- up in 7th mo sec 37(g)--pages 31-32	
spill surcharge total	no change (5 cents)	no change (5 cents)	increase 1 cent, to 6 cents	increase 1 cent, to 6 cents	increase 1 cent, to 6 cents	
spill surcharge split (2011/300)	.23	1/4	1/5	1/5	1/5	
spill surcharge payable	no change	increase 1 cent page 24-25	increase 2 cents page 22-23	increase 2 cent 201, 300 pages 27-28	increase 2 cent 201, 300 pages 27-28	
surcharge treatment	creditable against PFI 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 22	not creditable, not ded .160(d)(2)(L)--page 22	
SB 165 credit	no change	extends 10 years, only usable against PPT .025(b), .025(b)--page 11-12	no change	extends 10 years, faces \$20 m issue .025(b), .025(b)--page 12-14	extends 10 years, faces \$20 m issue .025(b), .025(b)--page 12-14	

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

key differences from Senate
Version
minor differences

4/25/2006

source: DOR

	governor's bill	House Resources CS Version L	Senate Resources CS Version C	Senate Finance CS Version R	SENATE (per refs = S Fin CS)	House
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 deduction or credit for abandonment on old production 160(d)(2)(P) page 22	no deduction or credit for abandonment on old production .160(d)(2)(P) page 22	
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 7	against PPT only .024(a)--page 7	
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	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	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 8	yes, at 22.5% .024(b)--page 8	
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)--pages 28-29	upstream of gas treatment upstream .900(7)--pages 28-29	
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 18	no	
IRC sec 482 as a tool	no	no	yes, including 5% penalty .160(i)--page 21	no	yes	
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)	yes, if on lease (not precluded)	
DNR gets exploration Data				yes 024(a) page 8	yes 024(a) page 8	
020 (f) Sales Language				yes .020(f) page 7	yes .020(f) page 7	
NPSL regs after industry practice				yes 160(c)(1)(B) page 20	yes 160(c)(1)(B) page 20	

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: _____
Bill Version: CS for SB 305(FIN) am
() Publish Date: _____

Revision Date/Time (Note if correction): _____ Dept. Affected: Revenue
Title An Act Relating to the Production Tax on RDU Tax and Treasury
Oil and Gas Component Tax
Sponsor Rules Committee
Requester Hcuse Finance Component No. 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	577.6	589.2	600.9	613.0	625.2	637.7
Travel						
Contractual	517.5	487.9	118.2	118.6	121.0	123.4
Supplies	42.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous [OH office, etc]	37.1	37.1	37.1	37.1	37.1	37.1
TOTAL OPERATING	1,174.2	1,114.1	756.2	768.7	783.3	798.2

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()	<i>See analysis section</i>					
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FUND SOURCE (Thousands of Dollars)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
1002 Federal Receipts						
1003 GF Match						
1004 GF	1,174.2	1,114.1	756.2	768.7	783.3	798.2
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	1,174.2	1,114.1	756.2	768.7	783.3	798.2

Estimate of any current year (FY2006) cost: 275.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Full-time	7	7	7	7	7	7
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)
Relative to Status Quo

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes. The net income would be subject to a 22.5% tax, less a credit of 25% which applies to capital costs upstream of the point of production. There would also be a progressive surcharge based on .2% of one less the tax rate (22.5%) on the difference between actual the Alaska North Slope (ANS) oil price and \$50 applied to the gross value at the point of production. We note that the bill defines ANS wellhead price to be the prevailing value for oil produced in the Alaska North Slope area; this distinction, if intended, would result in an average 10% increase in the progressive surcharge at today's prices, or about \$35 - \$50 million per year over the amount shown in this fiscal note. There would be no surcharge when the ANS price was under \$50. The surcharge would not be considered a deductible lease expenditure. There would be an additional allowance of 22.5% of the production tax value multiplied by the quotient of 5,000 divided by the average daily production, limited to \$14 million annually, which sunsets in 2016. In addition, as a transition provision, there would be a 20% credit for capital costs incurred over the period April 1, 2001

Prepared by: Robynn Wilson, Michael Williams, Roger Marks, and Cheryl Nierhuis
Division: Tax Division

Phone: 269-1019
Date/Time: 4/26/06 12:00 AM

Approved by: Jerry Burnett
Agency: Department of Revenue

Date: 4/26/2006

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for SB 305 (FIN) am

ANALYSIS CONTINUATION

through April 1, 2006, which can be realized over the first 7 years following the effective date. However, credits in a given year are limited to expenditures based on one-half the qualified capital expenditures incurred in that year. It is estimated this would reduce revenues about \$700 million total over that period. Finally, the conservation surcharge on oil is decreased from 2 cents/bbl to 1 cent/bbl, while the additional conservation surcharge on oil is increased from 3 cents to 5 cents. The net impact of this, assuming that the oil and hazardous substance release prevention account is at capacity, would be a 2 cent/bbl increase in revenues.

The bill would be effective April 1, 2006.

Relative to Governor's Bill

The Governor's bill had no progressive surcharge. There was an deductible allowance of up to \$73 million of net income per company per year. There was a transition provision where all qualified capital expenditures incurred between July 1, 2001 through July 1, 2006 would be deductible over six years. The 3 cent conservation surcharge on oil would have been a credit against the oil tax.

The bill would have been effective July 1, 2006.

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. Columns 1-3 reflect the original fiscal note for the bill. Columns 4-5 reflect adjustments to the original fiscal note that correspond with net adjustments in state corporate income tax from changes in the severance tax, the recognition of the credit for the additional conservation surcharge on oil, the re-assessment of the number of full allowances from 7 company equivalents to nine, and minor model changes. Columns 6-8 reflect changes from converting from the Fall 2005 Department of Revenue Source Book data to Spring 2006. The volumes for the last quarter have been adjusted to reflect short-term production impacts resulting from the North Slope oil spill in March. Columns 9-11 reflect the Senate Resources CS. Columns 12-14 reflect the Senate Finance CS. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- \$100 mm/yr exploration
- \$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 cost on conventional oil
- \$5/bbl operating cost on heavy oil

The table shows the 2006-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a \$40 price, and a \$60 price. (Note that the status quo numbers are slightly different from what is reflected in the Spring 2006 Revenue Sources Book because of volume adjustments from the oil spill, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 5 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 3 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax, an amendment in the Senate regarding requires additional staff. In addition, we request 2 additional Tax Tech III positions (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenditures include \$100,000 and \$70,000 for programming in FY 07 and FY 08, respectively, \$300,000 in each of FY 07 and FY 08 for help in writing regulations, \$100,000 in each year for consulting services and an estimate of chargeback costs.. Supplies include computers and other supplies necessary for new positions.

See Page 3 for revenue estimates

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

GOVERNOR'S BILL
ORIGINAL FISCAL NOTE

Fiscal Year	DOR Forecast	Col. 1 Status Quo Tax	Col. 2 Tax from Bill	Col. 3 Gain from Bill
2006	na	na	na	na
2007	\$49.20	934	1,363	429
2008	\$40.95	697	915	217
2009	\$25.50	404	349	-55
2010	\$25.50	387	339	-48
2011	\$25.50	362	351	-11
2012	\$25.50	343	332	-10

GOVERNOR'S BILL
WITH CORPORATE INCOME TAX,
CONSERVATION SURCHARGE
NINE COMPANY ALLOWANCES
MINOR MODEL CHANGES

Col. 4 Tax from Bill	Col. 5 Gain from Bill
na	na
1,317	383
876	179
320	-84
310	-77
319	-43
300	-42

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill	Tax from Bill	Gain from Bill
2006	na	na	na	na	na	na
2007	\$40.00	737	1,038	301	997	260
2008	\$40.00	679	1,031	353	988	309
2009	\$40.00	673	1,118	445	1,070	397
2010	\$40.00	646	1,106	460	1,058	411
2011	\$40.00	606	1,138	532	1,086	480
2012	\$40.00	576	1,112	536	1,059	483

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill	Tax from Bill	Gain from Bill
2006	na	na	na	na	na	na
2007	\$60.00	1,165	1,938	773	1,879	714
2008	\$60.00	1,069	1,917	848	1,855	786
2009	\$60.00	1,042	2,007	965	1,939	897
2010	\$60.00	1,003	1,992	989	1,923	921
2011	\$60.00	941	2,051	1,110	1,977	1,036
2012	\$60.00	896	2,014	1,117	1,939	1,043

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for SB 305 (FIN) am

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

GOVERNOR'S BILL
CHANGES FROM FALL 2005 FORECAST
TO SPRING 2006 FORECAST

FISCAL NOTE
SENATE RESOURCES CS

Fiscal Year	DOR Forecast	Col. 6 Status Quo Tax	Col. 7 Tax from Bill	Col. 8 Gain from Bill	Col. 9 Status Quo Tax	Col. 10 Tax from Bill	Col. 11 Gain from Bill
2006	na	na	na	na	262	658	396
2007	\$53.60	989	1,514	526	989	2,379	1,390
2008	\$46.90	759	1,136	377	759	1,766	1,006
2009	\$25.50	355	302	-52	355	491	136
2010	\$25.50	315	283	-32	315	451	136
2011	\$25.50	281	291	10	281	445	164
2012	\$25.50	271	291	20	271	439	168

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill	Status Quo Tax	Tax from Bill	Gain from Bill
2006	na	na	na	na	174	315	141
2007	\$40.00	708	978	270	708	1,288	580
2008	\$40.00	655	953	298	655	1,255	600
2009	\$40.00	631	1,021	390	631	1,336	705
2010	\$40.00	532	990	408	582	1,296	715
2011	\$40.00	544	1,012	468	544	1,321	778
2012	\$40.00	536	1,021	485	536	1,330	794

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill	Status Quo Tax	Tax from Bill	Gain from Bill
2006	na	na	na	na	275	693	418
2007	\$60.00	1,120	1,840	720	1,120	2,834	1,715
2008	\$60.00	1,032	1,786	754	1,032	2,759	1,728
2009	\$60.00	978	1,848	871	978	2,839	1,861
2010	\$60.00	901	1,800	899	901	2,772	1,871
2011	\$60.00	842	1,841	999	842	2,824	1,982
2012	\$60.00	831	1,861	1,029	831	2,848	2,017

INCLUDES VOLUMES, PRICE, TAPS, MARINE, UPSTREAM, WELLS

SPRING 2006 VOLUMES FOR THE LAST QUARTER OF FY 2006 HAVE BEEN REDUCED TO REFLECT SHORT TERM ADJUSTMENTS FROM THE NORTH SLOPE OIL SPILL

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for SB 305 (FIN) am

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

FISCAL NOTE
SENATE FINANCE CS

Fiscal Year	DOR Forecast	Col. 12 Status Quo Tax	Col. 13 Tax from Bill	Col. 14 Gain from Bill
2006	\$57.45	262	546	284
2007	\$53.60	989	1,937	948
2008	\$46.90	759	1,404	645
2009	\$25.50	355	377	22
2010	\$25.50	315	341	26
2011	\$25.50	281	337	56
2012	\$25.50	271	332	61

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill
2006	\$40.00	174	255	81
2007	\$40.00	708	1,050	342
2008	\$40.00	655	1,022	367
2009	\$40.00	631	1,039	468
2010	\$40.00	582	1,063	483
2011	\$40.00	544	1,090	546
2012	\$40.00	536	1,059	563

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill
2006	\$60.00	275	580	305
2007	\$60.00	1,120	2,382	1,262
2008	\$60.00	1,032	2,317	1,285
2009	\$60.00	978	2,393	1,415
2010	\$60.00	901	2,334	1,433
2011	\$60.00	842	2,384	1,542
2012	\$60.00	831	2,409	1,578

Replaced on 4/26/06

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: SB 305
(S) Publish Date: 2/21/06

Revision Date/Time (Note if correction): _____ Dept. Affected: Revenue
Title An Act Relating to the Production Tax on RDU Tax and Treasury
Oil and Gas Component Tax
Sponsor Rules Committee
Requester Governor Component No. 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	359.2	366.4	373.7	381.2	388.8	396.6
Travel						
Contractual	1,200.0	520.0				
Supplies	24.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous (OH office, etc)	18.0	18.0	18.0	18.0	18.0	18.0
TOTAL OPERATING	1,601.2	904.4	391.7	399.2	406.8	414.6

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

CHANGE IN REVENUES () See analysis section

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	1,601.2	904.4	391.7	399.2	406.8	414.6
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	1,601.2	904.4	391.7	399.2	406.8	414.6

Estimate of any current year (FY2006) cost: 275.0

Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time	4	4	4	4	4	4
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes, and an additional \$73 million per year allowance for each producer. (The allowance can be no greater than the net value before the allowance.) The net income would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production. In addition, there would be a deduction for capital costs incurred over the previous five years, which can be realized over the next six years, but only in years where the ANS price is over \$40. It is estimated this would reduce revenues about \$170 million in years when it was realized. In years where the ANS price is under \$40 the deduction can be carried forward.

Prepared by: Robynn Wilson, Michael Williams, and Roger Marks
Division: Tax Division
Approved by: Jerry Burnett
Agency: Department of Revenue

Phone: 269-1019
Date/Time: 2/21/06 12:00 AM
Date: 2/21/2006

FISCAL NOTE # 2

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. SB 305

ANALYSIS CONTINUATION

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. They are predicated on the oil volumes in the Department of Revenue Fall 2005 Revenue Sources Book. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. They assume that seven producers utilize the full allowance. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- \$100 mm/yr exploration
- \$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 cost on conventional oil
- \$5/bbl operating cost on heavy oil

The following table shows the 2007-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a \$40 price, and a \$60 price. (Note that the status quo numbers are slightly different from what is reflected in the Fall 2005 Revenue Sources Book because of some minor changes in assumptions introduced since Fall 2005, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 3 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 1 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 1 additional position for a Tax Tech III (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenses include \$100,000 and \$70,000 for programming in FY 07 and FY 08, respectively, \$250,000 in each of FY 07 and FY 08 for help in writing regulations, and \$850,000 and \$200,000 in FY 07 and FY 08, respectively, for auditing costs related to the new transition rules. Supplies include computers and other supplies necessary for new positions.

FISCAL NOTE # 2

STATE OF ALASKA
 2006 LEGISLATIVE SESSION
ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

BILL NO. SB 305

Fiscal Year	DOR Forecast	Status Quo Tax	Tax from Bill	Gain from Bill
2007	49.20	934	1,363	429
2008	40.95	697	915	217
2009	25.50	404	349	-55
2010	25.50	387	339	-48
2011	25.50	362	351	-11
2012	25.50	343	332	-10

.....

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007	40.00	737	1,038	301
2008	40.00	679	1,031	353
2009	40.00	673	1,118	445
2010	40.00	646	1,106	460
2011	40.00	606	1,138	532
2012	40.00	576	1,112	536

.....

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007	60.00	1,165	1,938	773
2008	60.00	1,069	1,917	848
2009	60.00	1,042	2,007	965
2010	60.00	1,003	1,992	989
2011	60.00	941	2,051	1,110
2012	60.00	836	2,014	1,117

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: SB 305
(S) Publish Date: 2/21/06

Revision Date/Time (Note if correction): _____ Dept. Affected: Natural Resources
Title: Repealing the oil production tax and gas RDU: Resource Development
production tax etc. Component: Oil & Gas Development
Sponsor: Rules by Request of Governor
Requester: Governor Component No: 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()						
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2006) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

There is no anticipated fiscal impact for DNR associated with implementation of this legislation.

Prepared by: Bill VanDyke, Acting Director
Division: Oil & Gas
Approved by: Michael Menge, Commissioner
Agency: Natural Resources

Phone: 907-269-8600
Date/Time: 2/15/2006
Date: 2/15/2006

**Alaska State Legislature
HOUSE FINANCE COMMITTEE
AGENDA**

*Testimony by invitation only.

April 3, 2006 – Monday
9:00 a.m. – 11:00 a.m.

HB 488-OIL AND GAS PRODUCTION TAX

Round Table with:

Marianne Kah, Chief Economist, ConocoPhillips-Houston

Dr. Tony Finizza, Special Consultant, Econ One Research

Barry Pulliam, Senior Economist, Econ One Research

Dan Dickinson, Consultant, Tax Division, Revenue

Angus Walker, Commercial Vice President, BP-Alaska

David Bramley, Vice President, CRA International

TF

BP

DD

AW

DB

Co Chair

April 6, 2006
Questions for PPT Panel

General

1. Legislators took an oath to maximize the return on resources for the benefit of Alaskans. What do you believe is the best proposal to maximize this return while at the same time encouraging investment and exploration to extend the production life of our oil/gas resources?
2. Econ One stated that 25/20 was better in a low rate environment. What tax/credit rate best meets the balance between government and industry and high and low prices? Should we be considered a two-tiered system dependent on price?

4-6-06

Progressivity

3. Substantial discussion has occurred over the progressivity surcharges in the House and Senate bills. Outstanding issues of concern include inflation, the slope, and the cap. What do you consider to be a reasonable way to address these issues?
4. What issues are different when considering a progressivity surcharge on gas?
5. Are you aware of any other elements used by governments world wide that we should be aware of? Is our system too complex?

Transition

6. What does the State give away (monetarily) with the Senate version on transition? Is there some balance of 2 for 1 and the look back period? Is a sunset for transition needed?

Payment of Taxes

7. What is the benefit of a quarterly true up versus an annual true up? State and Industry perspectives.
8. What is the potential loss of revenue to the State of delaying implementation of PPT by a three-month period? What is the estimated time needed to write the regulations?

Conoco

Questions for House Finance Panel Discussion – April 6, 2006

- 1) How much of the future production is likely to come from exploration versus known fields versus heavy oil?
- 2) How will PPT impact these three (exploration, known fields, heavy oil) differently?
- 3) What mean field size is the likely expectation of explorers in Alaska?
- 4) Do you agree that for the existing players, the original bill, the House CS and the Senate CS will result in a greater tax burden relative to the current system?
- 5) Can you explain again how an explorer can be better off under 25% rather than 20%?
- 6) What do you think will be the result of PPT with respect to investment, and how would that impact production?
- 7) What is your view of the most likely price forecast (including low and high prices as well as type of distribution of prices) used by existing investors in Alaska when evaluating projects in Alaska?

Ruth

April 5, 2006

Questions for Finance Panel/or later

Hi Sharon – Some of these questions should work for tomorrow, but others I know will take some time. Just wanted to get them to you now, but I don't expect them all to get answered tomorrow. Beth

1. Can you suggest a progressive PPT that would not take all profit at extremely high prices (this is the question I asked of ECON One on 4/5/06)?
2. Taking into account just cash expenses related to production, removing exploration costs, depreciation, amortization and depletion, along with any other non-cash expenses, what would the state have received in total for 2005, from all sources of revenue from oil companies under a progressive severance tax structure where the tax is 25% at \$40 per barrel, 30% at \$50 per barrel, and 35%, at \$60 per barrel? What would the producers have kept?
3. What oil or gas that is currently taxable would be exempt from tax under the amendment to AS 43.55.020 (e)? What is the revenue impact? Is oil or gas expended in lease operations also a deductible lease expenditure under the PPT? If so, did you intend that oil and gas used in lease operations would

be both exempt from tax and also form the basis for a deduction and credit? If so, please explain the rationale.

4. AS 43.55.160 provides that direct costs do not include "(B) royalty payments" Did you mean to limit the exclusion to just "royalty payments"? Would production payments, overriding royalty payments and other types of similar payments be deductible as direct costs?

5. What is your opinion of why, given high oil prices and the current tax regime, Alaska has not seen more exploration? In your opinion, what are the best ways to incentivize exploration in general?

6. Given the differences in the older, "legacy" fields and new fields, do you think a greater tax on the legacy fields is justifiable? How would you devise such a tax?

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

DRAFT 5/4/06 4:00pm.

5/4/2006

source: DOR

	governor's bill	House Resources CS Version L	SENATE (page refs = S. Fin. CS)	House Finance CS Version
tax rate	20% .011(a)-page 3	20% .011(a)-page 3	22.5% general 5% on Cook Inlet oil .011(e)-pages 3-4	20.0% .011(e)-page 3 3/4 rev. excl. for Cook Inlet oil .160(a)-page 20 tax ceiling on Cook Inlet gas .011(l)-page 5
credit rate	20% .024(a)-page 5	20% .024(a)-page 8	25% .024(a)-page 7	20% .024(a)-page 7
private royalty tax rate	no special rate	5% .011(e)-page 3-4	5% oil & 1.67% gas Report from Commish .011(f)-page 4 & .180 pg 26	5% oil & 1.67% gas Report from Commish .011(f)-page 3 & .180 pg 27
Gas (GRE)	n/a		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 19	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 20
progressivity surcharge	none	over \$50/bbl WTI, (.3% x (WTI - \$50) x gross; <\$110 rate is 37.5% .011(f)-page 4	over \$50/bbl, (ANSwc - \$50) x .002 x ANSw h x .775 x bbls (oil only) .011(g) and (h)-pages 4-5	over \$35/bbl (net value/boe) x .0025 x net value .011(g) and (h) page 4-5
special gas progressivity?	n/a	yes .011(i)-page 4-5	no	n/a
progressivity deductible?	n/a	yes .160(a)-page 18	no .160(d)(2)(O)-page 22	no .160(d)(2)(O)-page 23
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)-pages 10-11	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	20% credit; no oil price test .024(i)-pages 10-11	20% credit; no oil price test .024(i)-page 11
sunset of transition	no	n/a	3/31/2013 .024(i)-page 11	7 yr rolling .024(i)(3) page 11
base allowance	\$73M deduction .160(i)-page 16	\$12M credit (equates to \$60M ded.) .170(a)-page 23	Revised 5000 bbl equivalent credit capped at 14 million .170(a)-pages 25-26	\$12M credit (equates to \$60M ded.) .170(a)-page 26
gold-plating solution				avail. up to 1/2 curr invest .170(a)-page 26
sunset of base allowance	none	3/31/2016 (exp incurred) .170(a)-page 24	3/31/2016 w/commissioner report .170(a)-page 25, .180 pg 26-27	10 yr rolling .170(a)-page 27
safe harbor	90%, annual true-up, no interest .020(a)-page 3	90% with interest .020(g)-page 7	95%, annual true-up, no interest .020(a)-pages 5-6	95%, annual true-up, no interest .020(a)-page 6
pmt < safe harbor??	interest only .020(a)-page 3	5% penalty + interest .020(h)-page 7	interest only .020(a)-pages 5-6	interest only .020(a)-page 6
effective date	7/1/2006 page 20	4/1/2006 Section 45-page 30	4/1/2006 Sec. 40 -page 33	7/1/2006 Sec. 40 -page 35

5/5

COMPARISON OF PPT BILL VERSIONS--HIGHLIGHTS

DRAFT 5/4/06 4:00pm.

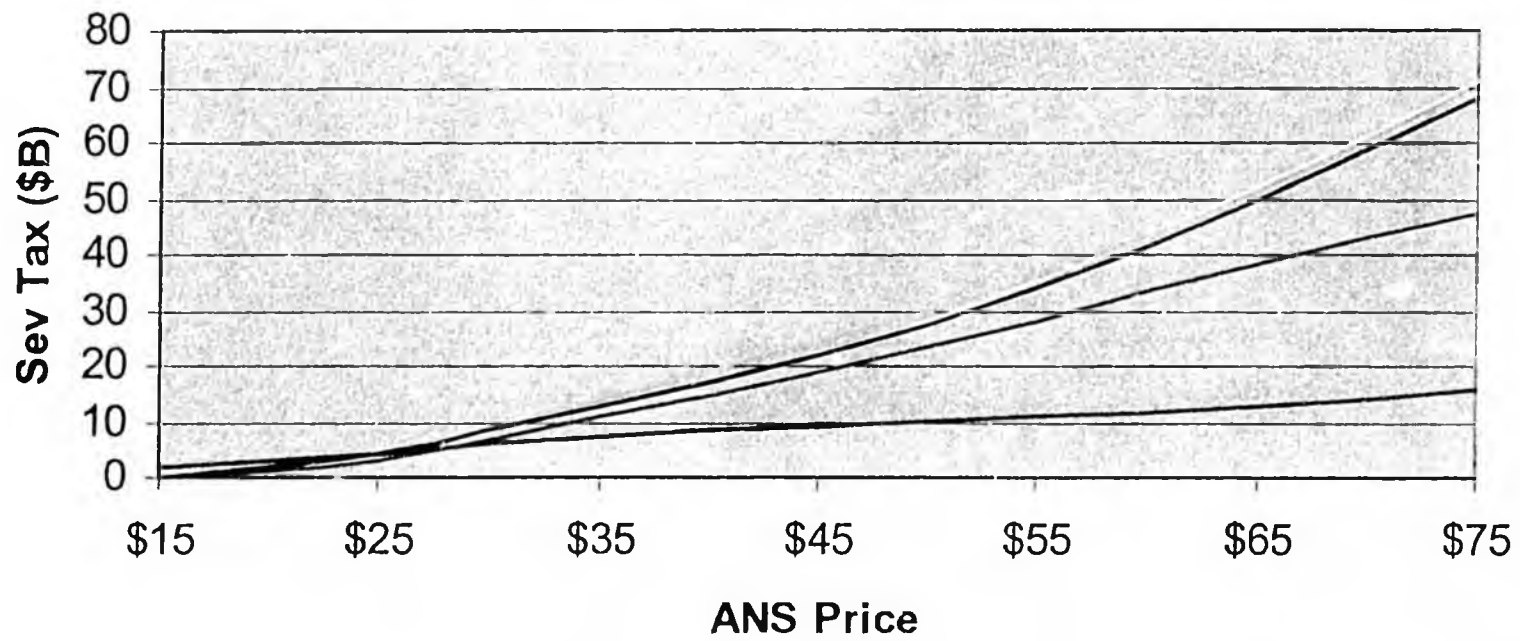
5/4/2006

source: DOR

	governor's bill	House Resources CS Version L	SENATE (page refs = S. Fin. CS)	House Finance CS Version
transition payment	none	6 mos. pymt on old system; true-up in 7th mo. <i>sec. 39--page 28</i>	6 mos. pymt on old system; true-up in 7th mo. <i>sec. 37(g)--pages 31-32</i>	6 mos. pymt on old system; true-up in 7th mo. <i>Sec. 36(h)--page 34</i>
spill surcharge total spill surcharge split (.201/.300) spill surcharge payable	no change (5 cents) 2/3 no change	no change (5 cents) 1/4 increase 1 cent <i>page 24-25</i>	increase 1 cent, to 6 cents 1/5 increase 2 cent <i>.201, .300 pages 27-28</i>	no change (5 cents) 1/4 increase 1 cent <i>pages 28-29</i>
surcharge treatment	creditable against PPT <i>page 17-18</i>	not creditable, not ded. <i>.160(d)(2)(L)--page 21</i>	not creditable, not ded. <i>.160(d)(2)(L)--page 22</i>	not creditable, not ded. <i>.160(d)(2)(L)--page 23</i>
SB 185 credit	no change	extends 10 years; only usable against PPT <i>.025(b), .025(f)--page 11-12</i>	extends 10 years; fixes \$20 m issue <i>.025(b), .025(f)--page 12-14</i>	extends 10 years; fixes \$20 m issue <i>.025(b), .025(f)--pages 13-14</i>
abandonment	no provision	no credit <i>.024(i)(2)--page 11</i>	no deduction or credit for abandonment on old production <i>.160(d)(2)(P) page 22</i>	no deduction or credit for abandonment on old production (improved language) <i>.160(d)(2)(P)--page 22</i>
credits usable	against PPT only <i>.024(a)--page 3</i>	against PPT only <i>.024(a)--page 8</i>	against PPT only <i>.024(a)--page 7</i>	against PPT only <i>.024(a)--page 7</i>
credits transferable	yes--20% tax limit <i>.024(d)-(e)--page 6</i>	yes--20% tax limit <i>.024(d)-(e)--page 8-9</i>	yes--20% tax limit <i>.024(d)-(e)--page 8-9</i>	yes--20% tax limit <i>.024(d)-(e)--page 9-10</i>
credits refundable?	no	up to \$10M depends on investment <i>.024(f)(5)--page 9-10</i>	no	no
credits for annual loss	yes, at 20% <i>.024(b)--page 5</i>	yes, at 20% <i>.024(b)--page 8</i>	yes, at 22.5% <i>.024(b)--page 8</i>	yes, at 20% <i>.024(b)--page 8-9</i>
point of production	upstream of gas treatment upstream <i>.900(7)--page 19</i>	upstream of gas treatment upstream <i>.900(7)--page 25-26</i>	upstream of gas treatment upstream <i>.900(7)--pages 28-29</i>	upstream of gas treatment upstream (definition added) <i>.900(7)--page 29-30</i>
DNR royalty value	yes <i>.150(d)--page 11</i>	yes <i>.150(d)--page 17-18</i>	no	yes <i>.150(d)--page 19</i>
IRC sec. 482 as a tool	no	no	yes (incl. §6662) <i>.160(i)--page 24</i>	yes (w/o §6662) <i>.160(i)--page 26</i>
catastrophic oil spill deductible?	yes, if on lease <i>(not precluded)</i>	no <i>.160(c)--page 19</i>	yes, if on lease <i>(not precluded)</i>	yes, if on lease <i>(not precluded)</i>
DNI gets exploration Data			yes <i>.024(a) page 8</i>	yes <i>.024(a)--page 7</i>
020 (f) Sales Language			yes <i>.020(f) page 7</i>	yes <i>.020(f)--page 7</i>
NPSL regs after industry practice			yes <i>.160(c)(1)(B) page 20</i>	yes <i>.160(c)(1)(B)--page 21</i>

DRAFT
HB 488 House Finance CS
Comparative Revenues
Alaska Department of Revenue
May 5, 2006

Cumulative Severance Tax 2007-2030 (\$Billions)



— sq — gov house res cs sb 305 — house fin cs

Annual Severance Tax @ \$40 2007-2030 (\$Millions)

