

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 148 3210

FISCAL NOTE

STATE OF ALASKA
2007 LEGISLATIVE SESSION

Fiscal Note Number: HB89-DOR-TAX-2-22-07

Bill Version: HB 89

() Publish Date:

Revision Date/Time (Note if correction):

Dept. Affected: Revenue 04

Title Oil and Gas Production Tax

RDU Taxation and Treasury

Component Tax Division

Sponsor Representative Gara

Requester (H) Oil and Gas

Component No. 2476

Expenditures/Revenues

(Thousands of Dollars)

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

OPERATING EXPENDITURES	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Personal Services						
Travel						
Contractual	300.0					
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	300.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES

CHANGE IN REVENUES ()

See analysis section -----

FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	300.0					
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	300.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2007) cost: 0.0

Check this box (X) if funding for this bill is included in the Governor's FY 2008 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

This bill would amend the oil and gas production tax by changing the base on which is taxed. Instead of taxing oil on the net value (wellhead value less qualified lease expenditures), this bill would tax oil on the gross value at the point of production. The rate at which oil would be taxed is 15%, and either (1) plus a price index of 0.35% times the differential between the ANS average price for the year and \$35 if the price is above \$35 per barrel up to a maximum rate of 40%; or (2) minus a price index of 0.35% times the differential between the ANS average price for the year and \$20 if the price is below \$20 per barrel.

Units that produce less than 75,000 barrels per day receive an exclusion of 7,500 barrels per day of gross value at the point of production. Oil under 20 degrees API gravity receives a 50% reduction in

Prepared by: Jon Iversen, Cherie Nienhuis and Roger Marks

Division: Treasury and Tax

Approved by: Jerry Burnett

Agency: Department of Revenue

Phone: 465-2300

Date/Time: 2/22/07 11:00 AM

Date: 2/22/2007

FISCAL NOTE

STATE OF ALASKA
2007 LEGISLATIVE SESSION

Fiscal Note Number: HB089-DOA-AOGCC 2-27-07
 Bill Version: HB089 (O&G)
 () Publish Date: _____

Revision Date/Time (Note if correction): _____

Dept. Affected: Administration

Title: Oil and Gas Tax

RDU: AOGCC

Component: AOGCC

Sponsor: Representatives Gara and Crawford, et. Al.

Requester: House Oil and Gas

Component No. 2010

Expenditures/Revenues

(Thousands of Dollars)

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

OPERATING EXPENDITURES	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Personal Services	406.0	406.0	406.0	406.0	406.0	406.0
Travel	0.0	0.0	0.0	0.0	0.0	0.0
Contractual	230.0	230.0	230.0	230.0	230.0	230.0
Supplies	10.0	5.0	5.0	5.0	5.0	5.0
Equipment	10.0	0.0	0.0	0.0	0.0	0.0
Land & Structures	0.0	0.0	0.0	0.0	0.0	0.0
Grants & Claims	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING	656.0	641.0	641.0	641.0	641.0	641.0

CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
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CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0
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FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts	0.0	0.0	0.0	0.0	0.0	0.0
1003 GF Match	0.0	0.0	0.0	0.0	0.0	0.0
1004 GF	656.0	641.0	641.0	641.0	641.0	641.0
1005 GF/Program Receipts	0.0	0.0	0.0	0.0	0.0	0.0
1037 GF/Mental Health	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory Cost Charge	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	656.0	641.0	641.0	641.0	641.0	641.0

Estimate of any current year (FY2007) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2008 budget proposal: ☐

POSITIONS

Full-time	3	3	3	3	3	3
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

If HB 89 is passed it would amend the powers of the AOGCC to make the determination of excess facilities capacity and the fees to be levied for access to that capacity.

On the Personnel side, this will require specific expertise to fulfill the new commitments: 1 Facilities Engineer, salary and benefits \$203,000; 2 Financial Analysts, salary and benefits \$101,500 (each position); supplies and equipment estimated for new positions;

Contractually the impact becomes \$200,000 per yr for a professional service contract for engineering and/or financial specialization (not in-house retained); Under AS 42.04.050(c) The Regulatory Commission of Alaska shall make available to the Alaska Oil and Gas Conservation Commission the services of a hearing examiner if workload permits, so \$30,000 (1/4 of a hearing examiners salary and benefits) (contractual service) is the cost.

NOTE: The fund source would be the general fund because the services that we will be providing under this bill target entities that do not currently pay the regulatory cost charge.

Prepared by: Jody J. Colombie

Phone 465-2200

Division: Alaska Oil and Gas Conservation Commission

Date/Time 2/27/07 9:54 PM

Approved by: Rachael Petro, Deputy Commissioner

Date 2/27/2007 5:30pm

Agency: Department of Administration

FISCAL NOTE

STATE OF ALASKA
2007 LEGISLATIVE SESSION

BILL NO. HB 89

ANALYSIS CONTINUATION

gross value.

Tax credits for oil exploration previously contained in AS 43.55.025 are included in a new section, AS 43.55.026, and have been increased from 20% and 40%, to 30% and 50%, respectively. In addition, there is a 25% credit for oil development wells. Credits generated under AS 43.55.026 may be applied against the credit holder's current year production tax liability, or they may be carried forward or transferred. The amount of the credit applied against a taxpayer's production tax liability may not exceed the total production tax liability under AS 43.55.001 for that taxpayer.

Gas would still be taxed on the net value of production. The department would need to implement regulations to allocate lease expenditures between oil and gas.

The bill would apply to oil and gas produced after May 31, 2007.

For our production tax estimates, we assumed that two-thirds of the production from four fields would qualify for the heavy oil exemption. These four fields include Polaris, Orion, West Sak, and Schrader Bluff. We estimated that costs for development wells average \$600 million per year, generating a credit of \$150 million per year. We also assumed that the exploration incentive credits detailed in AS 43.55.025 and .026 would generate \$60 million in credits each year.

With the above assumptions, and with Fall 2006 Department of Revenue price and production assumptions, we estimate production tax revenue under the PPT and this bill to be as follows:

Fiscal Year	DOR Forecast ANS WC Price	PPT Production Tax Revenues	HB 89 Production Tax Revenues	Gain/(Loss) from HB 89
2008	\$51.25	1432	1942	510
2009	\$49.50	1358	1828	469
2010	\$49.00	1288	1745	457
2011	\$50.00	1320	1774	454
2012	\$47.50	1303	1632	329
2013	\$45.00	1162	1309	147

FISCAL NOTE

STATE OF ALASKA
2007 LEGISLATIVE SESSION

Fiscal Note Number: HB089-DNR-O&G-02-21-07
 Bill Version: HB89
 () Publish Date: _____

Revision Date/Time (Note if correction): _____ Dept. Affected: Natural Resources
 Title Oil & Gas Production Tax RDU Resource Development
 Component Oil and Gas Development
 Sponsor Rep. Gara Component No. 439
 Requester House Oil and Gas

Expenditures/Revenues (Thousands of Dollars)

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

OPERATING EXPENDITURES	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
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 (FY2007) cost: 0.0

Check this box (X) if funding for this bill is included in the Governor's FY 2008 budget proposal: ☐

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

Currently under AS 43.55.025 (Alternative Tax Credit for Oil and Gas Exploration), DNR evaluates, for Dept. of Revenue, both oil and gas wells to determine whether a well or a potential well is directed at a distinctly separate exploration target.

HB 89 would amend AS 43.55.025 so that it would apply only for gas exploration. In addition, the bill would add a new section to AS 43.55 for an oil exploration tax credit. This new section would continue to charge DNR with the responsibility to evaluate whether a well or potential well is directed at a distinctly separate exploration target.

(Continued on next page)

Prepared by: Kevin Banks, Acting Director Phone 269-8800
 Division Oil and Gas Date/Time 2/21/2007
 Approved by: Tom Irwin, Commissioner Date 2/21/2007
 Agency Natural Resources

FISCAL NOTE

**STATE OF ALASKA
2007 LEGISLATIVE SESSION**

BILL NO. HB89

ANALYSIS CONTINUATION

In addition, this bill would give AOGCC authority to require, under certain conditions, working interest owners to provide access for other producers to production and other facilities whenever necessary.

There is no anticipated fiscal impact to DNR.

ENHANCEMENT OF THE "GROSS" CHARACTER OF THE PPT BILL

August 5, 2006

Pedro van Meurs

This memo has been written at the request of Senator Wagoner. The request was to provide ideas as to how the "gross" character of the PPT bill can be enhanced.

This memo does not reflect the views of the Administration and is solely meant to provide Senator Wagoner with my professional advice on these ideas.

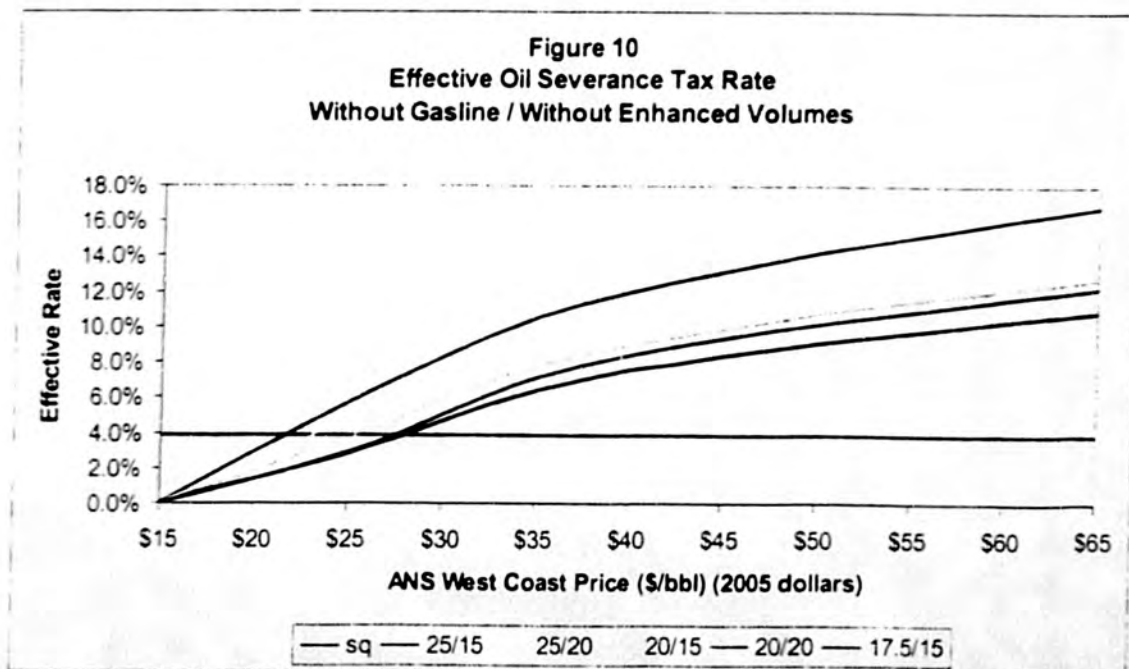
FLOOR

Considerable concern has been expressed about the fact that under some circumstances of low prices and high levels of investment, the PPT may result in less severance tax than we would have received otherwise under the current severance tax.

This can be prevented with the introduction of a "floor", very similar as was introduced in House Bill 3004.

The floor would be based on the **gross value** at the point of production of the taxable oil and gas.

Roger Marks presented to the Legislature in February this year a direct comparison between the various proposed PPT systems and the 4% average on gross that would be otherwise applicable to the year 2006.



These graphs prove that at about \$ 25 per barrel the current ELF produces about the same amount as a 22.5/20 PPT.

If we assume the adoption of a 22.5/20 PPT than one could take the position that the PPT should not be less than 4% of gross when the ANS West Coast price exceeds \$ 25 per barrel.

HB 3004 introduced the concept that at lower prices the North Slope oil becomes obviously less economic and it would be counter productive to continue to tax the oil industry. Therefore HB 3004 proposes a scale with a lower floor at lower prices.

This overall concept could be combined with the results of the analysis of Roger Marks as follows:

Over an ANS price of \$ 25 per barrel	-- 4%
When ANS is between \$ 20 and \$ 25 per barrel	-- 3%
When ANS is between \$ 17.50 and \$ 20 per barrel	-- 2%
When ANS is between \$ 15 and \$ 17.50 per barrel	-- 1%
Below \$ 15 per barrel	-- 0%

Each year the floor would be compared with the tax payable under the PPT and if the floor is higher, the higher amount would be paid.

Following is an example how the floor would work based on a PPT tax rate of 20% and a floor of 4%:

Gross Revenues	100	100	100
Cost deductions	40	90	120
Net Revenues	60	10	- 20
PPT Tax	12	2	-4
Floor	4	4	4
Tax payable	12	4	4

If the Gross Revenue based PPT is higher than the Net Revenue based PPT this extra payment can not be recovered in following years as a deduction. In other words this excess cannot be carried forward in order to be recovered in future years.

Of course, the payment of the differential between the Gross and Net Revenue based PPT cannot be taken as a deduction for the Net Revenue based PPT.

However, any carry forward credits as a result of a tax loss based on the Net Revenue based PPT remain unaltered.

Also under this scheme companies would not lose their capital investment credits of 20%.

It is also suggested that the additional non-transferable tax credits under Sec. 43.55.024 of the proposed House Bill 3001 (FIN) will still be creditable against the Gross Revenue Based PPT if this is higher than the Net Revenue Based PPT. These additional non-transferable tax credits were meant to protect small companies and encourage companies outside Cook Inlet and the North Slope. The Gross Revenue based PPT should not harm such companies.

INCREASE THE NON DEDUCTABLE ITEMS

The more costs are being excluded from the Net Revenue calculation the more the overall calculation becomes more similar to a Gross Revenue calculation. Therefore, the Gross Revenue character of the tax can be enhanced by simply adding to the list of items that are not considered lease expenditures.

There are two important cost components that could be excluded from lease expenditures:

- Costs related to gas development under a stranded gas contract, and
- Capital maintenance expenditures.

Gas development costs under a stranded gas contract.

Much concern has been expressed about the fact that with a net revenue based system there could be a joint cost problem in Point Thomson and other similar fields if the stranded gas contract would be implemented.

It is argued that all Point Thomson development and operating costs would be deductible under the PPT. At the same time under the stranded gas contract, companies would provide a 7.25% share to the State on gross and not pay the 20% or 22.5% PPT on gas. It is perceived that Point Thomson is being cross subsidized from what otherwise would be tax on oil under the PPT.

My view is that this is not a fair comparison, since reasonably all costs can be absorbed by the condensates. Nevertheless, this issue remains a concern of the Legislators.

It would be possible to add a further item on the list of non deductible costs under proposed AS. 43.55.165 (e) of House Bill 3001 (FIN) written as follows (*non legal language*):

- "(19) 75% of the capital and operating costs associated with the Point Thomson Unit and other gas fields that are being developed under a contract under AS.43.82, with respect to working interest owners which have concluded such a contract."

The 75% is based on the energy equivalent value considering that Point Thomson may have 400 million barrels of condensates and 7 - 8 Tcf of gas. In other words, the capital and operating costs would be allocated on an energy equivalent basis between condensates and gas. It is believed that many potential gas fields on the North Slope will have condensates and that these percentages may vary. For purposes of the bill, this percentage would be simply fixed.

The 25% allocated to condensates would be deductible for PPT purposes and would receive the related tax credits.

The 75% allocated to gas would not be deductible for PPT purposes and would not receive the related tax credits.

It can be assumed that the PTU would require a \$ 2.5 billion capital expenditure. Based on a 100% working interest, this arrangement would not receive a PPT tax reduction of \$ 750 million during development of the field. Assuming a \$ 1 billion operating expenditure over the life time of the field, it would mean that over time companies would pay \$ 150 million more tax during the operation of the field.

This is a significant tax increase, but in the total scheme of PPT taxation over the next 30 years this may represent only 1%-2% more tax.

Nevertheless, it would make the economics of Point Thomson development less attractive on an incremental basis and it would therefore make the entire gas project less attractive economically.

An interesting side effect of this arrangement is that it would place Chevron and other minority interest holders in a much better position relative to the sponsors. These companies have expressed concern that they would be discriminated against relative to the three sponsors. If Chevron and others do not join the stranded gas contract or would not be able to enter into a uniform upstream contract, they would at least benefit considerably relative to the Sponsors since they would receive the full tax deductions and credits. At the same time such companies would, of course, have to pay the full PPT on their gas income and therefore it is logical to permit them these tax credits and deductions.

Deemed Capital Maintenance Costs

Another concern that is regularly expressed is that the State should not permit the deduction of costs related to replacing equipment that is becoming defective or gathering lines that need to be replaced because of corrosion or other problems. The argument is that these assets should have been better maintained in the first place.

It should be noted that in most oil and gas fields, assets will have to be replaced after the technical life of such assets has expired. Therefore, such replacements are reasonable lease expenditures and are required to protect the health and safety of the workers and to protect the environment. Nevertheless, it is possible to exclude them from the lease expenditures under AS 43.55.165 (e) if this is politically desirable. A section could be added as follows (*non legal language*):

- (20) deemed capital maintenance expenditures which shall be capital expenditures equal to US \$ 0.30 per BTU equivalent barrel taxable production.

The US \$ 0.30 per BTU equivalent barrel is based on reasonable capital maintenance costs of fields for which I have (confidential) information. Based on a production of 900,000 barrel equivalent per day, this means that about \$ 100 million in capital expenditures per year will not be deductible for PPT purposes. Based on a PPT rate of 22.5% and a tax credit rate of 20% this means that the companies will pay \$ 42.5 million more tax per year.

An interesting side effect is that companies that would have a low level of capital expenditure per barrel would feel the effect more on a relative basis than companies that would have a high level of capital expenditures per barrel. Companies that re-invest strongly are therefore harmed less by this provision than typical harvesters.

HB 89
Gara / Crawford "Restore Tax on the Gross" Bill

Bill Comparison

	Former ELF	Murkowski PPT	Adopted PPT	Fair Share Bill: HB 89
Base Oil Tax	15%	20%	22.5%	15%
Progressivity	none	none	0.25% per dollar above \$40 (BOE net)	oil: 0.35% per dollar above \$35 gross gas: 0.25% per dollar above \$40 (BOE net)
Tax Basis	Gross Value	Reported Profits	Reported Profits	Oil: Gross Value Gas: Reported Profits
Deductions & Credits	none	broad definitions for lease expenditures and allowable tax credits	broad definitions for lease expenditures and allowable tax credits	Oil: exploration expenditures and development wells only Gas: retains PPT structure
Heavy Oil Benefit	None if oil over about \$10 / bbl	None (deduct all production costs)	None (deduct all production costs)	Rate cut in half when API below 20 degrees
Complexity	Moderate	High	Extreme	Low-Moderate
Verifiable?	Yes	No	No	Oil: Yes Gas: Retains PPT structure
Playground for Lawyers?	Moderate	High	High	Low
2007 Revenue at \$40 Oil	\$708 million	\$972 million	\$1,131 million	\$1,438 million
2007 Revenue at \$60 Oil	\$1,120 million	\$1,994 million	\$2,425 million	\$3,238 million

FAX

AUG 03 2006

SENT

"A letter to the legislature from Tom Irwin and Marty Rutherford"

August 3, 2006

Dear Representative GARA

Fax # 907-485-2518
269. 0109

We are writing to express our observations and concerns surrounding the creation of a new petroleum production tax system to replace the current severance tax system. We are encouraged by the effort of the legislature to revamp the current system and hope that the end product will be a tax that is straight forward, fair to all parties and is relatively easy to administer. In our view it is critical that the tax doesn't create opportunities for gaming behavior that will result in extensive litigation or arbitration. We believe that any new tax system should also have a progressive element so that the state can receive some of the upside at higher prices and provide some focused and easy to quantify investment incentives.

That said, it is relatively straight forward to achieve these objectives through modification of the existing gross production system by eliminating ELF, adding a progressive factor in which the state percentage increases at higher prices and by adding targeted incentives such as those for down hole well costs. New incentives should also be constructed with the current incentive programs such as exploration tax credits and with royalty reduction in mind.

The proposed alternatives that involve a net profits tax may work in theory but are very problematic in practice. We know because of our experience with net profit share leases. Under a net profit share system it is the companies' obligation to their shareholders for tax purposes to report the maximum amount of deductions and the minimum amount of profit. This will lead to extensive state auditing and disputes creating an adversarial relationship between the industry and the state along with a growth industry for accountants and lawyers on both sides of the disputes. Let's put more engineers, geologists and drillers to work instead by modifying the existing system to fix the current problems with ELF.

Finally we are concerned about the linkage between the proposed PPT and the proposed SGDA agreement for many reasons including the long term lock-up of an untested system and the interplay of the two agreements. For example, under the current tax system the state is entitled to a severance tax of between 9-10 percent of the non-royalty gas in the field without paying any development or operating costs. Under the combined PPT and SGDA agreement the state would give deductions and credits for 40 percent of the development costs and 20 percent of the operating costs and receive only 7.25 percent of the non-royalty gas. We strongly recommend that the legislature fully evaluate and understand how these linkages work and that you take the time to quantify the billions of dollars of additional value transfer from the state to the producers.

Thank you for listening to our concerns. We believe it is possible through relatively simple modifications of the existing gross severance tax system to achieve the goal of having a straight forward and manageable tax system that is fair to all parties.

Sincerely,

Tom Irwin and Marty Rutherford

PS. For clarification of any of the above, please call us c/o (907) 248-7954

COMMUNICATION PREV.
ADMINISTRATION

Backbone II
P.O. Box 101700
Anchorage, AK 99510 - 1700

Dear Representative *Bara*

Fax: (907) 465-3511 April 25, 2006

**An agenda for the maximum benefit
of all Alaskans**

- Don't pass new oil and gas provisions before you've seen the secret gasoline contract.
- If you do choose to take that risk, hold out for a minimum tax rate of 25% at \$40 per barrel with a progressive 1/4 percent increase per \$ per barrel.
- As a net profits tax can mean unending audits and litigation, include tough enforcement with big penalties for under-reporting.
- Even better for now, simply repeal ELF for the major North Slope production units. At \$60 oil, the state will receive an additional \$800 million this year.
- Don't mortgage our future with oil and gas taxes linked to a gas contract that apparently includes no commitment to build a project, and don't bind future legislatures to a 30-year tax rate. That clearly violates the Constitution and ensures decades of litigation and delay.
- Dump SB316 that effectively strips Alaskans of the right of judicial review and the democratic process.
- Protect the state's ability to develop North Slope gas. Include HB 71 in any oil and gas legislation and require the producers to provide a gas supply for the All Alaska gasoline and other legitimate competing proposals.
- This is the most important issue since statehood. Don't be rushed. Make sure that whatever you do is for the maximum benefit of the people. Take a break. After you've discussed these issues with your constituents, return to Juneau next year and work with a governor you can trust to do what's best for Alaska.

Thank you for your hard work on behalf of all Alaskans.

Wally

Walter J. Hickel

David Gottstein

David Gottstein

Co-Chairs, Backbone II

ALASKA STATE LEGISLATURE



REPRESENTATIVE LES GARA

June 8, 2006

Governor Frank Murkowski
State Capitol
Juneau, AK 99801

Dear Governor Murkowski:

On Wednesday you circulated a letter on how Alaska's oil tax revenue, under the House version of the oil tax bill, compared to other places in the world. However, the letter compared Alaska to some of the lowest taxing jurisdictions in the world and failed to mention the most relevant comparison: that the current House bill (23.5% tax) results in a tax that is substantially lower than the world average.

Your expert, Dr. Van Meurs, says the world average government revenue share is 65%, and the Legislature's experts have estimated it at 67% - 70%. The House oil tax bill results in a government share below even the lowest of these estimates. This is shown in the attached chart from Econ One, which I believe you also referenced.

At prices between \$20-\$70/barrel, the share under this bill ranges from 59% - 63%. Of note, even the highest tax passed by any legislative committee – the 25% tax adopted by the Senate Resources Committee which was in accord with the recommendations of our experts – resulted in a lower than world average tax, and was also quite competitive. The chart with that information is attached also.

Your letter compared the House bill to select low taxing jurisdictions – just those oil producing areas in North America. I think it would be fair for you to also mention the jurisdictions Alaska competes with around the world, as oil is a world commodity.

Under the global comparison, the rate imposed in the House bill is quite competitive. Dr. Van Meurs would concede our bill results in a lower than average tax, rather than a higher than average tax as your letters seems to imply.

Please feel free to call with any questions. I would appreciate it if you'd provide the correct information to those you sent your June 7 letter.

Sincerely,

Rep. Les Gara

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

Effective Tax Rate (Percent)

FROM TODAY

22.5/20, 0.25% at \$35 Net Trigger ²	0.0%	7.9%	12.0%	15.4%	19.3%	22.9%	26.2%
23.0/20, 0.25% at \$35 Net Trigger ²	0.0%	8.2%	12.4%	15.8%	19.7%	23.3%	26.7%
23.5/20, 0.25% at \$35 Net Trigger ²	0.0%	8.5%	12.7%	16.2%	20.1%	23.7%	27.1%

Alaska Government Take (Percent)

22.5/20, 0.25% at \$35 Net Trigger ²	32.7%	32.3%	32.9%	34.3%	36.8%	39.2%	41.6%
23.0/20, 0.25% at \$35 Net Trigger ²	32.7%	32.6%	33.3%	34.7%	37.2%	39.6%	42.0%
23.5/20, 0.25% at \$35 Net Trigger ²	32.7%	33.0%	33.6%	35.1%	37.6%	40.0%	42.4%

Total Government Take (Percent)

22.5/20, 0.25% at \$35 Net Trigger ²	62.6%	59.3%	58.9%	59.4%	60.8%	62.2%	63.7%
23.0/20, 0.25% at \$35 Net Trigger ²	62.6%	59.6%	59.1%	59.7%	61.1%	62.5%	63.9%
23.5/20, 0.25% at \$35 Net Trigger ²	62.6%	59.8%	59.4%	59.9%	61.3%	62.7%	64.2%

Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)

22.5/20, 0.25% at \$35 Net Trigger ²	(\$240)	\$111	\$525	\$1,068	\$1,843	\$2,760	\$3,818
23.0/20, 0.25% at \$35 Net Trigger ²	(\$240)	\$130	\$556	\$1,112	\$1,900	\$2,829	\$3,900
23.5/20, 0.25% at \$35 Net Trigger ²	(\$240)	\$148	\$588	\$1,156	\$1,956	\$2,898	\$3,981

FROM
ONE

Effective Average Tax Rates at Various Price Levels (FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

Effective Tax Rate (Percent)

Administration 20/20 ^a	0.0%	7.1%	10.8%	12.0%	13.5%	14.5%	15.2%
Senate Resources CS ^a	0.5%	9.9%	14.8%	18.8%	22.0%	24.8%	27.2%
Original Senate Finance CS ^a	0.0%	8.9%	11.2%	13.8%	15.7%	17.8%	19.8%
Final Senate Finance CS ^a	0.0%	8.9%	11.2%	14.5%	17.8%	20.7%	23.3%

Alaska Government Take (Percent)

Administration 20/20 ^a	32.8%	31.3%	31.5%	30.8%	31.0%	31.1%	31.2%
Senate Resources CS ^a	33.5%	34.7%	35.8%	37.7%	39.3%	40.9%	42.5%
Original Senate Finance CS ^a	32.8%	31.1%	31.9%	32.3%	33.2%	34.3%	35.4%
Final Senate Finance CS ^a	32.8%	31.1%	31.9%	33.3%	35.2%	37.1%	38.8%

Total Government Take (Percent)

Administration 20/20 ^a	62.9%	58.9%	58.1%	57.3%	57.2%	57.1%	57.1%
Senate Resources CS ^a (25% Tax + 20% Credit)	63.4%	61.1%	60.9%	61.7%	62.5%	63.4%	64.3%
Original Senate Finance CS ^a	62.9%	58.7%	58.4%	58.3%	58.9%	59.1%	59.7%
Final Senate Finance CS ^a	62.9%	58.7%	58.4%	58.9%	59.9%	60.9%	61.9%

Annual Average Tax Difference Above/Below Status Quo (\$2006 M)

Administration 20/20 ^a	(\$258)	\$55	\$416	\$683	\$1,044	\$1,405	\$1,768
Senate Resources CS ^a	(\$238)	\$240	\$787	\$1,489	\$2,280	\$3,160	\$4,128
Original Senate Finance CS ^a	(\$258)	\$42	\$453	\$885	\$1,384	\$1,972	\$2,639
Final Senate Finance CS ^a	(\$258)	\$42	\$453	\$875	\$1,673	\$2,470	\$3,368

Loss # 1: \$3.8 billion To Subsidize Gas Operations.

Loss # 2: \$500 Million to \$1 Billion to "Reward" Companies for Past Investments.

Loss # 3: \$350 - 700 Million For Delayed Implementation Date.

Loss # 4: \$1.3 billion at \$60/bbl - The New Proposed Tax Falls Far Short of the World Average Rate:

Total Loss:

Tax Write-offs: \$4.6 billion - \$5.5 Billion

**Taxing Below
World Average: \$1.3 billion/year**

Calculation from Econ One Charts As follows:

HB 3001 produces a 60.3% Government Take at \$60/bbl

World Avg is 67% Government Take

1% = \$200 million at \$60/bbl

Difference = Roughly \$1.3 billion/year

**Alaska State
Legislature
Representative Les
Gara**

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BACKGROUNDER · FOR IMMEDIATE RELEASE · August 1, 2006

\$5 Billion In Direct Oil Company Give Backs In Oil Tax Bill

Many of you have asked for a summary of the tax write-offs in the pending oil tax legislation. There are explained below, and total roughly \$5 billion.

The gas-related deductions and credits (Giveaway # 1) are not included in the revenue estimates our consultants issue on this legislation - per the Legislature's request. So when you're told what the various bills are projected to raise in future revenue, those numbers do not include a reduction for the gas-related deductions.

Please let us know if you have any questions. Rep. Les Gara (465-2647).

Giveaway # 1: \$3.8 billion To Subsidize Gas Operations.

The oil companies have demanded, in essence, that much or all of the additional oil revenue they pay under any oil tax legislation, at predicted average prices, be returned to them in gas subsidies. When the Legislature began this debate, we all agreed the oil tax system needed to be changed. Unfortunately, the bill now gives back much of what is raised in additional oil revenue through a series of gas-related write offs.

The proposed legislation requires that the state pay 40% (through a 20% deduction and 20% credit) of the cost of non-pipeline related gas field development costs (for exploration, production and production facilities). The state will not receive any ownership share in these facilities/projects.

In June the Legislature's consultants estimated those costs at \$9.2 billion, \$2 - \$3 billion of which will be for the development of Exxon-managed Pt. Thompson, a gas and oil field the Department of Natural Resources has already ordered (under former Commissioner Tom Irwin) Exxon to develop with no state subsidies. It is universally agreed that once a gas pipeline is agreed upon, gas production will be magnificently profitable, and that state subsidies to develop gas fields are unnecessary. This give back amounts to a roughly \$3.8 billion tax reduction. That eats away about 10 years of additional oil tax revenue raised (assuming companies fairly report their profits) under under this legislation.

BP has stated: "It is very likely that, in the medium term, prices will stand at about \$40 on average." Lord Browne, *Guardian Unlimited*, 7/12/06. It is projected that over the course of the next 10 years, at \$40 barrel, the new legislation will raise an additional \$4 - \$5 billion in oil tax revenue before these deductions and credits are subtracted. These gas write offs will eat away almost 10 years of projected future oil tax revenue.

Giveaway # 2: \$500 Million to \$1 Billion to "Reward" Companies for Past Investments.

The proposed legislation includes an unprecedented retroactive tax credit. Companies can receive a 20% deduction from their tax payments for their past 5 years of capital investments. It is estimated companies have averaged roughly \$1 billion in investment per year, and 20% of \$5 billion equals \$1 billion in tax payment

reductions. The formula provides that they can write off 1\$ in past investments for every \$2 they invest in the future. If companies simply invest at the level they have in the past, they are entitled to half of this credit, or \$500 million in tax payment reductions. If they increase their investments they can qualify for up to an additional \$500 million. It is irresponsible, and unprecedented, to give a \$500 million to \$1 billion tax break for past investments - especially past investments made under a broken tax system that helped earn them record profits. Again, this give back was requested by the oil companies to offset any increase in future tax payments.

Giveaway # 3: \$350 - 700 Million For Delayed Implementation Date.

Democrats, and the Governor when he originally proposed his bill, have called for the new tax to become effective on the first of this year. Normally tax legislation takes effect the first of the year, as did Alaska's 1989. The Governor now requests that the bill not take effect until July 1, and current legislative proposals would implement the bill as of April 1. A 3 month delay reduces this year's revenue by roughly \$350 million. A 6 month delay would reduce revenue by roughly \$700 million. If the oil companies are being given 5 years of retroactive investment credits, then the state is easily entitled to implement this tax, as is the norm, as of January 1, 2006.

Giveaway # 4: \$1.2 - \$2 billion/Year - The New Proposed Tax Falls Far Short of the World Average Rate:

According to the Legislature's Expert, Daniel Johnston, "the world average government take even right now is probably 67% or 70% depending on how you calculate it." Joint House Resources/Finance Committees, March 6, 2006. International consulting firm Wood Mackenzie says it's 70%. That's the total percentage of oil value received by local, state and federal government. Projections are that the current legislation would result in a government take rate of roughly 60% at \$60/barrel. At \$60 barrel each percentage of government take raises roughly \$200 million in revenue. Falling 7% - 10% below the world average costs the state between \$1.4 billion and \$2 billion/year in lost revenue. Early testimony on oil tax legislation was that the state would be justified, given the relative safety of investments, in taxing at the world average.

Total Loss To Alaska In Bill:

Tax Write-offs: \$4.6 billion - \$5.5 Billion

Taxing Below
World Average: \$1.2 = \$2.0 billion/year.

Effective Average Tax Rates at Various Price Levels (FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars:	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00
Effective Tax Rate (Percent)							
Administration 20/20 ¹	0.0%	7.1%	10.8%	12.0%	13.5%	14.5%	15.2%
Senate Resources CS ¹	0.5%	9.9%	14.8%	18.8%	22.0%	24.8%	27.2%
House Resources CS ¹	0.0%	7.2%	10.9%	14.9%	18.9%	22.5%	25.9%
Original House ¹	0.0%	7.2%	11.3%	14.6%	18.5%	22.0%	25.3%
Original Senate ¹	0.0%	7.0%	11.2%	14.5%	17.8%	20.7%	23.3%
Current Senate ¹	0.0%	7.3%	11.6%	14.4%	16.9%	19.0%	20.8%
Alaska Government Take (Percent)							
Administration 20/20 ¹	32.8%	31.3%	31.5%	30.8%	31.0%	31.1%	31.2%
Senate Resources CS ¹	33.5%	34.7%	35.8%	37.7%	39.3%	40.9%	42.5%
House Resources CS ¹	32.8%	31.5%	31.7%	33.7%	36.3%	38.8%	41.2%
Original House ¹	32.8%	31.5%	32.0%	33.4%	35.9%	38.3%	40.7%
Original Senate ¹	32.8%	31.2%	32.0%	33.3%	35.3%	37.1%	38.8%
Current Senate ¹	32.8%	31.5%	32.4%	33.2%	34.4%	35.5%	36.5%
Total Government Take (Percent) Senate HB 3001							
Administration 20/20 ¹	62.9%	58.9%	58.1%	57.3%	57.2%	57.1%	57.1%
* Senate Resources CS ¹ 25/20 PPT	63.4%	61.1%	60.9%	61.7%	62.5%	63.4%	64.3%
House Resources CS ¹	62.9%	59.0%	58.2%	59.1%	60.6%	62.0%	63.5%
Original House ¹	62.9%	59.0%	58.5%	59.0%	60.3%	61.7%	63.2%
Original Senate ¹	62.9%	58.8%	58.4%	58.9%	59.9%	60.9%	61.9%
Current Senate ¹	62.9%	59.0%	58.7%	58.8%	59.4%	59.9%	60.5%
Annual Average Tax Difference Above/Below Status Quo (\$2006 M)							
Administration 20/20 ¹	(\$256)	\$55	\$416	\$683	\$1,044	\$1,405	\$1,766
Senate Resources CS ¹	(\$238)	\$240	\$787	\$1,489	\$2,280	\$3,160	\$4,126
House Resources CS ¹	(\$256)	\$62	\$431	\$1,022	\$1,826	\$2,771	\$3,867
Original House ¹	(\$256)	\$62	\$462	\$993	\$1,767	\$2,688	\$3,755
Original Senate ¹	(\$256)	\$46	\$457	\$979	\$1,677	\$2,474	\$3,360
Current Senate ¹	(\$256)	\$66	\$492	\$971	\$1,546	\$2,180	\$2,873

World Average = 67.1% - 70.1%

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New HB 3001 = 60.3% Gov. Take at \$60/BBL
 WORLD AVE = 67.1% Gov. Take
 Each 1% = \$200 million.
 HB 3001 Difference \$1.3 Billion Less than World Ave.

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

Effective Tax Rate (Percent)

CS for HB 3001 (FIN) ²	0.0%	7.1%	11.2%	14.6%	18.7%	22.6%	26.2%
SCS HB 3001 (NGD) ²	0.0%	8.5%	12.4%	15.0%	18.6%	22.0%	25.3%
CC CS for SB 2001 ³	3.4%	8.2%	12.3%	15.5%	18.7%	21.5%	24.1%
Administration 20/20 ³	0.0%	7.3%	10.9%	12.1%	13.5%	14.5%	15.2%

Alaska Government Take (Percent)

CS for HB 3001 (FIN) ²	32.3%	31.3%	31.9%	33.5%	36.3%	39.0%	41.6%
SCS HB 3001 (NGD) ²	32.3%	32.9%	33.3%	33.9%	36.1%	38.5%	40.9%
CC CS for SB 2001 ³	38.0%	32.6%	33.2%	34.4%	36.2%	37.9%	39.7%
Administration 20/20 ³	32.3%	31.5%	31.6%	30.9%	31.1%	31.3%	31.4%

Total Government Take (Percent)

CS for HB 3001 (FIN) ²	62.0%	58.6%	58.2%	58.8%	60.4%	62.1%	63.7%
SCS HB 3001 (NGD) ² (new Senate)	62.0%	59.6%	59.1%	59.1%	60.3%	61.7%	63.2%
CC CS for SB 2001 ³	65.7%	59.4%	59.0%	59.4%	60.4%	61.4%	62.4%
Administration 20/20 ³	62.0%	58.7%	58.0%	57.2%	57.1%	57.1%	57.0%

Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)

CS for HB 3001 (FIN) ²	(\$240)	\$57	\$437	\$945	\$1,725	\$2,662	\$3,736
SCS HB 3001 (NGD) ² (new Senate)	(\$240)	\$140	\$546	\$989	\$1,700	\$2,571	\$3,581
CC CS for SB 2001 ³	(\$111)	\$125	\$539	\$1,046	\$1,714	\$2,482	\$3,348
Administration 20/20 ³	(\$240)	\$69	\$413	\$664	\$1,008	\$1,352	\$1,696

August 9, 2006
6:36 PM

¹ Assumes no major gas sale

² Calculated from April 2006. Includes transition (50% of sales over 1st 7 years to maximum of \$5 billion) and \$60 million exemption over 8 companies for 10 years. Volumes per DOR Spring 2006 Forecast

³ Calculated from July 2006. Includes 6-year transition (100% 2001-2005) and \$73 million exemption over 7 companies. Volumes per DOR Spring 2006 Forecast

econ
ONE

WOOD MACKENZIE

GLOBAL OIL AND GAS — RISKS AND REWARDS 2004

Alaska's Profitability – Full Cycle, Post Government Take

Rate of Return (IRR – Nominal)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	15/49	14/52	14/53
Alaska's IRR	18.09%	23.57%	29.11%
Global Average IRR	15.20%	18.94%	23.07%

Full Cycle Government Take

Full Cycle Gov't Take (% Of Pre-Take Net Cash Flow, Undiscounted)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	33/54	24/54	19/55
Take on AK Production	71.70%	63.63%	58.40%
Global Ave. Take	70.86%	70.26%	73.34%

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Representative Mike Chenault
Representative Bruce B. Weyhrauch
House Finance Committee
Juneau Alaska 99801

5 May, 2006

Re: Working Notes/Discussion Paper

Gentlemen:

Further to your letter of 27 April, 2006 I address here your questions. I was also asked to call-in on Saturday the 29th and this is in response to that as well. The 1-888-295-4546 number for the hearings on the 29th did not work from where I was in Abu Dhabi. I am now in Dundee, Scotland. I will be here until the 13th of this month.

You are certainly asking the right questions to determine if Alaska is "competitive, unreasonable, or is being taken advantage of". If I may summarize/paraphrase your questions:

- Should the system be *progressive*?
- What should the tax *base* be?
- What should the tax *rate* be?
- Will the tax rate and tax base destroy investment?

My answers to your questions follow your letter (below).

I hope this information is helpful. I wish you all the very best.

Sincerely,

Sent by e-mail

Daniel Johnston

Alaska 5 May 2006 Response

JOHNSON LETTERS

April 27, 2006

Representative Mike Chenault
House Finance Committee
Juneau Alaska 99801

Re: CSHB 488

Dear Mike:

I ask for a side-by-side comparison of Alaska's current and proposed tax rates with those of other major oil-producing regions of the world. I believe Daniel Johnstone could provide this information. I am trying to find out, at base, an objective basis for deciding if Alaska is competitive, unreasonable, or is being taken advantage of thought the provisions of PPT. I would suggest that regions producing at least 800,000 barrels daily be included in this analysis. I would not recommend rates from other states as none are really comparable, and each state's history of tax policy is unique.

Finally, I have questions that I would like Mr. Johnstone to address which I set forth in the form of assumptions that I would like feedback upon and would ask him to advise whether these statements are correct:

1. Virtually all other major oil-producing regions tax at a significantly progressive rate starting from as low as \$25, or lower.
2. Few regions have their revenue based on "net profit", but rather more objective (and less potentially litigious) criteria such as well-head value, gross revenue, or market price.
3. Alaska's current and proposed rates are both well below "market".
4. Many regions will be shown to have favorable investment incentive policies (something I see as important), and I think those proposed for Alaska would be seen as competitive, and perhaps generous, by world standards.

Sincerely,

Representative Bruce B. Weyhrauch

Question 1. Virtually all other major oil-producing regions tax at a significantly progressive rate starting from as low as \$25, or lower.

Short Answer: 25% of the world's systems are truly progressive. However, nearly 70% of the world's systems tried to do this with all kinds of sliding scales but most of them failed to accommodate today's situation with unexpectedly high prices (they didn't even come close).

Long Answer: Around one fourth of the world's systems from major oil-producing nations have a truly progressive system. (See the statistics below that were provided in my March 6 testimony.)

While only 25% or so of the worlds systems are actually progressive, around 70% have sliding scales based on production rates or accumulated production that attempt but fail to create a truly progressive environment. Most of these sliding scales are inefficient because they didn't even wiggle when oil prices spiked. Similarly, the ELF system did not respond to oil prices changes. Other countries are re-thinking their systems—particularly those countries with sliding scales that did not respond to the recent price shock.

The Petroconsultant's statistics (below) from their Review of Fiscal Regimes (RFR 1995) show just *how* progressive these systems are. Their analysis was based on a price differential of only \$10/BBL (i.e. \$13/BBL to \$23/BBL). This was one of the reasons why I stated that with a price differential of around \$20-30/BBL (i.e. going from \$20/BBL to \$40-50/BBL) government take should increase by at least 5 percentage points.

Some of the Production Sharing Contracts in Azerbaijan are considered to be very progressive and with oil prices going from \$20/BBL to \$60/BBL Government take increases by around 15 percentage points or more.

I believe a fair progressive change in "Take" in Alaska with oil going from say \$40/BBL to \$80/BBL would be at least 10 percentage points. This would equate to an increase in the PPT rate of around 25 percentage points (my estimate at the moment).

Database Table 7			
World Petroleum Fiscal System Statistics			
From: D. Johnston Database (PennWell Books, Tulsa, 2002) and found in my 6 Mar, 2006 testimony			
	PSCs	World Average	Royalty/Tax Systems
Number of Systems	72	136	64
Government Take	70%	65%	59%
Gvt. Participation			
Systems with Gvt. Participation (%)	36 (50%)	65 (48%)	29 (46%)
% Participation in those Systems with Gvt. Participation	25%	27%	30%
Royalty	5%	7%	8%
Effective Royalty Rate	23%	17%	8%
Ringfenced Systems	75%	55%	30%
Systems with ROR features or "R" factors	17%	21%	25%

Database Table 8			
Alaska's Prudhoe Bay and Kuparuk Fields belong here			
Fiscal System Statistics – for the more Prospective Countries			
From: D. Johnston Database (PennWell Books, Tulsa, 2002) and found in my 6 Mar, 2006 testimony			
20th Percentile			
	PSCs	Average	Royalty/Tax Systems
Number of Systems	19	25	6
Government Take	78%	79%	80%
Gvt. Participation			
Systems with Gvt. Participation (%)	12 (63%)	17 (68%)	5 (83%)
% Participation in those Systems with Gvt. Participation	28%	32%	42%
Royalty	5%	6.8%	11%
Effective Royalty Rate	29%	24.5%	11%
Ringfenced Systems	90%	76%	33%
Systems with ROR features or "R" factors	26%	24%	16%

Systems with ROR features or "R" factors are the more progressive systems in the world. Another progressive fiscal device is the "Price Cap Formula" (sometimes called *windfall profits tax*) which is rather rare and not represented in the statistics above. However, many countries are adding these features now or are simply changing their systems because their systems did not have adequate flexibility built-in.

World Fiscal Terms – Regular and Special Situations			
From: D. Johnston course workbook 2006			
	Government Take	Effective Royalty Rate	Comment
World Average for Oil (Includes all types of contracts: exploration, development, rehabilitation, EOR, heavy oil)	65%	20%	
World Average for Gas	56%	15%	Many contracts have a "gas clause"
Frontier Terms	56-60%	15%	
Heavy Oil Terms	50%	10%	These are still fairly rare
Deepwater Terms	58%	13%	

IMPORTANT:

Most published Government Take statistics represent the market for exploration contracts NOT developed-producing reserves like Prudhoe Bay and Kuparuk.

Average State Take for Deepwater Projects

From: Petroconsultants "Review of Petroleum Fiscal Regimes (Oil) 1997."

	Marginal Fields	Economic Fields	Upside Fields
UK	33.4%	33.0%	33.0%
USA (OCS)	46.1	41.4	37.1
Cote d' Ivoire	50.9	49.2	46.8
Nigeria	53.1	57.8	58.5
Thailand	53.3	54.7	50.5
Angola	56.2	52.6	64.8
Gabon	56.6	52.6	50.0
Congo	67.6	61.4	58.6
Indonesia	74.2	72.4	71.3
Malaysia	78.2	74.1	71.3
Average Deepwater	57.0	54.9	54.2
World Average (116 Fiscal Regimes)	69.9	65.1	63.9

Breakdown (From Petroconsultant's Review of Fiscal Regimes 1995)

72% Regressive	76.2	68.4	65.3
5% Neutral	56.5	55.8	55.7
23% <u>Progressive</u>	62.8	67.4	72.2

Average State Take (Peer Group Comparison)

From: Graham Kellas - Petroconsultants

"New Fiscal Incentives encouraging Global Push Into Deepwater Plays"

The American Oil & Gas Reporter - Special Report; April, 1997 (pg 47-50)

	Marginal Fields	Economic Fields	Upside Fields
20 Largest Producing Regimes	80.0%	74.6%	72.7%
30 Significant Producing Regimes	73.4%	66.7%	67.7%
66 Frontier Regimes	65.3%	60.5%	59.5%

IMPORTANT: Sorry to repeat myself BUT:

Most published Government Take statistics represent exploration contracts NOT developed-producing reserves like Prudhoe Bay and Kuparuk.

Question 2. Few regions have their revenue based on "net profit", but rather more objective (and less potentially litigious) criteria such as well-head value, gross revenue, or market price.

Short answer: Most of the revenues governments receive from petroleum operations come from profits-based mechanisms (like taxes).

Long answer: There are 4 main means by which governments get a piece of the pie:

- 1. Signature Bonuses**
- 2. Royalties**
- 3. Profits-based elements (such as taxes and profit-oil sharing)**
- 4. Government participation**

Of the overall share that Governments typically receive, the lion's share (around 70% by my estimate) comes from profits-based fiscal elements (i.e. net profit).

It is true that basing the levy on "gross" is more objective than "net" but the problem I have is this: if the PPT was to be shifted from "gross" to "net" then other major adjustments need to be made—most importantly the tax *rate* needs to be increased. I have not seen discussion yet of how much the rate needs to be adjusted but it is an exercise in algebra for the most part. But as we have seen there are other important factors as well. Basing the levy on "gross" is simpler no doubt, but the arguments regarding "fairness" to explorers is legitimate too.

Question 3. Alaska's current and proposed rates are both well below "market".

**Short answer: Yes — as far as Prudhoe Bay and Kuparuk are concerned
Not necessarily— as far as Arctic exploration is concerned
No — as far as Cook Inlet is concerned**

These answers apply to all versions (House, Senate, Administration) I have seen so far because they are not significantly different relative to this question.

Long answer: Please refer Table 8 from my Database above (also included in my 6 March testimony). Government take for these major producing regions is closer to

80%. However these regions are not typically "high-cost" regions like Alaska. But, just because a region is "high cost" does not mean that government take should be 15-20 points lower. ALSO those statistics do not represent fields like Prudhoe Bay and Kuparuk where there is long-standing production i.e. not exploration. By world standards, government take at Alaska's Prudhoe Bay and Kuparuk fields is very low. Even Table 8 represents for the most part exploration contracts and the market for exploration acreage.

Important note—For example: the UK statistic for Government take that I used at the time that my database was published (same as Wood Mackenzie and van Meurs) was 30%. Because we typically compare the marketplace for exploration projects we typically ignore existing established production like the 800,000 BOPD + production at PHB and KRU.

Question 4. Many regions will be shown to have favorable investment incentive policies (something I see as important), and I think those proposed for Alaska would be seen as competitive, and perhaps generous, by world standards.

Short answer: There is no short answer. And, this question is much more relevant to future exploration not existing established production at Prudhoe and Kuparuk.

Long answer: This of course is the fundamental issue and it is made much more complex by our attempt to achieve a "one-size-fits-all" system.

Remember the UK has a 75% Government take for fields that would more appropriately compare to PHB and Kuparuk. Statistics that are most often published (like Wood Mackenzie, Petroconsultants and my Database) are for new exploration and they are discussed in the context of "future investment activity" and competitiveness in the industry. For example I know of no data bases that use the 75% government take for the UK.

I believe the terms proposed by the Administration would work for Alaskan Arctic exploration but at the same time they are a give-away for PHB and Kuparuk. That is the problem. The terms proposed by the House and Senate are not significant departures from those of the Administration. It looks like "fine-tuning" to me when more significant changes are appropriate.

Figure 1

Figure 1 (below) depicts the situation we are faced with. It over-simplifies the overall situation but even on this relatively basic level it helps illustrate that there is the danger of focusing on the wrong objective.

The Base Production is comprised almost entirely of North Slope production from legacy fields as we have come to call them. It represents the production that would result if no further capital was invested. In terms of value to Alaska from royalties and taxes it is more valuable than future incremental production because of (1) timing and (2) new production will likely cost more because it requires capital investment as well as operating costs. The one thing that incremental production offers is more jobs. The questions are: Does Alaska need more jobs? How many? Isn't the important thing that we don't *erode* the job base? If we are not careful we will focus too much on job preservation with some job creation at a very high price. So is Alaska going to lose jobs to other parts of the world? Where might that be? The following quotes I believe have resonance here for us:

"BP hasn't done any exploration in the last five years, why would they do it now?"

Tom Irwin former Chief of the Department of Natural Resources.
Sun Star (online edition) University of Alaska Fairbanks News, Tuesday May 2, 2006

"When you start polling the world where major oil companies can do business, you have West Africa, Russia, the Middle East and Latin America. What they all share is that they're becoming more and more difficult operating environments,"

Bruce Lanni oil analyst with A.G. Edwards
Energy Nationalization Reshapes Politics, Brad Foss 3 May 2006 Associated Press

"Alaska is expensive, but none of the officials need armed guards or compounds with barbed wire."

Tom Irwin former Chief of the Department of Natural Resources.
Sun Star (online edition) University of Alaska Fairbanks News, Tuesday May 2, 2006

I agree with these sentiments. Many parts of West Africa especially Nigeria are extremely volatile, and dangerous these days. Russia is still an extremely frustrating place to do business and few (if any) western companies are making money the old fashioned way by developing and producing oil or gas fields (and after all these years too). And of course Latin America is leading the world with nationalizations like we are seeing in Venezuela and Bolivia. Much of the Middle East is simply not available to the kind of investment we are discussing in Alaska (Iran, Iraq, Kuwait and Saudi Arabia for example). So is Alaska really as difficult

as some would have us believe? No.

Alaska's Future — Basic Elements

Designing the fiscal system to accommodate new exploration (of any sort) means the existing production base (Base Production below) will likely be under-taxed. This is because it is so difficult to capture both fairly with the same terms. It means Alaska could pay a high price to encourage future exploration or investment activity.

Incremental Production

Whether or not Alaska is able to maintain or attempt to maintain the existing production rate is influenced mostly by oil prices. Companies like BP and ExxonMobil for example will not explore in AK regardless of oil price (based in past behavior and recent testimony). Further development such as enhanced oil recovery within existing fields will be the most likely source of "incremental production". But this kind of investment is much lower risk than exploration.

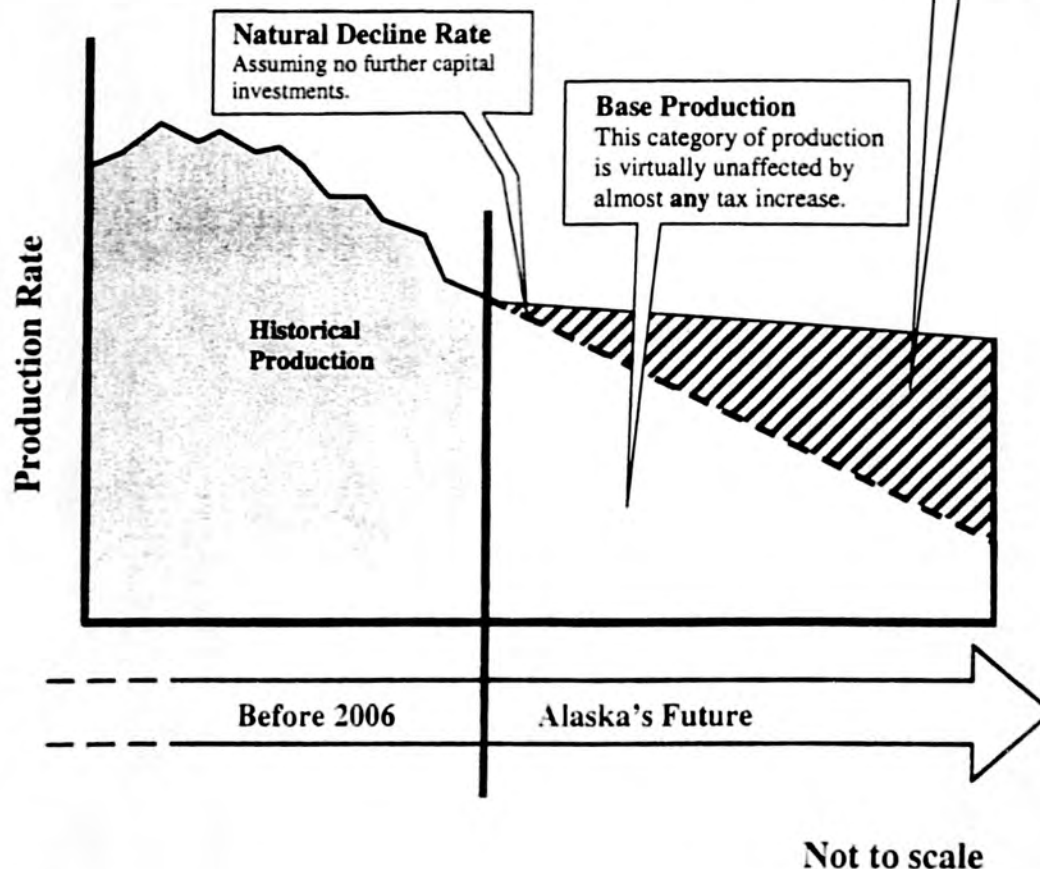


Figure 1

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**Alaska Legislative Budget and Audit Committee
Twenty-Fourth Legislature 2005-2006 Second Session
Juneau, Alaska**

22 April, 2006

Re: Alaska Oil Tax Legislation

Dear Legislators,

Further to our numerous meetings, discussions, my prior testimony, and in response to recent queries I submit these additional thoughts.

The Appropriate Tax Rate

Considerable discussion has centered on the tax rates that would be appropriate for the different situations, basins and provinces that exist in Alaska.

As you may recall some of the exploration companies in Alaska said the 20/20% PPT, as proposed by the Administration, could be acceptable. However, they were concerned about the status of the existing credit arrangement and whether or not that would continue. However, many of the smaller companies also confirmed that a 25/20% PPT arrangement would work too if oil prices remained above \$40-45/BBL. Below a \$35/BBL price threshold Arctic exploration under any circumstances gets tight.

If we consider that an explorer in the Alaskan Arctic could live with a 25/20% PPT (as originally structured) at \$40-45/BBL then clearly non-exploration efforts would be substantially better off. While much discussion from BP, ExxonMobil and ConocoPhillips centered on the risks associated with further development at Prudhoe Bay (PHB) and Kuraruk (KRU), these risks are simply not in the same category. Not even close.

The greatest beneficiaries of a single system that attempts to accommodate the needs of all parties will be the existing producers at PHB and KRU. The benefits AND the pain should be distributed equally amongst a wider group.

Why only 25% vs 20%?

It surprised me how quickly debate centered and focused on such a narrow band of tax rates i.e. 20% vs 25%. The difference between these two is just a government take of about 2%. I believe to a certain extent that it is a strange coincidence that we so quickly ended up in this narrow debate. It is certainly strange but unfortunate for Alaskans because the difference is minute and the oil companies must be ecstatic.

Different Tax Rates for Different Situations

I have been asked my opinion about the appropriate level of taxation (or credits) for each distinct region/situation. This of course is consistent with my views that a "one-size-fits-all" system is problematic at best.

In my opinion a more appropriate landscape would look like this:
(Please forgive the gross over-simplification)

Prudhoe Bay/Kuparuk	30/20% PPT	increasing above \$40/BBL
North Slope Exploration	20/20% PPT	increasing above \$45/BBL
Cook Inlet	10/20% PPT	or less, with options of royalty relief

Heavy or Challenged Oil

At current prices (by which I mean around \$50/BBL) many heavy oil projects are in good condition from an economic/financial point of view. However, if the fiscal system is to be designed to try and put these and other *challenged* projects on a "level-playing-field" (at any price) with **non-heavy**/viscous oil fields, then the proposed additional 15% credit is probably close to helping many of these projects compete (they are all different).

My working number for what constitutes "heavy oil" is 25° API and lower. A few good working numbers for the difference between a 25° API crude and a typical light 35° crude are:

- (1) Price discount for 25° crude (relative to 35° crude) at least 10%.
[Roughly a 1% price adjustment (in this range) per degree API (at least) — My experience]
- (2) 25° crude is typically about 10 times more viscous than 35° crude
- (3) Heavier crudes typically have higher operating costs
- (4) Heavier crudes typically have lower recovery factors (all other things being equal)

However, as we know there are other attributes that cause problems unrelated to API gravity.

Progressivity

This issue is extremely important. It is one of the first things I investigated when I evaluated (1) the Producer's and the Administration's Gas Pipeline Proposals last August and September, (2) the Governor's PPT 20/20% plan this winter and (3) the Committee Substitute proposals from the Legislature.

There are two key issues here:

- (1) Should the system be progressive or not?**
- (2) If it is going to be progressive – how progressive should it be?**

The system simply must be progressive. This has been a strong trend around the world and for good reason too. **It is an issue of fairness, flexibility, economic efficiency and dignity.** We have been discussing "terms" and hearing much rhetoric based on assumed future prices in the range of \$30-35/BBL (according to the oil companies) yet world prices today are in excess of \$70/BBL. It is possible that oil prices could get back down to \$30/BBL again but anything over \$50/BBL is fabulous for the oil companies. They have been particularly reluctant to share any upside i.e. reluctant to agree with a progressive system YET they insist on a degree of certainty that is nearly unprecedented. These things go hand-in-hand. With the kind of certainty they demand Alaska would be crazy to not have a reasonably progressive system.

How progressive should the system be?

I discussed this issue in my testimony on March 6th and provided a few examples from various sources. Around 25% of the worlds systems were progressive at the turn of the Century. Many governments are re-designing their systems in one fashion or another to either build-in greater flexibility (progressivity) or simply change their terms as the British have done (twice in the last 4 years). 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. I figure the average change in Government Take for these systems would be under 10 percentage points in that price range. If Alaska was going to only have a minimum-level of progressivity by these criteria and the progressive feature started at \$40/BBL then at \$70-80/BBL Government Take should increase by at least 5 percentage points. This represents a change in the PPT rate of around 12 percentage points (assuming a change in Government Take of 2 percentage points for every 5% change in PPT rate).

Therefore, from \$40/BBL to say \$80/BBL the PPT rate should increase by around 12-15 points. **Example:**

PPT 25/20% at \$40/BBL ⇒ PPT 40/20% at \$80/BBL

In this example going from \$40/BBL to \$80/BBL, Government Take would increase by only around 5 percentage points or so. Please be aware that a PPT 40/20% at \$80/BBL is extremely more profitable for the companies than PPT 25/20% at \$40/BBL. Don't think of it as "painful". This example is only modestly progressive.

This slope amounts to around 0.375% per \$/BBL. It compares as follows:

Example (above)	.375% starting @ \$40 WTI
House CS (Version L)	.3% starting @ \$50 WTI
Senate CS (Version C)	.2% starting @ \$40 ANSw
Senate Finance CS draft	.1% starting @ \$45 "net value"

The Senate Finance CS recommendation has virtually gutted the progressivity.

Gas Pipeline Linkage?

Complaints from various sectors regarding the threat to the gas pipeline are legitimate. In addition to some of the threats, I recall some rhetoric regarding the Administration's 20/20% PPT being structured in such a way that it would "help *enhance* the chances for a gas pipeline" or something to that effect. We know that there are some links between the gas contract and the oil taxes. However, I see no need for the oil terms to be structured in such a way that they "help" the gas pipeline economics. Furthermore, that threat is unfair without adequate information to justify the threats. My response to these threats is:

(1) What is the Producer's Internal Rate of Return for the Gas Pipeline Project:

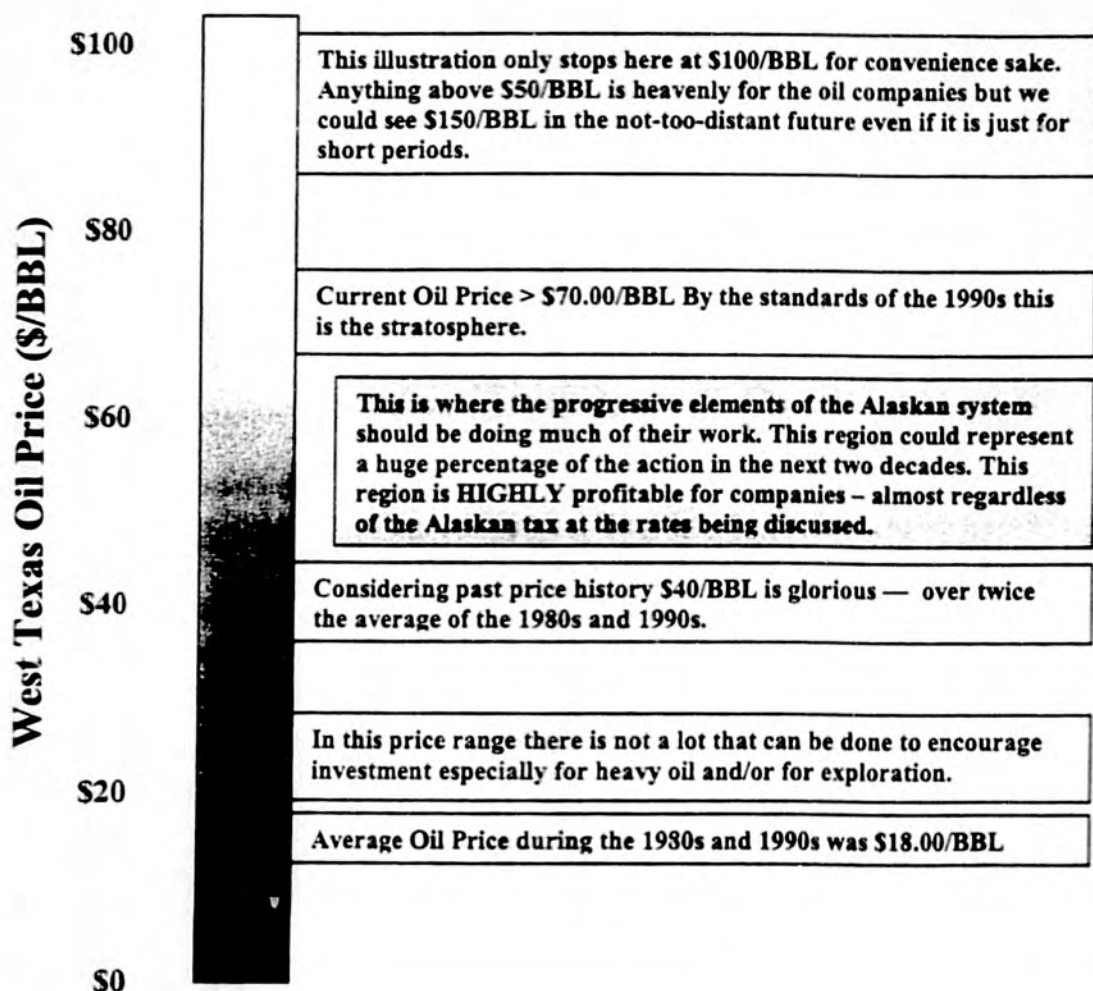
- A. Under the Administration's 20/20% PPT system as proposed?
- B. Under the Senate CS
- C. Under the House CS
- D. Under the Senate Finance Committee CS

Even this information is not sufficient to justify ratification of an oil tax system with the gas terms unknown. I could not in good conscience make a decision about the oil taxes without knowing the gas pipeline terms that have been agreed between the producers and the Administration. How can we claim to have exercised due diligence?

This did not become quite the issue it is now but for the numerous threats about the gas pipeline project from both the producers AND the Administration during these discussions about oil taxes.

Furthermore, the linkage (especially regarding "certainty") that has also obviously been agreed to must be understood. I feel more strongly about this now because of the way the gas pipeline project has been used by the producers to threaten Alaskans with petroleum economic doom, loss of jobs, and a ruined reputation.

Considering the history of oil prices and the drama involved with today's high prices it is impossible for me to contemplate a neutral or even a *mildly* progressive system. If we are going to do it let's do it right.



DJ

**Daniel Johnston
Daniel Johnston & Co., Inc.**

(sent by e-mail)

Alaska's Proposed Production Tax

"PPT 20/20%"

SB 305/HB 488

Issues for Discussion and Further Research

Daniel Johnston

Juneau, Alaska

6 March, 2006

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Risk vs. Reward and the PPT Credit plan (Careful: more work needed here)

One critical aspect of the PPT is the fact that it was designed in part to encourage exploration by providing Credits and allowing companies to sell (or trade) them and any Tax Loss Carry Forwards. This aspect should be particularly appealing to explorers. It reduces their risk. But by reducing exploration risk the State takes on added risk. Consistent with basic economic theory and extremely common industry rhetoric there should be commensurate potential for reward or a greater share of the "upside" for the State if it takes on added risk. As proposed the PPT places greater risk on the State without compensation on the reward side of the equation.

Examples of situations where countries exposed themselves on the "risk side" of the equation. Below I show for every dollar (\$1.00) of exploration capital how much each party was exposed to:

	<u>Company Exposure</u>	<u>Gvt. Exposure</u>	<u>Gvt. Take</u>	
Indonesia Grass-roots oil Exploration	\$1.00	0¢	N/A	Standard contract for
Indonesia Second-stage oil Exploration	15¢	85¢	85%	Standard contract for
Norway Grass-roots Exploration	22¢	78¢	78%	Fairly new (circa 2004)
UK (Circa mid-1980s) Grass-roots (1) Exploration	25¢	?	85%	Company exposure may have been less than 25¢ on the dollar
Canada	20¢	?	?	PIP Grants (2) (circa 1980±)
Alaska PPT 20/20% Without \$73 MM Allowance	39¢	AK & Fed	Depends	

These things can work quite well. Another example might be the credits for coal-bed methane in the lower 48 in the mid 1990s (as I recall). Worth further examination.

Variations on Government Take Calculation

This exercise is used to illustrate that there is added dimension to the problem mentioned in the previous graph i.e. there are more problems than just the difference between "Marginal Take" and ordinary "Government Take".

This time a royalty/tax system with a 15% royalty and a 50% tax is used but the system also has a 30% Government Participation element. The Wood Mackenzie report that ConocoPhillips referenced does not include the effects of Government Participation.

This is very important. The reason is because PPT 20/20% has many of the characteristics of Government Participation. In fact from an oil company point of view PPT 20/20% has many of the beneficial aspects of Government Participation without many of the painful aspects.

Government Takes

WoodMac ConocoPh Govt. Take	Johnston Govt. Take	BP Marginal Take	
\$40.00	\$40.00	\$40.00	Gross Revenues
- 6.00	- 6.00	- 6.00	15% Royalty
34.00	34.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
26.00	26.00	34.00	Taxable Income
- 13.00	- 13.00	- 13.00	Taxes 50%
13.00	13.00	21.00	Contractor Group Cash Flow
- .00	- 3.90	- 6.30	Government 30% Participation
13.00	12.10	14.70	Taxable Income
40.6%	37.8%	36.75%	Contractor Take

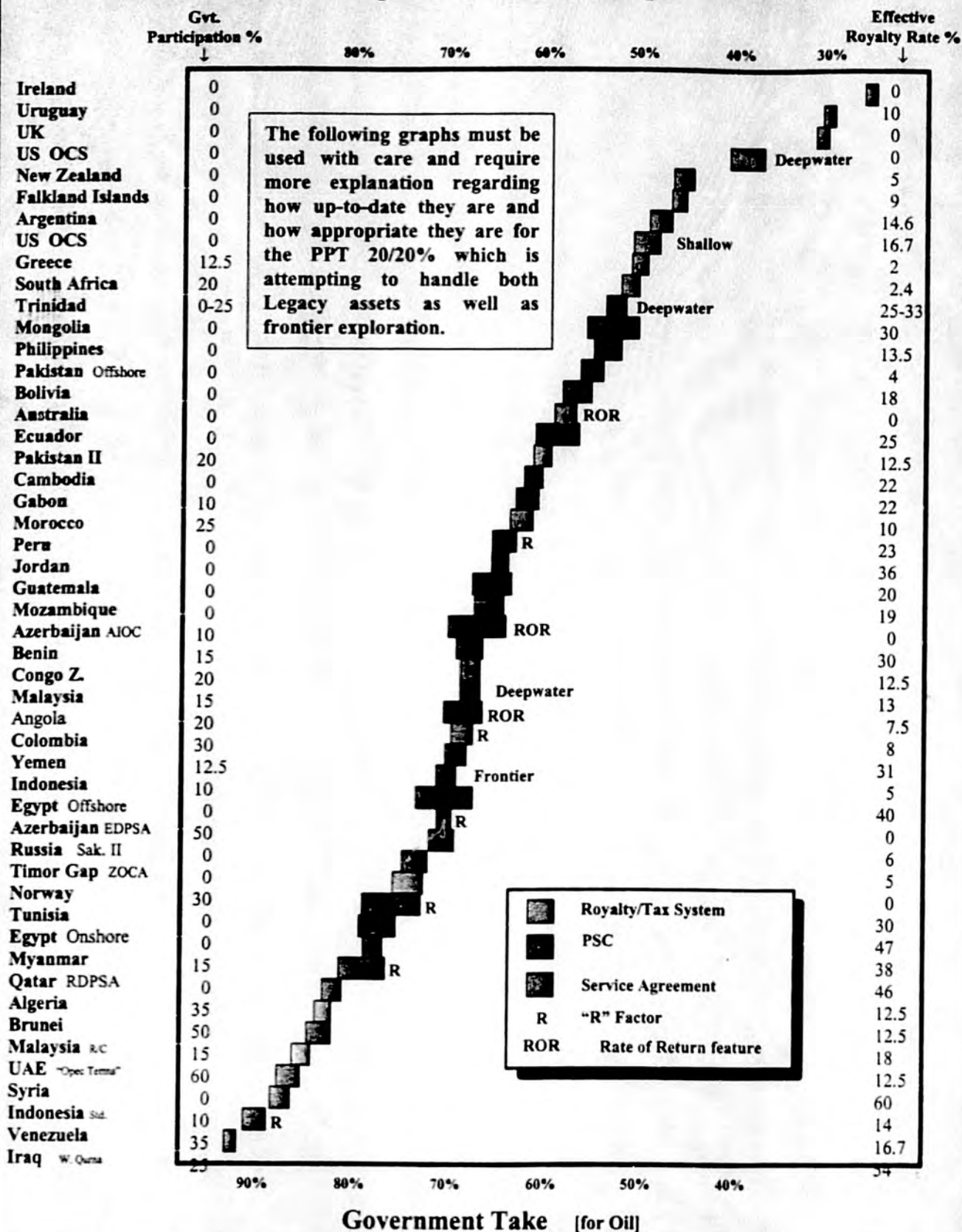
Regional Distribution of Petroleum Fiscal Systems

	Royalty/Tax Systems		Production Sharing Systems		Service Agreements
Africa 38	C. Af. Rep. ♦ Chad Congo (Z) Ghana ♦ Madagascar Mali Morocco Namibia ♦ Niger	Nigeria (Off) Senegal ♦ Seychelles Sierra Leone Somalia S. Africa ♦ Tunisia (Old) ♦	Algeria ♦ Angola ♦ + Benin Cameroon ♦ Congo (Br.) Cote D'Ivoire Egypt Eq. Guinea ♦ Ethiopia Gabon Gambia ♦ Kenya	Liberia Libya ♦ Madagascar ♦ Mozambique Nigeria (DW) Sudan Tanzania ♦ Togo Tunisia (New) ♦ Uganda ♦ Zambia	Nigeria (JVs)
Europe 20	Australia Bulgaria Czech Rep. Denmark France Greece ♦ Hungary Ireland	Italy Netherlands Norway Poland ♦ Portugal Romania ♦ Spain UK	Albania ♦ Malta Poland Turkey		
Far East 23	Australia ♦ Brunei Korea S. Nepal New Zealand	Pakistan (On) PNG ♦ Thailand + Timor Gap B	Bangladesh Cambodia China India ♦♦ Indonesia Laos Malaysia ♦ +	Mongolia MTJDA Myanmar Pakistan (Off) Timor Gap A Vietnam	Philippines
Former Soviet Union 7	Russia +		Azerbaijan ♦♦ Georgia Kazakhstan ♦ Kyrgyzstan	Russia ♦ Turkmenistan ♦ Uzbekistan	
Latin America 23	Argentina Bolivia Brazil Colombia ♦ +	Costa Rica Falkland Is. Paraguay Tr&To (On)	Belize Cuba Guatemala Guyana Jamaica	Nicaragua Panama ♦ Tr&To(Off) ♦ + Uruguay	Chile Honduras Ecuador Panama Haiti Peru ♦ Venezuela ♦♦
Middle East 18	Abu Dhabi Ajman Dubai Fujairah	Neutral Zone Sharjah Turkey	Bahrain Iraq Jordan Libya	Oman Qatar ♦ Syria Yemen	Iran Kuwait (OSA) Saudi Arabia
North America 2	Canada ♦ United States				
Total 131	58		63		11

♦ ROR Systems These are the systems that
♦ "R" factor are most likely to be
+ Price-based formulas progressive.

Adapted from: Course Workbook, Johnston

International Petroleum Exploration and Development Contracts #1



Contract Duration

This graph is provided in response to a statement made by one of the oil company representatives claiming that typical contract term, or duration, was 50-60 years. That is not consistent with my experience. The implications are heavy.

Examples of Contract Duration Worldwide

Province/Block	Exploration Years	Production Years
Abu Dhabi	3 + 2 + 2	33
Ajman	2 + 2 + 2	35
Albania	2 + 3 + 1.5	24
Algeria	5 + 2	15 - 30
Algeria	5 + 2	20 - 25
Australia	6 + 5	42
Belize	8	25
Benin	2 + 2 + 2	25 + 10
Bolivia		30 Max
Brunei	8	38 + 30
Brunei Offshore	17	40 + 30
Cambodia	3 + 2 + 1	22
Congo Br.	4 + 3 + 3	30
Congo Br.	10	30
Cote d'Ivoire	2 + 2 + 2	25
Czech Rep.	4 + 4	20
Dubai	3 + 2 + 3	35
Ecuador	4 + 2	22
Egypt	8	20
France	5 + 5 + 5	5 + 5 + 5
Gabon Deepwater	5 + 3	10 + 5 + 5
Gabon	3 + 2 + 2	25
Ghana	7	18 (25 Total)
Guyana	4 + 3 + 3	25 + 5
Honduras	4 + 2	20 + 5
Hungary	2 + 2 + 1	25
India	3 + 2 + 2	25 + 5
Indonesia	3	20
Liberia	3 + 3	25 + 10
Madagascar	8	15 + 5
Malaysia	3 + 2 2 + 2 Dev	15
Malaysia R/C	5	29 Total
Netherlands	10	40
Nigeria	3 + 3 + 4	20
Oman	2 + 2 + 2	20 + 10
Peru	7	30
Poland	3 + 3	20 + 5 + 5
Rep. of Guinea	5	21 (Maz 25)
Senegal	3 + 2 + 2	25 + 10
South Africa	4 + 3 + 3	as long as is profitable
Syria	3 + 2 + 1	20 + 10
Vietnam	3 + 1 + 1	20 (total not to exceed 25)
Zambia	8	25
Average/Typical	3 + 2.5 + 2 (7.5)	25

Consultant Daniel Johnston on Average Worldwide Government Take

Joint House Resources / House Finance Committee

March 6, 2006 (2:45 – 2:48 pm)

Rep. Kerttula: That was my last question was... Are you aware of any other country that allows that dollar for dollar kind of set off for the oil or, I mean, the gas against the oil or any other manner - one against the other like that. That confuses me to allow that.

Daniel Johnston: Through the Chair, Representative Kerttula. I think I understand the question... dollar-for-dollar credits...

Rep. Kerttula: Right.

Daniel Johnston: But you're talking about dollar-for-dollar credits from oil expenditures against gas profits?

Rep. Kerttula: Right, or vice-versa, the gas against the oil.

Daniel Johnston: I'm sure that they do exist and specific examples of, you know, where you have the 2 different types of production and the credits can "cross the fence" as we say. Many many countries apply and allow either credits or the cousin to credits that we call "uplifts" - investment allowances and things like that. But when governments have different terms for gas as they often do - and quite often they do - the statistics that I showed, and I know there were a lot of those, *the world average government take even right now is probably 67 or 70 depending upon how you calculate it.* Wood Mackenzie aggregates their statistics a little bit differently too [inaudible] but in the Wood Mackenzie world average government take statistic from their study was I think 71%. The world average statistic for gas take is maybe 61. When you have a different tax system for one versus the other, then you've got problems.

Rep. Kerttula: Thank you.

WOOD MACKENZIE

GLOBAL OIL AND GAS — RISKS AND REWARDS 2004

Alaska's Profitability – Full Cycle, Post Government Take

Rate of Return (IRR – Nominal)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	15/49	14/52	14/53
Alaska's IRR	18.09%	23.57%	29.11%
Global Average IRR	15.20%	18.94%	23.07%

Full Cycle Government Take

Full Cycle Gov't Take (% Of Pre-Take Net Cash Flow, Undiscounted)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	33/54	24/54	19/55
Take on AK Production	71.70%	63.63%	58.40%
Global Ave. Take	70.86%	70.26%	73.34%

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

2

Average ANS West Coast Price in Real 2006 Dollars:	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00
Effective Tax Rate (Percent)							
CS for HB 3001 ²	0.0%	7.1%	11.2%	14.6%	18.7%	22.6%	26.2%
CC for SB 2001 ²	3.4%	8.2%	12.3%	15.5%	18.7%	21.5%	24.1%
SB 2001 ¹	0.0%	7.4%	11.7%	14.5%	17.0%	19.1%	20.9%
Administration 20/20 ⁴	0.0%	7.3%	10.9%	12.1%	13.5%	14.5%	15.2%
Alaska Government Take (Percent)							
CS for HB 3001 ²	32.3%	31.3%	31.9%	33.5%	36.3%	39.0%	41.6%
CC for SB 2001 ²	38.0%	32.6%	33.2%	34.4%	36.2%	37.9%	39.7%
SB 2001 ¹	32.4%	31.7%	32.5%	33.4%	34.5%	35.6%	36.7%
Administration 20/20 ⁴	32.3%	31.5%	31.6%	30.9%	31.1%	31.3%	31.4%
Total Government Take (Percent)							
CS for HB 3001 ²	62.0%	58.6%	58.2%	58.8%	60.4%	62.1%	63.7%
CC for SB 2001 ²	65.7%	59.4%	59.0%	59.4%	60.4%	61.4%	62.4%
SB 2001 ¹	62.4%	58.9%	58.7%	58.8%	59.3%	59.9%	60.5%
Administration 20/20 ⁴	62.0%	58.7%	58.0%	57.2%	57.1%	57.1%	57.0%
Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)							
CS for HB 3001 ²	(\$240)	\$57	\$437	\$945	\$1,725	\$2,662	\$3,736
CC for SB 2001 ²	(\$111)	\$125	\$539	\$1,046	\$1,714	\$2,482	\$3,348
SB 2001 ¹	(\$240)	\$77	\$482	\$940	\$1,488	\$2,093	\$2,752
Administration 20/20 ⁴	(\$240)	\$69	\$413	\$664	\$1,008	\$1,352	\$1,696

August 4, 2006
12:01 PM

¹ Assumes no major gas sale.

² Calculated from April 2006; includes transition (50% of capex over 12 years to maximum of \$1 billion) and \$80 Million exemption over 5 companies for 10 years; volumes per DOR Spring 2006 Forecast.

³ Calculated from April 2006; includes transition (50% of capex over 12 years to maximum of \$1 billion) and \$60 Million exemption over 5 companies for 10 years; volumes per DOR Spring 2006 Forecast.

⁴ Calculated from July 2006; includes 8-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Spring 2006 Forecast.

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ALASKA'S TOTAL GOVERNMENT TAKE UNDER CURRENT LAW, 20/20 AND 25/20 PROPOSALS

Projected Government Takes with Sliding Scale Tax DOR Forecast Production (FY 2007-2030)*

WTI Price (\$ 2006)	Status Quo	20/20	20/20 with Sliding Scale Tax							
			\$35 Threshold Price				\$40 Threshold Price			
			0.20%	0.25%	0.30%	0.35%	0.20%	0.25%	0.30%	0.35%
			Increment	Increment	Increment	Increment	Increment	Increment	Increment	Increment
			(Percent)							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
\$30	57.0%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
\$40	53.7%	57.3%	57.9%	58.0%	58.2%	58.3%	57.3%	57.3%	57.3%	57.3%
\$50	52.3%	56.9%	58.5%	58.9%	59.3%	59.7%	58.0%	58.2%	58.5%	58.7%
\$60	51.5%	56.9%	59.4%	60.0%	60.7%	61.3%	58.9%	59.4%	59.9%	60.4%
\$70	50.9%	56.9%	60.3%	61.2%	62.0%	62.9%	59.8%	60.6%	61.3%	62.0%
\$80	50.6%	56.9%	61.2%	62.3%	63.4%	64.5%	60.7%	61.7%	62.7%	63.6%

		20/20 with Sliding Scale Tax							
		\$45 Threshold Price				\$50 Threshold Price			
WTI Price (\$ 2006)	25/20	0.20%	0.25%	0.30%	0.35%	0.20%	0.25%	0.30%	0.35%
		Increment	Increment	Increment	Increment	Increment	Increment	Increment	Increment
		(Percent)							
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
\$30	59.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
\$40	59.7%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%
\$50	59.3%	57.4%	57.6%	57.7%	57.8%	56.9%	56.9%	56.9%	56.9%
\$60	59.3%	58.4%	58.8%	59.2%	59.5%	57.9%	58.1%	58.4%	58.7%
\$70	59.3%	59.3%	59.9%	60.6%	61.2%	58.8%	59.3%	59.8%	60.3%
\$80	59.4%	60.2%	61.1%	61.9%	62.8%	59.8%	60.5%	61.2%	61.9%

* Calculated from July 2006, includes 8-year transition and \$73 million exemption volume for DOR FY 2007-2030. Forecast with constant oil price.

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Projected Government Take EIA Price Assumptions 2006-2016

Average WTI Price in Real 2006 Dollars	Total Government Take (Percent)				Alaska Take (Percent)			
	EIA WTI Price Forecast			Fixed \$40 Price	EIA WTI Price Forecast			Fixed \$40 Price
	Base	Low	High		Base	Low	High	
	\$54.70	\$35.40	\$72.00	\$40.00	\$54.70	\$35.40	\$72.00	\$40.00

FY 2007-2016

Status Quo	53.3%	55.0%	52.4%	55.5%	24.8%	26.0%	23.7%	27.2%
20/20 PPT	57.2%	57.6%	57.1%	58.2%	30.9%	30.9%	31.0%	31.5%
25/20 PPT	59.6%	59.9%	59.8%	60.6%	34.5%	34.5%	34.8%	35.1%

FY 2007-2030

Status Quo	51.9%	54.7%	50.8%	53.7%	23.4%	27.2%	22.0%	25.7%
20/20 PPT	56.9%	57.1%	56.9%	57.3%	31.2%	30.9%	31.3%	31.3%
25/20 PPT	59.3%	59.3%	59.3%	59.7%	34.9%	34.3%	35.2%	34.8%

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**Consultant Testimony/Presentation Points & Other Data On PPT Issues
(through March 20, 2006)**

- 1) Statements that an oil tax rate of 25%, and greater at higher prices, would not deter long term investments, and would maximize long term state revenue. The difference between a 20% and 25% rate, at current prices, is roughly \$600 - \$700 million in state revenue. See attached testimony from consultants Daniel Johnston, Dr. Tony Finizza, and Barry Pulliam (p. 1-2). Also, Dr. Pedro Van Meurs February Testimony (p. 2).
- 2) A 20% and 25% PPT rate, and the Status Quo, all provide a tax rate lower (and at certain prices much lower) than the world average government take of 67% - 70%. See attached testimony from Johnston; Econ One Charts (p. 3-5).
- 3) Implementing the bill as of January 1, 2006 (as originally proposed by the Governor and Van Meurs, and done with the 1989 ELF revisions) would not adversely impact investment decisions, and would raise significant additional revenue for the state. At a 25% tax rate, moving the implementation date to July 1 will cost the state approximately \$600 - \$700 million. See attached testimony of Van Meurs (p.6).
- 4) A higher rate for more profitable, existing North Slope fields would be justified. See attached Johnston testimony (p.7).
- 5) Without a minimum tax, a 20% PPT would provide no production tax revenue at \$23/barrel, and less revenue than current law at \$28/barrel. A 25% PPT would provide no production tax revenue at \$22/barrel, and less than current law at \$26/barrel. See attached Econ One projection (p.8). Johnston recommends the state consider imposing a minimum tax so the production tax does not fall to 0%. Johnston testimony attached (p.9).
- 6) Conoco has raised questions about its profitability in Alaska. According to Conoco Annual Reports, the company's profits and profit margins in Alaska have been as follows: 2005: \$2.55 billion (43.1%); 2004: \$1.83 billion (41.3%); 2003: 1.45 billion (40.5%); 2002: \$870 million (29%); and 2001: \$866 million (28.7%). Conoco Annual Report excerpts attached (p. 10-11).
- 7) The Department of Revenue has calculated the state and corporate profit share on North Slope oil production. According to these figures, FY'05 state oil revenue totaled \$3.22 billion and estimated company profits totaled \$5.25 billion. In FY'04 state revenue totaled \$2.41 billion and company profits were \$3.47 billion. In FY '03 state revenue totaled \$2.095 billion and company profits were \$2.926 billion. The Dept. of Revenue also projects that at \$59/bbl, company profits for this year will exceed \$7 billion, while the state's share will be approximately \$4 billion. See attached November, 2005, DOR Revenue estimates. (p. 12-14)
- 8) A more detailed transcript of consultant testimony (Finniza, Pulliam, Van Meurs, and Johnston) is provided here as well. See attached (p. 15-21).

Consultant Statements On An Appropriate PPT Tax Rate

Daniel Johnston, Legislative Consultant:

(Joint House Resources / House Finance Committee – March 6, 2006)

(Quoted in the Anchorage Daily News – March 7, 2006):

"I am just not happy with 20/20. 25/20 is a starting point, and then it's got to be progressive from there."

Barry Pulliam, EconOne Consultant

(House Resources Committee – March 13, 2006):

"Our view, we sat down with the administration folks who came up with the PPT, Dr. Van Meurs, and considered those very questions when he was first submitting his recommendations. And in our view certainly the 20/20 was very safe. Very safe. The 25/20 we even thought was safe."

"But you don't want to lose a lot of interest and as, as economists who have worked with forecasting, and looking at decision-making, I think our view would also be you don't want to be in a position where you're... you've calculated that you've taken every last penny of what's available. You want to leave something... *you want to make it attractive. You want to leave enough to make it attractive. Keep people real interested. We don't think the 25/20 goes beyond that at all, and then with some increment above that, we think it still stays real attractive.* Now, in thinking about the sliding scale. What would you do? I think our view in general would be if you're thinking about starting it lower, have a lower increment. If you're thinking about starting it higher, have a higher increment. I think that's probably... just as a general thing. Otherwise, if you start real low and have a real high increment, you go pretty steep. So, that would be our..."

Rep. Samuels: Representative Gatto.

....

Rep. Seaton: Thank you. And, so just to be clear, within these scenarios, are there any of them that you've projected here that you think are, from your standpoint, in your analysis, that would be detrimental to investment in the industry here in Alaska?

Barry Pulliam: No. Looking at these, *I don't see any that would be, that would fall into the detrimental area.* I put, as I look at this, I try to put these into a historical context – look at what the rates have been at given price levels. And as you look at those, even as you look at the highest one of these that you'd have, which would be the 35 threshold with a .35% increment, you see as you... you know, when you're at 40 dollar prices there your tax rate is only 11.4%. That's at a higher price level, that's a lower percentage than your historical average. You start to ratchet up beyond there, but you have some pretty high prices that those are associated with. So, there might be a little bit of stuff around the margin that would look at that and say that's not of interest. I don't think for the majority of what you have that would be the case. But, I can see reasons why you wouldn't do that either. You might have a more cautious approach."

Dr. Tony Finizza, EconOne Consultant
(House Resources Committee March 13, 2006):

"And, to illustrate this question that was raised earlier about is *25/20, could it look better for a producer, and in a funny kind of way it does*. I'm saying... lets... no one's going to drill a one well program, but just say you did, and it was 20 million dollars - and that's the number I'm actually going to use for a well, 20 million - it's pretty expensive, but this is an expensive state and they're low product wells, etc. and eventually we have the high cost assumptions to make. If you did this well exploration - 20 million dollars - with a pattern I put in here under a status quo your negative cash flow would be roughly 20 million dollars. There's inflation in there that makes it higher, and then there's some tax sheltering that goes on. In the other cases, the PPT, you get to deduct capital as a credit, etc. and sell it and all that stuff. So naturally in actuality the producer or the explorer has less cash flow. Negative cash flow. And by this calculation, *marginally better off with 25/20 than 20/20.*"

Rep. Gara: Just a follow up so I'm clearer in your answer to Representative Berkowitz. He asked you, you said at 25/20, you might be, that might be the point where you start maximizing revenues before you start hitting diminishing returns. Is that, did I understand that fairly?

Dr. Finizza: I said that I had a gut reaction that that was a point of diminishing returns, and that's... for an exploration, yup. I wouldn't think that you would have to go further than that to encourage or, you wouldn't, and then take a greater risk yourself.

Rep. Gara: Am I wrong in assuming... If I'm looking for the point where's you've started to maximize your long term state revenue but before you start losing money because you're taxing too much - that's your gut reaction on 25/20 or am I missing...?

Dr. Finizza: That's my gut reaction, yeah.

Dr. Pedro Van Meurs, Consultant
(House Resources Committee - February 23, 2006):

"The 25/20 and the 20/20 both are very competitive systems, that you could see from the investment. If I say competitive, it means that both systems would be considered quite attractive by investors."

"Whether you start the tax on January 1 or July 1 really has no impact on the competitiveness of the system. Because new investors would look at new investments and would not even have to pay tax for now, for awhile. So consequently whether you have a July or January start day, that would not have impact on new investors. So would be equally, say, attractive either way. The only difference between the January 1 and the July 1 start date is that of course it has enormous impact on existing production. So as far as existing production, you would have 6 months more of revenues if you moved the date back to January 1st of this year."

Dr. Pedro Van Meurs on Retroactivity

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-Dr. Pedro Van Meurs

Consultant

House Resources/Finance Meeting – February 23, 2006

Consultant Daniel Johnston on Separate PPT Tax Rate For Legacy Fields

Representative LeDoux:

Well this is probably a little bit of a follow up on Representative Ramras's question but... if this were totally up to you. You were elected emperor as far as this thing was concerned, and your only consideration is: what is going to bring the most money into the state of Alaska over the next 25 or 30 years and also what is going to facilitate exploration, and your only political consideration is you don't want to do something to make the oil companies pack up and go home. *What system would you recommend?*

Daniel Johnston:

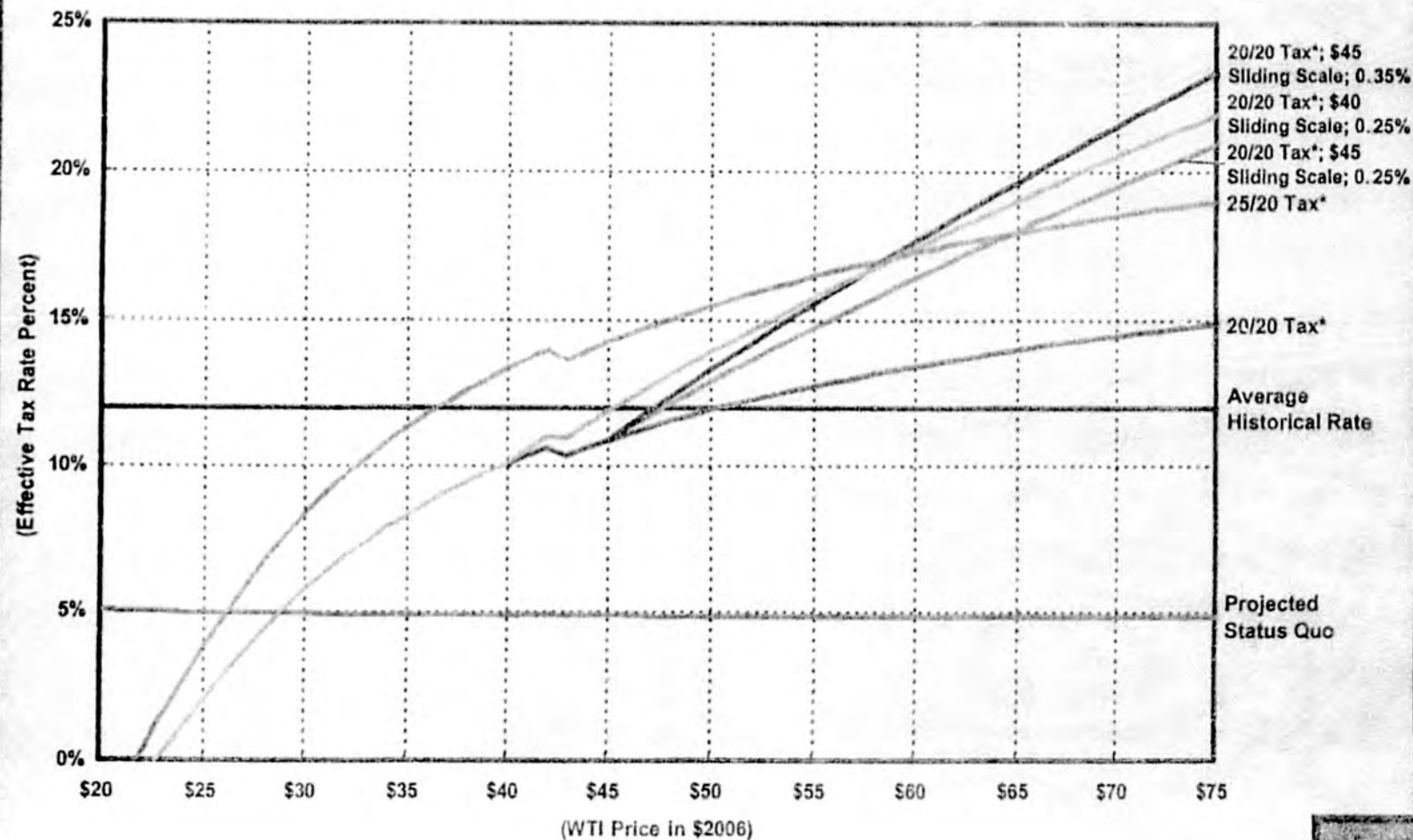
Through the Chair, Representative LeDoux, I'm glad you added that last part to that question. I would try as best I could... well you'd have to get rid of all the lawyers, because there's a legal issue... if I can do what I'd like to do, I'd like to just treat different provinces in different ways, and many countries do. And we see the bigger fields, the *older fields in the United Kingdom that receive a higher tax rate than the smaller, newer fields and stuff like that because they're just so different. So I would structure the system in such a way that we could just really truly segregate the different classes of investor*, because that would have to be better it seems to me than trying to use that magic 73 dollar number because that is the thing that really makes the difference.

-Daniel Johnston

Legislative Consultant

Joint House Resources/Finance Meeting – March 6, 2006

Effective Average Tax Rates at Various Price Levels (FY 2007-2030)



Calculated from July 2006, includes 8-year transition and \$2.8 Million exemption. Source: RRC DOR Fall 2005 Energy with Ogoniuk projection.

Source: Historical: Alaska Department of Revenue

Econ
ONE

Consultant Daniel Johnston on a Minimum Alternative Tax

Rep. Kelly:

Okay, and the, on the safety net. All of the families of curves that everyone shows, on the progressive system, which I think is a slam dunk that we're going to certainly go for the progressive system. But those curves, all on the bottom when they come below the ELF line are diving for zero like a rock falling. Would you under gird this progressive system with either a left-in-place ELF or something else so that that hits a leveling point before it goes right through the bottom.

Daniel Johnston:

Through the chair, Representative Kelly. To quote a previous witness, "All the numbers are wrong." You... every one of the runs that people do, it seems, in all the different analyses show different crossover points – we talk a lot about crossover. It's my opinion that with a fair share of the profits, the state of Alaska would be fairly dramatically protected, but that's not enough of a guarantee. *I feel that you should draw a line in the sand so that you'd never be worse than what ELF would have yielded.* And, so you might contemplate something where you calculate the tax in 2 ways – you calculate ELF and you calculate the new PPT, whatever that might be, and take the higher of the 2. *That's the way we did it in New Zealand. That's the way it's done in Newfoundland. There's a few other places – Kazakstan has 3 calculations.*

-Daniel Johnston

Legislative Consultant

Joint House Resources/Finance Meeting – March 6, 2006
(2:40 – 2:42 p.m.)

■ Results of Operations

Years Ended
December 31

	Millions of Dollars								
	Consolidated Operations							Equity	Combined
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Affiliates	Total
2003									
Sales	\$3,564	2,464	6,028	3,872	879	225	677	423	12,104
Transfers	103	545	648	903	142	841	77	266	2,877
Other revenues	(11)	93	82	8	33	31	10	34	198
Total revenues	3,656	3,102	6,758	4,783	1,054	1,097	764	723	15,179
Production costs	792	657	1,449	645	175	271	170	179	2,889
Exploration expenses	56	143	199	121	51	94	127	2	594
Depreciation, depletion and amortization	436	571	1,007	954	163	326	40	104	2,594
Property impairments	—	65	65	160	—	5	—	—	230
Transportation costs	666	188	854	266	40	40	23	20	1,243
Other related expenses	7	78	85	29	13	91	44	27	289
Accretion	25	18	43	50	5	11	2	2	113
Provision for income taxes	1,674	1,382	3,056	2,558	607	259	358	389	7,227
Results of operations for producing activities	595	486	1,081	1,539	225	57	362	83	3,347
Other earnings	1,079	896	1,975	1,019	382	202	(4)	306	3,880
Cumulative effect of accounting change	223	34	257	51	3	68*	(46)	(51)	282
E&P net income (loss)	143	(1)	142	20	—	(8)	(12)	(2)	140
2002									
Sales	\$2,997	927	3,924	1,194	347	125	400	180	6,170
Transfers	102	401	503	1,315	—	235	—	62	2,115
Other revenues	(2)	3	1	63	7	7	14	12	104
Total revenues	3,097	1,331	4,428	2,572	354	367	414	254	8,389
Production costs	769	444	1,213	343	76	118	114	57	1,921
Exploration expenses	101	108	209	67	45	32	231	—	584
Depreciation, depletion and amortization	552	334	886	480	59	105	26	30	1,586
Property impairments	4	8	12	41	—	—	—	—	53
Transportation costs	681	87	768	125	10	—	5	8	916
Other related expenses	23	16	39	75	1	14	11	12	152
Provision for income taxes	967	334	1,301	1,441	163	98	27	147	3,177
Results of operations for producing activities	294	66	360	981	79	49	196	(18)	1,647
Other earnings	673	268	941	460	84	49	(169)	165	1,530
E&P net income (loss)	197	18	215	10	(2)	24*	(4)	(24)	219
2001									
Sales	\$3,020	1,178	4,198	546	154	31	324	8	5,261
Transfers	119	119	238	1,039	—	—	—	—	1,277
Other revenues	34	26	60	23	(4)	5	—	1	85
Total revenues	3,173	1,323	4,496	1,608	150	36	324	9	6,623
Production costs	784	328	1,112	165	37	6	55	2	1,377
Exploration expenses	61	69	130	31	33	—	121	—	315
Depreciation, depletion and amortization	531	203	734	233	22	4	27	2	1,022
Property impairments	—	—	—	—	—	—	23	—	23
Transportation costs	726	77	803	60	—	3	6	—	872
Other related expenses	2	5	7	(8)	5	1	23	2	30
Provision for income taxes	1,069	641	1,710	1,127	53	22	69	3	2,984
Results of operations for producing activities	392	173	565	779	22	7	117	—	1,490
Other earnings	677	468	1,145	348	31	15	(48)	3	1,494
E&P net income (loss)	189	8	197	17	—	—	(9)	205	205
2000									
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Property impairments	—	—	—	—	—	—	23	—	23
Transportation costs	726	77	803	60	—	3	6	—	872
Other related expenses	2	5	7	(8)	5	1	23	2	30
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Other earnings	677	468	1,145	348	31	15	(48)	3	1,494
E&P net income (loss)	189	8	197	17	—	—	(9)	205	205

*Includes \$63 million and \$27 million in 2003 and 2002, respectively, for a Syncrude oil project in Canada that is defined as a mining operation by U.S. Securities and Exchange Commission regulations.

- Results of operations for producing activities consist of all the activities within the E&P organization, except for pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and gas marketing activities, which are included in Other earnings. Also excluded are non-E&P activities, including our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.
- Transfers are valued at prices that approximate market.

- Other revenues include gains and losses from asset sales, including net gains of approximately \$165 million in 2003; certain amounts resulting from the purchase and sale of hydrocarbons; and other miscellaneous income.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include taxes other than income taxes, depreciation of support equipment and administrative expenses related to the

• Results of Operations

Years Ended
December 31

Years Ended December 31	Millions of Dollars										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
2005											
Sales	\$ 5,927	3,385	9,312	5,142	2,795	1,642	423	—	19,314	1,055	2,415
Transfers	172	1,206	1,378	2,207	26	—	640	—	4,251	455	1,003
Other revenues	2	168	170	(253)	11	40	4	—	(28)	37	—
Total revenues	6,101	4,759	10,860	7,096	2,832	1,682	1,067	—	23,537	1,547	3,419
Production costs excluding taxes	488	492	980	611	274	316	115	45	2,341	196	256
Taxes other than income taxes	537	311	848	41	26	33	18	2	968	3	1,632
Exploration expenses	120	66	186	86	139	147	69	42	669	—	56
Depreciation, depletion and amortization	443	848	1,291	1,074	329	399	53	—	3,146	140	148
Property impairments	—	1	1	(10)	—	13	—	—	4	—	—
Transportation costs	665	350	1,015	296	64	53	5	—	1,433	—	255
Other related expenses	67	48	115	28	38	(12)	32	8	209	21	5
Accretion	29	19	48	84	7	16	2	—	157	—	1
	3,752	2,624	6,376	4,886	1,955	717	773	(97)	14,610	1,187	1,066
Provision for income taxes	1,342	900	2,242	3,311	747	228	759	(19)	7,268	370	303
Results of operations for producing activities	2,410	1,724	4,134	1,575	1,208	489	14	(78)	7,342	817	763
Other earnings	141	15	156	53	7	93*	(28)	35	316	(58)	(32)
Cumulative effect of accounting change	1	(3)	(2)	(2)	—	—	—	—	(4)	—	—
Net income (loss)	\$ 2,552	1,736	4,288	1,626	1,215	582	(14)	(43)	7,654	759	731
2004											
Sales	\$ 4,378	2,568	6,946	4,215	1,777	1,214	704	—	14,856	470	397
Transfers	121	832	953	1,255	71	—	75	—	2,354	359	122
Other revenues	4	(36)	(32)	9	10	116	5	14	122	32	1
Total revenues	4,503	3,364	7,867	5,479	1,858	1,330	784	14	17,332	861	520
Production costs excluding taxes	430	422	852	523	216	271	120	36	2,018	154	46
Taxes other than income taxes	373	267	640	38	17	35	12	1	743	—	206
Exploration expenses	82	101	183	85	106	112	67	144	697	—	5
Depreciation, depletion and amortization	426	586	1,012	1,095	275	349	43	—	2,774	94	43
Property impairments	6	12	18	2	—	47	—	—	67	—	—
Transportation costs	598	241	839	296	48	43	2	—	1,228	8	57
Other related expenses	14	43	57	20	(2)	4	14	7	100	39	—
Accretion	21	21	42	72	6	14	2	—	136	—	1
	2,553	1,671	4,224	3,348	1,192	455	524	(174)	9,569	566	162
Provision for income taxes	888	584	1,472	2,233	477	127	514	(94)	4,729	67	41
Results of operations for producing activities	1,665	1,087	2,752	1,115	715	328	10	(80)	4,840	499	121
Other earnings	167	23	190	102	(2)	130*	(35)	(10)	375	(53)	(6)
Net income (loss)	\$ 1,832	1,110	2,942	1,217	713	458	(25)	(90)	5,215	446	115

DISTRIBUTION OF ANS OIL & GAS REVENUES BETWEEN THE PRODUCERS, ALASKA GOVERNMENTS AND THE US FEDERAL GOVERNMENT*

Production & Value Added By TAPS

	FY 1996	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005
Note 1										
ANS West Coast Oil Price (\$/Bbl)	\$17.74	\$20.90	\$15.06	\$12.73	\$23.27	\$27.85	\$21.78	\$28.15	\$31.74	\$43.44
Transportation Cost to Market (\$/Bbl)	\$5.14	\$4.50	\$3.95	\$4.26	\$4.21	\$5.61	\$4.98	\$4.88	\$4.96	\$4.51
ANS Oil Wellhead Price (\$/Bbl)	\$12.60	\$16.40	\$11.91	\$8.47	\$19.06	\$22.24	\$16.80	\$23.27	\$26.78	\$38.92
ANS Oil & NGL Production (Million Bbl)	1.474	1.404	1.275	1.164	1.035	0.991	1.004	0.991	0.980	0.917
Oil & NGL Production Value (Million \$)	6,778.9	8,404.3	5,542.6	3,598.6	7,200.4	8,044.5	6,156.5	8,417.1	9,579.2	13,032.4
Note 2										
Production Costs (\$/Bbl)	3.09	3.67	4.24	4.67	5.10	5.96	6.44	6.44	6.50	6.70
Oil & NGL Production Costs (Million \$)	1,662.5	1,880.7	1,973.2	1,984.1	1,926.7	2,154.4	2,359.3	2,328.7	2,325.1	2,243.3
Note 1										
State Revenue + Muni Oil Prop (Millions \$)	2,011.7	2,429.5	1,620.7	1,144.9	1,955.1	2,324.4	1,621.5	2,095.6	2,412.9	3,223.5
Oil & Gas Production Tax (Inc Exp Credit)	754.2	915.2	576.7	351.4	684.5	696.4	462.8	571.3	621.7	796.1
Avg Economic Limit Factor (ELF)	0.8847	0.8422	0.8176	0.7404	0.8817	0.6429	0.5975	0.5519	0.5322	0.530
Gross Oil & Gas Royalty	819.7	1,007.2	603.3	403.4	898.2	1,100.9	762.8	1,146.4	1,296.1	1,754.5
Property Tax State Share	53.9	51.1	49.1	47.4	45.3	42.5	40.1	44.3	43.5	42.5
Property Tax Muni Share	245.0	240.5	231.6	226.6	217.0	214.1	213.0	212.8	212.5	211.2
Corporate Petroleum Income Tax	139.0	215.5	160.1	116.1	130.2	270.5	142.7	120.9	239.0	419.2
Income Tax Production	76.4	163.1	116.6	76.1	90.7	230.0	101.2	79.5	198.3	377.9
Income Tax TAPS	62.6	52.4	43.5	39.9	39.4	-0.4	41.5	41.4	40.8	41.3
Note 3										
TAPS tax allowance (Millions \$)	312.900	262.094	217.331	199.651	197.131	202.201	207.427	206.771	203.922	206.702
TAPS after tax margin	309.1	290.0	275.2	250.8	243.2	248.5	255.1	257.2	253.2	256.9
TAPS deferred return	153.7	99.0	48.9	47.2	50.1	51.1	51.2	47.1	46.2	45.5
Note 4										
Federal Revenue (Millions \$)	1,358.9	1,661.0	871.1	338.0	1,333.0	1,423.9	942.0	1,577.3	1,871.9	2,827.8
Percentage Federal	23.1%	23.2%	21.2%	16.0%	23.1%	22.3%	21.9%	23.9%	24.1%	25.0%
Note 5										
Company Net Revenue (Millions \$)	2,521.6	3,084.4	1,619.0	629.0	2,476.0	2,643.7	1,747.4	2,926.5	3,472.7	5,247.0
Percentage Company	42.8%	43.0%	39.4%	29.8%	43.0%	41.4%	40.5%	44.3%	44.8%	46.4%
State Revenue + Muni Property (Millions \$)	2,011.7	2,429.5	1,620.7	1,144.9	1,955.1	2,324.4	1,621.5	2,095.6	2,412.9	3,223.5
Percentage State & Local	34.1%	33.9%	39.4%	54.2%	33.9%	36.4%	37.6%	31.8%	31.1%	28.5%
Total Revenue Shared State, Federal, Company	5,892.2	7,174.8	4,110.8	2,111.9	5,764.2	6,392.0	4,310.9	6,599.5	7,757.5	11,298.3

* The Department of Revenue is in the process of reviewing the historical data with an eye to revising and improving the accuracy of these estimates.

Notes:

- 1 Revenues, Prices, and Production taken from *Fall Revenue Source Book* Appendices.

Production Taxes include oil and gas severance, regulation and conservation and hazardous release Production Tax, Exploration Incentives and Royalties, 1996 thru 2005 from ShortCut History

Total Alaska CIT is reduced by the percent oil volume produced in Cook Inlet (2%) to calculate a CIT for ANS.

Production Cost is taken from "How Much is Enough" by Richard Fineberg for FY 1988--FY1996, Dept. of Revenue estimates for FY 1997--FY 2003. The Department will be evaluating production costs in the future

- 2 TAPS tax, after tax margin, and deferred return allowances from actual filings

Federal Revenue is calculated as 35% of the difference between production value and production cost (including state taxes on production) plus 80% of the TAPS tax allowance.

- 4 80% is the fed rate divided by the sum of the fed and state rates. The maximum marginal fed rate is 35%, the state rate is 9.4%.

- 5 Company net revenue is calculated as production value less production costs less taxes on production plus the TAPS after tax allowance plus deferred return.