Deferred Reponses to Questions from LB&A asked on December 9 and 10th, 2008
Dan E. Dickinson & Dr. David Wood
January 12, 2009

On December 9 and 10, 2008 Dr. David Wood and Dan Dickinson testified before the LB&A Committee on the topic of oil and gas taxes. Dr. Wood's emphasis was on the appropriate regime for gas taxes - and the related issue of stability – required for a vibrant investment climate in future North Slope gas fields. In the subsequent round table discussion Dan Dickinson illustrated one of Dr. Wood's points by presenting an example whereby when the means finally existed for major sales of North Slope gas, the net result of those sales would be lower production taxes, rather than raise them. Most of the rest of this paper follows up on questions raised on that example and its possible implications. (Page 10 includes data requested in a separate context on use of the AS 43.55.025 exploration credit.)

I. Request for interactive model

Accompanying the electronic transmission of this letter to Ms. Cheryl Sutton, staff for the LB&A Committee is a three sheet Excel Spreadsheet entitled "December 10th Roundtable Example Jan 12 2009 Update". Sheet one (named "As Presented") is the basis for the graphic I presented on December 10, 2008 at the LB&A meeting. The point of that presentation was to illustrate an example of how if a much anticipated North Slope gas sales line were ever built and significant gas sales began, those sales might have the effect of lowering production tax revenues, rather than raising them.

The second sheet ("As modified") uses the exact same figures as "As Presented", but has been modified slightly. I have changed the appearance so the entire sheet can be viewed on a single screen without scrolling (at least on my laptop). Some of the underlying formulas have maxima and minima built into them to prevent certain "blow outs" when items might become negative or exceed statutory rates. Finally in the bottom rows I have attempted to highlight two distinct numbers that can be drawn from this exercise. The first, (on line 30) which was not presented in the December 10, 2008 meeting is the "gain (loss) in production tax from using current law vs. stand alone." This ties in with some of Dr. Wood's work and is calculated as the difference between the taxes calculated under current law, and the amount that would have been received under an alternative law if

- activity under both versions of the production law were identical, and
- the law was identical to current law except a separate progressivity calculation was made for gas and oil.[1]

[1] Or to put this in terms of Dr. Wood's December 2008 report – there is a CPT or combined progressivity tax versus distinct OPT and GPTs – oil progressivity tax and gas progressivity tax.

The second figure on the bottom line was presented in the December 10th 2008 meeting. It represents the "gain (loss) in production tax from adding a gas stream under current law." This is simply calculated as the difference between the tax received for oil only versus the (in the example presented - lower) tax received as a consequence of the gas stream being added. Essentially the arithmetic difference between this figure and the one presented in the prior paragraph will be any tax (calculated on a stand alone basis) on the gas.[2]

The third sheet (named "Exercise with Spinners") then incorporates spinners so one can easily change the major variables and see the effects. I have built the following ranges into the exercise, though of course these ranges (or tying spinners to some of the other variables) can be further modified. In addition it should be noted that the gas upstream cost figure is tied to the oil cost figure so that changing the former changes the allocation of costs between gas and oil, while changing the latter changes total costs (Consequently, the upside limit for total Upstream Costs is a total dollar figure, while the other upstream cost limits are $/unit produced or zero.)

Oil			
Daily Volume	0.1	1	Million bbls day
Destination Price	10	300	$/bbl
Transportation to Market	5	10	$/bbl
Upstream Costs	$1/bbl	$7 billion	
Gas			
Daily Volume	1	7	bcf/day
Destination Price	1	36	$/mcf
Transportation to Market	2.5	5	$/mcf
Upstream Costs	0	$2.5/mcf	

Figure one – maxima and minima in sheet "Exercise with Spinners"

This model is set up so that one can quickly change several variables and see the effect. Of course with so many variables a wide range of outcomes is possible – some likely some less likely. After the events of the last year while I am loath to say certain cases are not likely, obviously oil selling for say $300 a barrel while gas sells for $1 an mcf is fairly unlikely.

What are some of the settings that one might want to look at?

Because I have used rounded figures for the spinners, this third sheet can only approximate the first two. However, with the same volume figures, $80 barrel and $6/mcf oil and gas prices, $6 and $2.75 deduction to get to market respectively for oil and gas and 4.4 billion dollars in costs (all allocated to oil) the loss from adding gas is $54.1 million (about $15.3 million different from the $69.4 shown on the first two sheets, while

[2] And indeed in the example given the math works out - The loss of $69.4 million when a gas stream is added does not count the fact that stand alone the gas would have generated a tax of $821.6 million. The sum of those two figures is $891.0 million – the amount of tax that would be lost by not having distinct oil and gas progressivity calculations.

the difference between stand alone and combined oil and gas progressivity calculations is only about a million dollars different – a loss of $891 versus $892.4 million. (Hardcopy snapshot follows at the end of this document.)

If one believes that the system was set up as an incentive for gas production so, for instance, when a 4.2 bcf gas stream is added to a 700 bbl a day oil stream total taxes should go down, and not up, then one might want to look at the following settings. All settings are the same as in the prior paragraph, except the gas price rises to $13/mcf roughly the highest level we have see for an historical monthly value. At these values, bringing the gas online **increases** production tax revenue by $4,558.8 million, essentially doubling total revenues. In short, $4 billion in oil taxes is augmented by an additional $4 billion in gas taxes for a total take of roughly 8 billion dollars. At these prices there is no fiscal subsidy or tax-driven incentive to produce gas. (Hardcopy snapshot follows at the end of this document with the gas price highlighted in red.)

On the other hand, if one believes such a result is well and good and the expected outcome of getting a pipeline is increased taxes, then one might want to look at the following settings. Restore the gas price to $6, (and all other settings should be as in the initial paragraph). Set the oil price to $134, again roughly the highest level we have seen for an historical monthly value. At these values, the existing oil stream provides a huge subsidy to gas and tax-driven incentive to produce gas as so total production taxes **fall** by $2,107.4 billion, or roughly 17%. (Hardcopy snapshot follows at the end of this document with the oil price highlighted in red.)

Incidentally, that amount of decrease in this last example is significantly more than 12.5% of the gross value at the point of production for this example (12.5% of the 3.3 billion dollars of gross value of gas at the point of production is roughly $420 million). This may be pertinent to a question Representative Samuels raised in the December 10th 2008 meeting, when he confirmed that the lower production tax in my example would be offset by increased royalties. However, for this set of inputs, the net effect on revenues of adding the gas, even taking royalties into account, is still negative. (If property taxes and income taxes from the gas exceeded $1.7 billion, there could still be a net increase in state revenues from bringing gas on line in this example.)[3]

There are other combinations of prices (and volumes and costs) which yield tax results which may be counterintuitive and hard for an investor or the revenue agency to predict. To go back to one of Dr. Wood's themes – if bringing gas on line may result in either a large decrease or increase in tax for a producer already producing oil it would hardly seem that the state has articulated a strategy and has a tax that reflects that strategy on

[3] A story in the Petroleum News indicates my testimony being that royalties and property taxes would generally increase with a gas stream while income taxes would decrease. I wish to clarify this point in relation to AK corporate income taxes. The sales factor is likely to shrink, and what happens to the property factor is highly dependent on who might own which parts of the project. None the less the production factor should increase –perhaps dramatically - and this will likely mean that as a whole, income tax revenues will increase with a gas line relative to what they would be without it.

this matter. If the intent was higher taxes, however, and taxes fell, one could hardly imagine any response other than a change to the tax law.

When does bringing gas on line result in increased revenues and when does it result in decreased revenues? One way to look at this is to look at various pairings of oil and gas per boe production tax values (PTV/boes) assuming equal boe volumes of oil and gas. On the graphic below the two red stars indicate the positions of the two examples given above. Furthermore the dark blue diamonds represent all the pairings of oil and gas PTV/boes over the last five years 2004 – 2008 assuming the TransCanada Tariff figure. The light purple squares represent the same set of pairings assuming the Black & Veatch Tariff figure.[4]

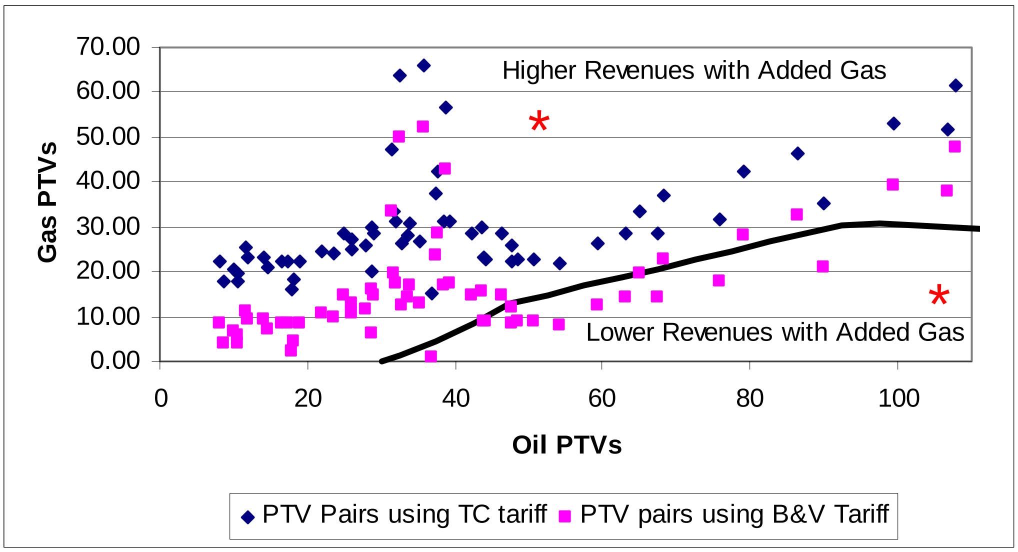

Figure Two – Months when adding a gas stream at 2004-2008 historical prices and costs would have increased or decreased total production tax revenues.

The dark line divides the pairs into a region where adding gas results in higher production tax revenues (most of the chart) and the lower right hand corner where that particular combination of gas and oil PTV/boe will yield lower production tax revenues when gas is added to an oil stream.

However to get back to another of Dr Wood's themes, the tax system should be robust over a wide range of prices, otherwise it is likely to lead to instability which in turn may hamper investment. What happens if trends are examined for higher prices? Using the same conventions as above, the division between situations where the gas will increase is plotted for up to oil PTVs/boe of $400 dollars a barrel. On the one hand, it may be unlikely that we will have crude prices that are high with gas prices really low. On the other hand the pattern is truly bizarre. At a given gas PTV/boe, occasional oil price

[4] Other assumptions include (i) downstream transportation costs for oil for each of the years in question from Appendix B-2a and (ii) a $20 a barrel upstream cost which approximates the current FY 2009 figure, both from the Fall 2008 DOR Revenue Sources book. The gas value is the Henry Hub price, not adjusted for a location differential, while the oil price is ANS WC. The tariff figures (nominal levelized) do not include fuel and are $2.41 for Trans Canada and $4.73 for Black and Veatch.

spikes (highs) could move a taxpayer from a situation when adding gas would raise the taxes to one where taxes would be lowered. At other combinations of oil and gas PTV/boe rising oil prices could do the exact opposite and move a taxpayer from a situation where bringing on a gas stream would lower taxes to one where it would raise taxes.

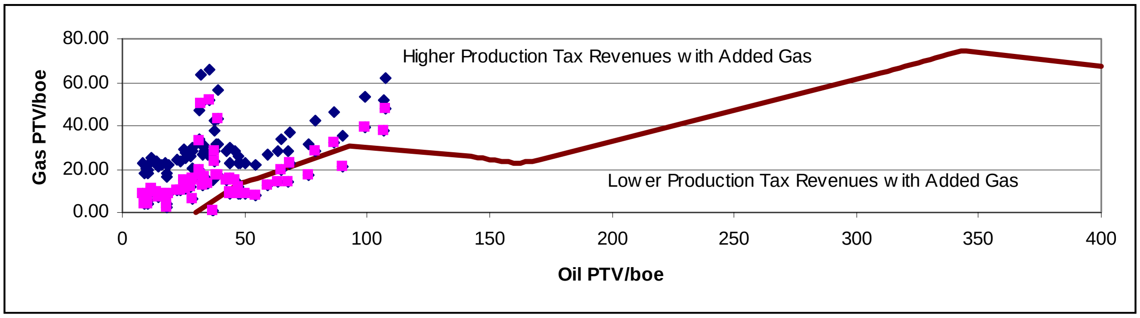

Figure Three – Figure Two extended out to an oil PTV of $400/boe

This is not the only discontinuity under the current law. In fact, in the upper areas of the chart, how much additional tax is produced by bringing on a gas stream is highly variable, and again driven by all the factors that contribute to PTV. In particular while gas at Prudhoe Bay may require relatively small upstream investments, other yet to find gas projects may require significant investment to bring on line. Hence, it is important to be careful not to give the impression by using a single simplistic cost assumption in this model that at given oil and gas price combinations the production tax outcomes are going to be predictable.

Dr. Wood has focused on this issue noting that under the current system, changes in investment can have similar disparate effects. A producer about to bring gas on line might find that if it makes certain investments, adding gas will mean increased taxes, while not making those investments would mean lower taxes, or it might find the opposite.

In fact Dr. Wood has taken the approach of analyzing all combinations of PTV between 0 – $400 per boe (which for gas is roughly from 0 up to $66.7 per mcf). Interesting patterns emerge – although as mentioned above, some combinations of oil and gas prices appear to be relative unlikely to occur or prevail over a long time.

Dr Wood's analysis has identified that three issues are relevant to dilution of production tax under prevailing production tax terms (i.e. BPT + CPT using his terminology) paid to an oil-only case by adding gas production (and vice versa):

1. Magnitude of value differential (high oil value minus low gas value, or vice versa)
2. Relative volumes of oil and gas produced
3. Amount of PTV reinvested by a producer (which depending on the PTVs has significant influence)

An Excel model that combines a wide range of Oil PTV and Gas PTV ($0 to $400 in both cases) and calculates production taxes (BPT + CPT) for each case has been developed and evaluated. The calculated difference in production tax paid by a combined oil and gas stream versus just the production tax paid by the oil stream alone (negative numbers means that producer pays less by adding the gas) reveals the range of value combinations over which a gas stream would dilute production taxes due from an oil stream. This analysis is summarized for 1 boe of oil and 1 boe of gas in Figure 4.

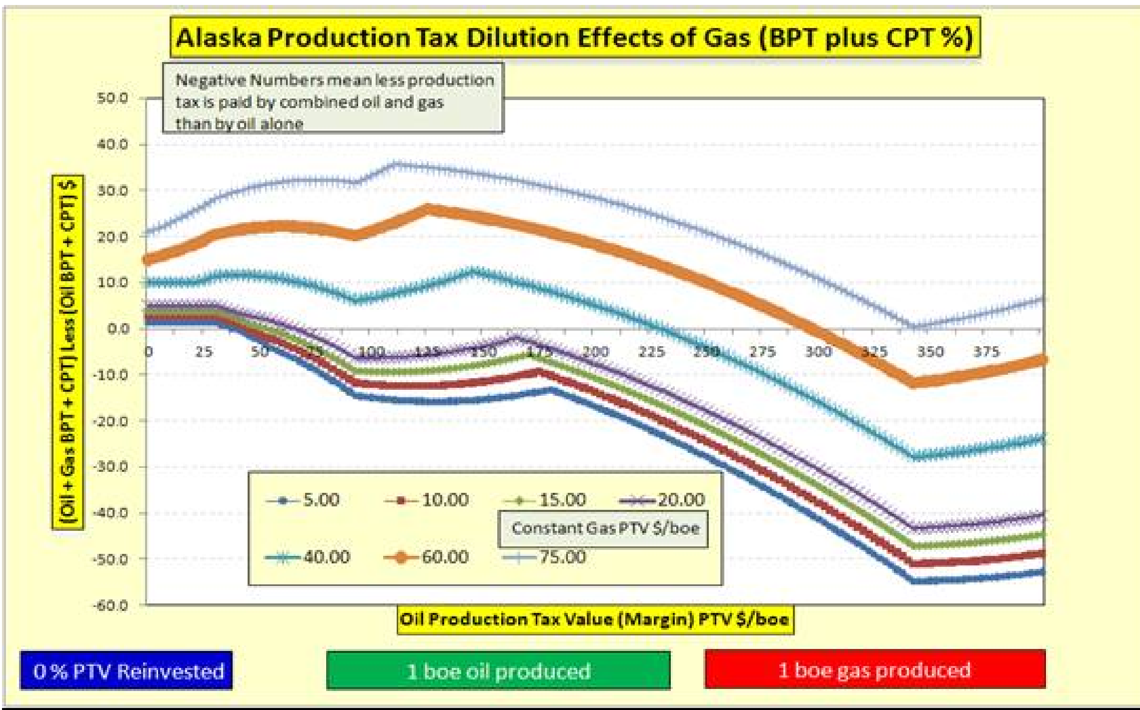

Figure 4 Dilution effect of gas on combined production taxes under prevailing production tax rules.

The horizontal axis in Figure 4 is oil PTV ($0/boe to $400/boe). Effects are quite significant for oil PTV above $50/boe and become more substantial for higher oil PTV $/boe. The trends are non-linear with slope changes reflecting changing gradients of the progressivity mechanism (i.e.0.4 to 0.1/boe) and the threshold values at which those changes occur and at which the progressivity ceiling applies. Varying the relative volumes of oil and gas clearly will change the relationships displayed.

A careful analysis will show that the discontinuities in this table line up with those in the prior graphic (Note both have oil PTV as the X axis, otherwise are different ways of looking at this phenomena.)

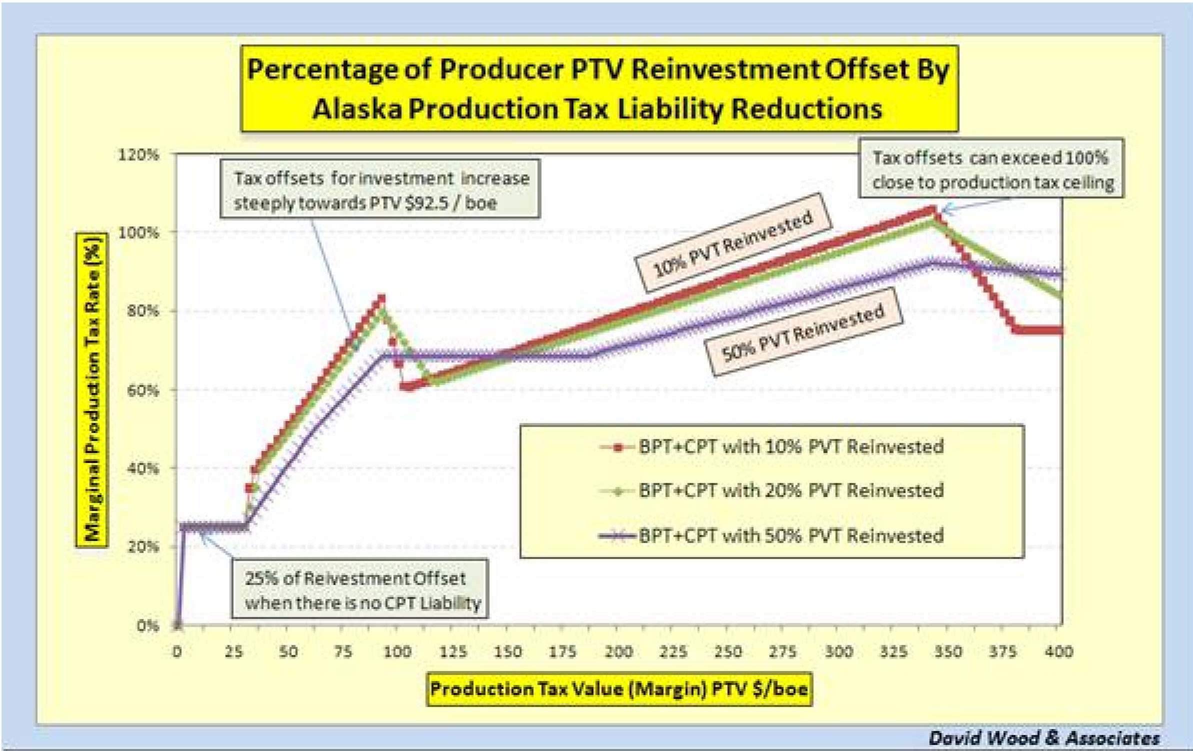

Figure 5 shows non-linear and counter-intuitive behaviour which complicates prediction and modelling associated with reinvestment. The vertical axis shows the percentage tax reduction associated with the incremental re-investment (or the marginal tax rate offset by the producer by its reinvestment). Note the peak around PTV$90/boe and values above 100% at PTV $350/boe.

The analysis suggests that the prevailing production tax system has the following complications: 1) it is difficult to predict (from tax authority and producer perspectives) and relationships between oil and gas tax liabilities are non-linear; 2) the magnitude of combined production tax impact caused by adding a gas production stream varies with relative oil and gas PTVs, oil and gas volumes and percentage of PTV re-invested; 3) without detailed analysis (and speculative forecasting of oil and gas prices) production tax outcomes can be counterintuitive.

These complications lead to the following general conclusions:

1. Under the current production tax rules the impact of gas revenue on the magnitude of combined production taxes is difficult to predict and could lead to counterintuitive outcomes depending on the respective PTVs of oil and gas, their relative production volumes, investment / re-investment and investment credits. Such a situation makes tax

planning difficult (for both state and producers) and is more likely to require future adjustments by the legislature to rates and thresholds according to prevailing conditions. Such adjustments risk undermining fiscal stability and credibility over the long term.

2. By separating CPT into GPT and OPT these problems are removed and incentives can be structured in a transparent way. Under separate oil and gas streams the combined production taxes become more predictable and stable. Also a gas progressivity component could be tailored to provide the state initially with appropriate production tax revenues from the development of existing associated gas reserves (Prudhoe Bay etc.), recognizing the relatively low upstream investment requirements and substantial oil revenues of such projects. At the same time it could also be tailored to provide production tax incentives to explorers and would-be producers focused on the higher risk capital investments needed to identify and develop yet-to-find gas reserves needed over the next 10 to 15 years to sustain gas supply to a gas line. It would be difficult to tailor the prevailing production tax system to such objectives.

II. Request for an example of where an added gas stream would result in a producer losing revenue.

An additional question arose concerned with whether a producer could bring its gas on line and after paying all its incremental taxes and royalties (and income taxes and property taxes) could find itself with less revenue than had it not brought that gas on line.

At one end of the spectrum, clearly for a year in which the gas price which the producer could command in the market is equal to the transportation tariff, this would be the case. If the pipeline is a third party pipeline, and no risk sharing measures have been implemented in their negotiated rates, then the contractually required payment from the producer/shipper to the carrier will wipe out the producer's sales revenues. Before even evaluating the effect of income taxes or property taxes if there were any upstream costs at all, the producer has lost money and if the oil PTV is such that there is no progressivity, then there will be no subsidy effect from oil for the production tax in that year.[5]

At the other end of the spectrum where progressivity would be at work and where I think this question was aimed, I was not able to create an example of such an event with reasonable numbers. However, the model can be manipulated to create such a result and perhaps looking at one such solution will illustrate why such an outcome is unlikely. In Figure 6 below, the yellow highlighted cells were changed from the "As Presented" baseline model. As can be seen, to achieve the intended result inputs must go way outside the relevant ranges. Two manipulations were undertaken – the first notion is to get a small but very high value gas stream which raises the progressivity tax on a large amount

[5] As Figures 2 and 3 show, if the oil PTV is high enough to generate progressivity, then under current law, 0 valued gas production can bring down total production taxes.

of oil so that the resulting tax overwhelms the value added by the gas. Thus when the size of the gas stream is cut by 90%, and the per mcf gas value is constrained to be no less than 1/3 of the per barrel oil value, the required prices raise to $335 a barrel and $111.67 an mcf. The second manipulation was to split upstream costs between oil and gas so that 12.5% of the gross value is a larger % of the PTV. It must be emphasized that these figures were selected to drive the arithmetic of the outcome, not because they are a likely model of reality.

	Oil Only		Incremental Gas		Combined	
Daily Vol	0.7	mmbbls/day	0.42	bcf/day		
days per year	365		365			
Annual Volume	255.5	mmbbls/yr	153.3	bcf/yr		
Convert to boe	1		6			
Annual Barrel Equivalents	255.5	boe/yr	25.55	boe/yr	281.05	boe/yr
ANS WC Price/ Henry Hub Price	$ 335.00		111.67			
Adj to Alberta			(0.75)			
Transportation to Market	(6.34)		(2.88)			
Gross Value at Point of Production	328.66		108.04			
Value times Volume	$ 83,973		16,562			
Non Royalty %	87.5%		87.5%			
Taxable Wellhead	$ 73,476		14,492			
US Costs (millions $)	2,169		2,169			
Taxable Value or PTV (millions $)	$ 71,308		12,323		$ 83,630.3	
Non Royalty Fraction	87.5%				87.5%	
Taxable volumes boe	223.6				245.9	
Prog Base (taxable value/volume)	$ 318.96				340.07	
Less $30	30.00				30.00	
Starting Point	$ 288.96				310.07	
Prog rate (.4% or .1% per dollar)	47.65%				49.76%	
base rate	25.00%				25.00%	
Total Rate	72.65%				74.76%	
	Stand Alone Oil				Combined	
Total Tax (Tax Rate * PTV)	**$ 51,802.1**				**$ 62,519.77**	
Gain (loss) in production tax from adding gas stream under current law:			**10,717.7**			

Figure Six – An unrealistic example showing how even at high prices a gas stream can involve a loss to the producer

How does the math work?

Pre Tax and Royalty value to producer (PTV)	12,323
less	
Royalty = 12.5% of Taxable Value or $14,492	(1,811)
Incremental Production Tax	(10,718)
Net Loss to Producer	(206)

While this simplistic model can generate such a loss, I was not able to find a high gas price that appeared reasonable either in relation to the oil price or to the other dollar values that could produce a sufficiently large impact on the oil progressivity tax while being small enough to be overwhelmed by the effect.

III. Request for data on the use of AS 43.55.025 Exploration Credits

The DOR has supplied the following information on the amounts of AS 43.55.025 credits that the department has certified by year,

	Sum of Total Credit Certificate Amount
2004	1,510,412.00
2005	13,096,356.00
2006	21,734,313.11
2007	41,019,872.46
2008	21,141,394.47
Total	98,502,348.04

Note that during the period April 2006 – June 2008 it might well have been immaterial to an explorer whether certain exploration credits were filed for under AS 43.55.025 – the exploration tax credit program, or under AS 43.55.023 – the more general investment credit. (When the 20% credit under AS 43.55.023 became law it was made available retroactively for investments made on or after April 1, 2006. While there were distinctions between the two programs, in many cases, explorers would not have cared whether they received a 20% credit under AS 43.55.025 or AS 43.55.023. In 2007, the minimum AS 43.55.025 credits available for new investments was raised from 20% to 30% effective July1, 2008, so once again for a cost that qualified under both programs, an explorer was likely to file under the program granting the largest credit.)

First Snap shot: Model close to that presented in December 10, 2008 LB&A meeting

	Oil Only		Incremental Gas		Combined	
Daily Vol	0.700	mmbbls/day	4.2	bcf/day		
days per year	365		365			
Annual Volume	255.5	mmbbls/yr	1533	bcf/yr		
Convert to boe	1		6			
Annual Barrel Equivalents	255.5	boe/yr	255.5	boe/yr	511.0	boe/yr
ANS WC Price/ Henry Hub Price	$ 80.00		$ 6.00			
Adj to Alberta			(0.75)			
Transportation to Market	(6.00)		(2.75)			
Gross Value at Point of Production	74.00		2.50			
Value times Volume	$ 18,907		$ 3,832.5			
Non Royalty %	87.5%		87.5%			
Taxable Wellhead	$ 16,544		$ 3,353			
US Costs (millions $)	4,400		-			
Taxable Value or PTV (millions $)	$ 12,144		$ 3,353.4		$ 15,497	
Non Royalty Fraction	87.5%		87.5%		87.5%	
Taxable volumes boe	223.6		223.6		447.1	
Prog Base (taxable value/volume)	$ 54.32		$ 15.00		$ 34.66	
Less $30	30.00		30.00		30.00	
Starting Point	$ 24.32		$ -		$ 4.66	
Prog rate (.4% or .1% per dollar)	9.73%		0.00%		1.86%	
base rate	25.00%		25.00%		25.00%	
Total Rate	34.73%		25.00%		26.86%	
	Stand Alone Oil		Stand Alone Gas		Combined	
Total Tax (Tax Rate * PTV)	**$ 4,217**		**838.4**		**$ 4,163**	
Sum of stand alone oil & gas		**5,055.53**				
Gain (loss) in production tax from using current law vs stand alone				**(892.4)**		
Gain (loss) in production tax from adding gas stream under current law:			**(54.1)**			

Second Snap Shot: By altering the gas price, a situation is created where adding a gas stream to an oil stream doubles the production tax.

	Oil Only		Incremental Gas		Combined	
Daily Vol	0.700	mmbbls/day	4.2	bcf/day		
days per year	365		365			
Annual Volume	255.5	mmbbls/yr	1533	bcf/yr		
Convert to boe	1		6			
Annual Barrel Equivalents	255.5	boe/yr	255.5	boe/yr	511.0	boe/yr
ANS WC Price/ Henry Hub Price	$ 80.00		$ 13.00			
Adj to Alberta			(0.75)			
Transportation to Market	(6.00)		(2.75)			
Gross Value at Point of Production	74.00		9.50			
Value times Volume	$ 18,907		$ 14,563.5			
Non Royalty %	87.5%		87.5%			
Taxable Wellhead	$ 16,544		$ 12,743			
US Costs (millions $)	4,400		-			
Taxable Value or PTV (millions $)	$ 12,144		$ 12,743.1		$ 24,887	
Non Royalty Fraction	87.5%		87.5%		87.5%	
Taxable volumes boe	223.6		223.6		447.1	
Prog Base (taxable value/volume)	$ 54.32		$ 57.00		$ 55.66	
Less $30	30.00		30.00		30.00	
Starting Point	$ 24.32		$ 27.00		$ 25.66	
Prog rate (.4% or .1% per dollar)	9.73%		10.80%		10.26%	
base rate	25.00%		25.00%		25.00%	
Total Rate	34.73%		35.80%		35.26%	
	Stand Alone Oil		Stand Alone Gas		Combined	
Total Tax (Tax Rate * PTV)	**$ 4,217**		**4,562.0**		**$ 8,776**	
Sum of stand alone oil & gas		**8,779.19**				
Gain (loss) in production tax from using current law vs stand alone				**(3.2)**		
Gain (loss) in production tax from adding gas stream under current law:			**4,558.8**			

Third Snap Shot: By altering the oil price a situation is created where adding gas to an oil stream significantly reduces the production tax.

	Oil Only		Incremental Gas		Combined	
Daily Vol	0.700	mmbbls/day	4.2	bcf/day		
days per year	365		365			
Annual Volume	255.5	mmbbls/yr	1533	bcf/yr		
Convert to boe	1		6			
Annual Barrel Equivalents	255.5	boe/yr	255.5	boe/yr	511.0	boe/yr
ANS WC Price/ Henry Hub Price	$ 134.00		$ 6.00			
Adj to Alberta			(0.75)			
Transportation to Market	(6.00)		(2.75)			
Gross Value at Point of Production	128.00		2.50			
Value times Volume	$ 32,704		$ 3,832.5			
Non Royalty %	87.5%		87.5%			
Taxable Wellhead	$ 28,616		$ 3,353			
US Costs (millions $)	4,400		-			
Taxable Value or PTV (millions $)	$ 24,216		$ 3,353.4		$ 27,569	
Non Royalty Fraction	87.5%		87.5%		87.5%	
Taxable volumes boe	223.6		223.6		447.1	
Prog Base (taxable value/volume)	$ 108.32		$ 15.00		$ 61.66	
Less $30	30.00		30.00		30.00	
Starting Point	$ 78.32		$ -		$ 31.66	
Prog rate (.4% or .1% per dollar)	26.58%		0.00%		12.66%	
base rate	25.00%		25.00%		25.00%	
Total Rate	51.58%		25.00%		37.66%	
	Stand Alone Oil		Stand Alone Gas		Combined	
Total Tax (Tax Rate * PTV)	**$ 12,491**		**838.4**		**$ 10,384**	

Sum of stand alone oil & gas **13,329.43**

Gain (loss) in production tax from using current law vs stand alone **(2,945.7)**

Gain (loss) in production tax from adding gas stream under current law: **(2,107.4)**