TESTIMONY ON HB 72
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to the
HOUSE RESOURCES COMMITTEE
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Mister Chair, Members of the Committee:

Good Afternoon. For the record, my name is Thomas K. Williams and I am Senior Royalty and Tax Counsel for BP Exploration (Alaska) Inc. Thank you for inviting us here to testify on House Bill 72, which has been introduced by Governor Parnell and proposes to amend the so-called "ACES" production tax on oil and gas produced in Alaska.

There are three primary changes that HB 72 would make to ACES: one, repeal progressivity, which we think is good; two, change the system of tax credits that now exists, which threatens to harm some producers even if it may help others; and three, create a new "gross revenue exclusion" for new production that we view as innovative but largely misdirected. My testimony today will review these changes in the context of the tax issues that my employer faces under the present tax, which the Governor and apparently the entire Legislature, with the introduction of Senate Bill 50, agree needs to be reformed.

First, progressivity. As you know, progressivity is a sliding-rate tax that runs quickly up to a 25% rate and then rises more slowly above 25 percent. It is in addition to the basic 25% tax that is also levied on the "production tax value" of a producer's taxable production. Repealing progressivity is a good idea for a number of reasons, which AOGA has identified in its testimony on Monday and which other taxpayers will probably present to you as well. Many of those objections are for effects from progressivity that were intentional as part of the way progressivity was designed. What I'd like to do today is to describe two significant, <u>un</u>intended effects of progressivity that seem largely unknown and even less understood. I have eight slides to present that will show you exactly what these unintended consequences are.

To begin, let me quickly review how the tax is calculated for the example I will use.

		Bbl	**$/bbl**
USWC Price	$1,000,000	10,000	$100.00
Transportation	<u>$150,000</u>	10,000	<u>$15.00</u>
GVPP	$850,000	10,000	$85.00
Field Expense	<u>$300,000</u>	10,000	<u>$30.00</u>
PTV	$550,000	10,000	$55.00
25% Base Tax	$137,500		
Prog'y Rate	10.000%		
Prog'y Tax	<u>$55,000</u>		
Total Tax	$192,500		

Slide 1. How ACES works

If you look at this first slide, you will see the tax calculation for a hypothetical producer with 10,000 barrels of oil who sells it on the West Coast for $100 a barrel and receives a million dollars. It cost $150,000 – or $15 a barrel – to transport that oil from the field in Alaska to the West Coast, which leaves $850,000 as the gross value at the point of production or "GVPP." The producer had $300,000 of allowable lease expenditures, or field expense, to produce the oil, which leaves a taxable production tax value, or "PTV," of $550,000 or $55 a barrel. The base tax is 25% of the PTV, or $137,500.

The progressivity rate equals four tenths of a percentage point times the difference between $30 and the producer's PTV per barrel. Here the difference between $30 and $55 is $25, and $25 times four tenths of a point per dollar equals 10 percent. Ten percent of $550,000 is $55,000 of progressivity tax. That plus the base tax of $137,500 equals a total tax of $192,500. So far there is nothing here that is new to you.

So now let me begin to show you something you probably have not seen before. This scenario is not about what the producer has actually produced, but about an evaluation of what could happen from the development of a new reservoir or field if the investment is made. And let's suppose that this producer sees three different ways that she could potentially improve this investment. One is that she knows of a buyer willing to pay a premium of a dollar a barrel for the oil delivered on the West Coast, the second is a way to save $20,000 in transportation costs, and the third is a way to cut the costs for field operations by $30,000. If she can do all three, what is the change in the tax?

	Base Case	**Revision**	**As Revised**	**Bbl**	**Base Case $/Bbl**	**Revised $/Bbl**	**Change in Tax**	
USWC Price	$1,000,000	$10,000	$1,010,000	10,000	$100.00	$101.00	$35,640	All 3
Transportation	$150,000	($20,000)	$130,000	10,000	$15.00	$13.00		
GVPP	$850,000		$880,000	10,000	$85.00	$88.00		
Field Expense	$300,000	($30,000)	$270,000	10,000	$30.00	$27.00		
PTV	$550,000		$610,000	10,000	$55.00	$61.00		
25% Base Tax	$137,500		$152,500					
Prog'y Rate	10.000%		12.400%					
Prog'y Tax	$55,000		$75,640					
Total Tax	$192,500		$228,140					
Change in tax			$35,640					

Slide 2. Example – The three changes together

In this slide we see the three changes. The extra dollar a barrel in the price increases the sales revenue from the oil to $1,010,000. The transportation savings reduces that cost from $150,000 to $130,000. Between the increased price and the transportation savings, the GVPP of the oil back in the field is $880,000 instead of $850,000. And the reduction in upstream lease expenditures raises the taxable PTV by another $30,000, for a total increase in PTV of $60,000 from $550,000 to $610,000.

The 25% base tax is now $152,500 instead of $137,500. And with PTV per barrel now $61, the progressivity rate is $61 minus $30, or $31, times four tenths of a percentage point per dollar, or 12.4 percent. Twelve-point-four percent of $610,000 is $75,640, and the total tax is $228,140 instead of $192,500. This is an increase of $35,640.

I have highlighted this change in yellow and recorded it in the upper right corner of the slide in order to keep it on screen so we can remember what it was, because in this scenario the producer next asks what the tax change is separately for each of these improvements to the investment. This next slide shows the change resulting only from the extra dollar in the West Coast price.

	Base Case	Revision	As Revised	Bbl	Base Case $/Bbl	Revised $/Bbl	Change in Tax	
USWC Price	$1,000,000	$10,000	$1,010,000	10,000	$100.00	$101.00	$35,640	All 3
Transportation	$150,000		$150,000	10,000	$15.00	$15.00		
GVPP	$850,000		$860,000	10,000	$85.00	$86.00	$5,740	Price
Field Expense	$300,000		$300,000	10,000	$30.00	$30.00		
PTV	$550,000		$560,000	10,000	$55.00	$56.00		
25% Base Tax	$137,500		$140,000					
Prog'y Rate	10.000%		10.400%					
Prog'y Tax	$55,000		$58,240					
Total Tax	$192,500		$198,240					
Change in tax	-		$5,740					

Slide 3 Example – Price change only

The higher price increases the sales proceeds by $10,000 to $1,010,000. And as you go down the "As Revised" column you see this $10,000 flowing down into the $860,000 GVPP and then into the taxable PTV, raising it to $560,000. The 25% base tax on $560,000 is $140,000. The progressivity rate is $56 minus $30, or $26, times four tenths of a percentage point per dollar, which is 10.4 percent. Ten-point-four percent of $560,000 is $58,240 and the total tax is $198,240, an increase of $5,740 from the base case. Again, I have recorded this at the right side of the table so we can remember what it is without having to flip back and forth between slides.

The next slide shows the change in tax from the $20,000 savings in transportation costs.

	Base Case	Revision	As Revised	Bbl	Base Case $/Bbl	Revised $/Bbl	Change in Tax	
USWC Price	$1,000,000		$1,000,000	10,000	$100.00	$100.00	$35,640	All 3
Transportation	$150,000	($20,000)	$130,000	10,000	$15.00	$13.00		
GVPP	$850,000		$870,000	10,000	$85.00	$87.00	$5,740	Price
Field Expense	$300,000		$300,000	10,000	$30.00	$30.00	$11,560	Transpo.
PTV	$550,000		$570,000	10,000	$55.00	$57.00		
25% Base Tax	$137,500		$142,500					
Prog'y Rate	10.000%		10.800%					
Prog'y Tax	$55,000		$61,560					
Total Tax	$192,500		$204,060					
Change in tax	-		$11,560					

Slide 4. Example – Transportation cost savings

The $20,000 again flows straight down into the taxable PTV, increasing it from $550,000 to $570,000. The progressivity rate is now $57 dollars minus $30, or $27, times four tenths of a percentage point per dollar or 10.8 percent. That plus the 25% base rate on $570,000 of PTV yields a total tax of $204,060, an increase of $11,560 from the base case. This, too, I have recorded on the right side of the table.

Finally, this next slide shows the effect of saving $30,000 in field expense. The PTV increases by $30,000 to $580,000, the progressivity rate is 11.2 percent. The base tax and progressivity add up to $209,960 — an increase of $17,460 from the base case.

	Base Case	Revision	As Revised	Bbl	Base Case $/Bbl	Revised $/Bbl	Change in Tax	
USWC Price	$1,000,000		$1,000,000	10,000	$100.00	$100.00	**$35,640**	All 3
Transportation	$150,000		$150,000	10,000	$15.00	$15.00		
GVPP	$850,000		$850,000	10,000	$85.00	$85.00	$5,740	Price
Field Expense	$300,000	($30,000)	$270,000	10,000	$30.00	$27.00	$11,560	Transpo.
PTV	$550,000		$580,000	10,000	$55.00	$58.00	$17,460	Lease Exp.
25% Base Tax	$137,500		$145,000				**$34,760**	
Prog'y Rate	10.000%		11.200%					
Prog'y Tax	$55,000		$64,960					
Total Tax	$192,500		$209,960					
Change in tax	-		$17,460					

Slide 5. Whole is greater than the sum of its parts

And here at last, this slide shows what it is that you probably have not seen before. The sum for the three changes separately is $34,760, which is in bold font to make it easier to spot. This is less than the $35,640 change in tax when all three are factored in at once (also in bold font). In other words, with progressivity, the whole is greater than the sum of its parts.

And that's not all. The amount of tax that is calculated for each individual part changes, depending on what order you look at them. Here's a slide that looks at the $20,000 savings in transportation cost and the $30,000 reduction in field expense together.

	Base Case	Revision	As Revised	Bbl	Base Case $/Bbl	Revised $/Bbl	Change in Tax	
USWC Price	$1,000,000		$1,000,000	10,000	$100.00	$100.00	$11,560	Transpo. Only
Transportation	$150,000	($20,000)	$130,000	10,000	$15.00	$13.00	$17,460	Field Exp. Only
GVPP	$850,000		$870,000	10,000	$85.00	$87.00		
Field Expense	$300,000	($30,000)	$270,000	10,000	$30.00	$27.00	$11,560	Transpo. 1st
PTV	$550,000		$600,000	10,000	$55.00	$60.00	$17,940	Field Exp.2nd
25% Base Tax	$137,500		$150,000				$29,500	
Prog'y Rate	10.000%		12.000%					
Prog'y Tax	$55,000		$72,000				$12,040	Transpo. 2nd
Total Tax	$192,500		$222,000				$17,460	Field Exp.1st
Change in tax	-		$29,500				$29,500	

Slide 6. ACES's continuously changing tax effect

The two cost reductions together increase PTV by $50,000, to $600,000. The base tax on that is $150,000. Progressivity for $60 of PTV per barrel is $60 minus $30, or $30, times four tenths of a percentage point per dollar, or 12 percent, times $600,000, which is $72,000. The total tax change from the two is $29,500. From the previous cases where we considered each cost reduction separately, the tax increase with transportation only was $11,560 and for field expense only was $17,640, and these appear in the upper right of the slide.

If we look at transportation first, it is equivalent to looking at it standing alone, and we have already calculated what that is — $11,560. So $11,560 of the combined $29,500 tax increase is from the change in transportation cost, and the rest – $17,940 – is for the change in field expense. But this means the field expense is almost $500 greater than what it is when it's standing alone. And if you reverse the order, then the field-expense tax increase is the same as when it stands alone, but now the tax increase for the transportation savings is different — $12,040 instead of the $11,560 when it stands alone or is taken first.

What we have done here on this sixth slide is to look at the pair of cost savings for downstream transportation and upstream lease expenditures, and we've looked at that pair first, ahead of the change in market price. If we go back to the previous slide, we see that if we take transportation first and subtract its $5,740 from the total $35,640 tax effect for all three, then that leaves a different number – $29,900 – for this pair of changes instead of the $29,500 we have here on slide six when we calculate that pair back first.

There is nothing special about this particular pair of changes that creates this difference. There would be a similar difference if we pair price with transportation or price with lease expenditures. With either one, we'd get one set of tax effects for this pair if we calculate them first, and a different set of tax effects if we calculate the effect of the unpaired change first. And, as here, within each pair, there is a different cost for each change in that pairing depending on whether its effect is calculated first or the other's effect is first.

These examples involve a triplet of categories of change that could be made to improve the economics of the project: an increase in price, a reduction in transportation costs to market, and greater efficiency in field operations. But I have simplified these examples by using lease expenditures generically as a single cost category. In the real world a would-be investor would look at capital expenditures separately from operating costs because the timing for when the two kinds of cost are incurred is different and – especially important in the context of analyzing tax effects – the capex generates a 20% Qualified Capital Expenditure tax credit in addition to changing the PTV and the progressivity rate. So there are really four categories of change to look at: changes in sales price, changes in transportation costs, changes in operating expense, and changes in capital expenditures.

For each one of these four categories, its respective tax effect can be calculated separately from the other three, either ahead of them or after them. And each such triplet of changes has the same analysis and the same variations in tax effect for individual changes that we have seen in the entire analysis that we have just gone through in this and the four earlier slides — namely, the tax effect for the entire triplet being greater than the sum of the effects for the individual categories in it; the different amount for the unpaired category in each triplet relative to the pair of other categories, depending on whether the effect of the pair is calculated first or second; and within each such pair, the different amount depending on which category in that pair is calculated first. Each of these numerous variations and combinations will divide the $35,640 total tax effect up into a different set of amounts calculated for the four categories. Yet even with all those sets of calculated amounts for the categories, none of those sets will add up to the tax effect for all the changes taken together as a whole.

And all this complexity doesn't begin to reflect the likelihood that there may well be several different changes that could be made within one or more of these four basic cost categories.

These bizarre effects are not mere abstract curiosities. If you are an investor and you have a variety of ways to try to improve the performance of an investment, these effects from progressivity mean there is no single correct answer about how much each one changes the tax and improves the investment. The more ways you have to improve the investment, the more the change in tax for each one depends on where you put it in the sequence of calculating the changes for all of the opportunities. This is because each opportunity in that sequence not only increases the PTV, but it also increases the progressivity rate applicable to the base case PTV plus all the PTV that has been added by the prior opportunities in the sequence.

Interestingly, the Department of Revenue has exactly the same problem when it audits a taxpayer and makes multiple changes to figures reported on the tax return and increases the amount of tax. The auditor can quantify the whole tax increase from all the changes, but he or she cannot make a definitively correct determination of the amount of any one of those changes. A taxpayer might have an interesting time in an appeal having an auditor admit, issue by issue, that there is no correct amount for each one.

There is a second unintended consequence of progressivity that is also important. I call it a tax on price volatility because it increases the tax when prices change during a tax year even though the total PTV is exactly the same as if the prices had stayed constant at the average price for the year.

	PTV per Bbl	MM bbl	PTV ($MM)	Prog'v'y Rate	Prog'v'y Tax ($MM)
Jan	$61.25	2.00	$122.50	12.50%	$15.31
Feb	61.25	2.00	122.50	12.50%	15.31
Mar	61.25	2.00	122.50	12.50%	15.31
Apr	61.25	2.00	122.50	12.50%	15.31
May	61.25	2.00	122.50	12.50%	15.31
Jun	61.25	2.00	122.50	12.50%	15.31
Jul	61.25	2.00	122.50	12.50%	15.31
Aug	61.25	2.00	122.50	12.50%	15.31
Sep	61.25	2.00	122.50	12.50%	15.31
Oct	61.25	2.00	122.50	12.50%	15.31
Nov	61.25	2.00	122.50	12.50%	15.31
Dec	61.25	2.00	122.50	12.50%	15.31
Full Year	$61.25	24.00	$1,470.00		$183.75

Slide 7. Flat price scenario

On this slide we see such a "flat price" scenario. To fit conveniently within the space available in a slide, the table omits columns for West Coast prices, transportation costs and field expenses, and starts instead with the PTV that is calculated from them. Here the PTV is $61.25 per barrel, and with 2 million barrels of production a month, the amount of the taxable PTV is $122.5 million a month.

Progressivity starts when the PTV per barrel exceeds $30, and it reaches 25% at a PTV per barrel of $92.50. I have chosen $61.25 as the PTV per barrel in this base case because it is half way between $30 and $92.50. The progressivity rate at this price is $61.25 minus $30, or $31.25, times four tenths of a percentage point per dollar, or 12.5 percent. This also is half way between the zero rate at $30 and the 25% rate at $92.50. As you can see, each month the PTV is $122.5 million, the progressivity rate is always 12.5%, and the progressivity tax is exactly the same for each month as $15.31 million. Total progressivity for the year is $183.75 million.

	PTV per Bbl	MM bbl	PTV ($MM)	Prog'v'y Rate	Prog'v'y Tax ($MM)	PTV per Bbl	MM bbl	PTV ($MM)	Prog'v'y Rate	Prog'v'y Tax ($MM)
Jan	$61.25	2.00	$122.5	12.50%	$15.31	$30.00	2.00	60.0	0.00%	-
Feb	61.25	2.00	$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Mar	61.25	2.00	$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Apr	61.25	2.00	$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	$46.25
May	61.25	2.00	$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jun	61.25	2.00	$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jul	61.25	2.00	$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Aug	61.25	2.00	$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Sep	61.25	2.00	$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Oct	61.25	2.00	$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Nov	61.25	2.00	$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Dec	61.25	2.00	$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Full Year	$61.25	24.00	$1,470.0		$183.75	$61.25	24.00	1,470.0		$277.50

Slide 8. Progressivity increases taxes with fluctuating price even when the economics don't change

In this next slide the left half is exactly the same as the previous one with the flat-price scenario. The right half of the table shows what happens when there are six months in the year when the PTV per barrel is $30 and six when it is $92.50. In this case the first three months and the last three have the $30 PTV per barrel, and the middle six from April through September have the $92.50. This price profile resembles what actually happened with West Coast prices for North Slope oil during 2008, when they peaked at the all-time record of $144.59 a barrel on July 3rd.

For the six months when the PTV per barrel is $30, the progressivity tax rate is zero because $30 of PTV per barrel minus the $30 threshold for progressivity is zero. So, as you can see, there is no progressivity tax for the first three months of the year and the last three. In the middle six, the PTV per barrel is $92.50. That is $62.50 higher than the $30 threshold, so the progressivity rate is four tenths of a percentage point times 62.50, or 25.00 percent. At $92.50 a barrel, the progressivity tax on two million barrels a month is $46.25 million, so the total progressivity tax for the six non-zero months is $277.5 million.

The progressivity tax under the changing-price scenario is <u>51% higher</u> than the $183.75 million of progressivity for the flat-rate scenario.

This tax increase is entirely the result of the fact that prices changed during the year instead of being flat. You can see this for yourselves. The total PTV for the year in the right-hand column is 1,470 millions of dollars, or $1.47 billion — exactly the same as in the flat-price scenario on the left. Total production for the year is exactly the same — 24 million barrels. Dividing $1.47 billion of PTV by 24 million barrels equals $61.25 per barrel, exactly the same. But progressivity is 51% higher.

And if you look at the monthly calculations in the changing-price scenario, you can see that the monthly progressivity tax will be exactly the same for each of the $30 months no matter what order you put those months in. The same is true for the $92.50 months. So this phenomenon is different from what I showed you earlier about the whole being greater than the sum of its parts, because here there are no changes in the actual progressivity calculation for a $30 month or a $92.50 one.

The bottom line here is this. The year under the changing-price scenario is just as profitable as the flat-price one, and for the same amount of production. The tax base to which progressivity applies is exactly the same for the year. Yet the tax is 51% higher when prices change during the year.

Now, I have chosen these PTV-per-barrel figures so they would show the greatest amount of tax increase resulting from prices that are not flat all year long. I did this because, if I showed you an example with a smaller effect, someone would surely ask me what the maximum effect could be. My example gives you that answer at the same time it explains the phenomenon.

Those of you who were here in the Legislature in 2009 may recall the surprise of the Department of Revenue when the actual ACES tax collected during its first full year of operation – the 2008 calendar year – came in about half a billion dollars higher than the Department had forecasted. This tells you why: 2008 was a very volatile year for prices. While that volatility did not generate the maximum 51% increase that my example illustrates, it did produce a very substantial increase in progressivity tax – on the order of half a billion dollars – from the mere fact that prices fluctuated during 2008, instead of being flat at the volume-weighted average price for the year.

So, to summarize: Progressivity has two major unintended consequences. First, when you are analyzing combinations of steps to take to improve an investment opportunity, the whole is greater than the sum of its parts. Second, if you do not take into account the effect from price volatility during each year in an investment's life, the progressivity could turn out to be 50% higher than what you have estimated. Both of these unintended effects promise to increase the risks and reduce the competitiveness of an Alaskan investment relative to a comparable one elsewhere.

These negatives of progressivity complement what AOGA told you during its testimony last Monday. Without repeating that testimony here, I will only list AOGA's main points. One, progressivity sacrifices the one advantage Alaska has from its economic remoteness – namely, the greater improvement in financial performance for investments here if prices turn out better than projected – because progressivity taxes away more and more of that improvement the better it turns out to be. And two, progressivity makes the tax extraordinarily complex and inconsistent to compute, and to analyze.

For these reasons BP fully endorses the proposed repeal of progressivity that House Bill

72 proposes.

Let me now turn to the second main feature in this Bill — the changes it proposes to the present system of tax credits, and in particular to the sunset of the credit for "qualified capital expenditures" or "QCE" at the end of this calendar year.

The first, and probably most important observation I can offer about tax credits in general is they would not be so significant for the economics of oil and gas production here if the production tax were not so high.

Second, the QCE tax credit depends solely on how much a company invests for oil and gas exploration, development and production in Alaska. Period. If you want to address the North Slope decline curve, there have to be investments here leading to more production — not just by finding and developing new fields and new reservoirs, but also by getting more recovery out of fields already in production. The QCE tax credit is a direct incentive for making these investments. And it costs the State nothing unless there are investments: if investment is zero, then 20% of zero is zero. The QCE tax credit arises only when it succeeds, and costs nothing if it doesn't.

The QCE tax credit is not affected by oil prices, the costs of transporting oil and gas to market, nor the operating costs of the field. Consequently its value to a business like BP's is the same for a given amount of QCE expenditure, regardless of the price and the transportation and field operating cost scenarios that the business estimates in its investment decisions. And it is the same regardless of how prices and those other costs actually turn out. Progressivity, on the other hand, is dependent on prices and costs in a twofold way: once in determining the amount of PTV that is subject to tax, and again in calculating the tax rate that progressivity will apply to that PTV.

Thus, the point where the cost of losing the QCE credit year begins to outweigh the benefit from repealing progressivity depends both on the price of oil and, for each individual producer, on that producer's own unique portion of the lease expenditures for the North Slope. For BP's own business and expenditures, this crossover comes at a higher price level – in the mid to upper 90s – than that which Econ One and others are presenting for North Slope producers as a whole. So the improvement to our investment economics from the repeal of progressivity stands to be substantially undone by the sunset of the QCE tax credit. Since I am a tax man who is here to testify about this tax, I would ask, please, for your patience for just a few minutes if you have questions regarding this point, so I can quickly finish up and Mr. Bilbao can testify.

The third major feature in HB 72 is its proposed "gross revenue exclusion" or "GRE" which is something new. It would exclude from the taxable PTV (production tax value) a percentage of the gross value at the point of production for additional or new volumes of oil or gas being produced. This concept could have significant potential, and indeed it may prove very valuable for explorers and others who can bring new fields and reservoirs into production.

Unfortunately, the proposed GRE aims away from the significant opportunities for new production that BP has identified for its business. HB 72 would allow a GRE only for production "from a lease or property that does not contain land that was within a unit on January 1, 2003[,]" or if it does have land that was in a unit before 2003, "the oil or gas is produced from a participating area established after ... 2011 [that] does not contain a reservoir that had previously been in a participating area established before ... 2012."

BP's business centers primarily around units that were established before 2003 — the Prudhoe Bay Unit, Kuparuk River Unit, Duck Island Unit and Milne Point Unit. These units are fully explored, and the likelihood is small that any significant new participating area will be established in them that "does not contain a reservoir that had previously been in a participating area established before ... 2012." So these units are unlikely to receive any GRE, as the Bill reads now.

The present focus of the proposed GRE is misdirected. Econ One a week ago told you that an estimated 29.1 billion barrels of oil and barrel-equivalents of gas on the North Slope and offshore in the OCS is "Economically Recoverable @ $90/bbl". But, as AOGA pointed out it its testimony on Monday, only 10% of that resource is in an area that Alaska has any direct economic stake in and control over — the central North Slope. Of the 3 billion barrels there that Econ One identified, AGOA's testimony (in which we and the other members of AOGA all concurred) estimated that "2.5 billion barrels or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production" that have little or no chance of getting any GRE under the Bill.

If you're going to hunt for eggs, you have to look where the hens nest. The same is true for oil. If you are going to provide an incentive to increase production rates and ultimate recovery, offer it where the oil is.

There are several problems with the present ACES law that HB 72 does not address, and I will quickly brief you about them.

The first is the disallowance under AS 43.55.165(e)(19) of "costs incurred for repair, replacement, or deferred maintenance" of production facilities "in response to a failure, problem, or event that results in the unscheduled interruption … or reduction in the rate of … production … or in response to … an unpermitted release of a hazardous substance or [natural] gas[.]" This was enacted in 2007 in response to the partial shutdown of Prudhoe Bay in 2006 after two corrosion-caused leaks were discovered. BP is <u>not</u> seeking change to the substance of the disallowance itself, but we think the statutory language should be improved to establish clarity about its applicability.

There are minor hiccups in production operations almost every day in fields around the world, and Alaska's fields are no exception. The present statute sets no standard of materiality for an "unscheduled interruption .. or reduction" in production. If production at a facility is "interrupted" for five minutes because of a temporary hiccup in operations, does that cause a disallowed expense? If production is "reduced" by five barrels a day for a field producing over 400,000 barrels daily, does that cause a disallowed expense? If production is interrupted for a material period of time, but ultimately it turns out to cost only $10 to respond to it, is it worthwhile to identify and quantify this $10 so it can be disallowed? There is no answer to these and similar questions in the statute, and the Department of Revenue has not adopted regulations that answer them.

We are not asking you to try to write the answers to these questions in the statute, although you certainly could if you want do to all that work. But we suggest, instead, that you expressly give the Department of Revenue not only the authority, but the duty, to adopt regulations that set reasonable thresholds for materiality about how long an "interruption" has to last, about how large a "reduction" in production has to be, about how much an unauthorized release has to be or in what circumstances must it occur, and about how much the cost "incurred … in response to" such situations has to be, in order to trigger the disallowance.

As you know, I worked in the Department of Revenue some 30-odd years ago, and if I had to administer this statute in light of the circumstances and controversy that led to its enactment, I would be reluctant to adopt regulations on my own initiative to establish such thresholds unless I had some kind of go-ahead or permission from the Legislature. Perhaps the Department is waiting for such a sign from you.

The second unaddressed problem comes from the changes that ACES made to AS 43.55.150, the statute that determines the gross value at the point of production on the basis of destination prices or values minus the costs of transporting the oil or gas to those destinations from the point of production in the field. As amended, the actual cost that a producer pays to a regulated pipeline carrier to ship the producer's oil could be set aside if the producer and carrier are "affiliated." The Department has adopted regulations calling for "cost-based" tariff calculations in lieu of the actual regulated tariffs that are paid.

But under those regulations these calculations of the "cost-based" tariffs are made by the Department, not the taxpayer, and there is no deadline in the regulations or in AS 43.55.150 for the Department to make its calculations and share the results with the taxpayer. The only deadline is the six-year statute of limitations under AS 43.55.075(a). We concur with AOGA's testimony about the interplay between this six-year statute and interest at 11% APR, compounded quarterly, for any tax underpayment that, in this regulated-pipeline situation, might result from the Department's calculation of a lower tariff than the one allowed by the governmental regulatory agency having jurisdiction over that tariff. Six years at 11% almost doubles-up the amount of a tax increase from such a "cost-based" tariff.

Further, the tax laws of the State are not an appropriate place for Alaska to try to regulate pipeline tariffs. That is a function of the Police Power, and the Regulatory Commission of Alaska has been established as the executive agency to exercise that regulatory power. The Federal Energy Regulatory Commission has similarly been created by Congress to regulate pipeline tariffs for interstate shipments under the Congressional power created by the United States Constitution power to regulate interstate commerce. State tax authorities have no business trying to supplant either of these agencies.

Any further matters regarding HB 72 that we would bring to your attention have already been addressed by AOGA in its testimony to you on Monday.

Thank you for this opportunity to testify to you today.