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ALASKA OIL AND GAS ASSOCIATION
TESTIMONY ON COMMITTEE SUBSTITUTE SENATE BILL 21 (VERSION C)
TO THE SENATE FINANCE COMMITTEE

March 5, 2013

Good Morning. My name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding Senate Bill 21, and specifically Committee Substitute Senate Bill 21 (CSSB 21)version C, have been reviewed by all members and have been approved unanimously.

The industry's greatest challenge today, which we share with the State is the decline of oil production from the North Slope. We believe that the greatest, most urgent issue facing this Legislature in 2013 is how you will address this problem. We cannot fix the basic, inherent properties of any oil and gas field, that is that the resource is finite and production will eventually decline. We can fix some of the economic principles that drive the development of more and new resources. Corrections to the ACES tax regime will remove impediments to development and exploration and assist the industry in investing in projects that could both extend the life of TAPS and open up new resources to long term development. When we look to the future Alaskans see a robust industry on the North Slope growing like it is the rest of the United States. We want the jobs here and not in the Lower 48. We want to create developments that will last for decades more, creating jobs for our children and opportunities for our communities to flourish. Alaskans want to see the industry continue to support the education and skills training that are needed to qualify for many of those jobs. A healthy oil and gas industry is one that sees the economic benefits of continuing to invest in projects in Alaska and keeping its employees here, where they volunteer their time, talent and treasure to make Alaska a better place to live for us all. Alaskan's, and the Alaskan economy, depends on the industry and its direct and indirect contributions as well as its funding the vast majority of the costs of our government.

Our goal today is to offer insights into how the CSSB21 impacts the industry. Specifically, how the present tax laws are fundamentally broken, and instead of incentivizing investments that benefit us all, are actually hindering the very development and growth Alaskan's deem essential. We have ideas of how the current tax structure can be modified to better suit the needs of the State.

The Tax "Give Away" Fallacy

We hear all too often of the $2 billion dollars that will be a "give away" to the industry should the tax regime be changed. It is a simple and effective communication that completely misstates the reality of the tax structure and its impact on the industry. It is simple to calculate how a change in a tax rate will impact amount of taxes collected if all "other" things remain constant. For example, if production does not decline further, if lifting costs don't rise, if the $2 billion dollars of annual investment by the industry to slow that decline continues, and if oil and gas prices do not shift. All of these "other" items seem to be considered a given in these calculations and it is assumed they will remain unchanged in the future – the pundits of the "give away" theory want you to believe it's that simple. But it is not.

However resourceful the State's revenue estimators are, they cannot control decline, lifting costs, future investment, or the price of crude oil. As the rest of the nation swims in new industry investment and development, Alaska languishes. The costs of operations continue to rise as North Slope fields decline. The $2 billion a year of industry investment spent in wrestling decline must now compete with more lucrative projects elsewhere, and with growing US production and supply of oil and gas the future price of that oil and gas is anyone's guess. Naysayers to these necessary and fundamental changes to our tax structure look only to the downside simple calculations they take from a Revenue Sources Book they forget is only a "guesstimate" of future revenue. The upside potential of that change, though, is very real. If a restructuring and tax rate reduction make investments here more competitive, companies will want to make more investments here for that upside. Deciding to make long term investments in Alaska's North Slope requires the industry to see potential upside to their investments and assessing that the essential risks of those investments are offset by the opportunities afforded in success. Without that potential opportunity in Alaska, investment dollars will be spent elsewhere, where risks are less and opportunity is greater.

<u>Core Principles to Address North Slope Production Decline</u>

As you consider potential solutions to the challenge that production declines creates for Alaska, AOGA believes Governor Parnell's four "core principles" offer an excellent cornerstone for this:

- "First, tax reform must be fair to Alaskans."
- "Second, it must encourage new production."
- "Third, it must be simple, so that it restores balance to the system."
- "Fourth, it must be durable for the long term."

We believe the addition of a fifth such principle would be required to meet Alaska's goals, because the challenge is not that there are too many companies pursuing opportunities, but that there are too few. Alaska should therefore avoid tax changes that artificially create "winners" and "losers."

With respect to the CS to Senate Bill 21, there are several features in it that we wish to address; such as the elimination of progressivity, an increase in the base tax rate to 35%, changes to the present system of tax credits – including the addition of the manufacturing credit, a gross revenue exclusion for certain new production and the concept of a competitiveness review board. I will also identify some of the issues with the current system that the CS does not address.

<u>1. Repealing Progressivity</u>.

AOGA endorses the elimination of progressivity.

Impact of Progressivity as part of the ACES tax rate in industry investment decision making is the single most influential component of Alaska's tax structure negatively impacting investment decisions related to Alaskan projects. Taxes are paid by the industry in virtually every jurisdiction in which we function and so we are very familiar with how they work. But the uniformity and consistency in the application of tax impacts as they relate to investment decision making found in almost every jurisdiction is missing in Alaska. As my member companies have testified in the past, investment decisions are driven by combining high and low case scenarios where costs and revenues are estimated and best case cash flows and worst case cash flows are measured, risked and analyzed. Each potential project, in every jurisdiction, is measured and compared and only some are funded. As your consultant, Roger Marks pointed out yesterday, the international investment climate is characterized by plenty of opportunities, fluid capital, but finite capital. To choose what they can and cannot fund, companies have compared each potential project, no matter the jurisdiction, by application of a uniform investment decision measuring formula. When Alaska's tax system is quantified and added to this measure for proposed Alaskan projects the best cases are always burdened with an excessively high tax rate and as the assumed high cases get better, the burden only increases. We can find almost no other jurisdiction that so burdens investment return where the better the cases assumed for the decision, the higher the tax burden that applies. As I will address in a moment, we have no real maximum tax rate, and Alaskan investments are further burdened because the lower the case assumed, the higher the tax burden that applies as well.

EXAMPLE 1 BELOW:

Progressivity brings extraordinary complexity to the tax, not only in calculating what the tax is, but also in analyzing what the amount of the progressivity is for any particular item that affects a taxpayer's Production Tax Value (PTV). This complexity exists because the tax rate for progressivity depends on the taxpayer's PTV per barrel, and then the resulting rate is applied to the very same PTV that set the rate. This circularity in the tax calculation leads to bizarre effects. For instance, simply the fact that oil prices fluctuate during a year instead of remaining perfectly flat increases the tax due even though the average of the fluctuating prices is the same as the flat price — and the greater the fluctuation, the greater the tax from progressivity becomes. There is no objective economic or financial reason for the tax to go up; instead, this occurs entirely because the progressivity calculation is circular.

The repeal of progressivity is consistent with all four core principles outlined above. Its removal improves fairness because operators that increase margins through efficiency would no longer be automatically penalized. Its removal encourages new production because it reduces the tax burden on investment, as discussed above. Its removal is a significant step toward simplicity. And, lastly, its removal enhances durability because it satisfies the three preceding core principles.

2. Increasing the base tax rate from 25 to 35%.

AOGA does not endorse increasing the base tax rate to 35%.

Let's go back to the industry investment decision process again. Increasing the base tax rate, besides burdening every investment case with a higher tax rate, now adds an additional burden to the worst case scenarios when oil prices are low or project costs are high. When applying the current base tax rates to the investment cases for a proposed project, until one assumes a price collapse occurs and the minimum fixed rates apply, even when little revenue is assumed to be generated, the base tax applies. The burden of a 35% versus a 25% rate is easy to envision as every middle case and every worst case scenario is burdened with an additional 10% tax rate. This assumed cost will negatively impact the potential returns deemed available for any Alaskan project and drive investments to be made elsewhere. Increasing the base tax rate is contrary to the second core principle; there is not any reasonable argument that suggests increasing the base tax rate would encourage new production. Indeed, using the progressivity formula as a benchmark, the ten percentage point increase in the base tax rate could be viewed as equivalent to a sustained reduction in oil price of $25 per barrel, all else being equal.[1]

3. Tax Credits

In general, tax credits, because they act to offset a part of the costs of certain investments when the expenditure is made are an important tool in reducing the deemed risks of those expenditures. Industry makes investments to seek returns. Costs of any kind, including taxes reduce those returns, so the offset of tax cost by a tax credit provides immediate benefit to the investment return calculation. Whether those costs are for drilling a well, building a facility to gather new oil, or installing a pipe to gather oil, a tax credit represents an immediate and direct reduction in the amount that a potential investor puts at risk in spending money on equipment and facilities that benefit production.

Those tax credits are directly related to production as investments must actually be made for the credit to be utilized and those investments will positively impact production. It is important to note that there is no tax credit liability for the State at all until an investor invests here. The investment has no other purpose than creating return by positively influencing production. So it costs the State nothing to offer the credit until the investment is made and at that point the tax credit has already succeeded in what it is supposed to do – namely to attract investment dollars here for investments that will act to increase production and reduce decline. The production impacts of the investments, although partially offset by tax credits, will act in other ways to increase taxes collected.

A. Repeal of the Qualified Capital Expenditure ("QCE") Tax Credit.

AOGA does not support the repeal of the Qualified Capital Expenditure Tax Credit.

Even while the elimination of progressivity would improve the competitiveness of Alaskan investments from the present ACES tax, the elimination of the QCE Credit would claw back one

[1] In other words, a sustained $25 per barrel price change would be needed under progressivity to get the same 10% change in the base tax rate. Under progressivity, each $1 increase in PTV (or price, all else equal) per barrel would result in a 0.4% increase in the tax rate surcharge. Thus, a 10 percentage point change in the tax rate under progressivity would be equivalent to a $25 change in PTV or price because 25 = 10% divided by 0.4%.

important financial incentive and a part of ACES that actually acts to improve the competitive environment. The QCE Credit depends entirely on how much is invested here, and provides benefits for investments even when oil prices are lower. While the benefit from ending progressivity, which depends on the price of oil relative to a producer's lease expenditures, helps when oil prices are higher the QCE provides benefits when prices are not. In this mid-range of oil prices the loss of QCE Credit would outweigh the benefit from the end of progressivity.

Repeal of the QCE credit is contrary to the second core principle. Furthermore, because every producer's costs are different and prices will impact them differentially AOGA, fears the repeal of the QCE Credit is worse than creating "winners" and "losers" because it only creates "losers" artificially among producers, and we see no sound tax policy justification for doing so.

For these reasons, AOGA believes the elimination of the QCE tax credits would be a mistake. Instead of that, one possibility might be to expand the scope of the "well lease expenditure" tax credit under AS 43.55.023(l) so it is available to producers on the North Slope. This credit has several meaningful advantages. First, it focuses investment incentives on subsurface intangible-drilling expenditures, which are a reasonable proxy for direct spending on well activity and, in turn, production. Second, the credit is clear because it uses already established concepts in the federal Internal Revenue Code. Third, it is fair because it applies equally to well-related spending in all areas of the state, without creating winners and losers merely on the basis of geography.

B. The $5 dollar per barrel tax credit.

AOGA is not certain that the potential benefit of a $5 dollar per barrel tax credit under AS 43.55.024(i) will be offset by other burdens.

There are multiple issues to balance when taking in the numerous proposed changes found in CSSB21. The removal of progressivity, the increase in base rate, early sunset of the QCE credit all create interrelated issues and while a $5 dollar per barrel tax credit would provide benefits both in real tax costs and in investment decision making, the weight of the benefit in respect to the other changes is hard to measure. AOGA applauds the concept of tying incentives to the goal of increased production and as such allowing a tax credit per barrel. One must consider, though, what the $5/bbl credit will mean to a small producer with little production as opposed to the legacy producers that already have established large scale production. In view of the investment decision making process and the Alaskan tax structure's impact on it, we are not certain that this benefit is offset by the other burdens contemplated when striving for the goal of increasing production.

C. Small-Producer and Exploration Credits.

AOGA endorses the proposal to extend the small-producer tax credit under AS 43.55.024 and exploration tax credits under AS 43.55.025 from the present sunset dates in 2016 to a later date.

The State had sound policy reasons for creating these small producer and exploration tax credits, and those reasons are just as valid today as they were then. AOGA believes these credits have increased the likelihood of participation by new industry players and act to increase the opportunities that could be found by expanding exploration. The purpose of the small-producer tax credit was to attract new players to Alaska who might otherwise have been deterred from coming here by presumptions of increased risks and of higher-than-average costs and expenses. The success of the credit in attracting new participants is a fact that cannot be denied. AOGA sees this success in its own membership, and in other companies that have come here and are now active. Smaller producers often have a different perspective about the opportunities around them, and as such can bring with them new ideas and opportunities. New participants with new ideas can only strengthen and improve the Alaskan petroleum industry and help the state stem the decline in production. We know from testimony that the small-producer tax credit has made a material difference in individual companies' decisions to do business and invest in Alaska.

The purpose and justification for the exploration tax credits under AS 43.55.025 are equally clear. Huge parts of this state remain unexplored or underexplored. Again, these tax credits are only earned when actual expenditures for exploration occur. The credits tangibly reduce the risks faced by an explorer and as such incentivize them to go out and search for oil and gas that is much needed. Increased exploration leads to increased development and these credits act to increase exploration and should be extended as well. Just as with the QCE credits for capital investments, there is no exploration tax credit without real money having first been spent on exploration work that qualifies for these tax credits.

D. Limiting the transferability of "carried-forward annual loss" tax credits.

AOGA does not support the limitation on transferability of these losses.

We have some reservation about the proposal to bar almost completely the transferability of the current "carried-forward annual loss" tax credits under AS 43.55.023(b). New participants and new explorers are many times not yet producing in the state or only producing small volumes of oil and gas and as such have little or no production tax liabilities. The ability to transfer their losses to others allows them to monetize the investments they have already made, both reducing their cost exposure on the original expenditure and hopefully at the same time acquiring additional capital for more investment. These credits arise every year for any active explorer until it finds oil or gas and finally incurs production taxes to apply the credit against. At present explorers can only realize immediate benefit from these credits by selling them to other taxpayers or cashing them in at the state Oil and Gas Tax Credit Fund established in AS 43.55.028.

Under the Bill as proposed, transfers would cease and explorers would have to hold on to losses for up to 10 years for possible use against taxes on their own production. The potential that a loss could not be offset against tax expenses or monetized in the near term places more risk on the decision to invest and as such makes such activities less likely to occur. If the transferability must cease, then the cost of the expiration of the loss carry forward after only 10 years, where on the North Slope exploration success to production can easily take longer, is another factor that negatively impacts investment decisions. Although the annual addition for interest will allow the losses to retain some value, we also believe that a 15 year period before expiration of the loss carry forward is the minimum timeframe that should apply if transferability is removed.

E. The "Anti-stackable" section

AOGA does not think this new section is necessary.

In Section 22 of the CS, AS 43.55.025 is amended by adding a new subsection to read:

(q) An exploration expenditure incurred after December 31, 2013, to explore for oil or gas located north of 68 degrees North latitude that is the basis for a credit under (a)(1), (2), or (3) of this section may not also be the basis for a credit claimed under AS 43.55.023 or this section.

AOGA does not understand why this new section is being proposed as it is our understanding the concern this new language is to trying address is already covered in existing statutes.

F. New credit for Manufacturing

AOGA supports the new proposed manufacturing credit.

Although this credit is directed to the incentivizing of development and manufacture of drilling and exploration methods and materials, it may not have a great impact on the reduction of the current production decline. However, it is a step in the right direction to incentivize jobs and additional investment, and having more jobs and investment in Alaska is never a bad thing.

<u>4. Gross Revenue Exclusion</u>.

AOGA endorses the proposed 30% gross revenue exclusion or GRE, but has concerns on breadth of applicability.

The GRE would, in calculation of the taxable Production Tax Value, exclude 30% of the Gross Value at the Point of Production of what we'll call "non-legacy" production. Thus the GRE provides incentive for finding new oil and getting it produced. As much as AOGA supports this proposal we are also concerned that it is too narrowly focused. This narrow focus and application to only certain areas, especially those outside existing Units where the best prospects of new oil are likely to be found, needlessly restricts the benefits that such a proposal could have on increasing production. Fields likely to lose out on getting any GRE are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, and Alpine; as well as the Prudhoe Bay satellite fields Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion and Polaris and the Kuparuk satellites Meltwater, NEWS, Tabasco, Tarn and West Sak.

Econ One Research, Inc. has previously provided this body a presentation entitled *Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal, HB 72*. In that presentation oil and gas resources described as "Economically Recoverable @ $90/bbl" total 29.1 billion barrels of oil and barrel-equivalents of gas of which 3 billion are in the central North Slope where all the currently producing and therefore ineligible fields are. Of this 3 billion barrels, an estimated 2.5 billion or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production. The Governor's second "core principle" for tax legislation is that "it must encourage new production." But, in order to get results from such encouragement, the tax legislation must incentivize the best opportunities that Alaska has for getting results. The GRE as proposed may get some results but in terms of what it attempts to "encourage," it leaves out at least 80 – 90 percent of the 3 billion-barrel opportunity in the central North Slope that Econ One has identified.

AOGA is continuing to search for ways to adapt the Gross Revenue Exclusion to include legacy fields in a way that might be acceptable to the Administration and the Legislature. It may turn out, however, that a different approach may be necessary to "encourage new production" from legacy fields.

<u>Oil and Gas Competitiveness Review Board</u>

The proposed Board provides an oversight and review process that we believe would be burdensome to the industry and contravenes the Governor's principles relating durability in the long term. The perspective that the proposed changes found in the Bill would provide a long term solution to problems we know exist are placed in jeopardy because the very certainty that is required for sound investment decision making would be placed in question with each annual report of the Board. Instead of moving forward with projects that might help stem decline, industry resources would be used to assist the Board in collecting and understanding complex information of long term consequence on a quarterly basis. Finally, the documentation and information the Board might request or require is of the highest proprietary value to oil and gas companies and confidentiality concerns and related complexities would hinder the efforts of the industry as well as the Board. While we appreciate the ability to represent industry on the proposed board, our concerns cause AOGA to question both the viability and the effectiveness of the proposed Board and as such we cannot support its proposed formation.

<u>Issues that the current draft does not address</u>.

There are several significant problems in the present ACES tax that are not addressed in CSSB21, and I will address a few of them this morning.

<u>A. Minimum tax for North Slope production</u>. AS 43.55.011(f) sets a minimum tax that is targeted solely against North Slope production. That tax is based on the gross value of that production instead of the regular tax based on "net" Production Tax Value. The rationale for adopting it was to protect the State against low petroleum revenues when prices are low.

The minimum tax only complicates potential new investors' analyses of what their tax would be if they invest here instead of someplace else, and consequently it has, if anything, driven investments away. AS 43.55.011(f) should be repealed or consideration given to significantly reducing the rate of the minimum tax.

<u>B. Statute of limitations & statutory interest</u>. Here we have two concerns that are interrelated, but not in an immediately obvious way.

The statute of limitations under AS 43.55.075(a) is six years from the date when the tax return was filed for the tax being audited, while the limitations period for other taxes under AS 43.05.260(a) is three years from the filing date of the tax return. Under both statutes, the period may be extended by mutual consent of the taxpayer and the Department of Revenue (DOR).

The statutory rate of interest under AS 43.05.225(1) for tax underpayments is "five percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter[.]" Currently the Federal Reserve rate is very low, so 11% APR is the applicable rate.

We are asking that, if the Department chooses to not exercise its authority in providing certainty to the taxpayer to allow them to be able to calculate the correct amount of tax due, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making Department "determinations" from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.

SEE EXAMPLE 2.

C. Joint-interest billings. Our concern about joint-interest billings is also primarily a problem caused by the approach the Department has chosen to take with its tax regulations. Instead of starting with the joint-interest billings that participants in a unit or other joint operation receive from the operator, the regulations reflect an assumption that each non-operating participant has information, in addition to the operator's billings to them, that allows them to determine which expenditures are deductible as allowed "lease expenditures" under AS 43.55.165 and which are not. This assumption is wholly unrealistic. And even if there were some merit to it, the regulations opt to audit each participant separately regarding that participant's interpretation of which expenditures are deductible and which are not, instead of auditing the system of accounts used by the operator and telling all participants which cost items in that accounting system are deductible and which are not. In other words, instead of one audit of the expenses by a joint venture for any given period, the Department audits each participant separately for its respective share of the same pool of expenses.

We are not asking for legislation to put the Department's regulations on a different track. But there are some in the Department who believe that the repeal by the 2007 ACES legislation of AS 43.55.165(c) and (d) — which specifically authorized the Department to rely on joint-interest billings — means the Department cannot legally rely on them now. While we disagree with this position (which is also at odds with what the Department testified to during the enactment of the 2007 ACES legislation), we do think it would be appropriate to restore language specifically authorizing the Department to rely on joint-interest billings if it chooses to do so.

Conclusion.

We support the proposed elimination of progressivity, but we have great concern with the increase in the base tax rate to 35%, and with the mixed proposals for tax credits allowing a new $5 per barrel credit but removing qualified capital credits. The trade-off between repealing progressivity and losing the QCE credit is not a net benefit for industry at low oil prices, and will create a greater barrier to investment from existing and new independent players.

We also agree with the comment by Roger Marks yesterday when in one slide he pointed out the tax system should not favor investing in certain cost fields over others, which in our view is the same as saying we encourage the legislature not to devise a tax system that creates “winners” and “losers”.

The concept of the Gross Revenue Exclusion has considerable potential, but its narrow focus misses 80 – 90 percent of the opportunity in the central North Slope described by Econ One. We will continue to work with you and the Administration to find a fair and reasonable way to expand its scope, or to find an alternative that will address the central North Slope appropriately.

The reasons that led the State to create the small-producer tax credit under AS 43.55.024 and the exploration tax credits under AS 43.55.025 remain valid today. We are pleased that CSSB21 will provide some minimum extension to the sunset date for the small-producer and exploration tax credits.

We believe it is up to you, and the Governor, to shape a competitive oil fiscal policy that is supported by strong principles that will work to arrest North Slope production decline and will lead Alaska towards a prosperous future for the long-term. Overall, the Bill represents a base for significant and crucial tax structure reform that move toward Governor Parnell’s four “core principles” — fairness for Alaskans, encouraging new production, simplicity with balance, and durability for the long term, but as I have outlined today, AOGA members believe there is still many structural changes that should be included for this bill to truly change investment behaviors to the benefit of Alaskans. You have a difficult task ahead and AOGA stands ready to assist you throughout this process.

EXAMPLE 1:

Progressivity directly attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness. It costs \$9.42 on average to ship a barrel of oil from the North Slope to the West Coast, according to the Fall 2012 Revenue Sources Book, Appendix D-1b. This means Alaska starts off with a cost disadvantage of \$9.42 a barrel against Outside competition, so other parts of return on Alaskan investment must be stronger than outside investment in order to overcome this disadvantage. If returns Outside are deemed either less risky or providing more opportunity Alaskan investments won't be made.

If oil prices turn out to be higher than what they were projected to be in the industry investment decision analysis, nearly 100% of each extra dollar in price flows directly into the Gross Value at the Point of Production (GVPP) and then, after royalties and taxes, the remainder flows directly into the investor's bottom line. This, in turn, improves the economic performance of an Alaskan investment relative to an equally competitive one Outside, because the Alaskan baseline was \$9.42-a-barrel lower and an additional dollar in price is a larger percentage of that baseline than for the percentage for the Outside investment. This opportunity can be particularly significant for potential investors who are bullish on oil prices.

Currently, progressivity in conjunction with a 25% base tax will take half of each dollar from higher prices when the West Coast price is \$132.38 (using the Fall 2012 Source Book numbers) — a price that has already been seen, although somewhat higher than today's. So, even for investors who <u>are</u> bullish on oil prices, progressivity destroys half of the one strategic advantage that Alaska's economic remoteness provides. Sadly, the more bullish they are, the more this advantage is undone because they will see ever higher rates for progressivity at those prices in their investment analysis.

EXAMPLE 2:

Taxpayers are required under AS 43.55.020(a)(1)-(3) to make monthly estimated tax payments for each calendar month's taxable production during a year, but the final tax amount for the entire year is reported on March 31 of the following year under AS 43.55.030(a). And AS 43.55.020(a)(4) requires any additional tax to be paid at that time. The statutory interest under AS 43.05.225(1) starts to accrue on any underpayment from that March 31st true-up date.

In practical terms, what these various statutes all mean is this.
For each dollar of underpaid tax that the Department of Revenue may claim after an audit, statutory interest on that dollar at the end of three years would be —

$$\$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times 3 years})} - 1] = \$1.00 \times [1.38478 - 1] = \$0.38.$$

After six years the statutory interest on the dollar would be —

$$\$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times 6 years})} - 1] = \$1.00 \times [1.91763 - 1] = \$0.92.$$

Thus, for each dollar of uncertainty there is in what the taxpayer reports on its March 31st true-up for a given year, there is about 38 cents of additional uncertainty due to statutory interest under a three-year statute of limitations, but 92 cents under a six-year statute.

It is the combination of a six-year statute of limitations plus a minimum statutory interest rate of 11% APR that is so harmful for a taxpayer and any would-be investor. Each dollar of uncertainty in the amount of tax will nearly be doubled by statutory interest after six years.

When we speak about uncertainty and audit assessments six years after the filing of tax returns, many people will think the oil companies could calculate their correct tax liability under the ACES tax if they wanted to. Frankly, so did I before I got this job. So let us take a few moments to illustrate why this is not the case.

As amended by ACES, AS 43.55.150 (captioned "Determination of gross value at the point of production") says the Gross Value at the Point of Production (GVPP) "is calculated using the actual costs of transportation" from the field to market unless the "shipper ... is affiliated with the transportation carrier[,]" or the "contract for the transportation ... is not a[t] arm's length[,]" or the "method or terms of [the] transportation ... are not reasonable in view of existing alternative transportation options." "If the department finds that" any of these situations exists, then the GVPP "is calculated using the actual costs ... or the reasonable costs of [the] transportation ..., whichever is lower."

The immediate questions about the statute are — How does the Department of Revenue get the information to make such a finding? What is the procedure for making them; is there a hearing, an investigation or what? How does a taxpayer ascertain what the Department has found?

15 AAC 55.193 is the regulation with an important part of the Department's answers to these questions. Before getting to those answers, we note that subsection (a) seems to disregard the statutory distinction between "actual" and "reasonable" costs, by declaring that "Costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas"[2] — which could get to the same result as the statutory terms, but not necessarily.

Subsection (e) of the regulation starts answering our questions. It says "a tariff rate ... adjudicated as just and reasonable by the Regulatory Commission of Alaska ... establishes the reasonable costs of the pipeline transportation[.]" So, suppose there has been full-blown tariff dispute before the Regulatory Commission of Alaska, and the RCA has "adjudicated [a tariff] as just and reasonable[.]" And suppose also that a producer ships its oil through its pipeline-company affiliate and pays that RCA-approved tariff. Is this "reasonable" cost under (e) of the regulation the same as the "ordinary and necessary" cost for it for purposes of subsection (a)? Apparently so, but the inconsistent terms in the two subsections prevent this from being completely clear. Moreover, if the transportation occurs "later than five years after the end of the test period on which the tariff rate is based[,]" then even subsection (e) says the tariff ceases to "establish [the] reasonable costs" for the transportation. But it doesn't say what the right tariff is after those five years are up, or even how to find out or calculate what it is. It is utterly silent.

The very next sentence in subsection (e) after the one speaking about that five-year period starts, "If a complaint challenging [a] tariff rate has been filed with [the RCA] and accepted for investigation" — this is not a situation involving an already "adjudicated" tariff, but one that deals with a new tariff that has been filed for RCA's approval, which is then challenged. Here, too, the tariff on file is not allowed as the transportation cost under (e) of the regulation. Instead, the cost that is allowed is "103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197, for the period [while the complaint is being heard and adjudicated by the RCA.]"[*] Note that it is the Department of Revenue, not the

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[2] Emphasis added.

taxpayer that makes the calculation under 15 AAC 55.197. It is impossible for the taxpayer to know beforehand what the Department's calculation will turn out to be.

Now it is true that 15 AAC 197(m) says a taxpayer may each year "request in writing the department's determination of the applicable after-tax rate of return under (f) of this section [and t]he department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 90 days after the department receives the producer's request." But the "after-tax rate of return" that the Department promises to provide is only one of the parameters in the cost-based tariff calculation under 15 AAC 55.197. The taxpayer is left on its own to find the correct numbers for the other parameters. More importantly, subsection (m) applies <u>only</u> to "a producer [that] expects to produce oil or gas the actual costs of transportation of which are required by 15 AAC 55.193(b)(6)[.]" Section -193(b)(6) applies only to "transportation of oil or gas by a nonregulated pipeline facility ... that is owned or effectively owned ... by the producer of th[e] oil or gas[.]" In the situation I'm describing, it is a regulated pipeline, not an unregulated one, so this promise in 197(m) does not apply.

We find nothing else in the calculation-methodology regulation, 15 AAC 55.197, nor in 15 AAC 55.193(e), the transportation-cost regulation, that commits the Department to make the cost-based tariff calculation called for in 193(e) and inform the producer of that result before the producer has to report and pay estimated tax each month, or before it makes its annual true-up on March 31st of the following year. The only deadline for informing the producer of the Department's calculated tariff is the six years under the statute of limitations.

And the same or very similar unknowable answers — including tariff calculations by the Department under 15 AAC 55.197 — arise under 15 AAC 55.193(f) regarding tariffs for new transportation facilities that are just being placed in service, and under -193(g)–(h) regarding tariffs set under a settlement agreement to which the State of Alaska is a party.

And just to prevent any misunderstanding, although I have been testifying about proceedings and adjudications by the RCA, these regulations also apply to proceedings and adjudications by some "other regulatory agency" — which would include FERC.

There is a built-in uncertainty created by these regulations, and others that is beyond a taxpayer's allowed authority to answer and beyond its ability to know before the Department gives the answer. And to see a "Technicolor®" version where essential elements of the tax calculation are being reserved for the Department to "determine" in its discretion with no specific deadline, one should look at all the crucial "determinations" in 15 AAC 55.173 ("Prevailing value for gas") that are reserved for the Department to make regarding the valuation of natural gas that would be transported to markets outside Alaska.

We are not asking for a statutory fix to the regulations. But we are asking that, if the Department chooses to defer making calculations and similar determinations that are necessary in order even to be able to calculate the correct amount of tax at all, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making those "determinations" from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.