State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Paul Seaton
The Honorable Eric Feige
Co-Chairs, House Resources Committee
Alaska State Legislature
Juneau AK, 99801

February 21, 2011

SUBJECT: Response to Questions from House Resources Meeting on February 7, 2011

Dear Representatives Seaton and Feige:

The purpose of this document is to respond to the follow-up questions from the House Resources Committee meeting on February 7, 2011. The requests/questions and responses follow.

(1) Provide information about the department's record in forecasting.

The majority of revenue comes from oil production. The department's revenue forecast is driven primarily by two inputs: oil production and oil price. The following discussion briefly discusses the department's history in forecasting these two variables.

Production Forecasting
Recently, inquiries have been made regarding the accuracy and reliability of historical oil production forecasts published by the Department. History has shown that our production forecasts have been overstated for many years. With changes to methodologies and processes in the last two years, the amount by which production forecasts have been overstated has been reduced to 2%. Because of the production forecasting changes made in 2009, it is unfair to compare the last two years to the past. The Department will continue to exercise due diligence and care in the preparation, and review of the production forecasts. The response that follows will examine factors that may have contributed to differences in forecast vs. actual production for Alaska's North Slope (ANS).

The Department of Revenue relies on historical production data as well as both public and private information as the basis for its biannual production forecast. Because forecasts are directly affected by the quality of the input data, the Department of Revenue production forecasts are sensitive to data provided both publicly and privately by the field operators.

It is important to define both what is involved in a production forecast and what is not. In general terms, a forecast is simply an opinion of future oil production. In addition to the quality of the input data, the uncertainty of the forecast will also depend on the methods employed by the forecaster. Historically, the Department engaged a single contractor to conduct its forecasts until 2009. This contractor relied on a certain method to produce his forecasts. Beginning in 2009 a new contractor was engaged to perform the forecasts and relies on a different methodology to forecast production.

It is also necessary to understand from the outset that, under both current and former methodologies, the production forecasts conducted for and under the directive of the Department have been based only on technically recoverable oil. The forecasts do not include any analysis of whether or not barrels that are technically recoverable are also economically recoverable. This is reasonable given that near term oil production should be relatively certain. Involving an analysis that included economically recoverable barrels would add another layer of complexity and uncertainty to the forecast and require that the department, in essence, predict the future value of a barrel of oil. At the same time this added uncertainty would not provide any cure for near term production overestimates.

As previously mentioned, the accuracy of the forecast will be highly dependent on the methods used by the person making the forecast. In this regard, the current methods employed by the department's staff and contractor have changed significantly from the previous contractor. The result has been that the near term forecasts have been within about 2% of actual production during that same time period.

Perhaps one of the most significant changes in methodology relates to the use of a well-by-well analysis to forecast production and decline curves as used in the current practice, whereas in the past, forecasting had been done on an area-wide or field basis. While the well-by-well basis is more time and labor intensive, the methodology reveals trends that are not observable on an area-wide basis.

Current practice also includes internal staff in addition to the contractor. The department performs in-depth analysis of production trends, forecast to forecast by field, and comparisons of forecasted production to actual, among other analyses.

Another factor that has likely had a material impact and is currently employed in the new methodology is the magnitude of the "b factor" used to calculate the production decline curve. The factor previously used had been as high as 1.4 and has now been reduced to be less than 1.0 in current practice. There is a large body of empirical evidence indicating that "b" factor should never be greater than or equal to 1.0 in any field.

By employing a method of forecasting that adheres to strict and standard petroleum engineering principles the department now excludes barrels that may fall into a high risk area of eventually being brought into future production. For example, both back out barrels and certain recovery projects that have not been tested and proven could be subject to many variables that may or may not lead to their ultimate production. Accordingly, these volumes are now only included in the department's forecast if they are shown to be in place and have demonstrated a response.

Some factors are beyond the state's control. A standard practice is to go to the producer's and ask when new fields may come on line. A good example is Liberty, which had originally been predicted to begin production in 2011. However, recent events and decisions by the company have delayed start-up until somewhere around 2013. Even though the Liberty pool is in federal waters, facilities are located onshore and production will flow through TAPS and had been included by the state in forecasting total ANS production. When setbacks in timing such as Liberty are unforeseeable, they will by definition, show up as errors in any forecast at a later date.

Below are three additional examples:

1. Aurora Field
   "BP Exploration (Alaska) Inc. said Feb. 23 that production is expected to increase to a peak rate of 15,000 to 20,000 barrels per day as field development continues." *"Aurora field begins production." 2/28/01 Petroleum News*
   - Production at Aurora peaked at an average of 10,447 barrels per day in 2006 according to DNR – just over half of the highest estimate by BP in 2001.

2. Polaris Field
   "BP will develop Polaris with water flood, which is expected to improve total recovery to 15-30 percent of original oil in place, with production rates expected to peak at 12,000-15,000 barrels of oil per day from water injection…" *"BP applies for pool rules for viscous Schrader Bluff Polaris accumulation: Company tells AOGCC western Prudhoe satellite will be developed with water flood, EOR test deferred; initial wells proving up productivity, but hydrate formation causing problems in keeping wells operating; Ugnu sand included." 12/29/02 Petroleum News*
   - Through 2009 production at the Polaris field had not reached the levels predicted by BP in 2002. Specifically, production at the Polaris field peaked at an average of 4,764 barrels per day in 2008 – approximately 60% less than BP predicted in 2002.

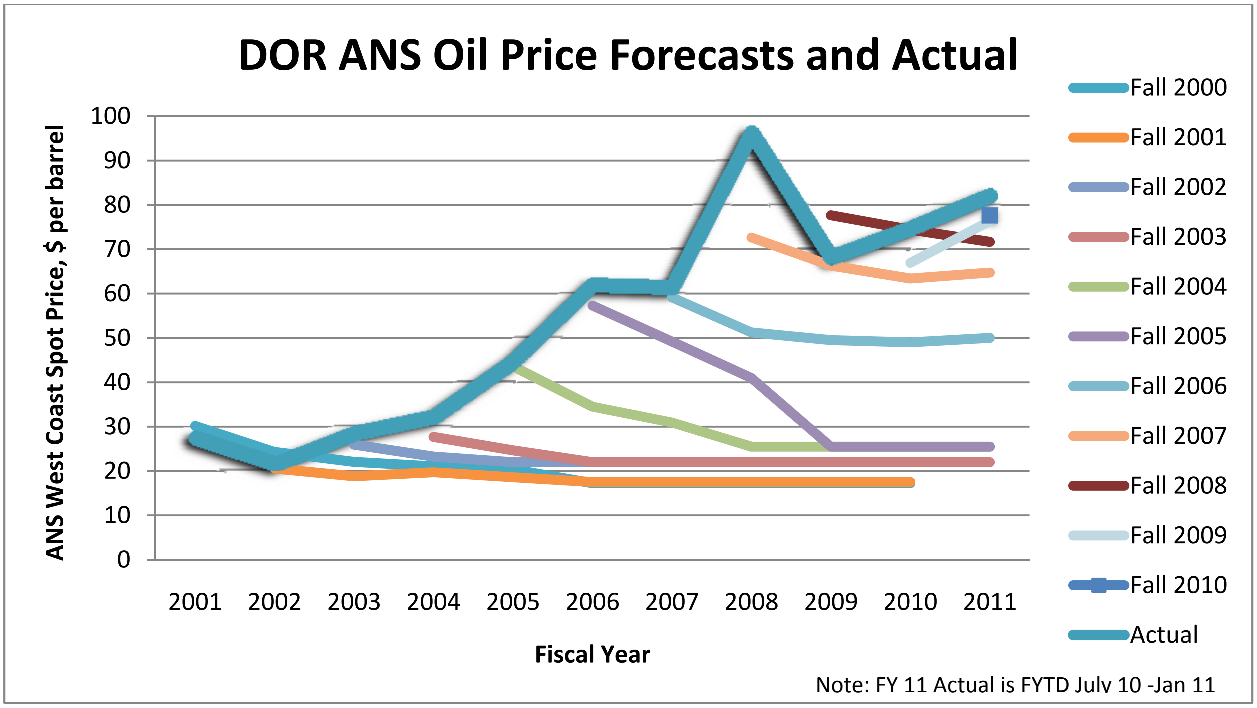
3. West Sak Field
   "The companies said production of West Sak oil is now at about 10,000 barrels per day, and with the Drill Site 1E and 1J project, production is expected to reach approximately 45,000 bpd by 2007." *"$500 million West Sak heavy oil project approved." 8/15/2004 Petroleum News*
   - According to DNR, production at West Sak was just over 11,000 barrels per day in 2004. In 2007 West Sak produced an average of 17,575 barrels per day or less than 40% of the rate forecast by BP in 2004. As of 2009, production at West Sak still has not reached 20,000 barrels a day.

Because the Department of Revenue relies, at least in part, on information provided by the operators of each field in order to forecast production, bias or error inherent in the operator's view of future production often translates into the forecast variances by the Department of Revenue. In short, the forecast is limited by the quality of the data inputs, the methodologies used, and unforeseen events. Incorporating internal staff, the additional in-depth analysis and controls, and sound petroleum engineering methods are steps taken by the department to improve the quality of the production forecast.

Price Forecasting

The chart below shows the DOR fall oil price forecasts from fall 2000 through fall 2010 compared to actual oil prices. The past decade was defined by a swift rise in oil prices from FY 2002 to FY 2007, followed by a sudden spike in FY 2008 and a subsequent crash. The chart shows the rapid rise in price was not anticipated by the department's forecasts. This is on par with other forecasts made during this period. For example, in 2002 the U.S. Energy Information Administration (EIA) forecasted the world oil price would be $23.36 (2000 dollars) in CY 2010. The actual CY 2010 price was $60.56 per barrel (2000 dollars). Moreover, during the previous decade the EIA's forecasts were typically more bullish than other oil price forecasts made by several reputable groups, such as the International Energy Agency, Petroleum Economics Ltd., Natural Resources Canada, and others.

After the price crash, prices remained around $70 to $80 per barrel until last fall when prices began to climb above this range. The price of ANS West Coast (ANS WC) peaked close to $100 per barrel in early February of this year. The department's current ANS WC price projection for FY 2011 is $77.96. As of the end of January, the fiscal-year-to-date price for ANS WC is $82.32.



(2) Provide information about transit pipelines for new developments. Specifically, who would construct them, how much would they cost, and who would pay for them and how?

Oil is transported through gathering lines, transit lines and feeder pipelines before it gets into the Trans-Alaska Pipeline System (TAPS). The owners (producers) of the oil incur the costs of gathering crude oil from the wellhead and getting it to a point where it can be processed and treated to become pipeline quality. Additional lines may need to be constructed from the central processing facility if no infrastructure exists.

An upstream pipeline is the first pipeline to transport oil en route to an interconnection point for delivery to another pipeline. Producers usually provide the gathering lines, central processing facilities and transit lines to the downstream pipelines.

A downstream pipeline receives oil from another pipeline. Producers often have ownership in feeder pipelines and larger lines like TAPS where they provide transportation for others as a common carrier and are subject to RCA and FERC regulations. Rates on such pipelines are designed to recover the cost of providing the transportation service (including a return of and a return on investment) through a tariff paid by the shippers on the line. Shippers nominate volumes and the pipeline company manages the flow.

The cost of a pipeline depends on the location, length of the line and size and quality of the pipe. Costs for a particular system will depend on the specification of those variables. The scope of a project quantifies those variables from estimates of throughput, reserves, production and life of the field, which are some of the factors that also determine if a find is economic to develop. The range of costs per barrel mile of oil transported is not meaningful without defining the scope of the project.

The Oil and Gas Journal publishes an annual Pipeline Economics Report which includes data on pipeline and compressor station construction costs. Data also includes estimated pipeline costs as presented in applications to FERC. The study is available for purchase through the following link:

http://www.pennenergy.com/index/research-and_data/oil-and_gas/product-display/2130774133/products/pennenergy/research/Petroleum/PipeLines-Transportation-Storage/surveys/us-pipeline-study.html

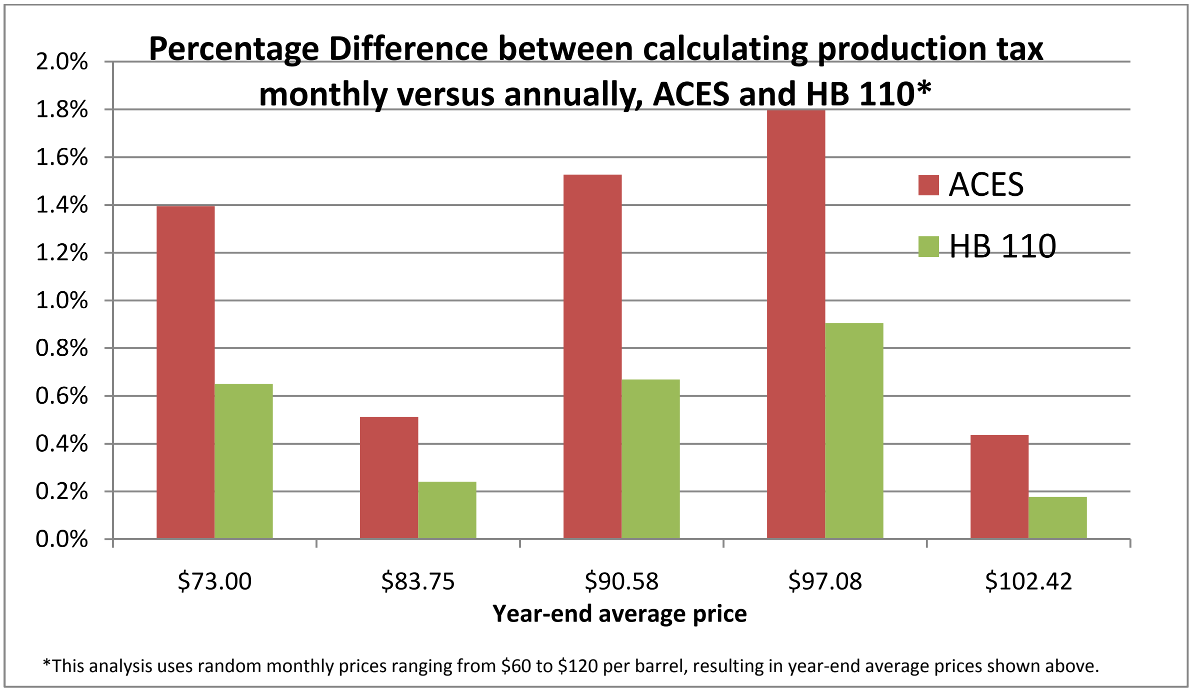
(3) Provide a discussion on the fiscal impact of switching from a monthly to an annual tax rate calculation.

Under current law, ACES is an annual tax with monthly estimated payments based on production levels and oil price in the months the estimate is calculated and on one-twelfth of annualized lease expenditures. The proposal under HB 110 is to change the calculation such that the tax liability is calculated using average annual production levels and an average annual price along with annualized lease expenditures. Estimated monthly production tax payments would still be made under this proposal, but would be "trued up" in the annual tax return when the average annualized figures are known.

The fiscal impact to state revenues of this change alone may be significant in years where there is substantial monthly oil price volatility. A recent example of the extremes in oil price volatility may be found in FY 2009, when oil prices reached $133 per barrel in July and decreased 71% in five months to $37 per barrel in December 2008.

The impact of changing from a monthly to an annual tax calculation is greater under the current ACES tax than it is under the proposed tax structure with bracketed tax rates. This is because the progressive tax under current law is formulaic, and each dollar increase in profit increases the tax rate. Under the proposed HB 110, the tax rate would be bracketed, with the same tax rate applied to a range of profits per barrel. For example, profits of $56 per barrel would be taxed at the same rate as profits of $67 per barrel under the HB 110 proposal. This means of calculating the tax rate provides for less production tax volatility even if it were calculated using monthly values.

We tested this theory by applying a range of monthly prices to forecasted assumptions about production levels and lease expenditure levels, holding these levels flat from month to month, despite potential seasonal variation. With these assumptions, we found that although more production tax was generated by calculating the production tax monthly than by calculating the tax annually, there was less of a difference in the monthly/annual calculation under the bracketed rates in HB 110 than with the rates currently under ACES, as shown below.



(4) What was the rationale for the $12 million figure for the Small Producer Credit and the $6 million figure for the New Area Development Credit in ACES?

The original PPT proposal in 2006 from then-Governor Frank Murkowski proposed a "standard deduction" of $73 million per year for each taxpayer.

As a deduction under the proposed tax at 20%, the tax savings per taxpayer would have been $14.6 million per year (20% x $73 million). The deduction would have applied to all companies, regardless of how much oil they produced, although there was legislative testimony that indicated that the amount was calculated based on production of 5,000 barrels of oil per day at $40 per barrel (5,000 x $40 x 365).

The tax proposal was heard in several legislative committees and underwent numerous changes in each committee. Among the changes was a shift in the standard deduction provision from a deduction to a credit. The committee substitute from the House Resources Committee changed the provision into a $12 million credit, which closely approximates the $14.6 million in the original proposal.

Although it is unclear how and when the provision was pared down to include only producers with 100,000 barrels of oil equivalent, the credit was generally regarded as an incentive to small producers. Later in the process, likely in one of the special sessions held to consider the tax changes, the New Area Development Credit was added. It is also likely that the amounts were fixed at $12 million and $6 million for ease in applying to the 12 months of a year.

(5) Provide a list of small producers that qualify for the Small Producer credit.

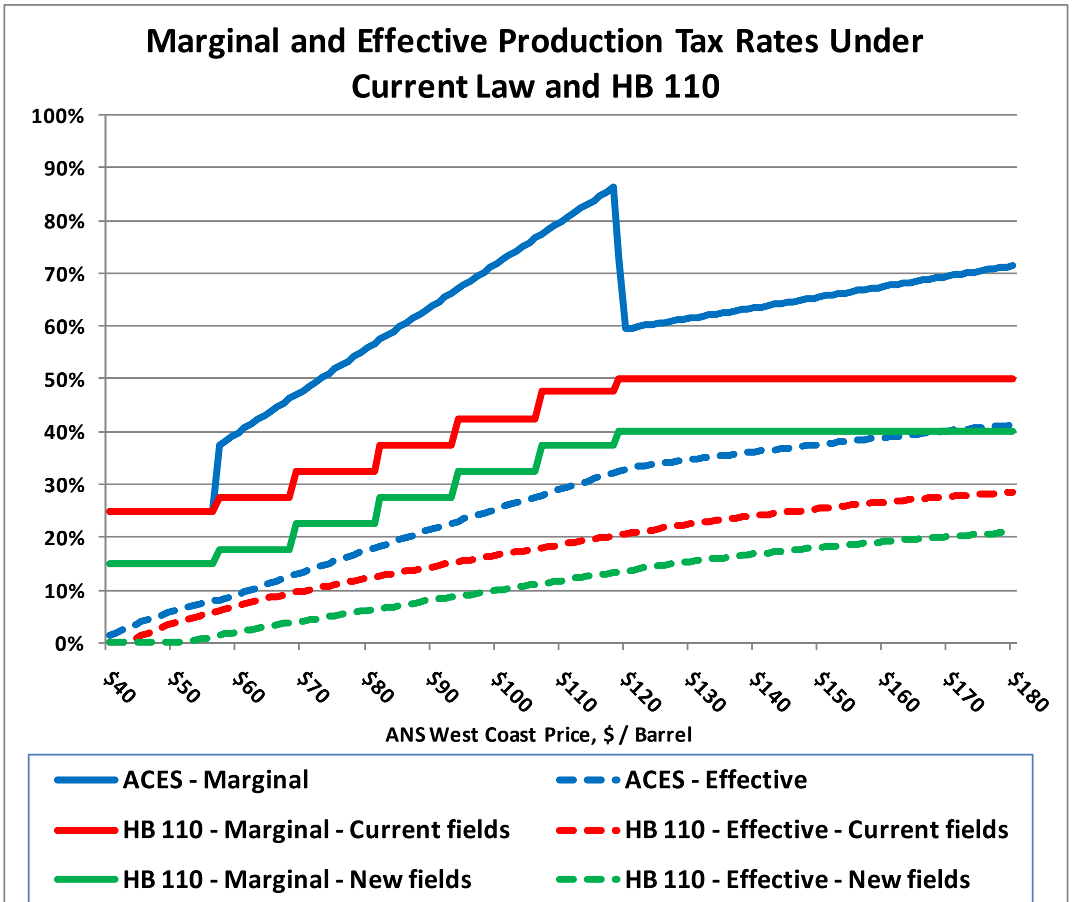
The small producer credit at AS 43.55.024(c) is available to producers who produce less than 100,000 BTU equivalent barrels of oil or gas per day and the credit may only be applied against a tax liability, and not carried forward or certificated. Although the amount of tax liability a producer has and the amount of credit they have earned is considered taxpayer-confidential, the production level of each of the producers is not confidential. Provided below is a list of producers who are currently producing oil and/or gas at levels below 100,000 BTU equivalent barrels per day. Assuming they have a production tax liability, they would be eligible for some or all of the $12 million tax credit.

Companies Currently Eligible for Credit under AS 43.55.024(c)

1. Anadarko Petroleum Corporation
2. Aurora Gas
3. Chevron Corporation
4. Cook Inlet Energy
5. Doyon Limited
6. ENI S.p.A.
7. Marathon Oil Corporation
8. Municipal Light and Power
9. Nana Regional Corporation
10. Pioneer Natural Resources
11. XTO Energy

(6) Provide a figure showing ACES marginal and effective tax rates on same chart.

The chart below shows the marginal and effective tax rates under ACES and HB 110. The marginal tax rate reflects the tax rate on a $1 increase in production tax value. The effective tax rate is the average tax rate assessed on the gross value at the point of production after credits have been applied.



"New fields" means fields that were not in production or part of a unit prior to 2011. Assumes $6 transportation costs and $20 lease expenditures. Effective rates are calculated on Gross Value at Point of Production.

(7) Provide a list of the top ten petroleum producing states that we are competing against for investment.

According to the Energy Information Administration, the following table shows the top ten oil producing states in 2009.

Top Ten Oil Producing States in the U.S.

State	Average Daily Production (thousands of barrels per day)
Texas	1,106
Alaska	645
California	567
North Dakota	218
Louisiana	189
Oklahoma	184
New Mexico	168
Wyoming	141
Kansas	108
Colorado	78

(8) Compare credits offered by other states with Alaska's credits.

This response is composed of two parts. The first part discusses tax incentives in various states and the second part discussed corporate income tax credits in other states.

Many other states offer tax incentives, exemptions, credits, or temporary suspensions, to reduce the tax on certain production. Generally, these tax incentives apply to production from a specified geographic area or a type of well or drilling technique. The incentive may be a reduced tax rate or an exemption from tax for a specified time period. States may exempt production from some wells, such as stripper wells entirely. Incentives may be limited to a certain volume or gross value at the well, or allowed only up to a certain percentage of project recovery costs.

Here are some common types of tax incentives:

Horizontal drilling definition: Some states offer incentives to encourage use of horizontal drilling. Although horizontal wells may have higher drilling costs, they may also have higher recovery rates. North Dakota defines horizontal well as meaning "a well with a horizontal displacement of the well bore drilled at an angle of at least eighty degrees within the productive formation of at least three hundred feet." Other states require an angle of at least 70 degrees, or less of a drilling depth.

Tax rate variation: Adjustable tax rates may apply to all production based on the price of oil or gas, or only to production from new, stripper, or horizontal wells. The reduced tax rate may apply only up to a certain volume or market price, when that "trigger" volume or market price is reached, some of the tax incentives no longer apply.

Exemptions or reduced rate: A common tax incentive in a gross tax system is to exempt production for certain time, or to allow a reduced rate up to a certain production volume. To qualify, the well may need to be certified as a new, horizontal, or other type of well that qualifies for favored tax treatment.

Demonstration of increased production: This type of incentive can be related to a marginal well, an enhanced-recovery project or any well with declining production. In short, a baseline production amount is established and the operator applies to the tax or other commission for approval of a project designed to increase production. If the well production does increase, the operator may be eligible for a tax refund, exemption or other tax incentive, such as recovery of all or part of the project costs.

The following are some tax incentives in other states[1]:

Louisiana Severance Tax Exemptions, Rates and Suspensions
<u>Oil Full Rate</u>: 12-1/2% of its value at the time and place of severance
<u>Incapable Oil Rate</u>: 6-1/4% of its value. Oil produced from a well is incapable of producing an average of more than twenty-five barrels of oil per day during the entire taxable month and which also produces at least fifty percent salt water per day.

<u>Stripper Oil Rate</u>: 3-1/8% of its value. Oil produced from a well that is incapable of producing an average of more than ten barrels of oil per day during the entire taxable month.

<u>Oil tax deduction</u> allows producers to deduct a $0.25 per barrel for transporting oil or condensate from producing fields to processing facilities.

<u>Tertiary recovery severance tax suspension</u>: Allows crude oil production from a qualified tertiary project not to pay severance tax until the project has reached payout.

<u>Horizontal mining and drilling projects severance tax suspension</u>: Taxed at the special reduced rate of 3.125% of value until the cumulative value of hydrocarbon production from the project equals 2.33 times the private investment invested by the working interest owners.

<u>Horizontal wells severance tax suspension</u>: On any horizontally drilled well or any horizontal recompletions from which production commences after July 31,1994, all severance tax shall be suspended for a period of 24 months or until payout of well cost is achieved, whichever comes

[1] These states have gross tax systems, so upstream costs are not accounted for in determining the wellhead value, although some tax credits may incorporate a determination of exploration and development costs to calculate a project payback.

first. Pay out of well cost shall be the cost of completing the well to commencement of production.

Deep wells severance tax suspension: Wells drilled to a true vertical depth of 15,000 feet or more, where production commences after July 31, 1994 shall be exempt from severance tax for 24 months from the date production begins, or until payout of well cost, whichever comes first.

Texas Severance Tax Incentives
Enhanced Oil Recovery(EOR) Incentive: Oil produced from an approved new enhanced oil recovery project or expansion of an existing project is eligible for a special EOR tax rate of 2.3 percent of the production's market value(one-half of the standard rate) for 10 years after Commission certification of production response. For the expansion of an existing project the reduced rate is applied to the incremental increase in production after response certification.

The two year inactive well incentive: If an oil or gas well has been inactive(i.e., has no more than one month of production) during the preceding two years, any new oil, gas well gas, or casing head gas production may be eligible for up to a 10-year severance tax exemption.

Severance tax relief for marginal oil wells: The bill provides three levels of tax credits on oil production from qualified low-producing oil leases for any given month, depending on Comptroller's average taxable oil prices, adjusted to 2005 dollars, based on applicable price indices of the previous three months. An operator of a qualifying low-producing oil lease would be entitled to: (1) a 25% tax credit if the average taxable oil price were above $25 per barrel but not more than $30; (2) a 50% tax credit if the price were above $22 per barrel but not more than $25, and (3) a 100% tax credit if the price were $22 or less. The bill defines a qualifying low-producing oil lease as a lease that averages, over a 90-day period, less than 15 barrels per day per well or 5% recoverable oil per barrel of produced water per well.

Enhanced Efficiency Equipment Severance Tax Credit: Severance tax credits are available for marginal wells (an oil well that produces 10 barrels of oil or less per day on average during a month) for using equipment that reduces the energy required to produce a barrel of fluid by 10% as compared to alternative equipment.

Oklahoma Severance Tax Incentives
Tertiary Oil Recovery Projects: Any incremental production of crude oil or other liquid hydrocarbons which results from an enhanced recovery project is exempt starting from the project beginning date until project payback is achieved but not to exceed a payback period of 36 months.
Horizontally Drilled Well: The production of oil and gas from a horizontally drilled well producing prior to July 1, 1994, is exempt starting from the project beginning date until project payback is achieved, but not to exceed a payback period of 24 months commencing with the month of initial production.

North Dakota Oil Extraction Tax Incentive
Oil Extraction Tax Incentive for Bakken Horizontal Wells: The first seventy-five thousand barrels of oil produced during the first eighteen months after completion, from a horizontal well drilled and completed in the Bakken formation after June 30, 2007, and before July 1, 2008, is subject to a reduced tax rate of 2% of the gross value at the well of the oil extracted under this chapter.

*The gross production tax rate on gas is subject to a price index change on July 1 each year, the rate through June 30, 2011 is $.0914 per mcf. The gross production tax rate on oil is 5% of the gross value and the oil extraction tax rate is 6.5% of the gross value; 4% if the well qualifies for a reduced rate; 2% from qualifying wells in the Bakken formation; and 0% if the well qualifies for an exemption.

The following list discusses credits that are offered against corporate income tax in several other oil and gas producing states.

- California: **Enhanced Oil Recovery Credit:** Taxpayers are allowed a credit of one third of the federal tax against state tax.[2] This results in a credit of 5% of allowable costs for projects in California. No deductions for costs allowed as a credit; reduce basis in property by amount of the credit. Because federal credit is currently phased out, there is no current California credit. (See federal credits page).
- Oklahoma: **Coal Credit:** For tax years beginning on or after January 1, 2007, the credit shall be Five Dollars ($5.00) for each ton of coal mined, produced, or extracted in, on, under, or through a permit in Oklahoma.[3]
- Wyoming: **The state does not levy a corporate income tax**
- Texas, North Dakota, South Dakota: **No credits for oil & gas**

(9) Provide information about oil tax structure, environmental regulation, and land ownership for other oil producing states in the U.S.

The following discusses oil and gas tax structures in other states. We are in the process of compiling information about environmental regulation and land ownership in other states, and will provide that information to the committee when it is available.

Most state oil and gas severance[4] taxes are imposed on the gross taxable value of oil and natural gas. Under a gross tax, wellhead value is calculated net of transportation, processing and

[2] Cal. Rev. & Tax. Cd. § 23604 Oil recovery credit.
[3] Okla. Stat. § 2357.11 Tax Credit.

manufacturing costs. Generally, costs incurred upstream of the point of production are not deducted or considered when calculating gross taxable value. Gross production taxes can be levied on gross income, with a higher percentage applying as the income level increases. As an example, if gross income attributable from the sale of oil and gas is under $25,000, the tax rate is 2%; if $25, 000 but under $100,000, 3%, and so on. The following table shows the severance tax rates for several of the top oil producing states.

Severance Tax Rates by State	
Wyoming	6%
Texas	4.6%
Oklahoma	7%
North Dakota*	11.5%
Louisiana	12.5%
California	0%
New Mexico	3.75%
Kansas	4.33%

Alaska's severance tax is a net tax on the annual production tax value of oil and gas. Downstream transportation costs are deducted or "netted out" to arrive at a gross value at the point of production. Upstream costs, typically referred to as lease expenditures, are deducted from the gross value at the point of production to arrive at the annual production tax value upon which the tax is levied. If upstream costs are also qualified capital expenditures, they can qualify for a 20 percent credit that can be applied to the production tax liabilities, or redeemed as a certificate. Other credits, such as exploration credits, may also apply.

(10) Discuss the federal tax credits available in Alaska.

The following list presents the primary oil and gas related tax credits that are available against federal corporate income tax. There are also many federal tax credits that are available to all corporations which are not detailed here.

Enhanced Oil Recovery Credit (EOR)

- Credit of 15% of qualified costs against federal tax.
- Credit phases out when price of oil exceeds $28 /bbl (adjusted for inflation).
- No EOR allowed since 2005, because the list price exceeded the inflation adjusted price of oil. The list price for 2009 was $56.39 /bbl

[4] Severance taxes can also be called a mining license tax, net proceeds tax, royalty tax or production. Of course, there may also be property taxes, state income taxes and federal taxes levied on mineral production.

Marginal Well Credit

- Credit up to $3/bbl available only to owner of operating interest.
- Marginal well = oil production not more than 25 bbls/day, and not less than 95% water.
- Credit available only when price of oil less than $18/bbl.

Nonconventional Fuel Source Credit

- Credit up to $3 (adjusted for inflation) per BOE (barrel of oil equivalent, with 5.8 million Btu content)
- Credit completely phased out when inflation adjusted price of oil exceeds $33.46/bbl. List price of oil in 2009 was $56.39 /bbl.
- Credit on oil only from shale or tar sands.
- Credit on synthetic fuels from coal.
- Credit on gas produced only from:
  1. Devonian shale
  2. coal seams
  3. tight formations
  4. biomass
  5. geo pressured brine

(11) Provide a list of credits available from the federal government, and indicate what credits companies operating in Alaska have applied for. Provide examples of federal credits for the examples cited in our presentation (new explorer and existing producer with $200 million exploration program).

As a note on tax administration, corporations claim credits on tax returns when filed. Corporations do not apply for credits prior to filing a return.

No oil companies operating in Alaska have claimed federal corporate income tax credits in recent years because the federal credits have been phased out at current oil prices.

(12) Provide copies and a discussion on the Frazier Institute 2010 Global Petroleum Survey.

The complete Fraser Institute 2010 Global Petroleum Survey is available for free to the public at the following address: http://www.fraseramerica.org/commerce.web/product_files/global-petroleum-survey-2010_US.pdf

The Fraser Institute is an independent, non-profit research organization. The Global Petroleum Survey is based on the responses from managers and executives of petroleum exploration and production companies, and service providers, around the world. 645 professionals, representing 364 companies with a combined budget of $161 billion, contributed to the 2010 survey. Survey respondents rate various jurisdictions on 17 metrics related to investment attractiveness.

(13) If 44% of respondents to the Frasier survey indicated that Alaska's tax regime deters investment, what did the other 56% say?

Following is the detailed breakdown of responses regarding Alaska's tax regime:

- 25% said Alaska's tax regime "encourages investment"
- 31% said Alaska's tax regime "is not a deterrent to investment"
- 25% said Alaska's tax regime "is a mild deterrent to investment"
- 16% said Alaska's tax regime "is a strong deterrent to investment"
- 3% said they "would not invest due to this criterion"

(14) If Alaska modified petroleum taxes so that they were "the most favorable" where would that put AK on the Frazier graph?

The Fraser composite index takes an unweighted average of responses to 17 different factors affecting investment. Therefore, moving to a more favorable tax regime would likely result in a modest improvement in Alaska's composite index score. Also, improving our tax system would demonstrate to companies that Alaska is open for business and is taking steps to partner with industry and actively encourage investment in the state.

One example of a jurisdiction that recently made changes in its fiscal regime is Alberta. Alberta announced changes to its royalty system (Alberta's primary mechanism for receiving revenue from oil and gas) in early 2010. Alberta's composite index score went from 47.46 in 2009 to 36.70 in 2010, and its ranking in the Fraser composite improved from 92 in 2009 to 60 in 2010.

(15) If the state invested in infrastructure development, such as a road to the Umiat area, where would this put Alaska on the Frazier graph?

Quality of infrastructure is one of the 17 factors studied in the Fraser survey. Generally speaking, investing in improved infrastructure, such as roads to resources, would likely improve our score in this area. The impact on the overall perceptions of Alaska would likely depend on whether a road was an isolated investment in a specific project, or part of a broader initiative to improve the attractiveness of Alaska for industry investment.

(16) Please provide statistics on the major producers in Alaska and whether they are currently investing in the five Most Attractive and five Least Attractive jurisdictions on the Frazier graph.

The three largest oil producers in Alaska are currently Conoco Phillips, Exxon Mobil, and BP. As measured by the composite index in the Fraser survey, the five most attractive jurisdictions for investment are South Dakota, Texas, Illinois, Wyoming, and Austria. The five least attractive jurisdictions for investment are Bolivia, Venezuela, Russia, Ukraine, and Iran. To determine areas where the companies are invested, we reviewed Exxon's 2009 Financial &

Operating Review, Conoco's 2009 Fact Book, and BP's 2009 Annual Report. Note that there may be minor investments, or plans for future investments, that are not readily identified.

Among the most favorable jurisdictions, Conoco has investments in the Williston Basin of South Dakota; all three major producers are heavily invested in Texas; Conoco has a 50 percent interest in a refinery in Illinois; Conoco and Exxon both have operations in Wyoming; investments in Austria were not identified.

Among the least favorable jurisdictions, BP had operations in Bolivia that were nationalized in 2008; all the major producers were invested in Venezuela prior to nationalizations in 2007, with Conoco and Exxon pulling out and BP agreeing to joint venture contract terms; all three major producers have significant investments in Russia; investments by the major producers in Ukraine and Iran were not identified.

We hope our responses fully answer your questions. As mentioned above, we are currently compiling additional information to fully respond to request number 9 above, and we will provide that information when it is completed.

Sincerely,

Bruce Tang

Bruce Tangeman
Deputy Commissioner