Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114
Email: crockett@aoga.org
Marilyn Crockett, Executive Director

COMMENTS OF THE ALASKA OIL AND GAS ASSOCIATION
ON CSHB 110(RES)
HOUSE FINANCE COMMITTEE
MARCH 23, 2011

The Alaska Oil and Gas Association (AOGA) appreciates the opportunity to express its support for CSHB110(RES), the Governor's proposed amendments to the ACES production tax. We sincerely believe these provisions, when enacted into law, will increase the competitiveness for investment dollars in Alaska, resulting in increased job opportunities and the development necessary to stem the decline in oil production currently facing Alaska.

Today we are providing our comments on specific provisions of this legislation:

PROGRESSIVITY RATES/BRACKETING/TAX CAP

AOGA supports the provisions in CSHB110(RES) which establish bracketing of the progressivity rates and caps progressivity at 25%, for a maximum rate of 50% for progressivity and the base rate combined.

Under the current form of ACES, at $30, the taxpayer pays at the 25% base rate. But as the taxable Production Tax Value (PTV) raises above $30, the progressivity feature kicks in, and instead of applying the higher tax rate to just the incremental dollar, the current tax system reaches back and taxes the entire original $30 at the higher rate. Each time the PTV per barrel increases further beyond $30, all prior dollars are taxed at the higher rate instead of just that further increase. This approach is what creates such high marginal tax rates, and creates an imbalance in the risk-reward investment environment in Alaska. Removing the upside to the degree the progressivity feature does makes it much more difficult to compete for investment dollars with other areas that are not as fiscally challenged as investments here in Alaska.

Bracketing sets tax rates for the different levels of PTV so that each level is taxed only once and at a specific rate for that bracket, moderating the impact of ACES' high rate of tax. As you have seen, the bracketing described in CSHB110(RES) generally follows the same line of progressivity as in the current version of ACES. But by not reaching back and taxing those dollars that have already added value to the project and that have had taxes paid on them and not taxing them again, CSHB110(RES) adds much needed

stability and predictability to the tax. As companies realize higher prices and greater PTV, the State likewise continues to share in those benefits.

Bracketing of income to pay taxes is a time-tested approach. There isn't a person here that doesn't have a personal interest in the concept and how it works. Just look to your personal income taxes with the IRS. The difference between what we are currently experiencing with ACES' progressivity feature and the notion of bracketing is quite compelling. Under ACES, as you've heard already from the DOR and in a number of presentations and publications over the last year, the rate is too high.

In addition, capping progressivity and the base tax at the 50% combined rate under CSHB110(RES), rather than the current 75%, also provides the impetus needed to motivate companies to undertake the high risk projects on which the future economic health of Alaska will depend. This change creates a business climate where the reward is commensurate with the risk and keeps the needs of the State and the producers in a more appropriate balance.

You will be hearing from our member companies regarding this risk/reward and the need for an adequate upside, and the challenges they face when presenting projects to their respective Boards. The competition for these dollars is real and anything to move Alaska to a more competitive position will make those arguments more palatable and possible.

ANNUAL –v- MONTHLY

Another aspect of progressivity is the monthly calculation of the progressivity rate. The inherent flaw in this and why AOGA supports moving to an annual progressivity is simple. The revenues that are used in the calculation of the progressivity are actuals, reflecting current production and current prices. They are subject to the seasonal swings in production or market pressures of price. In calculating the PTV, though, the deductible lease expenditures are the actual expenses for the whole year, with 1/12 of the annual total being allocated to each month during the year. In other words, the present version of progressivity creates a huge mismatch by using each month's *actual* gross value at the point of production (GVPP), but deducting 1/12 of the actual expenses. This result is achieved at the annual true-up on March 31st of the following year. In making estimated monthly payments, however, the mismatching is compounded because taxpayers have the actual GVPP for each month but will have to rely on a monthly figure for the *estimated* lease expenditures for the whole year, in order to calculate the PTV and the resulting progressivity rate for that month.

The monthly approach to progressivity actually taxes artificial PTV, raising the Alaska tax rates higher than reported on any graph of tax rates. None of those graphs account for mismatching in the progressivity tax on monthly PTV. The difference is solely driven by the fact that progressivity taxes the inflated, incorrect monthly PTV resulting

solely from this mismatching. We support moving from a monthly calculation of progressivity to an annual calculation to synchronize the revenues with the expenses, avoid the mismatching, and more accurately reflect the philosophy behind what a progressivity feature should look like.

TAX CREDIT INCENTIVES EXTENDED TO NORTH SLOPE

CSHB110(RES) expands the existing 40 percent *well lease expenditure* tax credit currently available only to qualifying expenditures in "Middle Earth" and the Cook Inlet Sedimentary basin,[1] so it will also be available for qualified expenditures made on leases or properties north of 68 degrees North Latitude.

The well lease expenditure concept was introduced and enacted into law in May 2010 in connection with chapter 16, 2010 Session Laws of Alaska (the Cook Inlet Recovery Act). Under AS 43.55.023(o) a well lease expenditure (WLE) is defined as:

> a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c) . . . [2]

A well lease expenditure is the subset of qualified capital expenditures (QCE) that currently define the scope of capital spending that qualifies for the 20% QCE credit under sub-section .023(a). Thus, within the QCE "bucket" are a set of costs that would be eligible for a full 40% tax credit instead of the usual 20% QCE credit. The definition of WLE as *intangible drilling and development cost* (IDC) has several advantages. First, IDC is a concept that is well-defined in oil and gas tax law. IDC is designated for special tax treatment under the U.S. Internal Revenue Code.[3] It represents the part of

---

[1] i.e., South of 68 degrees North Latitude under AS 43.55.023 (l) and (n).

[2] The full language under subsection .023(o) reads as follows:

> (o) For the purposes of (m) and (n) of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is
>
> (1) directly related to an exploration well, a stratigraphic test well, a producing well, or an injection well other than a disposal well, located in the state south of 68 degrees North latitude, if the expenditure is a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well includes an expenditure for well sidetracking, well deepening, well completion or recompletion, or well workover, regardless of whether the well is or has been a producing well; or
>
> (2) an expense for seismic work conducted within the boundaries of a production or exploration unit.

[3] Intangible well costs are distinct from tangible costs such as equipment and drill pipe and are 70-100 percent deductible against federal taxable income when incurred. (See *Petroleum Accounting: Principles, Procedures, & Issues*, 5th Ed. (University of North Texas: PriceWaterhouseCoopers), p.72.

capital expenditures that has no physical attributes or salvage value, such as fuel, labor and rig rental. Thus it is a convenient and readily accessible accounting designation.

Second, WLE is consistent with language already existing in the PPT-ACES framework. Producers will not have to wait for the DOR to write regulations that describe what is included and not included in the WLE.

Third, IDC is focused on costs associated with drilling wells and getting more production out of both existing fields and new field development. As stated in sub-section .023(o)(1), well lease expenditures include "well sidetracking, well deepening, well completion or recompletion, or well workover expenditures" that would target new areas of the reservoir.

Lastly, since labor costs may be included in IDC, the 40% WLE credit indirectly supports hiring and job creation.

In sum, AOGA strongly endorses this special category of QCE that is targeted for the credit uplift because 1) this category of expenditure is tied directly to in-field drilling; 2) includes labor costs; and 3) is a convenient and readily accessible accounting designation. Also, this proposal has the advantage of an earlier effective date compared with other provisions in HB 110, thus potentially jump-starting production sorely needed to stem the production decline in the near-term.

LOWER TAX RATES FOR NEW FIELD DEVELOPMENT

CSHB110(RES) includes provisions (under Sections 6 and 8) that would lower the base tax rate from 25% to 15% for oil and gas produced from areas outside of current fields and units or not in commercial production prior to December 31, 2008.

In addition, the progressivity surcharge for oil and gas produced from areas outside of current units would be capped at 40%, or 25% above the base tax rate. And progressivity would be subject to parallel tax-bracketing treatment, where tax rates for a particular discrete tax bracket are applied only to incremental income in that bracket. Also, the progressivity tax is levied on an annual basis instead of monthly, the same as for the fields in production. This change would be effective January 1, 2013, and apply to production after December 31, 2012. The proposed base and progressive tax rates applicable to existing and new field development are summarized in Exhibit 1, below.

Exhibit 1. Summary of Proposed Base Tax and Progressivity Surcharge for New and Existing Fields

Taxable Production	Field or Unit In Production Prior to 31-Dec-2008	Field or Unit In Production After to 31-Dec-2008
Base Tax	25%	15%
Max Progressive Surcharge	25%	25%
Max Combined Tax Rate	50%	40%
Progressivity Annual instead of Monthly	Yes	Yes
Bracketing Applies	Yes	Yes
Effective Date	1-Jan-2013	1-Jan-2013

AOGA cautiously supports this proposal for new field development, which represents a significant reduction in the implied tax burden. However, it raises several questions. First, as with other provisions in CSHB110(RES), the implied lag in the effective date is problematic. There clearly is a sense of urgency with regard to the need for investment and stemming the decline in production, and delaying the effective date of these provisions seems counter to that urgency.

Second, the DOR *Fall Revenue Sources Book* anticipates production from new developments from state and federal lands to account for a significant portion of total ANS production over the next decade. (See Exhibits 2 and 3, below.) But almost all of these areas of potential new field development overlie existing producing fields and/or units. Would new field development from these areas qualify for the lower base tax and progressivity schedules contained in Sections 6 and 8 of CSHB110(RES)? Providing an answer to this question by regulations could be a drawn-out, difficult process — assuming they could be drafted in a way that provides the answer while remaining consistent with the statute.[4]

Third, the provisions in sections 6 and 8 of CSHB110(RES) are silent on the treatment of lease expenditures for new field development. Since the proposed change in base tax and progressivity is driven by the PTV associated with new field development, some form of ring-fencing production, revenue and costs is implied. This in turn raises

[4] AS 44.62.030: "a regulation adopted is not valid or effective unless consistent with the statute" that it is "implement[ing], interpret[ing], mak[ing] specific, or otherwise carry[ing] out.

questions about the complexities of allocating joint operating and capital costs. AOGA favors addressing the matter of cost allocation in statute rather than through regulation.

Exhibit 2. DOR Commissioner's Presentation to the House Resources Committee, February 7, 2011

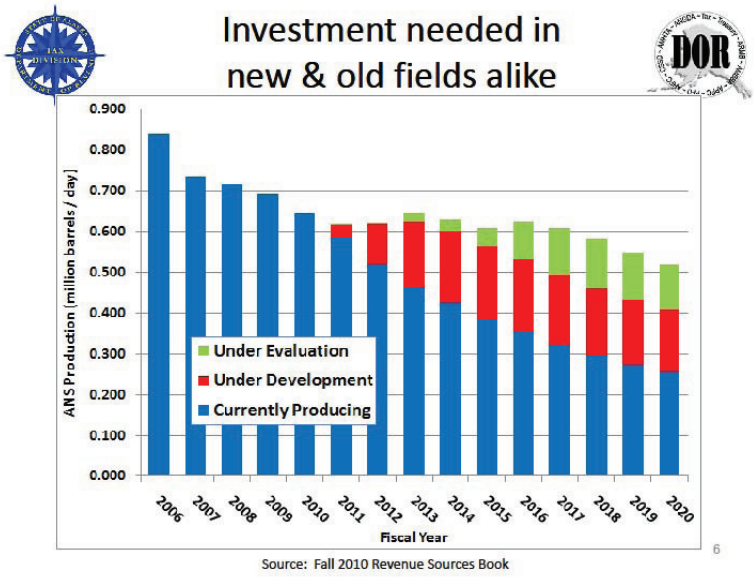

Exhibit 3. Areas of New Field Development over Next Decade

1. State lands
    a. Expanded heavy/viscous oil development
        i. West Sak
        ii. Orion
        iii. Polaris
        iv. Schrader Bluff fields
    b. Continued satellite development at Alpine
        i. Fiord
        ii. Nanuq
        iii. Qannik fields),
    c. New developments
        i. Oooguruk
        ii. Nikaitchuq
    d. Point Thomson – startup in 2015
    e. Badami - Restart 4Q 2010
2. Federal lands
    a. NPR-A,
        i. Alpine West field (start up in the 2013)
        ii. Mooses Tooth unit
        iii. Umiat field.
    b. Liberty development 1Q 2012
    c. Nikaitchuq field start-up 1Q 2011

Lastly, and most importantly, it is important to incentivize ALL new oil. This means new oil associated with new field development and from exploration, as well as new oil from existing producing fields using in-field drilling, secondary recovery, and tertiary recovery techniques. If attracting investment in the near term is the goal, then AOGA respectfully urges consideration of extending the new field incentives in sections 6 and 8 to any and all new oil development, including that arising from existing fields.

Reducing the Interest Rate on Tax Under and Over Payments and the Statute of Limitations

AOGA supports the Administration's proposed reductions to the statutory interest rate on tax under and over payments and the statute of limitations for performing tax audits. We are pleased to see the Administration and particularly the Department of Revenue recognize the need to address these two provisions and their negative impacts on Alaska's investment climate.

Unfortunately, the provision reducing the timing of the statute of limitations in the version of the bill before you now was deleted in the previous committee. We encourage you to reinstate it.

Currently the state's interest rate applicable on tax under or over payments is the greater of the federal funds rate plus five percentage points, or 11%, whichever is greater, compounded quarterly. Interest rates in other states are much lower.

The time period for which the Department can audit a taxpayer's tax return is three years from the date of the filing of the tax return for all taxes except for the production tax. With the enactment of ACES, the statute of limitations for auditing production tax returns was increased to six years. We never understood why that change was needed when the three-year audit period has worked successfully for all other taxes and can be extended and re-extended any number of times as appropriate and taxpayers were generally willing to do so.

The longer an audit is allowed to run, the greater the amount of interest there will be that accrues on any underpayment claimed in the audit. Under the current interest rate provisions, after three years, interest represents at least 38¢ for each dollar of additional tax claimed. But after six years the accrued interest grows to at least 92¢ for each dollar of additional tax claimed. The longer statute of limitations, coupled with the high interest rates, mean a greater likelihood that audit disputes will be litigated instead of settled, because the interest, which under state law cannot be compromised or abated, represents such a substantial portion of the amounts at issue even at the very beginnings of the disputes.

Reducing the interest rate provisions to the lower of the federal fund rate plus three percent or 11%, and shortening the statute of limitations from six years to four, are both clear steps in the right direction to improve Alaska's tax regime. They are long overdue. We encourage this Committee to reinstate the previous provision reducing the statute of limitations from six years to four.

Minimum Tax

A provision of CSHB110(RES) which concerns AOGA is increasing the minimum tax on North Slope production.

One element that increases the attractiveness of a tax system is the sharing of risk by the government with the investor, whether the risk turns out well or poorly. Even with the changes to the progressivity tax proposed in CSHB110(RES), Alaska would still take a greater share for itself of the upside for price risk. The minimum tax avoids or reduces the State's exposure on the downside of price risk, increasing the risk on investors, thereby making investments in Alaska less attractive.

Complicating this problem is the fact that the minimum tax is imposed on the gross value at the production of the oil and gas, without deductibility of any development or processing costs. Therefore, the minimum tax in essence is akin to a second regressive royalty payment as upstream costs of producing the oil or gas are ignored. The producer could be obligated to pay the tax even when losing money. This disproportionate shift of the investment and price risks to the producer or explorer could result in less investment and premature shut-in and thus lost production and state revenues.

Having a minimum tax along with the high level of progressivity tax has harmed Alaska's investment climate. Further increasing the minimum tax is a step backwards. It will not increase Alaska's competitiveness and is inconsistent with what the rest of CSHB110(RES) is seeking to do.

Again, thank you for the opportunity to submit these comments.