Alaska's Oil & Gas Production Tax Deconstructed

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Contents

Section 1

A Brief History of Alaska's Oil and Gas Production Tax

Section 2

Current Production Tax and Proposed Changes

Section 3

Section 1. A Brief History of Alaska's Oil & Gas Production Tax

I. The Economic Limit Factor (ELF)

A production tax is a tax levied by a sovereign government when publicly owned natural resources are produced from state land or water. In addition to the production tax, Alaska also receives oil and gas revenue from royalties (the mineral owner's share of production), the state corporate income tax and property taxes. Currently, the production tax provides the most state revenues, followed by royalties. Together the two income streams make up approximately 91% of oil revenue to the state.[1] This paper discusses just the production tax.

Until 2006, Alaska had a production tax levied on the gross value of oil and gas. A gross tax is a tax on the value of oil and gas at the point it is measured. In Alaska, the gross value is determined by subtracting the costs of transporting the resource from the destination sales price.

The gross tax had an Economic Limit Factor (ELF) that adjusted the tax rate based on the productivity and size of each field. The ELF formula was intended to provide low tax rates for small, low productive fields and higher rates for large, highly productive fields. But eventually the system broke down – based on the formula, more than half of all oil and gas fields in Alaska paid no production tax, including the very large fields. Other problems were that the ELF formula was not sensitive to variations in oil prices, so the state could receive taxes even when low oil prices meant producers had no profit, and the state would not benefit when oil prices, and profits, were high. In addition, the ELF formula did not provide incentives for reinvesting in Alaska's oil and gas fields.

II. The Petroleum Profits Tax (PPT)

In 2006, the production tax system was changed to one based on net profit value rather than gross value. With a net tax, the net income value of oil and gas is determined by subtracting from the gross value, the costs of exploring for, developing and producing the resource. A net tax is sensitive to variations in oil prices, so the state risks not getting any production taxes if oil prices, and company profits, are very low, but receives more tax revenue when oil prices are high.

The 2006 change has its origins in negotiations between the Murkowski administration and the three major North Slope producers (BP, ConocoPhillips, and ExxonMobil) for a contract aimed at getting the producers to develop a natural gas pipeline (the Stranded Gas Development Act (SGDA) contract). In addition to long-term contract terms for the gas production tax, the producers wanted 35 years of fiscal certainty for oil based on the ELF tax system. In 2005, as part of the SGDA negotiations, the state offered a contractual term

[1] In FY 2011, the production tax brought in $4.5 billion, royalties $1.8 billion, corporate income tax $542 million, and property tax, $111 million. Dept. of Revenue, Revenue Source Book, Fall 2011.

of 20 years of fiscal certainty for oil if the oil and gas production tax was changed. This led to development of a profit based production tax (known as the PPT).[2]

The gas pipeline contract was not approved by the legislature because of significant concerns that its terms were not in the state's interest. However, following multiple attempts, the legislature enacted a new net based production tax system in August of 2006. The objectives of the new system were to encourage investment in the state and, at high prices, to generate more revenue than the existing ELF-based system.

The new PPT established a base tax rate of 22.5% on the net value of oil and gas – the value after deducting transportation costs and qualified operating and capital lease expenditures. The PPT also offered a 20% tax credit for capital expenditures and operating losses. The intent of the tax credits was to encourage development of smaller conventional oil fields and heavy oil (a costlier, more viscous oil that requires new technology to develop). The PPT also had a progressivity provision (an increase to the tax rate as oil and gas prices increase) that was triggered at $40 net value per barrel (the value of a barrel of oil less transportation, capital and operating costs) with a 0.25% increase per dollar increase in net value and a 25% tax cap on the progressivity rate for a total production tax rate of up to 47.5% (22.5% base tax rate plus up to 25% progressivity). The base tax plus progressivity applied to the entire net value, not just the additional value.

III. Alaska's Clear and Equitable Share Act (ACES)

A. 2007

In 2007, based on lower tax returns due to higher than anticipated lease expenditure deductions, and on concerns that not all legislators were considering the state's best interest during the PPT debates, various changes were made to the PPT under the Alaska's Clear and Equitable Share Act (ACES). Though the new Palin administration considered changing the tax back to one based on the gross value of oil and gas, it was concluded that a gross tax would not be flexible enough to address the differences between oil and gas fields in terms of size, productivity and profitability, or account for more expensive resource development such as heavy oil.

Among other changes, ACES increased the base tax rate to 25% and changed the progressivity trigger to $30 net value per barrel, with a 0.4% increase per dollar up to $92.50, and a 0.1% increase per dollar above $92.50. The progressivity tax rate was capped at 50% for a total production tax rate of up to 75% (25% base tax rate plus 50% progressivity). Like the PPT, the base tax plus progressivity applies to the entire net value, not just the additional value.

[2] *See* Appendix T to Interim Fiscal Interest Finding dated November 16, 2006 – Chronology of Negotiations http://www.courts.alaska.gov/outreach/scl2012-anc-exhibit2.pdf

The 20% tax credit for capital expenditures was retained, but amended to require the use of the credits be spread over two years. The 20% tax credit for operating losses was amended to match the base production tax rate of 25%.

B. 2010: ACES Status Report and Tax Credit Increase

In 2010, a status report on ACES by the Department of Revenue (DOR) found that "Overall, the information reviewed by the department indicates that ACES is performing as expected when it was passed by the Legislature in 2007." The report stated:

> The ACES production tax has been effective in allowing the state to share in the benefits of high oil profitability. It has also responded well to lower oil prices by reducing state tax burden on Alaska's oil and gas producers. Over $2 billion in new capital investment was reported in fiscal year 2009 reaching near-record levels. While these and other indicators suggest that the profits-based tax system has supported North Slope exploration and development, it would be misleading to suggest that ACES alone influences the level of investment. While tax is recognized as being an important factor in investment decisions, it is not the primary determinant. Long-term price forecasts, as well as the resources themselves, have proven to be much more significant drivers of industry activity. [3]

Also in 2010, the tax credit for capital expenditures was amended to provide for a 40% credit for a producer or explorer's well related lease expenditures incurred in areas outside the North Slope. The Petroleum News reported on the changes, saying:

> [Governor] Parnell said there is significant evidence that the tax credits in ACES are encouraging companies to explore in Alaska and that the administration's proposed changes to the tax would bolster that effect, with the main goal being the creation of more jobs for Alaskans in the near future.
>
> On the other hand, the administration's discussions with oil companies failed to discover any evidence that the lowering of the progressive tax rates in ACES would result in new investments in Alaska, regardless of claims that lower rates would make Alaska more competitive for those investments, Parnell said.
>
> "At this moment I am working for providing more opportunity for Alaskans in jobs," Parnell said. "I'm not interested in changing progressivity so they [the companies] can take that money and invest it somewhere else. If they're willing to invest it here, I'm open to considering it, but I'm standing up for Alaskans in this, not some other country."[4]

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[3] Alaska's Clear and Equitable Share (ACES) Status Report, Alaska Department of Revenue, January 14, 2010, page 15.

[4] Petroleum News, January 17, 2010.

C. 2011: ACES Status Report

Among other things, a 2011 status report from DOR to the legislature found the following:

- state revenues under the net profits tax exceeded the amount that would have been received under ELF;
- although the production tax rate may be as high as 75%, tax rates in each of the four years since the net profits tax was passed were much lower than the maximum rate;
- industry capital investment in the form of capital expenditures increased since implementation of ACES, though whether expenditures were production-related or for maintenance was not clear;
- exploration generally increased from 2003, but dropped off in 2010;
- industry employment rose from 2006 through 2009, but dipped slightly in 2010; and
- the use of tax credits increased annually since 2006.[5]

The report concluded:

> Based on the multiple changes to the tax laws over the past few years, drawing any conclusion about their effect on Alaska's investment climate is difficult. However, what is clear is that production continues to decline. The state should continue to monitor its competitiveness with other oil and gas jurisdictions worldwide and be prepared to change its tax structure as needed.[6]

IV. 2011 Changes to Current Production Tax – House Bill 110

A. House Bill 110

On October 15 2010, Governor Parnell announced a plan to increase production from the North Slope. The governor proposed capping progressivity at higher oil prices and offering tax credits for technically challenged fields.[7]

Following the 2010 election, the governor's Resources, Energy and Environment transition team recommended that the governor proceed with "urgency" to increase oil production on the North Slope, saying that increasing production is vital to Alaska's economic future. The report stated:

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[5] Oil and Gas Production Tax, Status Report to the Legislature, Alaska Department of Revenue, January 18, 2011, page 1-2.

[6] *Id*.

[7] Governor Parnell Press Release, October 15, 2010.

> Alaska's taxation policy must be revised to encourage more investment in order to reverse this dramatic, continuing production decline. The Governor should introduce meaningful reform of Alaska's oil production tax system that reduces the State's tax burden on all Alaska oil and gas exploration and development activities and encourages increased production. Specific emphasis must be placed on addressing the negative investment climate caused by progressivity.[8]

In January 2011, Governor Parnell introduced proposed changes to the current production tax system through House Bill 110 and Senate Bill 49. In his transmittal letter, the governor said the aim of the legislation was to make Alaska more competitive as an oil producing state, get more oil into the pipeline to stem the decline in North Slope production, and create jobs for Alaskans.[9]

HB 110 passed the House in the spring of 2011. Among other changes to the production tax, the bill establishes different production tax rates for different fields, and brackets progressivity so that the tax rate increase applies only to the specified bracket rather than the entire net value. For production in areas where there has been commercial production, the brackets range from a base tax rate of 25% for a net production tax value up to $30 per barrel to 50% for a production tax value over $92.50. The maximum total production tax rate is 50%. For new areas without commercial production, the brackets range from a base production tax of 15% for a production tax value up to $30 per barrel to 40% for a production tax value over $92.50 per barrel. The maximum total production tax rate for new areas is 40%.

The DOR fiscal note for CSHB 110(FIN) shows that the tax rate change in current producing areas is estimated to reduce revenue to the state in the amount of $5.6 billion for the first five years if there is no new production. If oil production rose 5% from present forecasts, the reduction in revenue to the state would be $4.9 billion over the same period. The administration said it expects that if there is no new investment, the legislature would act to change the tax rate.

CSHB 110(FIN) is currently in the Senate Labor and Commerce Committee.

B. HB 110 Rationales Examined

In addition to the assertion that HB 110 will improve Alaska's competitiveness and increase production, rationales for changing the current production tax as proposed under HB 110 include

- the claim of a "premature" shutdown of TAPS in a decade if oil production falls below 300,000 barrels per day;

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[8] Transition Reports 2010 – 2011, page 5.

[9] House Journal, January 18, 2011, page 0060.

- the loss of industry jobs to North Dakota and Texas where production is "booming;" and

- the commitment by the industry to invest $5 billion over the next three years if HB 110 is enacted. During the 2012 legislative session, these claims have come under scrutiny in the Alaska State Senate with the following results:

1. TAPS Premature Shutdown

Oil production from the North Slope peaked in 1988 at approximately 2 million barrels per day and has steadily declined since. Current production is slightly over 600,000 barrels per day with a decline rate of approximately six percent. With the decline in oil production, throughput in the Trans Alaska Pipeline System (TAPS) has decreased. A report published by the TAPS pipeline operator, Alyeska Pipeline Service Co., says that low-flow problems may start arising at 600,000 barrels per day. The report concluded that "the TAPS can continue to be operated safely and with reasonably high operational confidence down to throughputs of about 350,000 [barrels per day]" if specified mitigation measures are taken.[10] The recommendations did not address problems that would likely arise at flow rates below 350,000 barrels per day.

In its examination of a TAPS property tax court decision by Judge Sharon Gleason, the Senate Resources Committee learned that there were other, earlier studies that indicate that, while low production creates technical challenges for TAPS, the pipeline is expected to function at much lower production rates than 350,000 barrels per day.[11]

When arguing for a lower property tax, the pipeline owners (including BP, ConocoPhillips and ExxonMobil) asserted that TAPS will be unable to transport oil when the amount transported through the pipeline reaches between 300,000 and 350,000 barrels per day (bbl/day). Yet, the court decision reveals that, in its 2010 filing with the federal Security Exchange Commission, BP reported that the pipeline could operate with throughput of 70,000 to 100,000 bbl/day, potentially extending the life of the line from around 2049 to 2075 depending on the amount of recoverable reserves.

In support of HB 110, advocates for the legislation warned that the production tax must be changed to encourage additional production and avoid a "premature" shutdown of TAPS, possibly within a decade. Since the other studies and SEC filings in the court case were made public, advocates now assert that, while it may be possible for the pipeline to operate to 100,000 barrels per day, such a reduction in production will severely impact revenue to the state's budget.

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[10] Low Flow Impact Study, Final Report, June 15, 2011, page 3.

[11] BP Pipelines, et. al. v. Fairbanks and State of Alaska, Case No. 3AN-06-08446 CI.

2. Job Loss

A key argument advanced in support of the provisions in HB 110 is that oil industry jobs in Alaska are being lost to lower-tax jurisdictions such as Alberta and North Dakota, where new technologies have significantly increased oil and gas production. A McDowell Group report commissioned by the Senate found that, while North Slope employment dropped significantly in 2009, employment is now at an all-time high, with over 9,000 jobs on the North Slope in November and December 2011. In testimony before the Senate Labor and Commerce Committee, a McDowell spokesperson suggested that industry losses in 2009 were linked to the global economic downturn. The increase in jobs appears to be related to new developments due to high oil prices, and investments in maintaining the Prudhoe Bay infrastructure.[12]

3. Five Billion Dollar Investment by North Slope Producers

On multiple occasions, Governor Parnell has stated that the three major North Slope producers have "pledged" to fund $5 billion in projects within three years if HB 110 passes. However, in a Senate Resources Committee hearing on March 1, 2012, a BP spokesperson said that the $5 billion would be invested over the course of six to ten years. A ConocoPhillips spokesperson said ConocoPhillips has committed to spending $5 billion in the next three to five years jointly with the other two Prudhoe Bay working interest owners, BP and ExxonMobil. As revealed during the hearing, the Prudhoe Bay Operating Agreement requires project approval of all three major owners of the Prudhoe Bay field and, while both BP and ConocoPhillips have expressed support for the potential investment, ExxonMobil has not indicated they would approve the investments.

In addition, among the projects that BP and ConocoPhillips suggest may receive funding under the new tax is the development of the Prudhoe Bay I Pad. The project would involve about 50 wells and additional facilities, and may lead to approximately 80 million barrels of recoverable oil. During a Senate Resources Committee hearing on February 22, 2012, the Department of Natural Resources (DNR) director for the Division of Oil and Gas testified that DNR was told that the delay in I Pad was due to technical reasons, as opposed to economic reasons. Consequently, there is no certainty that I Pad would be developed even with the proposed tax changes.

V. 2012 Changes to Current Production Tax – Senate Bill 192

In 2012, the Senate Resources Committee introduced SB 192 as its own vehicle for possible changes to the ACES tax structure.

In response to the information acquired during committee hearings, a committee substitute for SB 192 passed out of the Senate Resources committee. The bill retains the ACES trigger for progressivity at $30 net value per barrel, but changes the rate of increase from 0.4% to

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[12] Oil and Gas Industry Employment on Alaska's North Slope, McDowell Group, January 2012.

0.35% per dollar increase in net value up to $101.43, and has a 0.1% increase per dollar above $101.43. The progressivity tax rate is capped at 35% for a total production tax rate of up to 60% (the cap kicks in when oil prices are at $201.43 per barrel).

Initial modeling by DOR indicates the change in progressivity is estimated to reduce revenue to the state in the amount of approximately $200 to $250 million per year.

SB 192 also modifies the existing minimum tax floor (a set tax rate that ensures some revenue for the state when oil prices are exceptionally low), adds an allowance for new oil production, requires the creation of an oil and gas information management system, and includes provisions that create separate taxing systems for oil and for gas (referred to as “decoupling”).

CSSB 192(RES) is currently in the Senate Finance committee.

Section 2. Current Production Tax and Proposed Changes

Base Oil & Gas Production Tax

Current Tax System

The current base production tax rate is 25% on the production tax value (PTV) of the taxable oil and gas calculated on an annual basis. The production tax value is the net value of the taxable oil. Taxable oil does not include state and federal royalty barrels and barrels used in production.[13]

The net value of the taxable oil or gas is determined by deducting allowable lease expenditures from the gross value of the oil or gas at its point of production.[14] The gross value is the value of the oil or gas at its point of production with transportation costs deducted.[15] For oil, the point of production is where the oil is metered before entering the main carrier pipeline. For gas, there are four possible points of production, depending on whether or how the gas is processed.[16]

Different base production tax rates apply to Cook Inlet oil and Cook Inlet gas production. Tax rates for oil and gas produced from Cook Inlet are effectively capped at the rate that was imposed on oil and gas produced from each lease or property during the period April 1, 2005 through March 31, 2006. [17] The same cap applies to gas produced outside Cook Inlet and used in the state.[18]

Discussion

One aspect of Alaska's net profits production tax is that a company is able to deduct expenditures from costlier, less profitable projects against more profitable production. For example, the high costs of developing a new resource such as thicker, technically challenging heavy oil can be deducted against the production tax on lower cost, more profitable light oil produced from existing fields. This is one incentive for encouraging new oil production.

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[13] AS 43.55.011(e).

[14] AS 43.55.160 and AS 43.55.165.

[15] AS 43.55.150.

[16] AS 43.55.900(20).

[17] AS 43.55.011(j) and (k).

[18] AS 43.55.011(o).

Both SB 192 and HB 110 offer additional incentives for increasing new oil production.

CSSB 192(RES)

- Establishes an allowance for production that is an increase over production from the previous year.
    - The allowance would reduce a company's production tax value by $10 multiplied by the number of barrels above the previous year's production.
    - In determining the average daily statewide production for a producer for the previous tax year, the days in which there is a significant slowdown in North Slope production or transportation will not be counted.
    - New production will not include any new oil that can be attributed to acquisitions or mergers.

CSHB 110(FIN)

- Establishes a 15% base tax rate for leases or properties not producing before December 31, 2008.
- The 15% base tax rate is in effect for the later of the first seven consecutive years after the start of sustained production or the first seven years after the effective date of this section of the bill. Using a definition under existing law, "sustained production" means "production of oil or gas from a reservoir into a pipeline or other means of transportation to market, but does not include testing, evaluation, or pilot production."

Progressivity

Current Tax System

A progressivity factor increases the tax rate as the net value on a barrel of oil increases, and decreases the tax rate when oil prices fall. Currently, progressivity is triggered when the net value rises above $30 per barrel. The rate of increase (the amount added to the base tax of 25%) is 0.4% for each dollar per barrel of net value increase above $30 up to $92.50. When the net value is above $92.50, the rate of increase drops to 0.1% per dollar of net value. The progressivity rate is capped at 50% for a total tax rate of 75% (25% base tax plus 50% progressivity). Progressivity is calculated on a monthly basis.[19]

The base tax plus progressivity applies to the entire net value, not just the additional value. That is, if the net value is $50 per barrel, the base tax plus progressivity would apply to the entire $50, not just the $20 between $30 and $50.

Discussion

The intent of a progressivity factor is to ensure the state gets its fair share of oil revenue when oil prices are high. Progressivity is also intended to help producers when oil prices are low. For example, in 2009, lower oil prices resulted in lower taxes in Alaska. Reporting on their first quarter earnings, ConocoPhillips president and chief operating officer told analysts that "Consistent with the lower price environment, we had a benefit of $153 million on production taxes, primarily in Alaska;" and the vice president of corporate affairs said that the "Lower 48 loss of $71 million was more than offset by the $244 million earnings that we had in Alaska."[20]

However, the administration and industry say that by being very progressive at high oil prices, Alaska is not as attractive an investment when compared to other worldwide oil and gas regimes. How Alaska compares to other oil and gas regimes, including states in the Lower 48, has been the subject of many legislative presentations by various consultants. As noted by a benchmarking study presented to the legislature in 2010, how Alaska compares with other regimes depends on what factors are considered in a particular study.[21] Over the past several years, studies generally show that Alaska ranks near the top in terms of its marginal tax rate (the percentage increase in government take when oil prices rise) when oil prices are exceedingly high, making the state potentially non-competitive on that factor. However, studies also show that, when considering other factors, Alaska is generally competitive when compared with similarly situated oil and gas producing regimes.

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[19] AS 43.55.011(g).

[20] *See* Petroleum News, April 26, 2009; ConocoPhillips Q1 2009 Earnings Call Transcript.

[21] *See* Fiscal System Benchmarking by Gaffney Cline, January 2010.

In presentations to the legislature, the Alaska Department of Revenue (DOR) and industry said that the progressivity factor in the current tax system is the main problem with the system – that it hinders new investment that could increase production. The complaints generally focus on the state's high marginal tax rate, and that the increased tax rate is not "bracketed" such that the increase applies only to the production tax value subject to the higher tax rate.

In a Senate Resources Committee hearing on March 1, 2012, a BP spokesperson said that "only a meaningful tax change, starting with bracketing around progressivity, will draw the additional investment that Alaska needs to put more oil in the pipe." At the same hearing, a ConocoPhillips spokesperson explained that in making investment decisions, they look at a number of "economic metrics," as well as the "total risk/reward equation" of the reservoir, the capital risk and the technology risk. In terms of economics, they look at their long term cash flow potential as margins increase. The spokesperson stated, "Right now in the State of Alaska, because of the progressivity element and the impact it has on the marginal tax rate, [ConocoPhillips] can't see it as a terribly interesting place to invest incremental capital . . . the key to making Alaska more attractive for additional investment is going to be to change the progressivity element of ACES."[22]

Another issue if a progressivity rate is too high is, it might lead to an issue called "gold-plating," where a company makes expenditures it normally would not make because, with deductions and tax credits, lower taxes are owed to the government.

While both SB 192 and HB 110 provide changes to progressivity, HB 110 makes far more dramatic changes to the current tax structure in regard to the progressivity rate. In addition, HB 110 establishes a bracketed progressivity system.

CSSB 192(RES)

- The progressivity rate is capped at 35% for a total production tax rate of 60% (25% base tax plus 35% progressivity).
- Changes the rate of increase from 0.4% to 0.35% for each dollar per barrel of net value increase above $30 up to $101.43.
- When the net value is above $101.43, the rate of increase drops to 0.1% per dollar of net value.
- The base tax plus progressivity still applies to the entire net value, not just the additional value (no bracketing).

[22] Senate Resource Committee Minutes, March 1, 2012.

- The estimated reduction to government take (the percentage of profit paid to the government after costs are deducted) at high oil prices is approximately $200 to $250 million per year.

CSHB 110(FIN)

- For producing fields, the progressivity rate is capped at 25% for a total production tax rate of 50% (25% base tax plus 25% progressivity).

- For fields not within a unit or in commercial production as of December 31, 2008, the progressivity rate is capped at 25% for a total production tax rate of 40% (15% base tax plus 25%).

- Establishes a bracketed progressivity system where the applicable progressivity rate applies only to the production tax value that falls within the incremental rate.

- Provides two bracketing systems, one for currently producing fields, and one for fields not within a unit or in commercial production as of December 31, 2008.

- For producing fields, the bracketing structure establishes the following progressivity tax rates:

  25.0% for each barrel with a production tax value (PTV) of $0 to $30
  27.5% for each barrel with a PTV between $30 and $42.50 (25% + 2.5%)
  32.5% for each barrel with a PTV between $42.50 and $55.00 (25% + 7.5%)
  37.5% for each barrel with a PTV between $55.00 and $67.50 (25% + 12.5%)
  42.5% for each barrel with a PTV between $67.50 and $80.00 (25% + 17.5%)
  47.5% for each barrel with a PTV between $80.00 and $92.50 (25% + 22.5%)
  50.0% for each barrel with a PTV over $92.50 (25% + 25%)

- For all other fields, the bracketing structure establishes the following progressivity tax rates:

  15.0% for each barrel with a PTV of $0 to $30 (base tax rate)
  17.5% for each barrel with a PTV between $30 and $42.50 (15% + 2.5%)
  22.5% for each barrel with a PTV between $42.50 and $55.00 (15% + 7.5%)
  27.5% for each barrel with a PTV between $55.00 and $67.50 (15% + 12.5%)
  32.5% for each barrel with a PTV between $67.50 and $80.00 (15% + 17.5%)
  37.5% for each barrel with a PTV between $80.00 and $92.50 (15% + 22.5%)
  40.0% for each barrel with a PTV over $92.50 (15% + 25%)

- The estimated reduction to government take at high oil prices is approximately $2 billion per year.

Deductible Lease Expenditures

Current Tax System

The production tax value of oil and gas is determined by subtracting from the gross value the deductible lease expenditures. Deductible lease expenditures are the ordinary and necessary costs incurred upstream of the point of production for exploring for, developing, or producing oil or gas deposits. Costs must be direct costs, and include overhead expenses. An activity need not be physically located on, near, or within the premises of a lease or property for the cost of the activity to be a deductible lease expenditure.[23]

AS 43.55.165(e) describes the costs that are not deductible for purposes of determining the production tax value. Non-deductible costs include, royalty and net income tax payments, costs incurred for deferred maintenance under specified conditions, violations of law, abandonment costs, and costs to construct, acquire or operate a refinery or topping plant.

Discussion

The Department of Revenue (DOR) adopted regulations in 2010 that further define deductible lease expenditures. As of February 2012, the department was continuing development of various expenditure reporting forms.

According to the 2011 Revenue Source Book, for FY 2011, a total of $4.9 billion in unaudited lease expenditures were reported by companies producing or exploring for oil and gas on the North Slope.

Neither SB 192 nor HB 110 propose any changes to deductible lease expenditure provisions.

[23] AS 43.55.165.

Tax Credits

Current Tax System

The current tax system offers several tax credit programs that reduce the amount of tax owed by a producer. Approximately $4.0 billion in tax credits have been used against companies' tax liability or purchased by the state since the net-profits tax was enacted in 2007.

The following are the credits that can be applied to the oil and gas production tax:

Qualified Capital Expenditure Credit

Tax credits are available for 20% of a producer or explorer's "qualified capital expenditures," or expenditures in connection with an exploration well. The same expenditures may qualify for both a deduction as a lease expenditure and a credit. "Qualified capital expenditures" are generally defined as lease expenditures that are incurred for geological or geophysical exploration, expenditures that are treated by the IRS as a capitalized expenditure, or intangible drilling and development costs that are deductible expenses under IRS rules. Some asset acquisition costs do not qualify for credits. Half of the available credits may be applied against the production tax in the year they are earned, with the other half applied in the following year.[24]

Tax credits are available for 40% of a producer or explorer's well related lease expenditures that are incurred outside the North Slope.[25]

An unused tax credit may be sold to other producers by applying to the department of revenue for a transferable tax credit certificate. The transferable tax credits do not expire and are endlessly transferable.[26]

The credits under this provision may not be used in conjunction with credits taken under the alternative credit for exploration in AS 43.55.025 or other tax credit programs.

Carried-Forward Annual Loss Credit

Tax credits are available for 25% of a carried-forward annual loss. Annual losses are lease expenditures that would be deductible except when the deduction would cause the net value of taxable oil and gas produced during a month to be less than zero. The total of

[24] AS 43.55.023(a).

[25] AS 43.55.023(l).

[26] AS 43.55.023(m).

these losses in a calendar year are the carry-forward annual loss for the purpose of a credit under this program.[27]

Small Producer/New Area Development Credit

A credit for new production in areas outside Cook Inlet and the North Slope (sometimes referred to as "middle-earth") is available for up to $6,000,000 per company annually. There is also a credit for small producers that produce less than 100,000 BTU (British Thermal Unit) equivalent barrels of oil or gas per day anywhere in the state. The credit is capped at $12,000,000 for producers with no more than 50,000 BTU equivalent barrels per day, and then phases out to zero when a producer reaches 100,000 BTU equivalent barrels per day. These tax credits are not transferable and may not be carried forward. The option to take the credits expires in 2016 or in the ninth year after a producer first has commercial oil or gas production before May 1, 2016, if the producer did not have production before April 1, 2006.[28]

Alternative Credit for Exploration

An oil and gas exploration credit is available as follows:

Outside of Cook Inlet:

- 40% credit for seismic costs outside an existing unit
- 30% for drilling costs greater than 25 miles from an existing unit
- 30% for pre-approved new targets greater than 3 miles from an existing well
- 40% for pre-approved new targets greater than 3 miles from a well and greater than 25 miles from an existing unit

Cook Inlet:

- 40% credit for seismic costs outside an existing unit
- 30% for drilling costs greater than 10 miles from an existing unit
- 30% for pre-approved new targets
- 40% for drilling costs that are greater than 10 miles from an existing unit and pre-approved new targets

This program expires on July 1, 2016.[29]

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[27] AS 43.55.023(b).

[28] AS 43.55.024.

[29] AS 43.55.025.

Cash Refunds

An oil and gas tax credit fund is established for the purpose of purchasing transferable tax credit certificates from small producers and explorers who have no tax liability against which to apply credits. The Department of Revenue may purchase a certificate if, among other things, the applicant's total tax liability for the year, after application of available tax credits, is zero, and the applicant's average daily production of taxable oil and gas is not more than 50,000 BTU equivalent barrels. Cash refunds are available for transferable tax credit certificates issued under AS 43.55.023, production tax credit certificates issued under 43.55.025 and for refunds claimed under the gas storage facility tax credit in AS 43.20.046. [30]

Transitional Investment Expenditure Credit

A non-transferable 20% credit is available for qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006, not to exceed 10% of the capital expenditures incurred between March 31, 2006 and January 1, 2008. This credit is only available to companies that did not have production in commercial quantities prior to January 1, 2008. Credit may not be used after December 31, 2013.[31]

Cook Inlet Jack-up Rig Credit

A credit is available for exploration expenses for the first three wells drilled by the first jack-up rig brought in to Cook Inlet. The credit is 100% of costs for the first well up to $25 million; 90% of costs for the second well up to $22.5 million; and 80% of costs for the third well up to $20 million. If an exploration well is brought into production, the operator repays 50% of the credit over ten years following production start-up.[32]

Discussion

Legislators have expressed frustration at the lack of information regarding whether tax credits are used for drilling and increasing production, or for maintenance. Much of the type of information needed to discern how tax credits are being used is either confidential, or is not currently required.

Another concern is with maintaining a balance between tax credits and any changes to the progressivity factor in order to ensure that the use of credits do not bring state revenues too low.

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[30] AS 43.55.028.

[31] AS 43.55.023(i).

[32] AS 43.55.025(a).

SB 192 makes no changes to tax credits. HB 110 increases credits for well related expenditures on the North Slope and changes how credits are claimed.

CSHB 110(FIN)

- Extends the 40% tax credit for a producer or explorer's well related lease expenditures to well expenditures incurred on North Slope leases after December 31, 2010 and before January 1, 2021.*

- Allows available capital credits to be claimed in one year, rather than splitting the credits over two years.

    - Provides that tax credit certificates will be issued as one certificate.

    - Repeals AS 43.55.023(m) since all capital credits certificates will be issued as one certificate.

* Dr. Pedro van Meurs, a consultant hired by Legislative Budget and Audit, expressed concern that the extended tax credits proposed in HB 110 could result in a situation where Alaska may pay all of the costs of a well. (Presentation to Senate Finance and Senate Resources, February 14, 2012).

How the production tax works

Step 1: Determine the gross value or the oil or gas at the point of production (subtract transportation costs from the destination sales price of the oil or gas).

Step 2: Determine the taxable net value by subtracting the qualified operating and capital costs from the gross value.

Step 3: The taxpayer owes 25% of the taxable net value.

Step 4: When oil prices are over $30, calculate the progressivity surcharge. For example, if the net value of a barrel of oil is $70, progressivity is determined as follows:

> $70 – $30 = $40
> $40 X 0.4% = 16%
> 25% base tax rate + 16% progressivity = 41% total tax rate
> 41% X $70 = $28.70 tax per barrel

Step 5: Apply the applicable tax credits against the tax due.

Minimum Tax

Current Tax System

The production tax currently has a minimum tax of not less than 4% of the gross value at the point of production when the average price for Alaska North Slope crude for sale on the West Coast during a calendar year is more than $25 per barrel. The minimum tax steps down to 3% for prices between $20 and $25; 2% between $17.50 and $20; 1% between $15 and $17.50; and zero percent when the average price is $15 or less.[33]

Discussion

Without a minimum tax (also known as a "floor"), at low oil prices, the state may not receive any tax revenues from its oil and gas resources.

Under the current minimum tax, it is possible that the state could owe money to companies at low oil prices, particularly with the application of tax credits.

SB 192 amends the minimum tax to provide more protection for the state when oil prices are low. HB 110 makes no changes to the current minimum tax.

CSSB 192(RES)

- Increases the minimum tax to 10% of the gross value of oil at the point of production for the largest producing fields (Prudhoe Bay and Kuparuk).

- Specifies that producers may not apply tax credits to reduce their production taxes below the 10% gross floor.

[33] AS 43.55.011(f).

Decoupling

Under ACES, the same tax rate applies to both oil and gas. However, because the value of oil and gas are so different, with the value for gas being significantly less than oil, once a major gas sale starts, combining the two resources has the potential to reduce the amount of revenue to the state significantly.

The reduction occurs because the progressivity factor in the current tax system is based on the producer's average monthly production tax value per BTU equivalent barrel of the taxable oil and gas above $30 dollars. BTU means "British Thermal Unit." Under AS 43.55.900(3), 6 million BTUs of gas is equivalent to one barrel of oil. This equivalency affects how progressivity is calculated. Combining the higher value oil with lower value gas lowers the total tax on oil, leading to a potentially significant reduction in state revenue. Consequently, there have been efforts in the past to create a separate tax system for oil and for gas, known as "decoupling." A decoupling bill, SB 305, passed both the House and the Senate in 2010. The governor vetoed the bill, stating that it would be a tax increase on oil and gas companies engaged in production, and it could have adversely affected gas line project discussions taking place at the time.[34]

In testimony to the Senate Finance and Resources committee, Dr. Pedro van Meurs said that combining oil and gas could result in a situation where new gas production could lead to massive losses of oil revenue. He described the situation as "the nonsensical cross subsidization of gas."

The primary argument against decoupling is the difficulty in determining whether certain capital and lease expenditures apply to oil production or to gas production (because they come out of the same well). However, in 2012 committee hearings, the DOR commissioner indicated a willingness to work with the legislature to separate the oil and gas tax structure, provided it is revenue neutral.

SB 192 includes a decoupling provision; HB 110 does not address the issue.

CSSB 192(RES)

- The progressivity surcharges for oil and Cook Inlet and in-state gas would be calculated together, but separately from gas produced for a major gas sale.
- Changes the progressivity structure to conform with the rates set forth in the legislation.
- Retains DOR's authority to adopt regulations to allocate costs between oil and gas, but adds the direction that a method based on relative BTU barrel of oil equivalents be considered.

[34] Governor Parnell Veto Letter, April 29, 2010.

Information & Implementation of a Net Profit Tax

A net production tax is inherently complex because determinations must be made regarding which expenditures may be legitimately deducted to arrive at a net production tax value. Proper implementation requires sufficient information presented in an efficient and usable format, and a sufficient number of experienced auditors to review the information for compliance with the tax requirements.

Under the current tax system, the Department of Revenue has six years after a tax return is filed to audit the producer's report and assess the amount of production tax.[35] According to DOR, audits on 2006 PPT tax filings were completed in July 2011. One of the three audits completed was challenged by a taxpayer. Tax reports filed under ACES have yet to be audited.

In 2011, a Legislative Audit report found that DOR's tax division needed improvements to make sure tax collections under the oil and gas production tax are correct. Among other deficiencies, the report found that the Tax Division was conducting audits without developing standard processes including audit plans and procedures.[36]

In 2010, a DOR report found that the department's current tax management system is antiquated and inadequate for managing the state's oil and gas tax revenues. The report further found that under the current system, DOR "cannot easily produce reports for the legislature and policy makers because the current systems prevent timely, complete, and correct extraction of data."[37]

The report highlighted the importance of an adequate level of funding for a new system, noting that with a modernized tax management system, revenue collections resulting from increased compliance could exceed the amount spent on the new system within two or three years after implementation is complete. The report estimated a project cost up to $34.7 million. The FY 2012 budget included an appropriation for $34.7 to fund a Tax Revenue Management System (TRMS). DOR is currently in the process of soliciting requests for proposals for the new system. The current timeline shows project completion by 2016.

In addition to concerns about an inadequate data system for revenue collection purposes, another concern raised during the recent production tax debate is how much information DOR collects is confidential, and how that hampers legislators ability to make reasonable decisions on the production tax. Taxpayer information is specifically excluded from the

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[35] AS 43.55.075.

[36] Division of Legislative Audit, Single Audit of the State of Alaska, February 28, 2011.

[37] Department of Revenue, Comprehensive Plan and Feasibility Study, October 2010.

public records act.[38] And AS 43.05.230(a) provides in relevant part, "It is unlawful for a current or former officer, employee, or agency of the state to divulge the amount of income or particulars set out or disclosed in a report or return made under this title . . ." The penalty for violating this section is a fine of up to $5,000 or by imprisonment for up to two years, or both.[39]

While recognizing legislators frustration with the lack of available taxpayer information as it relates to the oil and gas debate, DOR testified that the benefits of confidentiality include that it leads to better cooperation between DOR and taxpayers, fosters trust in DOR by the taxpayers, lends credibility to DOR and aids the department in obtaining information without costly litigation.[40] As a result of these benefits, and because of the severe penalties for any violations of the statutes, it appears that DOR interprets confidentiality very broadly to include almost all documents provided to the department by a taxpayer.

Concerns have also been raised regarding other oil and gas information that is or is not available to legislators, the public and companies doing business in Alaska. In a 2011 presentation to the legislature, the consulting firm of Gaffney Cline said that, when compared to other regimes, "Alaska is handicapped in its decision making by the small amount of either confidential or reliable public data on energy operations."[41]

Back in 2002, Mark Meyers, then director for the Department of Natural Resources, Division of Oil and Gas, recognized that independent oil and gas companies and newly involved major oil companies lack the data crucial for their evaluation of the North Slope and other basins, including, seismic, well log and core data. He suggested the state do all it can to assist in making data available to these companies. Among his recommendations was that the State should require that seismic data be made public 10 – 15 years after it is acquired, or require that it be made available for purchase at low cost through a brokerage system. He also suggested the state continue its effort to create a web-based system for downloading publicly available well log data.[42]

In a 2007 memorandum, Gaffney Cline provided an overview of how the acquisition, distribution and publication of oil company data are handled in other oil and gas producing regimes. The memo said that most countries stipulate the manner in which data is

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[38] AS 40.25.100(a).

[39] AS 43.05.230(f).

[40] DOR Presentation to the Senate Resources Committee, February 23, 2010.

[41] Petroleum Fiscal System Design, Gaffney Cline, Presentation to the House Resources Committee, February 11, 2011.

[42] Memorandum from Mark Meyers, Director DNR, Division of Oil and Gas to James Clark, Chief of Staff, Office of the Governor, January 2, 2002, pages 5 – 6.

transmitted to the state, and specify that the state owns all data obtained or produced as part of the petroleum operations. The publication of the acquired data varies among countries, but generally, information is designated as confidential or commercially sensitive, and depending on the nature of the data, it may be kept confidential for a period of time, usually 5 to 10 years. [43]

Current Alaska law requires that applicants for capital expenditure credits under AS 43.55.023 and exploration credits under AS 43.55.025 submit specified information to the Department of Natural Resources, including well and seismic data. The department is required to hold the information confidential for 2 to 10 years, depending on the type of data. Even after the expiration of confidentiality, data may continue to be held confidential at the discretion of the commissioner under specified circumstances.[44] It is unclear how much data is currently publicly available, or how and where it can be accessed.

To begin to address information needs for legislators, the public and companies doing business in Alaska's oil and gas basins, SB 192 adds a requirement for the creation of a Petroleum Information Management System. HB 110 does not amend or add to the existing auditing or information requirement provisions.

CSSB 192(RES)

- Establishes a Petroleum Information Management System developed and implemented by the Alaska Oil and Gas Conservation Commission (AOGCC).

- The purpose of the system is to consolidate publicly available oil and gas information with the ultimate goal of improving the administration of the oil and gas production tax, and facilitating exploration, development, and production of oil and gas resources.

- The system will include information gathered by AOGCC, DNR, DOR and the Department of Labor that is available and not confidential (the list of data for eventual inclusion in the system is from the Gaffney Cline 2007 memorandum described above).

- AOGCC is directed to develop and implement a work plan for the development of the Petroleum Information Management System so the system is operational before January 1, 2014.

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[43] Gaffney Cline Memorandum, RE: Oil and Gas Reporting and Disclosure in Selected Countries, October 19, 2007.

[44] AS 43.55.023(l)(2)(A) and AS 43.55.025(f)(2).

Section 3. The Million Barrel Objective

In March of 2011, Governor Parnell announced a goal of increasing oil production to a million barrels per day in a decade. According to the administration, the cornerstone to meeting this goal is the tax reform embodied in HB 110.

In testimony to the Senate Finance and Resources Committees on February 13 and 14, 2012, Dr. Pedro van Meurs expressed his belief that the administration's million barrel per day goal could be met by 2025. However, he also found multiple deficiencies in HB 110 for meeting that goal. The deficiencies include that the excessive tax credits may result in a situation where Alaska may pay all the costs of a well; the application of the same tax to both oil and gas could lead to massive losses of oil based revenues; and for marginal fields, the tax system creates a negative production tax. Dr. van Meurs also said that HB 110 creates new problems, including creating complexities for taxpayers and tax administration by specifying different rates for existing and new production.

In addition to the deficiencies in HB 110, Dr. van Meurs believes there are also problems with the current production tax system, including excessive tax rates, excessive price progressivity, excessive exploration support in the form of tax credits, the combination of oil and natural gas in the tax system, and that the system is overly complex.

According to Dr. van Meurs, the million barrel objective can only be met with major investments in existing light oil, new light oil, heavy oil, ultra heavy oil, and shale oil; and attracting the investment requires establishing competitive and fixed terms for all the resources, including terms for natural gas in anticipation of future gas sales. He believes that approximately $7.5 billion a year in new investment is needed to increase production.

Dr. van Meurs outlined a tax system he believed would help the state achieve the million barrel per day objective. He said that in order to be competitive, Alaska needs to develop a fiscal system that offers the following amount of government take for each resource:

- Existing light oil production 70 – 75%
- New light oil production 60 – 65%
- Heavy oil 55 – 60%
- Ultra heavy oil 45 – 55%
- Shale oil 45 – 55%
- Natural gas – new gas fields 45 – 55%
- Natural gas – Prudhoe Bay 55 – 60%

Dr. van Meurs says that his proposal creates a new "architecture" that resolves all the deficiencies associated with the current system, including offering a simpler production tax system. Recognizing that his proposal would require a major political and fiscal change, Dr. van Meurs suggested minor modifications to create a better bill than HB 110, including reducing progressivity, establishing a 20% gross revenue allowance for new oil production, and limiting tax credits to 20% on exploration and development.