Stranded Gas Hearings

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The Impact of Pipeline Costs or Tariffs on Royalty and Production Tax Payments Due the State
Mark Myers, Director, Division of Oil & Gas, Dept. of Natural Resources
Dan Dickinson, Director, Tax Division, Dept. of Revenue, June 16, 2004.

MARK MYERS, Director, Division of Oil and Gas, Department of Natural Resources, specified that he would address the impact of pipeline costs on royalty payments. He provided the committee with a copy of the slides he will present. He began by pointing out that although a producer shipping down a pipeline and a royalty owner have similar interests, in some way the two are different. Furthermore, royalties are different than taxes in that the royalties are based on the lease. Different leases have different provisions with regard to how royalties can be calculated and the allowable deductions. The lease is a contractual relationship that the legislature can't change, which is unlike taxation that the legislature can change. The lease provides some stability for all parties.

MR. MYERS explained that the state has two choices with its royalty share. The state can physically take possession of the royalty in-kind (RIK) and sell it, which the state does with much of its oil. Although the state normally takes its oil upstream and has the purchaser ship the oil, there is nothing restricting the state from selling it downstream in the market. The second choice is taking the royalty in-value (RIV), which means that it would leave [the royalty share] with the producer who would sell it and the state would receive the proceeds from that sale minus the deductions. Therefore, if RIV is chosen, the state receives from the producer the value netted back to the lease, but the state would incur the transportation costs and additional costs depending upon the language of the lease.

MR. MYERS specified that the netback equals the destination value minus the transportation as well as any field/conditioning costs. In Prudhoe Bay, the state in 1980 reached a settlement in which the state agreed to pay a certain amount for those costs. In newer formed leases, the state wouldn't incur either cost, no matter whether the royalties are RIK or RIV. However, for those leases formed prior to 1979, DO1 leases, the state wouldn't incur the costs under RIV but would be required to pay fuel costs under RIK. The aforementioned is the current view of the courts. Mr. Myers highlighted that one powerful protection the state has built into the lease is that the transportation is the actual and reasonable costs of transportation from field to market. On the oil side, the state is, on an ongoing basis, going through the process of determining whether the transportation costs are actual and reasonable through a reopener process.

MR. MYERS highlighted the bullet specifying: "Pipeline tariffs do not necessarily represent the actual and reasonable costs of pipeline transportation." He characterized pipeline tariff methodology as an art that can be done in various ways because there can be a disconnect between the tariff structure and what is actual and reasonable. The tariffs are a direct reduction against the royalty value that is netted back to the lease. The page entitled "Calculation of Royalty Netback Value for ANS Gas" shows the netback the state would hypothetically receive from various fields with a destination value of $4.00. He acknowledged that $4.00 is somewhat arbitrary. The illustration also assumes that the trunk pipeline tariff from Alaska to the Chicago market is $2.00. He pointed out that the document erroneously specifies that the conditioning cost for Prudhoe Bay would be $.20. The conditioning cost for Prudhoe Bay should be $.40 and the field cost should be $.20. Therefore, the netback royalty value would be about $1.65 per thousand cubic feet (mcf) at $4.00. For Point Thompson, the state wouldn't pay fuel costs if it was left RIV and there would be an allowable deduction to move the gas from Point Thompson to Prudhoe Bay, and an adjustment for the quality of the gas. The result is a higher netback. The North Slope Foothills lease is an example of a modern lease in which the gas, a cleaner gas, sells for $4.00 with no BTU [British thermal unit] adjustment and fuel costs. Therefore, the netback royalty value would be less since the development costs wouldn't be incurred. He noted that this is from the royalty perspective.

MR. MYERS clarified that there are two major classes of tariffs. One class is a recourse rate, which is established by Federal Energy Regulatory Commission (FERC). The other is a negotiated rate.

Furthermore, the rates can vary depending upon the class of shippers. Although the rates can't unduly discriminate, the rates can discriminate based on certain factors. He also pointed out that firm service versus interruptible service can have different rates. The interruptible service rate is a rate that is purchased in the market if the space is available, although there is no guarantee to ship the gas. Interruptible service can be more expensive or cheaper. Pipelines that are later in life typically have a lot of excess capacity, as is the case in the Alberta system in Canada. In that case, most folks would purchase interruptible service because of its availability. However, projects in the earlier stages may not have much interruptible service, which may mean that much of it may not be available or it might come at a premium cost. Mr. Myers explained that in the rate-setting mechanism there are a number of variations. The allowed rate of return on equity can vary quite a bit depending upon the view of FERC. The cost of the debt is a big factor as is the debt equity ratio. Generally, the rate of return allowed is only allowed on that capital supplied by the pipeline company itself. Therefore, the rate of return calculation is only on the amount borrowed. How the capital is structured will be a major determinant in the rate structure, he said. The rates are also affected by the length and method of depreciation.

MR. MYERS turned to the cost of service (COS), recourse tariff, versus a levelized tariff. The COS tariff, which is a typical type that FERC would approve as a recourse rate, would start higher and decrease over time. The aforementioned occurs because as the asset depreciates there is less and less rate base in the capital, and therefore the tariff is designed to reflect that. In negotiated tariffs, it's not uncommon to negotiate a levelized tariff in which the tariff is the same throughout the entire period. With a levelized tariff, the tariff would be lower at first, but later that tariff would be higher than it would've been under a recourse rate. The different tariff types provide advantages to different parties. The state, which doesn't own the pipeline, would want a higher netback to obtain income early in the project, and therefore a levelized tariff would probably be the preferable mechanism. The gas producers under a third-party pipeline ownership would also prefer a negotiated, levelized, tariff because of the desire to receive a higher netback earlier. However, the gas producers who own the pipeline would prefer a recourse rate, COS tariff, in order to receive the maximum rate of return upfront. He reiterated that the state may prefer a levelized tariff if revenue is a priority for the state. Negotiated tariffs, which are individually negotiated with each customer, have been permitted by FERC since 1996. Negotiated tariffs can be lower or higher than a recourse tariff. In the example presented in Mr. Myers' booklet, the recourse and negotiated tariffs are approximately equal in year nine.

MR. MYERS highlighted that the COS tariff doesn't follow a nice downward trend. The COS tariff is only adjusted at points when someone approaches FERC to request [an adjustment]. In a general scenario, the initial rate would hold for an 18[-year] period and then it would drop. If two years later someone makes a rate case and it takes two years to adjudicate that case, the adjustment would start at the point of adjudication. Therefore, [the COS tariff] ends up being a stair step effect that is dependent upon how often people go before FERC and file. Generally, the shippers will pay more under the recourse rate. Mr. Myers returned to the state's perspective and recommended that in order to receive just and reasonable [transportation] it will probably be necessary to obtain a pipeline tariff settlement or the default will be a COS type tariff.

SENATOR OGAN asked if any other states have an ownership position in an oil or gas pipeline. If so, what has been the experience of those states, he asked.

MR. MYERS answered that he didn't know of any other states that have an ownership position in an oil or gas pipeline, although he did know of cases in which states have set up authorities that have helped finance a pipeline. He noted that states have taken capacity on pipelines, have bought transport, and have marketed their royalty shares down stream. He noted that Texas does the aforementioned.

SENATOR OGAN offered his understanding that Wyoming may have some sort of ownership in a pipeline recently.

DAN DICKINSON, Director, Tax Division, Department of Revenue, emphasized Mr. Myers' earlier comments that sovereign taxes are very different than the royalty, which is a contract. He turned attention to a packet of information labeled "Alaska Natural Gas Pipeline Issues," and explained that there are four major bites at the apple on the oil side and the gas side. One is royalty because most of the development has been on land that the state owns. Additionally, there is a production tax, which is based on the amount of oil and gas that's produced. There is a special income tax that applies to producers of oil and gas. Finally, there is a special oil and gas property tax. Mr. Dickinson said that he would address the production tax.

MR. DICKINSON pointed out that the legislature set the rules and can unilaterally change those rules. Currently, there is a 10 percent production tax on gas and a 12.5-15 percent production tax on oil. He noted that for the economic limit factor (ELF) for gas he will use an estimate of about 80 percent. He explained that the 10 percent is multiplied by the ELF which is multiplied by the gross value at point of production, which equals the tax. In contrast to royalty, the gross value at the point of production includes no upstream costs that are deductible. Therefore, he likened it to the newly formed leases under royalty. In order to find the gross value at the point of production, one must take the value at the destination less the actual costs of transportation. The aforementioned looks a lot like the royalty situation, although how the actual transportation costs are determined is very different.

MR. DICKINSON turned to a document entitled, "Potential Production Tax Revenue." The document uses a destination value from $2.00 to $10.00 with a tariff of $2.40 and assumes the following: 4 bcf (billion cubic feet) per day; 365.0 days per year; 87.5% non-royalty fraction; 10% tax rate; and 80% estimated ELF. Multiplying all of the assumptions together at a $6.00 destination value would result in production tax revenues of about $367 million. At a $10.00 price, the production tax revenues will be close to three-quarters of a billion a year. However, if the price was $2.00 and the tariff didn't cover the costs, the minimum of $.064 cents per mcf will kick in. Therefore, if the price drops to $2.00, the tariff would no longer be relevant and a tax would be collected based on the $.064 a barrel. The aforementioned situation results in $2.8 million minimum. The tax deduction for the tariff would be about $245.3 billion a year, except for the cases in which the tariff is larger than the destination value.

MR. DICKINSON pointed out that there will be some issues with regard to whether the tariff or some other measure would be used. The law, AS 43.55.150, specifies that [the state] would be allowed to deduct the reasonable cost of transportation of the oil or gas. Furthermore, the law specifies that the reasonable costs of transportation will be the actual costs, except under the following circumstances: when the parties of the oil or gas are affiliated; when the contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation; when the method of transportation of oil and gas is not reasonable in view of existing alternative methods of transportation. If all three criteria are met, the law specifies: "the department shall determine the reasonable cost of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods." Mr. Dickinson turned to the part of the law that specifies: "Transportation costs fixed by tariff rates properly on file with the Regulatory Commission of Alaska or other regulatory agency shall be considered prima facie reasonable". The aforementioned means that the presumption is that the filed tariff is correct, although that can be challenged by the department.

MR. DICKINSON pointed out that the legislature has the ability to set what tax is levied on the gas. He informed the committee that in 1977 the Supreme Court laid down the rules regarding what one state can do when it wants to tax the business of a corporation that has interstate business. The Supreme Court specified that in order to tax the interstate activities of a corporation, the tax can't be discriminatory; the tax must be fairly apportioned to the state; the local activities in the taxing state must establish a sufficient nexus; the tax must be fairly related to services provided by the state. Mr. Dickinson explained, "As you think about the ... tariffs, which is what this is really about, the irony is you could probably set up a scheme that treated Alaska and looked at the Alaskan tariff as something that you could ignore ... whereas you're going to have to take [into] account the tariffs that are paid further downstream."

MR. DICKINSON informed the committees that Alberta, Canada, has a tax that's 1 percent of the gross receipts or 25 percent of the net receipts. In other words, all the cost deductions of a project are allowed and after all the costs are deducted there is a 25 percent tax. However, if the gross receipts are higher, then that's taxed instead. Therefore, the tariffs, the other deductible costs, become irrelevant to that calculation. Mr. Dickinson highlighted the difference between an allowance and a deduction. In conclusion, Mr. Dickinson turned to the Stranded Gas Act and explained that "we're" trying to create a contract which will be used to effect the sovereign's right to tax. The companies have expressed concern that when they develop a project with a 20-30 year time horizon, the sovereign will come in at a later year and effect the economics of the project. Therefore, the Stranded Gas Act attempts to create a situation in which the sovereign is restraining its right to tax over some time period in the hope that there will be a project to tax.

SENATOR OGAN recalled the Amerada Hess Corporation case, which was a very expensive and contentious case that resulted in the constitutional budget reserve. He asked Mr. Dickinson to review what was learned from that case.

MR. DICKINSON explained that the Amerada Hess Corporation case was specifically about royalties, although there were parallel tax cases that investigated many of the same issues. He said that case was fundamentally about value. During the time of the case there was no transparent market for oil as there is now for oil and gas. Therefore, he didn't believe there would be situations in which one huge exporter says the oil is worth $22 while the other says it's worth $35, although there will continue to be conflicts regarding the exact [amount]. The other piece [of the case] was in regard to transportation costs. In the lease that governed the royalty obligation there were no specifics, which resulted in both sides arguing that they had met the general statement of principle. From that, one can learn that it's better to determine [the specifics] beforehand, to the degree possible. One may hesitate being too specific when looking at something 10-15 years down the road because one may not know the factual situation that will be present. Mr. Dickinson opined that there will always be conflicts, although hopefully the conflicts can be $10-$30 million conflicts instead of $100 million conflicts.