April 28, 2009

The Alaska Gasline Inducement Act: Commercial Issues/Public Exposure

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THE ALASKA GASLINE INDUCEMENT ACT (AGIA):
COMMERCIAL ISSUES / PUBLIC EXPOSURE
Roger Marks

Abstract: The Alaska Gasline Inducement Act (AGIA) was enacted by the State of Alaska in 2007 to attempt to progress the construction of a natural gas pipeline from the Alaska North Slope to North American markets. The Act conveys monetary inducements from the state to the exclusive licensee in exchange for certain performance requirements. The financing of any pipeline requires the contractual commitment from the shippers (producers) to pay to ship the gas over an extended period of time. However, many of the performance requirements of AGIA are antithetical to the commercial interests of the shippers. Moreover, a flawed financial analysis of the project by the administration overstated the economic vitality of the project, and hence understated the severity of the commercial issues. Accordingly it appears unlikely that shippers will commit to the pipeline or that AGIA will result in a successful project. AGIA binds the state to significant financial obligations regardless of its outcome. Moreover, a clause in AGIA compels the state to considerably larger liabilities to the licensee if the state assists any competing project. Accordingly, the ultimate outcome of AGIA may be either substantial public expense, or the reluctance of the state to support the development of any pipeline.

1. INTRODUCTION

1.1. BACKGROUND

When oil was discovered on the Alaska North Slope at Prudhoe Bay in 1967, a very large natural gas cap was also found overlaying the oil, containing approximately 24 trillion cubic feet (tcf). Subsequent discoveries of other oil fields on the North Slope have also led to additional gas finds, the most significant of which is the Pt. Thomson field. In all, proved reserves are about 35 tcf, but geologists believe there could be much more.

Despite a flurry of producer studies and various governmental attempts/political efforts over the years, the gas has never been commercialized. The gas, however, has not sat idle. As it comes out of the ground with the oil it has been reinjected to pressurize the field and bolster oil production from the reservoir, though this benefit is diminishing over time at the Prudhoe Bay oil reservoir is drawn down.

The prospects for commercialization of this remote natural gas resource did not become financially possible until 2000, when natural gas prices increased to higher levels.
The commercial challenges are considerable. The most attractive market for the gas appears to be linking up with the North America pipeline network, reaching out from northern Alberta to serve the Pacific Northwest, Upper Midwest, Midwest industrial states and as far as upstate New York.

However, in order to capitalize on economies of scale, the pipeline would have to be very large, as well as very long. Cost estimates to the Upper Midwest vary between $30 billion and $40 billion in today’s dollars for such an endeavor, and so in addition to the construction cost and gas market risks, there is a size risk; the cost of failure would be huge. These risks have been insurmountable so far. Nevertheless, the project offers potentially much value for the producers.

It has been the dream of Alaskans to commercialize the gas as a way to extend the prosperity that oil brought to the state and its residents.

The producers have repeatedly expressed concerns about the need for fiscal stability in such a project. The Stranded Gas Development Act (SGDA) (AS 43.82), passed in 1998 under the Knowles administration (1994-2002), authorized the administration to negotiate fiscal terms through a contract that would be approved by the legislature. The contract would have provided fiscal stability but there was no consensus it was constitutional, given the constitutional prohibition against contracting away the power to tax.¹

The Murkowski administration (2002-2006) attempted to negotiate a fiscal deal with the producers under the SGDA. The deal was ultimately rejected by the legislature as not being in the state’s best interests. The issues included no commitment to build the pipeline, the amount of government fiscal take, and the duration of the fiscal stability period.

Many Alaskans have been frustrated by the failure to commercialize. Indeed, many Alaskans also feel the project is feasible, and that the producers have not proceeded because they are either holding out for fiscal concessions from the state, or are developing projects elsewhere in places where their leases will lapse if they do not develop. (The lease terms in Alaska apply to oil or gas. Producing only oil satisfies the terms, especially when gas is being used to produce the oil.) Some believe there is an implied duty-to-develop covenant that would obligate the lessees (producers) to construct or commit gas to the gas pipeline if it is minimally economic, but that is an untested and dubious legal theory in this context.

In addition, many Alaskans believe the oil development experience in Alaska was less than optimal due to producer ownership of the oil pipeline (the Trans-Alaska Pipeline [TAPS]), citing high tariffs filed by the producers that are deducted in deriving the tax and royalty basis of the oil. Moreover, despite federal law to the

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¹ Article 9, Section 1 of the Alaska Constitution: “The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article.” Nothing else in the article addresses this.
contrary, many Alaskans are concerned that a producer-owned gas pipeline would limit access to non-owners, thereby stifling new companies from exploring in Alaska.

These beliefs, namely, a) the project is currently economic, b) the TAPS experience suggests a producer-owned gas pipeline would lead to high tariffs, and c) a producer-owned pipeline would limit access to non-producers, were embraced by key resource development officials that came into power with the Palin administration in 2006.\(^2\)

Certainly there are countervailing arguments. Economic feasibility risks were discussed above. (In addition, inadequate financial analysis by the administration led it to believe third-party [non-producer] ownership would increase the rate of return to the producers, making the project more feasible than it really was. This is discussed in Section 2.)

Meanwhile the Federal Regulatory Commission (FERC) has testified repeatedly before the Alaska legislature that gas pipelines are regulated much differently than oil pipelines. FERC officials have also testified that the body of federal law has evolved since TAPS, per FERC statutes and regulations, particularly the Alaska Natural Gas Pipeline Act (ANGPA) of 2004. Because of these requirements, FERC said, a gas pipeline would have to have reasonable tariffs and could not discriminate against non-owners. But others have opined that the FERC process is often ineffectual. It is not the purpose of this paper to debate the merits of these attitudes.

It is against this background that the Alaska Gasline Inducement Act (Alaska Statute [AS] 43.90) (AGIA) was drafted and submitted to the legislature by Governor Palin, and passed in the early days of the administration. Using in part the argument that the failure of the SGDA stemmed from a lack of competition, the administration’s argument was that competition among companies for certain state inducements to build the line would move the project forward. Moreover, AGIA, its supporters say, ameliorates some of the concerns of a producer-dominated line.

### 1.2 AGIA OVERVIEW

AGIA operates as follows:

The state awards an exclusive AGIA licensee to a qualified applicant with a qualified application.

In exchange for certain performance requirements the state will reimburse a share of the licensee’s costs of a) getting to open season and b) trying to get a FERC certificate of public convenience and necessity (“certificate”) for the pipeline. In

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\(^2\) [http://www.gov.state.ak.us/agia/agia_findings.php](http://www.gov.state.ak.us/agia/agia_findings.php). The report contains many manifestations of the administration’s attitudes described here.
particular, the state will reimburse the licensee up to 50% of the costs of getting to the first open season, and up to 90% thereafter of the costs of getting to certification, up to a maximum of $500 million. The specific percentages and maximum dollar reimbursement are identified as part of the application.

The performance requirements include:

- Conclude a binding open season within 36 months of the license award.
- Apply for a FERC certificate by a certain date as established in the application.
- Advocate rolled-in rates for pipeline expansion capacity, not to exceed 15% above the base shipping rate. (This is discussed in Section 3.3.)
- If the licensee has credit support to finance construction (firm transportation commitments in the case of a third-party pipeline), sanction the project within one year after the effective date of the certificate. If the licensee does not have credit support, sanction the project before the later of a) two years after the effective date of the certificate, or b) five years after the first open season.
- In addition, there are requirements for periodic assessment of market demand, capacity expansion when warranted, capital structure limits on equity, providing for in-state gas, and local hire during construction.

There are upstream resource inducements to any shipper that signs on to the project. The royalty inducement includes provisions for determining royalty value, and modifying the notice period for the state to switch between taking its gas in-kind and in-value. The production tax inducement attempts to freeze the tax structure as it exists at the time of the open season for ten years. (This is discussed in Section 3.6.)

There are also assurances that grant exclusivity to the licensee, where the state would have to pay the licensee three times its expenditures if the state gives incentives to a competing project. (This is discussed in Section 4.)

AGIA called for the state to award the license among competing applications based on a combination of the net present value of the application to the state coupled with an assessment of its probability of success. AGIA passed the legislature in May 2007. In August 2008 the state awarded the license to the TransCanada Corporation after receipt of five applications, four of which did not meet all the stipulated terms.³ Per TransCanada’s application the state will reimburse them at the maximum AGIA dollar amount of $500 million and maximum reimbursement rates of 50% before open season and 90% after.

### 1.3 SUMMARY

³ The unsuccessful applicants were the Alaska Gasline Port Authority, the Alaska Natural Gas Development Authority, Little Susitna/Sinopec, and Aenergia.
As will be explained in Section 3, with any pipeline, without the commitments of the producers to ship their gas the pipeline cannot get financing, and will not be built.

Accordingly, AGIA cannot work to get a pipeline built without the producers committing gas to it. But there are some very significant commercial problems with AGIA that make it unlikely producers will commit gas, and unlikely that AGIA will ever lead to a pipeline.

AGIA was in part a reaction to the SGDA negotiations with the producers under the prior administration. The idea was to open the process up to competition. But what for?

The successful licensee receives $500 million from the state out of a $30 billion-plus project in exchange for certain efforts to try to move the pipeline forward. Most of these efforts require expenditure of money which will become part of the tariff charged by the license. Thus many of these efforts ultimately involve spending the proverbial “other peoples’ money.” In this case it’s the producers’ money, contributing to the likelihood of a failed process. Perhaps that explains the outcome of only one serious proposal received.

AGIA was also in part a reaction to the administration’s belief that the project is very economically viable. Yet, as will be shown, the administration analysis overstated the feasibility of a third-party pipeline relative to a producer-owned one. This impression may have led them to understate commercial necessities.

Perhaps the administration and legislature ignored these issues. Perhaps they were unaware of them. Perhaps something else. The purpose here is not to ascribe motive.

Moreover, AGIA commits the state to spending considerable sums, even as it fails. Further, even if AGIA fails, it exposes the state to considerable additional financial risk by either compromising a competing project, or forcing the state to pay huge sums to the licensee if the state later supports another project.

Section 2 of this paper is a critique of the reasoning the administration used to conclude a third-party pipeline would give producers a higher rate of return, making the project more economic. This was also used to promote the legislative passage of AGIA.

Section 3 discusses commercial problems with AGIA. These problems suggest why upstream producers will be unlikely to commit gas to an AGIA licensee, and subsequently why it is unlikely to produce a project. It also explains why none of them submitted an AGIA application. There is particular focus on the issues of inadequate preparation for the open season, rolled-in rates, the role of the Alberta Hub in TransCanada’s application, misalignment of interests, and the problem of procuring a FERC certificate without financial commitments.
Section 4 discusses the additional financial risks (the “triple damages clause”) that AGIA presents to the state if it fails to produce a project,

Section 5 summarizes conclusions.

2. PREAMBLE: OVERSTAYING THE ECONOMICS

2.1 INTRODUCTION

In examining the prospects of an Alaska natural gas pipeline, one of many issues of interest is the issue of a producer-owned vs. a third-party owned pipeline.

From the point of view of the producers, engaging a third-party to build the pipeline would simply be a financial decision; it does not affect the fundamental economics of the project. “Financial” means the mechanism for obtaining the funds to construct the project. “Economic” means the risk/reward balance inherent in the project.

However, in an April 11, 2007, presentation to the Senate Judiciary Committee of the Alaska Legislature, the Palin administration submitted the following internal rate of return (IRR) results in advocating for a third-party pipeline:4

<table>
<thead>
<tr>
<th>Price ($/mmbtu)</th>
<th>Producer-Owned</th>
<th>Third-Party Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3.50</td>
<td>12.6%</td>
<td>29.8%</td>
</tr>
<tr>
<td>$8.50</td>
<td>23.9%</td>
<td>95.6%</td>
</tr>
</tbody>
</table>

The third-party pipeline had a higher rate of return at a $3.50/mmbtu price than the producer-owned pipeline had at an $8.50/mmbtu price. These were presented as a straight “apples-to-apples” comparison. We will examine the veracity of these results.

A firm transportation (“FT”) commitment to a third-party pipeline company is simply one of many financing options available to the producers. Although the differences between a producer and third-party line may involve some issues of public interest, the economic difference to the resource owner (producer) is insubstantial.

The fundamental economic essence of an enterprise, i.e., that which establishes the risk/reward balance, consists of the costs to create it and the revenues it brings in; it lies outside of how it is financed. An FT commitment is a form of leverage (debt), which necessarily involves financing transactions, particularly the re-shuffling of the

4 http://www.gov.state.ak.us/agia/ : “Analysis of Producer Returns, Investment Attractiveness and Fiscal Certainty” (4/18/07)
timing of cash outlays, and the repayment of the obligation. Generally, companies run economics and make decisions based on the inherent, or unleveraged economics, and then figure out how to finance the projects they want to go ahead with. This creates a clearer picture of the activity, and allows them to compare all their opportunities on an “apples-to-apples” basis.

It is not impossible to run the economics with leverage. A leveraged approach will generally increase rates of return. However, debt and equity are much different, and the standard for performance (hurdle rate) under leverage will also increase, as well. Accordingly, one must exercise great care in comparing the results of leveraged and unleveraged analyses. In fact, the complexities involved in making the results comparable are one reason why all projects are run without leverage.

### 2.2 THE NATURE OF FT COMMITMENTS

Prospective owners of natural gas pipelines can only get financing to build the pipeline if the shippers (the owners of the gas moving through the pipeline) make long-term commitments to the carrier (pipeline owner) to pay the tariff to ship a fixed amount of gas regardless of the price of gas or whether there are sufficient gas reserves to fill the pipe for the term of the commitment. They pay regardless of whether they ship gas. The shippers, therefore, take the risk of low gas prices and the risk that future gas reserves will be inadequate to keep the line full. Regardless, the shipper has to pay the pipeline’s costs. Such commitments are also necessary to get a FERC certificate to build the pipeline. These are called Firm Transportation (FT) commitments, and generally have a term of 15-25 years, or longer.

The fixed commitments can be used by the pipeline company as collateral for borrowing money to build the line. In the case of producer-owned pipelines, the upstream producing affiliate makes the commitment to the downstream pipeline affiliate.

These commitments are considered liabilities, or debt. Liabilities are defined as “probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide service to other entities in the future as a result of past transactions or events.”

In the case of a third-party pipeline, the tariff itself represents the shippers’ repayment of the principal and interest on the pipeline owner’s obligation (plus operating expenses). The commitment is in essence like borrowing 100% of the costs for the capacity the FT supports, with the tariff being the principal and interest payments. The pipeline company (the lender) has priority claims to project cash flows to recover the tariff, much like any creditor in a debt arrangement.

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The FT commitments show up as liabilities in the producers’ financial statements under the category of “purchase obligations”. The Security and Exchange Commission (SEC) definition of purchase obligation is “an agreement to purchase goods or services that is enforceable and legally binding on the registrant and that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction.”

An FT commitment from the producers to a third-party pipeline transfers substantially all of the benefits and risks incident to pipeline ownership to the producers, so that the economic effect on them is similar to ownership.

In terms of how to look at a long-term purchase obligation economically, the following is from the standard Brealey and Myers finance textbook addressing the general treatment of financial leases:

From an economic point of view, you might say that the user is the real owner, because in a financial lease, the user faces the risks and receives the rewards of ownership. (The lessee) cannot cancel a financial lease. If the (asset) turns out to be hopelessly costly and unsuited for (the lessee’s purposes), that is (the lessee’s) problem, not the lessor’s. If it turns out to be a great success, the profit goes to (the lessee), not the lessor. The success or failure of the firm’s business operations does not depend on whether the (assets) are financed by leasing or some other financial instrument.

In this situation the user, or shipper, is the lessee, the pipeline company is the lessor, and the FT commitment is the financial lease.

The source of capital for the project is the liability of the party making the commitment to pay to ship the gas.

The rationale for either building the pipeline yourself or having someone else do it depends on other non-economic factors. For instance, the producers maintain that they have a greater incentive to keep costs down because they are ultimately paying the tariff. (Producers lose money on cost overruns; pipeline companies make money by earning more return on the equity portion of the additional costs.)

On the other hand, a third-party pipeline may provide the transfer of maintenance and administrative burdens from the producers, a differential tax status such that one party can utilize tax shields more efficiently, avoidance of capital expenditure controls, or the preservation of capital.

6 http://www.sec.gov/rules/final/33-8182.htm
Economic analysis can measure many things. One very important thing to measure is whether the project can pay back investors.

This is measured through net (after-tax) cash flows. Net cash flows are the residual amounts that remain when you start with gross revenues and subtract capital costs, operating costs, and taxes. Usually large amounts of capital are laid out before sales commence, and net cash flows are initially negative for a period of time.

Because of the time value of money, cash flows that happen sooner are more important than cash flows that happen later.

Whether projects can pay back investors is measured by the internal rate of return (IRR). The IRR is that discount rate which yields a net present value of zero for the net cash flows of a project.\(^8\)

Projects need money. It comes in the form of equity from shareholders and debt from creditors. For projects to be viable, they have to demonstrate that they can pay contributors a return for their money commensurate with the risk of the project. This is done with the IRR analysis.

In an unleveraged cash flow (no debt), which represents the inherent economic costs and revenues, there are no explicit debt (interest) payments. Thus the after-tax net cash flow can go to pay off the creditors (debt) and shareholders (equity). (A producer-owned pipeline paid for with their cash would be an example.)

The weighted average cost of capital (WACC) is the percentage of capital that is debt multiplied by the cost of debt, plus the percentage of capital that is equity multiplied by the cost of equity. For instance, if there is 70% debt at a cost of 5%, and 30% equity at a cost of 20%, the weighted average cost of capital is 9.5%:

\[
\begin{align*}
\text{Debt:} & \quad 0.70 \times 0.05 = 0.035 \\
\text{Equity:} & \quad 0.30 \times 0.20 = 0.060 \\
& \quad 0.095
\end{align*}
\]

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8 Discounting is the process of finding the net present value of an amount of future cash, forming the basis of time value of money calculations. The net present (discounted) value of a cash flow is determined by reducing its value by the appropriate discount rate, a fixed annual percentage, for each unit of time between when the cash flow is to be valued to the time of the actual cash flow. The IRR can be calculated with a simple function on Excel.
Equity will command a higher rate of return because it is more risky. Debt creditors are paid off first; if there is insufficient capital the equity contributors risk not getting paid.

That WACC is what the IRR has to exceed to show the project can pay off both the debt and equity investors for the money it is using. This is also known as the *hurdle rate*.

Table 1 illustrates a simple net cash flow. A project consists of three years of capital spending (capex) of $1,000 each year, followed by seven years of commercial activity. Each year, 25 units are sold at a price of $32, for gross revenues of $800 each year. Operating costs (opex) is $200 each year. Taxes are ignored here. The net cash flow is $600 each year when operational. The IRR is 7%. Since the IRR is less than the WACC the project is not viable.

<table>
<thead>
<tr>
<th>Year</th>
<th>CAPEX</th>
<th>Units</th>
<th>Price/ Unit</th>
<th>Gross Revenue</th>
<th>OPX</th>
<th>Net Cash Flow</th>
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**TABLE 1**

**UNLEVERAGED CASH FLOW**

<table>
<thead>
<tr>
<th>Year</th>
<th>CAPEX</th>
<th>Units</th>
<th>Price/ Unit</th>
<th>Gross Revenue</th>
<th>OPX</th>
<th>Net Cash Flow</th>
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</table>

**IRR** 7%

### 2.4 PARTIALLY LEVERAGED CASH FLOWS

Companies have a capital structure comprised of debt and equity. In general, their projects will be financed similarly to the overall corporate structure. However, as previously described, companies will make decisions based on the economics, without leverage, and then figure out how to finance the projects they want to go ahead with. Accordingly, they do not run the economics with leveraging; they run
them unleveraged. This allows them to compare all their opportunities on an apples-to-apples basis, with all projects having the same hurdle rate.\footnote{Assuming the same business risk between all projects. Projects with higher risk will have higher hurdle rates and projects with lower risk will have lower hurdle rates.}

Nevertheless, it is not impossible to run the economics with leverage. The IRR from leveraged cash flows will most always be higher than unleveraged. In an unleveraged cash flow, the high capital costs are laid out up front. In a leveraged cash flow these are exchanged for the later principal and interest payments. Costs that occur early count more on a net present value basis (at a given discount rate). Since the WACC is higher than the cost of debt, deferring the payments increases the rate of return.

(This is why borrowing is referred to as “leverage.” The classic example is putting 5\% down on a $100,000 house that appreciates 5\% right after the purchase: a 100\% return. While leveraging can vastly elevate the rate of return if events turn out favorably, it can send it plummeting if it does not. This is shown below.)

However, debt and equity are much different, and the standard for performance under leverage will also increase, as well. Accordingly, one must exercise great care in comparing the results of leveraged and unleveraged analyses. (In fact, the complexities involved in making the results comparable are one reason why all projects are run without leverage.)

This is shown in Table 2, which shows a partially leveraged cash flow consistent with the 9.5\% WACC above. When the cash flows are computed with leverage, the principal and interest payments are explicitly expended.\footnote{In the fully leveraged cash flows discussed below, the tariff payment would be an example of the explicit expenditure for principle and interest.} Note the “Principal & Interest Repayment” column.

Relative to the unleveraged cash flows, the IRR has, quite expectedly, increased from 7\% to 10\%.

At this point one could, naively, without any adjustments, conclude that leveraging has improved the project. However, since the payments to the creditors are explicitly included, all the after-tax net cash flows go purely to paying off equity. Therefore, the hurdle rate is no longer the WACC, but the cost of equity. And as we said above, the cost of equity will be higher than the WACC. Thus while the IRR has gone up, the hurdle rate has also gone up. In this example the hurdle rate would be the cost of equity, 20\%. Thus the IRR is still below the hurdle rate.

Therefore, leveraged cash flows cannot be simply compared with unleveraged cash flows because they reflect different considerations and have different standards of acceptability (hurdle rate).
A third-party pipeline represents 100% leverage to the producers (as opposed to 70% leverage if there is 70% debt and 30% equity). The tariff payment includes the repayment of the principal and interest on the pipeline.

How do you systematically compare the economics of a producer-owned pipeline and third-party pipeline? If you attempt to do the partially-leveraged approach with the adjustments described above, but on full leverage, the results are absurd. With full leverage there are no up-front payments. Because there is no capital for there to be a return on, the IRR will be infinity.

Let’s look at North Slope gas. Let’s assume all the gas is coming from Prudhoe Bay, and there are no upstream costs involved in commercializing the gas. Let’s assume the price of gas in Chicago is $5/mmbtu, and the tariff is $3/mmbtu. The tariff represents the recovery of all the principal and interest to construct the pipeline. The passive modeling of cash flows on this basis would yield an IRR of infinity to the producers.

On the administration’s presentation cited above the third-party pipeline had a higher rate of return at a $3.50/mmbtu price than the producer-owned pipeline had at an $8.50/mmbtu price. The reason the rates were not infinity under the third-party pipeline is because the modeling included some upstream development costs for Pt.

### Table 2

**PARTIALLY LEVERAGED CASH FLOW**

<table>
<thead>
<tr>
<th>Year</th>
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**IRR** 10%
Thomson. But if only Prudhoe Bay had been involved, this approach would have yielded an IRR of infinity for the third-party pipeline.

Was this an apples-to-apples comparison of two approaches that are economically the same? When one reflects on the similarity in the economic risk/reward balance between the two structures, no objective measure of economic performance could produce such drastically different results.\footnote{The same administration presentation had an equally distorted comparison of the profitability ratios, for the same reason.}

The IRR is infinity, but what is the hurdle rate?

In both prior examples (leveraged and partially leveraged) the WACC was 9.5%, even though the hurdle rate shifted from the WACC in the unleveraged example to the cost of equity in the partially leveraged example. It is a fundamental principle of finance that the WACC is unaffected by the debt/equity ratio. When more debt is incurred, the equity is at greater risk, which increases its cost. This is called the “Modigliani-Miller” principle, named after the two University of Chicago economists who proved it.\footnote{Franco Modigliani and Merton Miller later awarded the Nobel Prize in Economics 1985 and 1990, respectively. Later work by them established that depending on the relative tax rates between investors and the corporation, and on bankruptcy costs, among other things, the WACC may not be completely unaffected by the capital structure. However, directionally, the cost of equity will incontroversibly increase as there is more debt.}

Suppose you want to model the economics of using a third-party pipeline at face value, simply using the cash flows of the tariff payments (essentially treating them like operating costs) with no adjustments to the hurdle rate. It is 100% debt with the principal and interest payment embedded in the tariff. And again, let’s assume the interest rate in the tariff is 5%. And since the WACC should still be 9.5%, what has to happen to the cost of equity to yield the same 9.5% WACC is this:

\[
\text{WACC} = (\text{Pct debt} \times \text{cost of debt}) + (\text{Pct equity} \times \text{cost of equity})
\]

9.5\% \quad = (100\% \times .05) + (0\% \times x)

\(x\) is infinity, or undefined. Said another way, since there is 100% debt, there is no equity for the cash flows to go to. Since the hurdle rate is the cost of equity, and there is no equity, there is no hurdle rate. Thus while the IRR is infinity, so is the hurdle rate.

This administration used this same approach in calculating net present values (NPV) for the producer-owned and third-party pipelines. They used the WACC for the discount rate. The discount rate for NPV analysis should be the hurdle rate. Accordingly, they should have used the higher cost of equity for the discount rate. The results were a systematic overstatement of the NPVs for third-party pipelines, and an exaggerated depiction of the benefits of AGIA.
After the administration obtained passage of AGIA it used this same approach for calculating IRRs and NPVs for advocating the award of the license to TransCanada.

These analytical problems are but one manifestation of the failure to come to terms with commercial realities. The following is from the Administration’s Findings and Determinations:

A lessee’s internal hurdle rate, however, is irrelevant to the duty to produce and sell gas from leased state lands. So long as participation in the Project would provide the Major North Slope Producers the ability to earn a reasonable profit, they must provide assurances to support the Project—or unequivocally commit to some other means of commercializing the gas—regardless whether those profits would surpass their internally set hurdle rates.¹³

It is disturbing that whereas surpassing the hurdle rate is necessary to pay back investors for the use of their money, the administration sees a profit less than that as commercially acceptable.

There is an old adage in finance that you cannot make a bad project good by borrowing money. AGIA was in part a reaction to the administration’s belief that the increased rate of return made the project unquestionably economic, and why they championed a third-party pipeline. It may also explain why they may have understated what are serious commercial defects in AGIA.

3. COMMERCIAL PROBLEMS

3.1 INTRODUCTION

The Alaska Gasline Inducement Act (AGIA) gives an exclusive license to TransCanada to receive certain benefits from the state in exchange for the company taking certain steps toward getting a FERC license.

There are two major steps prior to constructing any gas pipeline. First, there is an open season, where firm contractual commitments are made by gas producers (or others, such as utilities) to pay to ship the gas over a long time period. These commitments allow the pipeline to get financing. Second, the pipeline owner needs to obtain a FERC certificate.

Without the commitments of the producers to ship their gas, the Alaska pipeline cannot get financing, and will not be built.

¹³ http://www.gov.state.ak.us/agia/pdf/findings/07-Chapter%203-2.pdf:: p.3-154
Under AGIA, TransCanada has to conduct an open season within three years of license award (late 2008), and then try to obtain a FERC certificate within five years. In exchange for this the state will contribute $500 million toward these activities.

It is very likely TransCanada will be unsuccessful at both these tasks. The previous section demonstrated how the administration believed the project was more economic than it really was. In addition, many of the AGIA provisions run counter to sound commercial arrangements that the parties financing the pipeline will need.

Moreover, the analytical framework established in AGIA only requires the administration to compare the NPVs of competing applications. The administration never systematically compared the AGIA project to a third-party pipeline. Whether the producer-owned pipeline is preferable to the producers such that they would shun AGIA was never examined.

### 3.2 INADEQUATE PREPARATION FOR OPEN SEASON

The open season documents contain an estimate of what the tariff is going to be. Before an open season, a significant amount of front-end engineering needs to occur so that subscribers are sufficiently confident in the estimate so that they are comfortable in making the commitment to sign a contract to use the pipeline.

The relationship between spending and cost accuracy is very pronounced. The Association for the Advancement of Cost Engineering (AACE) classification methodology depicts the relationship between level of project definition, expected accuracy range, and preparation effort.\(^\text{14}\) At the lowest level of project definition, the screening phase, the degree of cost accuracy is +200%/−100%. The final cost estimate prior to the commencement of construction will have an expected accuracy range of +10%/−5%. The difference in preparation effort in terms of spending between the two stages is a minimum of ten-fold up to one-hundred-fold.

It is generally recognized that for a project of this magnitude there should be a considerable amount of spending to get to a sufficient open season. For an idea of what these costs should be, we can look to the IPA Institute (a division of Independent Project Analysis, Inc.). They conduct a course given around the world (“Successful Megaprojects”) whichchronicles practices that cause large projects to succeed or fail, as measured by cost control, adherence to schedule, and quality of the end product. IPA stresses how early project definition is essential for success, and the spending that needs to occur commensurate with different stages of development.

IPA has segregated the front-end loading of costs into three phases:

\(^{14}\) AACE International Recommended Practice No. 17R-97: Cost Estimation Classification System: TCM Framework 7.3 – Cost Estimating and Budgeting
1) Business Planning – Validate the business opportunity and select the alternatives that will be analyzed in the next phase. Minimum level of expenditure (0.5% of total installed cost).
2) Facility Planning – Study identified options and narrow the project to one option, refine premises, update project economics, and begin project definition. Moderate level of expenditure (1.5% of total installed cost).
3) Project Planning – Develop detailed scope, execution plan, and cost estimate for the alternative selection in the Facility Planning phase. Higher level of expenditure (3% to 5% of total installed cost).

The level of detail necessary for an open season would be at least at the facility planning level, and justifiably higher. TransCanada’s 2008 construction cost estimate was $26 billion to Alberta\(^\text{15}\). So at a facility planning level, 1.5% would equate to $390 million. This is nearly five times what TransCanada is proposing.

The Denali project announced it plans to spend $625 million to get to open season.\(^\text{16}\)

Yet TransCanada is only going to spend $83 million to get to an open season.\(^\text{17}\)

Why? Because under AGIA the state will reimburse TransCanada for 50% of the costs before open season and 90% of the costs after. The AGIA structure motivates the licensee to do a scant job of engineering, back-end loading its costs to the 90% reimbursement period. Thus the cost estimate for open season will be inadequate, which will likely result in no significant commitments.

**3.3 ROLLED-IN TARIFF RATES**

Under AGIA, if expansion capacity in the pipeline has a higher tariff than the base capacity, the licensee must advocate rolled-in tariff rate treatment before FERC, where the costs of the base and expansion capacity are combined and averaged in a single tariff, not to exceed 15% above the base shipping rate.

Ordinarily under FERC rules if there is a pipeline expansion, and the new capacity is more expensive on a per-unit basis than the base capacity, the shippers on the additional capacity pay the difference. This makes perfect sense. Otherwise, the base shippers are subsidizing the expansion shippers. FERC recognizes this quite explicitly as a subsidy.

AGIA requires rolled-in rates, which means the additional costs are spread among everyone. The administration’s intent is that this would help encourage exploration

\(^{15}\) TransCanada’s application at: [http://www.gov.state.ak.us/agia/](http://www.gov.state.ak.us/agia/) (page 2.5-2). The aforementioned higher cost estimates were to the Upper Midwest. In general, the market value of gas in Alberta is the Upper Midwest price less the transportation differential.

\(^{16}\) Press release April 8, 2008.

\(^{17}\) TransCanada’s application at: [http://www.gov.state.ak.us/agia/](http://www.gov.state.ak.us/agia/) (page 2.11-1)
by having the base shippers help pay for new capacity.

TransCanada’s levelized tariff estimate for the Alaska portion of the pipeline is $1.03/mmbtu to Alberta.\textsuperscript{18} Thus the rolled-in rates could increase tariffs to base shippers by 15 cents/mmbtu (in 2007 dollars). To qualify for the AGIA upstream tax/royalty resource inducements the producers must agree not to oppose the rolled-in rate treatment.

The producers, or any initial shipper, will most likely never agree to this as an unfair and unreasonable subsidy of the expansion shippers at their expense. This is another reason why the current North Slope producers are unlikely to commit gas to an AGIA project, and why AGIA will fail to result in the construction of the pipeline.

Of course this is the reason why a pipeline company like TransCanada, and not a producer, could easily abide by the AGIA terms. They won’t be subsidizing the expansion shippers; the producers will. TransCanada is spending other peoples’ money.

However, even if it was desirable to have the producers subsidize explorers, there are some very important reasons why rolled-in rates should give the state pause.

First, rolled-in rates will encourage explorers to postpone exploration, so as not to commit gas at the first open season. Because their expansion capacity could be subsidized, they can afford to sit back and wait and see whether the pipeline has cost overruns, and how gas markets look down the road. If the pipeline turns out to be expensive, or gas markets falter, they can simply explore elsewhere in the world and avoid the project. But if things turn out good, they can explore and commit later knowing they won’t be penalized for waiting. The rolled-in rates create a value to delaying commitment. In essence, the producers will be absorbing the explorers’ exploration risk, with the result being deferred exploration and possibly a smaller base pipeline with higher tariffs, which reduces the value of the project.

Second, by having producers subsidize explorers, there is a transfer of value from the producers to the explorers. Under the state’s production tax, the progressivity component is based on a company’s statewide net per Btu value. The subsidy will shift value from the higher-tax companies to the lower-tax companies, with a resulting reduction in state production tax revenues.

Moreover, much of Alaska’s potential gas resources are on the federal outer continental shelf (OCS), for which the state receives no production tax and reduced or no royalties. The transfer of value from state to federal gas in the years ahead could induce a decline in state production tax and royalty receipts.

\textsuperscript{18} TransCanada’s application at:  http://www.gov.state.ak.us/agia/ (page 2.10-4)
3.4 Alberta Hub

Under TransCanada’s AGIA application the pipeline will bring Alaska gas into the Alberta Hub.\(^{19}\) The Hub is a series of pipelines within Alberta that transfer gas from one part of Alberta to another, where it can go on into existing pipelines to other North American markets. This was not a requirement of AGIA; it was part of TransCanada’s proposal. It is adopted by reference into their license.

TransCanada owns the Hub. It costs about 24 cents/mmbtu for shippers to put gas into the Hub, which devalues the Alaska gas.\(^{20}\) TransCanada will make lots of money off this. TransCanada also owns the pipes going out of the Hub, where it would also make money. The reduction of 24 cents/mmbtu in value to the producers and state would not be insignificant.

Bringing gas into the Hub may make sense if there is existing capacity in the pipelines exiting from the Hub and those pipelines go to the desired market. Gas production from Western Canada has been declining over the past few years, which may free up capacity in existing pipelines.

However, there are reasons it may not make sense to go into the Hub, particularly if there is insufficient capacity in these existing pipes. Rising gas prices have caused unconventional gas production (shale gas, coal bed methane) to explode in recent years. In the last 10 years unconventional gas production in the Lower 48 has increased by 3 trillion cubic feet per year, or two North Slopes. In the next ten years the Department of Energy forecasts it will increase another 3 trillion cubic feet annually, again another two North Slopes.\(^{21}\)

And there is good reason to think this will also happen in Western Canada. The gas shale potential of Western Canada is enormous. Apache, Encana, EOG and Nexen have announced estimated recoverable gas resources amounting to 24 to 37 tcf combined in the Horn River Basin of British Columbia.\(^{22}\) The Beaverhill Lake area in Alberta also has vast potential. This shale gas could absorb all the existing pipeline capacity out of Canada.

If all or most of the gas is going to the Upper Midwest, and it makes sense to bypass the Hub completely because there is not sufficient existing pipeline capacity out of Alberta to the desired market, there may be a need for a new dedicated line to Chicago, or use of existing capacity not owned by TransCanada, such as the Alliance Pipeline. But if it makes sense for the gas to bypass the Hub, it cannot be done under AGIA.

\(^{19}\) TransCanada’s application at: [http://www.gov.state.ak.us/agia/](http://www.gov.state.ak.us/agia/) (page 2.1-10)
\(^{20}\) TransCanada’s application at: [http://www.gov.state.ak.us/agia/](http://www.gov.state.ak.us/agia/) (page 2.10-4)
\(^{22}\) [http://www.woodmacresearch.com/content/portal/corp/resources/BritishColumbiasHornRiverBasinhefutureofCanadasgas.pdf?hls=true](http://www.woodmacresearch.com/content/portal/corp/resources/BritishColumbiasHornRiverBasinhefutureofCanadasgas.pdf?hls=true)
Forecasting most things beyond the short-term is notoriously inexact. And TransCanada’s long-run supply forecast embedded in its 2008 AGIA application will be no different. It is premature to lock into one forecasted future where many others are plausible.

This discussion of pipeline capacity provides another illustration of the perverse effects of the AGIA structure. Pipelines are initiated by producers and are built to transport a producer's gas based on where the producer wants to market the gas. Pipeline companies do not market gas, and they are not experts on marketing gas. They are passive carriers of gas to wherever producers have determined the best markets are. Producers who sell gas are the experts at marketing. What AGIA has set up is a structure where the pipeline company is determining the market.

### 3.5 MIS-ALIGNMENT OF INTERESTS

The producers ultimately pay the cost of the pipeline through the tariff. Thus they have a greater incentive to contain costs. Shippers lose money on cost overruns; carriers make money. That is why they want to build it.

Moreover, since TransCanada would only make money on the return on equity component in the tariff, they would have a greater incentive to have more equity and a higher return on it. Again, since the producers pay the bills, they would have an incentive to inject a lower cost of capital into the tariff. All this would generate a lower tariff with a producer-owned line, with higher value to the state.

### 3.6 WEAK UPSTREAM RESOURCE INDUCEMENTS

As mentioned in Section 1, AGIA provides upstream resource inducements (Section AS 43.90.320). For a producer that commits gas at the first open season, the production tax inducement freezes for ten years the tax structure for natural gas as it exists at the time of the open season.

The mechanism for effectively freezing the tax is a tax exemption equal to the difference between the tax in effect during the year and the tax as calculated under the provisions in effect at the time of the first open season.

To qualify for these inducements, the shipper must agree not to oppose the rolled-in rate treatment described above.

The tax inducement is arguably unconstitutional given the constitutional prohibition of contracting away the power of taxation, though others have opined differently.
Moreover, the original language for the inducement that would have made it a contractual commitment was removed expressly so that if the legislature wanted to change taxes within that 10-year period it could do so through a two step process: amend AGIA and change taxes. This should hardly provide any comfort to the taxpayers regarding tax stability.

### 3.7 FERC CERTIFICATION IN THE ABSENCE OF FT COMMITMENTS

Nevertheless, AGIA requires TransCanada to try to get a FERC certificate even if the open season fails. That mainly involves the environmental impact statement (EIS), permitting, and detailed engineering. TransCanada plans to spend $521 million beyond the open season to try to get the certificate, of which the state will pay 90%.\(^{23}\)

*Yet FERC has never granted a certificate for a natural gas pipeline in the absence of firm shipping commitments.* It would make no sense for them to do so, and FERC officials have said that they do not know how they could do it. It is the FT commitments themselves that demonstrate the public need underlying the certificate.

In their testimony before the legislature on June 16, 2008, J. Mark Robinson, Director, and Jeff Wright, Deputy Director, Office of Energy Projects, FERC, said:

> However, when FERC approves a project, it requires as a condition of its approval that until the contracts are acquired, that “you cannot break ground.” … We would just prefer not to be put into that position where we’re being questioned about our resource utilization for a project that doesn’t have anybody signed up to utilize that project.\(^{24}\)

Furthermore, from the minutes of the same testimony:

> Mr. Robinson answered that neither he nor Mr. Wright have a recollection of a project being authorized that did not have some portion - usually 50 [percent] or above - of firm commitments for gas transportation. … Mr. Robinson opined that it would be hard to imagine that a project of this magnitude could be constructed without having volumes under firm contract to pay for the pipe.

In the conclusion to its February 2008 report to Congress on progress made in licensing the project, FERC said in regard to AGIA:

\(^{23}\) TransCanada’s application at: [http://www.gov.state.ak.us/agia/](http://www.gov.state.ak.us/agia/) (page 2.5-2)

\(^{24}\) [http://www.legis.state.ak.us/basis/get_minutes.asp?chamb=B&date1=010181&date2=120180&session=25&Root=HB3001](http://www.legis.state.ak.us/basis/get_minutes.asp?chamb=B&date1=010181&date2=120180&session=25&Root=HB3001)
Based upon the statutory finding of public need in ANGPA, any project sponsor could conceivably proceed with a pre-filing request at the Commission, conduct an open season to obtain prospective customers, and file a certificate application for an Alaskan natural gas transportation project without actual commitments for the transportation of natural gas from the North Slope. However, this would be a less than desirable situation, given the considerable expenditures of financial and human resources required to complete the permitting process. Clearly, a proposed project which is backed by firm shipper commitments to transport natural gas supplies will have a greater chance of ultimate success.

The bottom line is that TransCanada does not have to build a pipeline under AGIA, and they most likely will not. But the state will be out $500 million and get nothing in return.

In April 2008 BP and ConocoPhillips formed the Alaska Gas Pipeline LLC (the “Denali project”) to pursue development of the project. It is proceeding completely outside the AGIA process.

**4. FINANCIAL RISK TO STATE: TRIPLE DAMAGES**

We discussed above the $500 million that will be spent by the state, with potentially very limited benefit. (The state is also spending millions of dollars to administer AGIA.) However, the costs could be much more.

It should not be assumed that both the AGIA and producer efforts outside AGIA to develop a gas pipeline can proceed independently. Many people believe the producers may need some adjustment to fiscal terms in the future. However, Section AS 43.90.440 of AGIA, the license project assurances," otherwise known as the "triple damages clause," states that:

Except as otherwise provided in this chapter, the state grants a licensee assurances that the licensee has exclusive enjoyment of the inducements provided under this chapter before the commencement of commercial operations. If, before the commencement of commercial operations, the state extends to another person preferential royalty or tax treatment or grant of state money for the purpose of facilitating the construction of a competing natural gas pipeline project in this state … the licensee is entitled to payment from the state of an amount equal to three times the total amount of the expenditures incurred and paid by the licensee that are qualified expenditures for the purposes of AS 43.90.110 that the licensee incurred in developing the licensee's project before the date that the state first extended preferential treatment to another person.

In other words, down the road, even if the state believes it is necessary to enact fiscal modifications to enhance the producer project, either a) the state may be unable to do so because of the large financial penalty it would incur from the damage claim by
TransCanada under AGIA, or b) the state would incur the financial penalty itself for doing so.

And the current production tax applicable to natural gas is very unstable:

- The production tax is based on net income (market price less transportation and production costs) on a combined oil and gas basis. There is a base rate of 25%. In addition, there is a progressivity component based on the combined oil and gas per Btu value. Prior to the onset of a natural gas pipeline, the tax will be based solely on oil. Oil, on a Btu basis, has a higher market price and a lower transportation cost than gas. Thus the introduction of gas into the oil structure will most likely reduce the per Btu value of the hydrocarbons, thereby reducing the progressivity factor currently attributable solely to oil.

There are very reasonable scenarios where the mixing of the lower-value gas with the higher-value oil will completely wipe out the oil progressivity. It is likely producers will view this as significant fiscal instability and uncertainty. The Alaska public may never stand for receiving less combined production tax revenue from gas and oil pipelines than it would have received from just an oil pipeline, and that public pressure could well force another change in state taxes. The political and financial risk will need to be rectified prior to proceeding with the project.

- Moreover, the lynch-pin of the current production tax structure is to punish producers with high tax rates unless they re-invest. The progressivity structure creates one of the highest marginal tax rates in the world at higher prices. (When prices go up one dollar, the marginal tax rate is the amount of the dollar kept by government.) Qualified upstream capital expenditures receive a 20% credit. The only way to reduce the high taxes is to invest.

However, in the case of a gas pipeline, especially for Prudhoe Bay where most of the gas will come from, and whose gas production infrastructure is mostly developed, nearly all the investment will be on the downstream pipeline. (In addition, after the large capital outlays for the pipeline, there would only be limited amounts available for any upstream investment.) Because there will be only limited opportunity for significant investment tax credits at Prudhoe Bay, production taxes will remove much of the upside potential from the project. The prospect of realizing the upside is often a prime goal of developing such projects.

For gas, net values above $9/mmbtu will have marginal tax rates approaching 70%, reaching 90% at about $12/mmbtu. Albeit these are high prices, much greater upside can be obtained from projects elsewhere
in the world. This is one more reason the tax structure will need to be addressed for the project, throwing open the triple damages threat.

- The progressivity feature is triggered off a fixed marker of $30/boe net income. The marker is not indexed for inflation. Over time, general inflation will cause the progressivity feature to become increasingly aggressive.

- In addition, the producers have long advocated that some long-term fiscal stability package will also be necessary for a project of this magnitude to proceed.

Thus it should not be assumed both AGIA and the producers efforts can proceed simultaneously, and the state can just wait to see how each turns out. The AGIA process could very well create a material interference with the producer project.

And the public may also be vastly underestimating the magnitude of the triple damages. Again, per AS 43.90.440(a), the payment would be:

... three times the total amount of the expenditures incurred and paid by the licensee that are qualified expenditures for the purposes of AS 43.90.110 that the licensee incurred in developing the licensee’s project …

"Qualified expenditure" is defined in AS 43.90.110(a)(1)(C) as " ... a cost that is incurred ... by the licensee ..."

AS 43.90.110 states that " ... the state shall reimburse the licensee's qualified expenditures at the level specified in the license (50% before open season / 90% after open season)."

Qualified expenditure thus clearly means TransCanada's pre-reimbursed expenditures.

So let’s say TransCanada, as per its application, spends $625 million to try to get a FERC certificate. (The state reimburses them $500 million of this.) And then let’s say the state makes a fiscal adjustment to help another project, invoking the triple damages. It is the $625 million expended by TransCanada that is subject to the triple damages, not the $125 million they pay on net after state reimbursement. The state would owe the company $1.875 billion, plus the $500 million the state had already paid. AGIA exposes the state to significant financial risk.

In testimony supporting the license award, the administration simply displayed, with no back-up as to the meaning of the language, triple damage exposure to the state
based on net expenditures by TransCanada. There was very little other discussion of the issue. Thus there may be significant public understating of the extent of state exposure.

5. CONCLUSION

Natural gas pipelines are simply conduits for producers to get their gas to market. The producers ultimately finance and pay for the pipeline. They ultimately incur the market risk. They decide when they are comfortable proceeding.

There are legitimate commercial reasons why the major North Slope producers have yet to commercialize the resource, and there is no doubt that at best it will be a long process. There is also no doubt that AGIA does little to change the commercial landscape. When the producers are ready to build the pipeline, the financing will follow. All AGIA offers is $500 million; certainly in a $30 billion-$40 billion project it is not want of $500 million that is slowing it down. (The administration estimates the inducement reduces the tariff by 6 cents/mmbtu.)

As much as some Alaskans may want a third-party pipeline, creating additional commercial challenges ensures the process will not work. Such challenges under AGIA include what will inevitably be an inadequate cost estimate for the open season, a misalignment of interests for containing costs, the structural subsidization of explorers by base shippers, the introduction of uncertainties, and even the appropriate market itself.

Many of the Alaskans behind AGIA have long maintained that the state leases compel the producers to develop a gas pipeline. And it is no secret they see AGIA, and the eventual producer non-response to it, as a way to create evidence in some future “duty-to-perform challenge to the companies’ right to retain the leases. Surely the commercial failures of AGIA will be defense enough against that.

Finally, if only the failure of AGIA itself were the end of it, the loss of $500 million to the public treasury might only be deemed a “considerable” calamity. The ultimate public policy failure will not be the failure of AGIA. It will be the triple damages: the “poison pill” that endures. AGIA leaves the state no room for risk if it does not work. It is not unimaginable that this is what motivated TransCanada to participate: laying out $125 million for the chance to recoup $1.875 billion.

So the scenarios are either TransCanada cashes in on that bet, or the state is powerless to fiscally accommodate another project, degrading the landscape for getting any gas pipeline. Either way there is a dreadful cost to the public.

25 http://lba.legis.state.ak.us/ : Gasline Proposals: “AGIA Summary of the Commissioners’ Findings and Determinations, June 19, 2008” p. 34. The amount from triple damages displayed was $374 million, or three times the $125 million.

26 www.gov.state.ak.us/agia/agia_findings.php, p. 3-79.