The Prospect Exploration Economics

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Report prepared by

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Introduction

Recovering Alaska's North Slope natural gas resources presents to explorers many challenges, including the high cost of working on the North Slope, the distance to markets, and facility access uncertainties. AGIA includes provisions that address timely and cost-effective access to the main gas pipeline for both incumbent and new entrant explorer/shippers that seek additional pipeline space after the initial open season process has concluded. This report first addresses AGIA provisions related to the tariff effects of debt-equity capital structure. Second, it explores additional AGIA provisions regarding tariff rate treatment for pipeline expansions and their economic implications. Lastly, it considers timely pipeline access and evaluates the effects that delay avoidance could have on the explorer's risk-adjusted economics. The exploration economic model used for this analysis explicitly accounts for risk using a decision tree framework. It is described in the second part of this document.

AGIA Offers Cost-effective Pipeline Expansion Through Tariff Treatment

AGIA requires the licensee to provide timely, cost-effective pipeline access for the explorer that may not be an initial shipper in the project. Cost effective access and timeliness are critical to the economics and decision making for risky and expensive exploration ventures. In order for explorers to monetize their newly discovered gas resources in a commercially reasonable manner, timely, cost-effective market access to a natural gas pipeline is essential.

AGIA's tariff and expansion provisions ensure a competitive upstream industry and improve the chances that exploration in Alaska and related benefits to Alaskans (including long-term jobs and revenue to the state) will be optimized. They also help ensure that Alaskans' interests will be secured regardless of who owns the pipeline.

Producer-owned Pipelines Do Not Have Incentive to Provide the Benefits that AGIA Offers

The parent-company tariff incentives under a producer-owned pipeline differ from those under pipeline without producer ownership and may not be in complete alignment with the tariff minimization objectives of other stakeholders, including new entrants. AGIA provides an approach to tariff making that directly addresses problems with incentives alignment.

Low Rates: At the parent company level the tariffs are generally a mere transfer payment from one pocket to another. The parent company can benefit from having a high tariff. Such a tariff reduces royalty and tax payments to the state.[1] Accordingly, a producer owned pipeline has incentive to have tariffs that are based upon greater equity, because this reduces their payments to the state.

AGIA's requirement that rates be based on and maintain a 70/30 debt to equity capital structure was designed to counter this problem. Under AS 43.90.130(10), the AGIA licensee is required to use at least 70 percent debt to finance the project, prior to pipeline expansions. This will serve to reduce the initial (base) tariff rate for *all* shippers. The effect of capital structure significantly affects the pipeline tariff and net back value. For example, a change from a 75/25[2] to a 50/50 debt-equity ratio would raise the estimated levelized cost-of-service tariff from the North Slope to Alberta (including the GTP) during a 25-year firm transportation period from about $4.73 to $5.90 per million British thermal units (mmBtu) shipped. (Appendix G1, Section 5.7.8.5)

Rolled-in Rates: Any existing shipper would prefer that their rates – including their responsibility to donate fuel to the pipeline to power the pipeline's compressors – not go up due to the possibility of another party causing the pipeline to expand. The Major North Slope Producers, as anchor shippers on the project, will necessarily be in that position. Their position is entirely understandable, but does not best serve the state's interests in having a vibrant and competitive environment for exploration and development on the North Slope.

When a pipeline expands as a result of increased demand for capacity, the incremental cost of expansion is either (1) born fully by the new shipper that petitioned for pipeline expansion("incremental" rate treatment), or (2) averaged (i.e., "rolled-in") into the existing tariff rate and charged to both incumbent and new shippers. Incremental rate treatment involves

[1] On the Trans-Alaska Pipeline System (TAPS) oil pipeline, the producer-owners have historically charges rates that are higher than justified by the costs.
[2] TransCanada, in their application, commits to 75 percent debt financing for the initial project and 60 percent debt financing for expansions in their negotiated rate. TransCanada similarly commits to 70 percent, initial, and 60 percent, expansion, debt financing for their recourse rate.

different prices being paid for the essentially the same service – moving gas from one location to another. Rolled-in rates involve all parties paying the same rate for the same service.[3]

The rate treatment for expansions on a non-AGIA, producer-owned pipeline would likely be structured to provide maximum benefit for the incumbent shippers. Contract provisions from the SGDA proposed contract, dated May 10, 2006, confirm this. Article 8.7 of the proposed contract between the State of Alaska and the three Alaska North Slope (ANS) sponsor-group producers provided for "State-Initiated Expansion" only under conditions that would ensure that rates for such expansion capacity would not be rolled-in.

AGIA sets the requirement to pursue rolled-in rates at 115 percent of the initial rate for incumbent shippers. The 115 percent cap under AGIA strikes a balance between the expansion shippers' desire for access and the incumbent shippers' desire to not pay higher tariffs.

<u>Expansions</u>: Producer-owned Pipelines have little incentive to expand their project merely to accommodate a third party's gas. An integrated oil and gas company invests in a pipeline to monetize their high margin gas resource. They are not necessarily interested in earning a regulated rate-of-return on their pipeline investment, as is a company whose primary business involves building and operating pipelines. Simply put, for an integrated producer-pipeline owner, more pipeline assets are not a good fit to their business model. The comparison in figures 1 and 2 of return on capital employed (ROCE)[4] and return on equity (ROE) for the Major North Slope Producers and TransCanada Corporation illustrate this.

Figure 1 illustrates how the three largest gas owners on the North Slope, all large multi-national integrated oil companies, have a history of higher, albeit more volatile, ROCEs than TransCanada Corporation during the 12 year period from 1995 through 2006. The shareholders of integrated petroleum companies expect a higher rate of return than a pipeline company such as TransCanada in exchange for risk associated with the more volatile returns seen from integrated petroleum companies.

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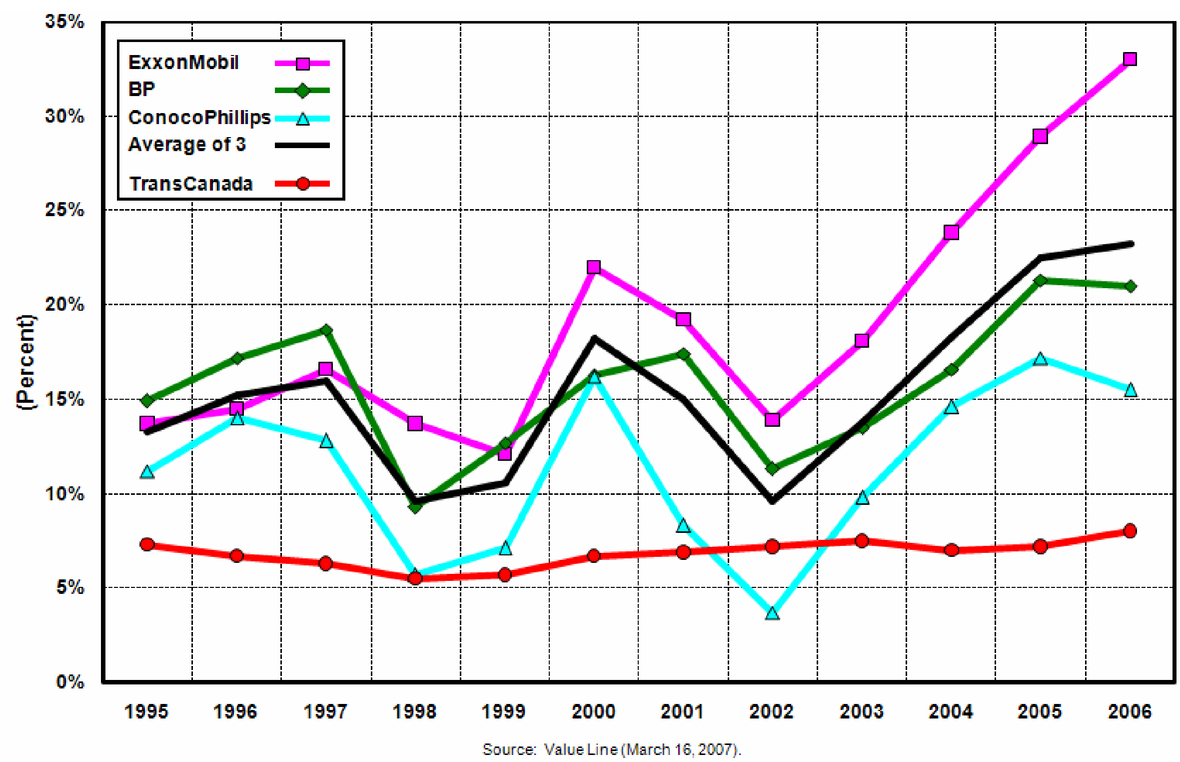
[3] The current rate policy for pipeline expansions administered through the FERC is to allow rolled-in rates for pipeline expansions if doing so decreases rates for existing shippers; otherwise, incremental rates apply. For the Alaskan pipeline project, however, the FERC has adopted a rebuttable presumption in favor of rolled-in rates. (FERC, 2005a) It is unclear exactly how this will play out.

[4] Return on capital employed (ROCE) is a publicly available rate-of-return measure and is calculated by dividing profit before interest and tax by the difference between total assets and current liabilities. The resulting profitability ratio represents the efficiency with which capital is being utilized to generate revenue. It is generally accepted that there is a strong relationship between earnings growth and ROCE.

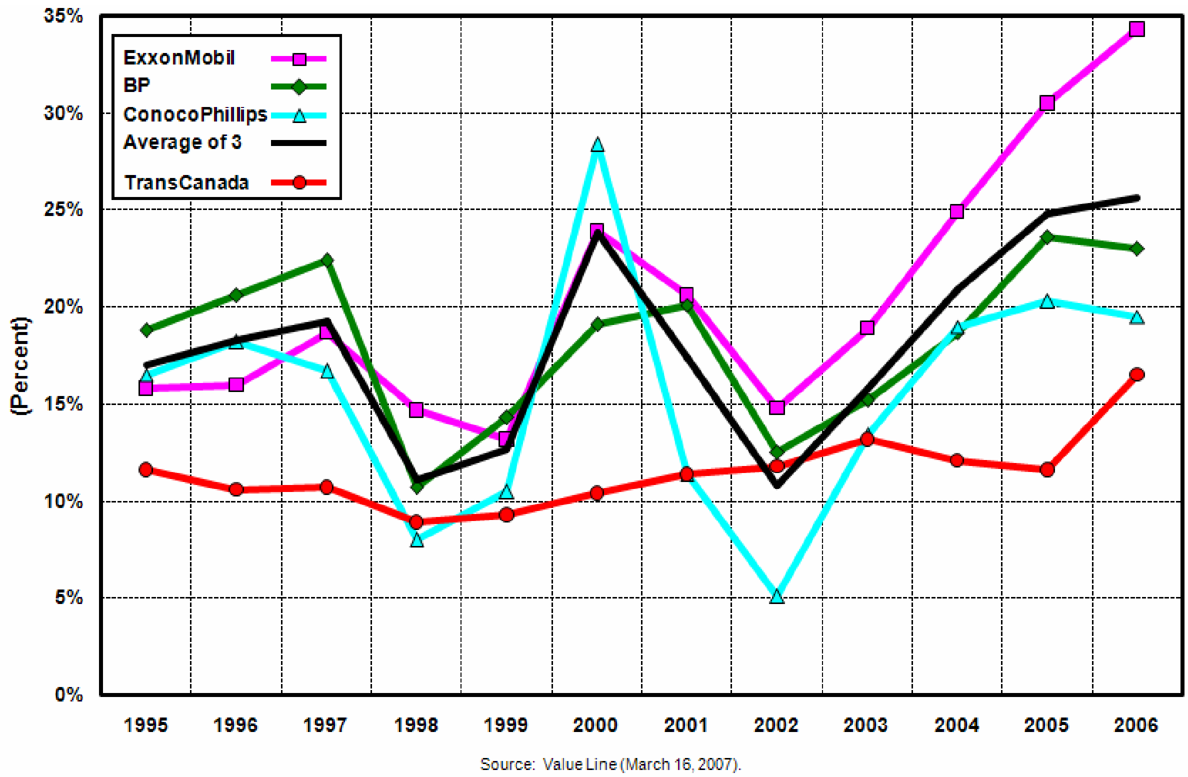
However, at the parent company level the producer-owned pipeline cannot earn the returns which shareholders expect them to pursue if, in expanding, they carry only a third-party's gas. The expansion yields only a regulated rate of return, not the additional high returns (and higher volatility) generated from the exploration and production of high-margin gas. The willingness of the integrated owner to invest in that expansion depends on the attractiveness of the regulated rate-of-return compared with the expected returns on other investment opportunities available to them at the time. It seems likely that the envisioned expansion investment will not have returns that are as high as returns on upstream projects available to the integrated oil companies (figures 1 and 2).

Figure 1. Return on Capital Employed (ROCE) for Selected Companies



TransCanada Corporation has much lower ROCEs, as seen in Figure 1. It also has much lower volatility. It is accustomed to and actively pursues pipeline opportunities, because they are core to its business. This suggests that expansion investments might appear more attractive to a pipeline company like TransCanada than it would to an integrated oil company like the three companies seen in figures 1 and 2.

Figure 2. Return on Equity (ROE) for Selected Companies



Again, contract provisions from the proposed SGDA contract, dated May 10, 2006, confirm that a Producer owned pipeline would not be anxious to pursue the business opportunities provided by expansion. Article 8.7 of the proposed contract between the State of Alaska and the three Alaska North Slope (ANS) sponsor-group producers provided for "State-Initiated Expansion". However, the conditions imposed on shippers were considered by explorers to be so onerous that explorers complained about the provision and had it removed.[5]

Analysis of AGIA's Tariff Provisions

<u>Background and Methodology:</u> Consider the explorer that faces prospect development too late to participate in the initial open season. To accomplish this we used our model to evaluate the economics of a hypothetical prospect. The explorer/owner of this prospect instead would

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[5] *See* Alaska Department of Revenue, 2006. Interim Finding and Determination Related to the Stranded Gas Development Act. November 16, 2006. Finding at ES-20 and 286.

participate as an expansion shipper in one of four subsequent pipeline expansions, with hypothetical dates and capacities depicted in Table 1.

Table 1: Attributes of Pipeline Expansion

	Mainline	1st Expansion	2nd Expansion	3rd Expansion	4th Expansion
Start Year	2020	2021	2023	2025	2027
Throughput (Bcfd)	4.5	0.3	0.3	0.8	0.6

The hypothetical prospect analysis considers how changes in tariffs that arise from an expansion would affect the explorer-expansion shipper's expected monetary value (EMV)[6] under rolled-in rates (AGIA policy) versus incremental rates (FERC policy, except when incremental rates would lower the rates for existing shippers). FERC policy here refers to current policy in the lower-48.

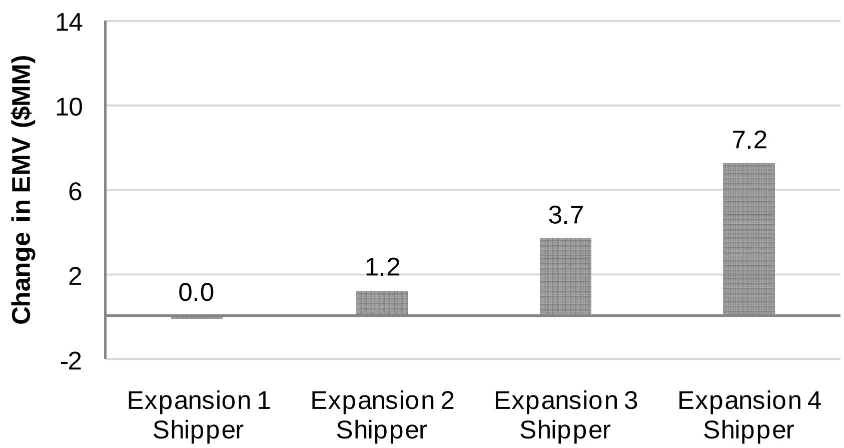
The tariffs cover three elements of the project: the Gas Treatment Plant on the North Slope (the "GTP"), the pipeline from the North Slope to the Canadian border, and the pipeline from the Canadian border to Alberta. The GTP is assumed to fall under the jurisdiction of FERC. The Canadian portion of the line is assumed to be treated in a manner that provides for consistent tariff treatment across both countries. The expansions considered in this illustration are accomplished through added compression. Depending on the size of the expansion, the compression expansion may require new compression stations at pre-determined mainline positions and usually involves increased fuel usage over rates that were required to maintain pre-expansion throughput. Under conventional rate making, the shipper pays a fixed demand charge and "donates" fuel in kind. Fuel usage is a significant cost element in the tariff and becomes more so as the value of gas increases. For the analysis of rate effects, the shipper's imputed fuel cost is based on net back value of gas from the AECO hub.[7] Thus, the rolled-in and incremental tariff effects of expansion are linked with the market price of gas.

[6] Expected monetary value is the total of the weighted outcomes (payoffs) associated with a decision, the weights reflecting the probabilities of the alternative events that produce the possible payoff. It is expressed mathematically as the product of an event's probability of occurrence and the gain or loss that will result. It also can be referred to as "expected value".

[7] The reasoning behind using net back value instead of destination value has to do with expansion effects on incumbent gas producers' increased fuel requirements under rolled-in rate treatment. In such cases, the incumbent producers may wish to transfer capacity to the expansion shipper, which they would value on a net back basis.

Results: The effects of AGIA versus FERC rate policy for expansion shippers is summarized in Figure 3, which shows the difference in the expansion shippers' EMV under AGIA as compared with Lower 48 FERC policy. The results assume an AECO price of $8.00 per mmBtu in constant 2008 dollars and a cost of service based tariff on 70/30 debt-equity ratio. This difference is characterized as the AGIA versus FERC "benefit" because rolled-in rates are generally lower than incremental rates.[8]

Figure 3.
EMV Benefits of AGIA versus FERC Expansion Policy Rate Treatment
70/30 D/E Capital Structure for Base and Expansion Tariffs
$8.00 AECO Price Flat, Real
(Millions of 2008$)



We now show the same effects of AGIA's rolled-in policy as compared with standard FERC policy. However, here we consider the importance of Debt/Equity ratio for the expansion tariffs in concert with AGIA's rolled-in rate policy. As the expansion is financed with more equity, the rates associated with the expansion can be expected to rise. In general, the beneficial effects of AGIA over FERC rate treatment to the expansion shipper increase as expansion costs rise.[9] Accordingly, the benefits of AGIA's rolled-in rate provisions will increase.

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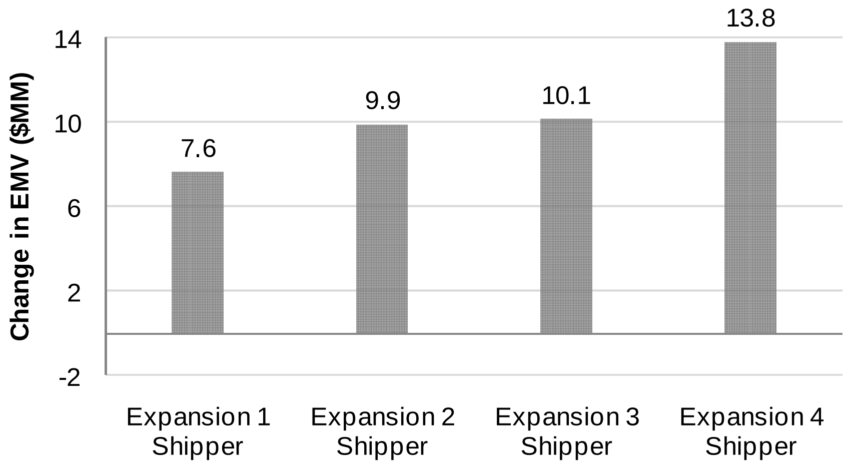
[8] There is no effect on the first expansion's EMV due to AGIA's rolled-in rate policy. This is because the first expansion actually causes a percentage *decline* in fuel use, because the compressors are operating at greater efficiency and because no additional compressors are required.
[9] Also, the AGIA benefits would become more pronounced as the gas price and, thus, the imputed value of in-king fuel usage rises.

In Figure 4, the incremental rates under FERC policy are evaluated under the alternative 50/50 debt-equity structure for both the base tariff and the subsequent expansions. Under the AGIA rolled-in rate policy is based on a 70/30 debt-equity ratio for the base tariff, and 60/40 for the expansion tariff.[10] In effect, in Figure 4 we contrast the EMV's for an explorer by comparing standard FERC-accepted rate making practice – what one might reasonably expect with a Producer owned project -- with those one could expect to receive under AGIA.

Figure 4. EMV Benefits of AGIA versus FERC for Pipeline Expansions
70/30 Base D/E Capital Structure, 50/50 DE Ratio for expansions
$8.00 AECO Price Flat, Real
(Millions of 2008$)



The EMV benefits of AGIA over FERC rate treatment are substantial and more pronounced than those described in Figure 3, above. The AGIA benefits in Figure 4 are positive rather than zero in the first expansion in Figure 3, because incremental rates under the more costly 50/50 financing structure would be higher than rolled-in rates. In this case, FERC treatment would require incremental rates for expansion shippers.

AGIA's rolled-in rate structure ensures that explorers can expect to have largely similar tariffs and transportation economics as the initial shippers. This is a distinct advantage to the State of Alaska and to all North Slope lessees. Significant uncertainty remains in the understanding of the North Slope's undiscovered resource potential that may feed into the gas pipeline, although this understanding is improving. (See NETL 2007 and the discussion of YTF potential in

[10] TC Alaska committed to a 60/40 debt equity ratio for expansions.

Appendix M.) The tariff regime that provides for fairness across generations of gas producers is likely to encourage competition and diminish entry barriers held by incumbent gas owners.

Analysis of AGIA's Tariff Expansion Provisions: Implications of Timely Access versus Project Delay

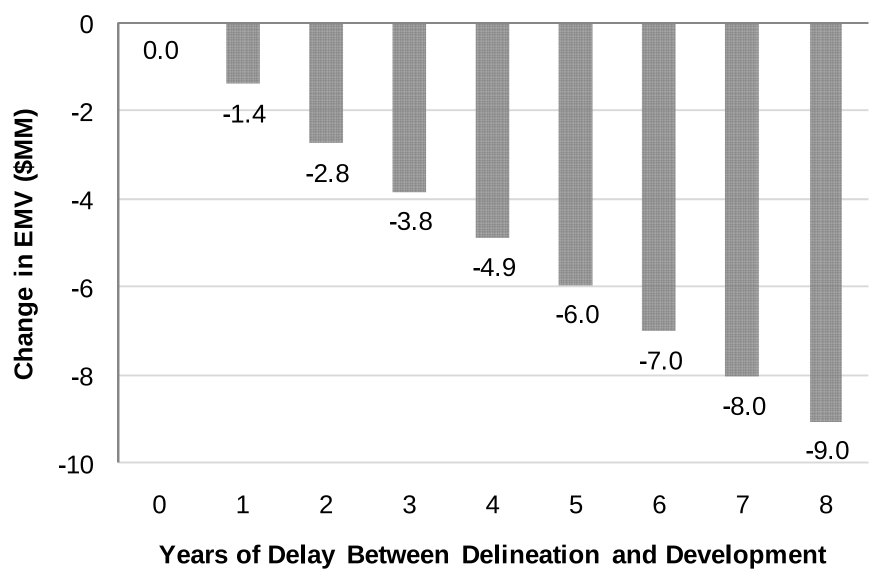
Under ANGPA Section 105, FERC can mandate expansion only if it finds that the following criteria are first met: 1) no rate subsidy; 2) no adverse effect on the projects' "financial or economic viability;" 3) no adverse effect on "overall operations" of the project; 4) the "contract rights of existing shippers to previously subscribed certificated capacity" cannot be diminished; and 5) adequate downstream capacity exists or will exist. These Section 105 criteria are ambiguous and represent fertile ground for litigation. Meanwhile, the FERC's authority to order expansions is new and untested, meaning that there are no regulatory or judicial guidelines. This implies uncertainty and delay.

In the absence of commercial incentives for expansion by the pipeline owners, would-be expansion shippers might hope that the FERC will exercise its authority under ANGPA and force an Alaska natural gas pipeline to expand. But dependence on a FERC-induced expansion can be expected to take years longer than what would be expected under an AGIA licensed pipeline. Importantly, the process can only be engaged after would-be expansion shippers have expended considerable resources finding and delineating new hydrocarbons. It is only after this process is complete that they would be in a position to request that an expansion occur. Unfortunately, the prospect of delay after significant expenditures are incurred would have a significant negative impact on the economics of an exploration venture in northern Alaska. The exploration might never occur in the first place for the would-be shipper to engage in the FERC "forced-expansion" process.

To quantitatively address this dynamic, we consider a scenario in which delay occurs between delineation drilling and full development (a mid-project delay). A mid-project delay could occur when an exploration company attempts to prove reserves to enable the FERC to authorize an expansion of the gas pipeline. In the face of a producer owned pipeline that did not wish to spend hundreds of millions, if not billions of dollars on an expansion, the operator would have to first drill exploration and delineation wells, then after proving reserves, petition the FERC to hold an open season, and then finally secure the needed pipeline capacity for their gas. All the while the sunk investment of exploration and delineation is producing no revenue or benefit to the explorer.

The expected monetary value of a mid-project delay for a hypothetical, Brooks Range foothills gas development project is shown in Figure 5. (Modeling methods and assumptions are explained in the attached addendum.)

Figure 5. Changes in EMVs due to Mid-Project Delay (2008$ millions)



A one-year in delay development, caused by a hypothetical pipeline's unwillingness to expand, and required by the speediest imaginable FERC process under ANGPA, generates a loss of project EMV of up to $1.4 million. The decline in EMV climbs significantly and regularly as the years of delay mount. After four years of delay, the reduction in EMV is nearly $5 million.[11]

In summary, project EMVs probably would diminish under any project delay. On many projects in remote areas of Alaska where the expected reserves are close to the minimum economic field size, the risk of delays will turn estimated EMVs negative, thereby dissuading the prudent operator from investing in exploration projects with a high risk of delay exposure. The

[11] The absolute losses are much greater under a mid-project delay than under a delay that occurs up front during the initial stages of exploration drilling. This is because under a mid-project delay, a large portion of the overall project capital expenditures for exploration drilling will have been expended while the revenue stream is delayed and suffers from time value of money exposure.

conclusion is that without AGIA's gas pipeline expansion provisions that allow operators to quickly get gas to market, expansions that are clearly in the explorers' and state's interests could be thwarted and valuable hydrocarbon resource and the associated revenue lost.

Conclusions

AGIA offers significant overall benefit to explorers and non-incumbent shippers and will encourage increased competition. It will improve the economics of projects that are near the minimum economic field size and therefore result in greater ultimate recovery of Alaska's resources.

The Prospect Exploration Model

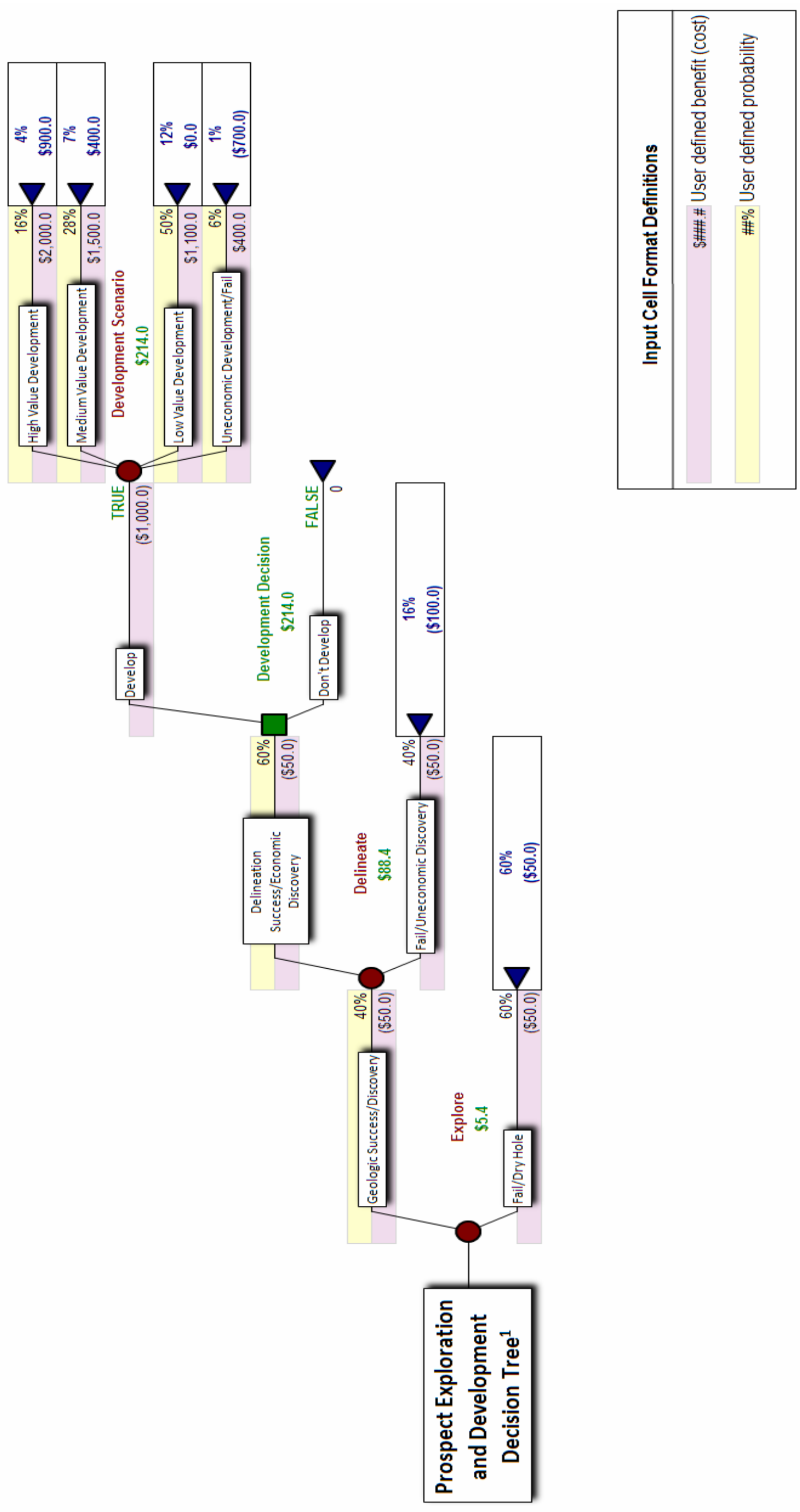
1. Model Framework: The Exploration Lottery

Modeling the economics of oil and gas prospect exploration and development was conducted by tying discounted cash flow models for multiple reserve outcomes directly to a “decision tree” model that rolls the reserve outcomes together. In our analysis, the prospect exploration model begins with a hypothetical, *baseline project* of a non-associated natural gas exploration and development project located in the Brooks Range foothills area. Exploration, delineation and development are decomposed into a sequence of expected decisions and outcomes framed as a decision tree. Key inputs having to do with cost and timing are varied and the corresponding EMV results are compared against the baseline case EMV, which serves as a point of reference. In the decision tree, project expected monetary values (EMVs) representing the overall risked-weighted value of the project is calculated. This decision tree EMV approach is consistent with methods used by the oil and gas industry to value exploration prospects in their portfolio.

Exploring for oil and gas can be compared to buying a ticket in a lottery, where there are four expected outcomes to buying that ticket, each with an associated probability that it will occur (i.e. scenario risks and rewards). In the case of oil and gas exploration, however, the cost of the lottery ticket to explore for hydrocarbons in Alaska can be quite high, possibly into the billions of dollars. But on the plus side, the chances of winning the exploration game are much better than (say) the chances of winning the big multi-million dollar jackpot in Vegas. Of course playing the bet requires that you can afford to lose your investment if your luck runs out and your well is dry.

A *simplified* version of a decision tree similar to what was used in this analysis is shown in Figure 6. Decision tree framework allows for multiple decision and chance nodes or branches with costs, benefits and probabilities assigned to the various branching paths and outcome possibilities. Each path, from beginning to end represents a complete outcome. In decision tree vernacular, positive outcomes are often referred to as the “success leg paths” and negative outcomes are referred to as those that contain a “failure leg”.

Figure 6. Simplified Prospect Economics Decision Tree.



[1] Assumes land position already established and prospect is identified and ready to drill.

In the decision tree model used for this analysis, nodes were defined as follows:

1. A yes-or-no decision is made to drill an exploration well. In the baseline project the exploration well is drilled in year 1 of the model.
2. If the decision to drill is made, chance of geologic success or failure is applied.
3. If exploration drilling is successful, a yes-or-no decision is made to drill a delineation drilling program. In the baseline project, a single delineation well is drilled in year 2 and an additional delineation well is drilled in year 3.
4. If the decision to drill is affirmed, the chance of economic success or failure is applied, conditional on the success of the exploration drilling.
5. If the delineation program is successful, a yes-or-no decision is made to develop the project. In the baseline project, development spending on facilities begins in year 3
6. If the decision to develop is affirmed, four possible development scenario outcomes with assigned probabilities are considered. They are: (1) high value, (2) mid value, (3) low value and (4) uneconomic, conditional on the success of the delineation drilling. Costs are assigned to the appropriate nodes and benefits are represented at the end of each of the success branches. For example, the cost of drilling a well would be realized by an explorer after a decision-to-drill node is passed and the decision is made to drill whether or not that well is successful. If, at a decision-to-drill node, the decision is made to not drill, the explorer incurs zero additional cost. Also, when exploration and delineation is successful and the development branch is followed, capital expenditures and operating costs are also realized in the model.

2. Odds of Winning: Chances of Lottery Success

The probability of exploration success for the sample project was set at 0.40 based on the historic success ratio of exploration wells drilled in Alaska. The probability of delineation success, conditioned on exploration success, is assumed to be somewhat higher at 0.60, based on the history of exploration in the Colville basin. Chance of finding an accumulation worth developing is found by multiplying the probability of exploration success (0.40) by the probability of delineation success (0.60). The result indicates that the baseline project has a 24 percent chance of making a commercial discovery after the decision is made to drill the first well in a prospect (0.40 × 0.60). This assumption does not take into consideration all of the exploration risks associated with a prospect before the decision to drill that first well is made.

The baseline scenario does not have "open season risk." In other words, the explorer has the opportunity to acquire space in the gas pipeline based on reasonably known resource through either the initial open season or a subsequent open season and that the space is available so that there is not any pipeline capacity bottleneck that would delay production start-up. The model was designed up to test, in part, how delays between prospect delineation and production start-up would affect project economics.

3. Assumed Costs of Entry: Buying the Lottery Ticket

There is significant cost of entry into the oil and gas exploration game, especially in Arctic Alaska. In our model projects we assumed that one exploration well would be drilled. In the baseline case, the initial exploration well is drilled in Year 1 and costs $76 million. If the initial well is a discovery and the decision is made to delineate the discovery, two additional wells are drilled in Year 2 and Year 3 costing $42 million each. The total for all three wells is therefore $160 million. These well costs are quoted here in 2008 dollars, but costs in the model are expressed in nominal dollars based on the cost escalation factors contained in the Black and Veach NPV Model.

This cost of entry assumes that the land position has already been acquired and the costs of manpower , seismic data gathering, and any other cost to initially identify and mature the prospect through the explorer's selection process is a sunk cost.

4. Assumed Payoff: Winning the Lottery

In this analysis tariff treatment and effect of mid-project delay are important issues to evaluate. Tariffs were modeled independently with a master NPV model and imported as fixed values for twenty years. Four sets of annual tariffs were modeled assuming 1) FERC expansion rules with 70/30 debt to equity ratio for the pipeline operator, 2) FERC expansion rules with 50/50 debt to equity ratio, 3) AGIA expansion rules with 70/30 debt to equity ratio, and 4) AGIA expansion rules with 50/50 debt to equity ratio. All tariffs were modeled at $8 per Mcf expressed in constant 2008 dollars.

Assumptions about timing are also important for the AGIA versus FERC expansion policy rate treatment. The baseline case assumes that the initial exploration well is drilled in Year 1. If the exploration well is successful, delineation wells are drilled; one each in years 2 and 3. We assume the operator's discount rate is eight percent (expressed in real, constant 2008 dollars) with a two percent general inflation. The land position over the exploration area is already acquired and is considered a sunk cost and not part of this model exercise. High quality, 3-D seismic survey data is already owned (also a sunk cost) and interpreted. An attractive prospect already identified on the successful outcome.

The overall probability of success in exploration ventures can vary significantly across play types and regions. This analysis focuses on project economics of a single project type, yet produces results that are representative with respect to tariffs and many other aspects of project economics. The hypothetical project considered here is envisioned as one located onshore, in the area of the Brooks Range foothills and of a risked reserves size that is close to the minimum economic field limit. The project is based on reasonable production and cost input assumptions that are illustrative in many ways of one of many projects that might contribute gas to a pipeline over the life of that facility. For this project the prospect has been identified, but is undrilled. After delineation drilling is complete, four discrete non-associated natural gas field-size outcomes and associated probabilities are assumed. They are:[12]

1. High reserves, 1.8 TCF field – 0.05 probability,
2. Medium size, 800 BCF field – 0.15 probability,
3. Low reserves, 400 BCF field – 0.75 probability, or
4. Small, uneconomic, 80 BCF field – 0.05 probability.

Once an accumulation is successfully delineated, field development may begin. Winning at the prospecting game does not come without significant additional investment after exploration and delineation drilling. However, once delineation is completed and the field-size outcomes are more certain, development decisions can be made with a greater certainty of the investor's payout. This approach follows standard industry practice for risk-evaluation of project economics. Additional assumptions included in our baseline example analysis are:

1. Pad and facilities construction to the field begins in Year 4 and takes five years to complete (Figure A.2).
2. Pipeline construction begin in Year 5 and takes three years to complete

[12] These field size chance factors are independent of geologic and delineation risk discussed above (i.e. they are conditioned on delineation). The joint probability that a complete successful outcome would occur is the product of the field-size chance factor cited here, along with the geologic risk (0.40) and by the delineation risk (0.60). For example, the probability of finding a 2.5 TCF field after a prospect has been identified but before the first exploration well is drilled is equal to 0.4 x 0.6 x 0.16 = 0.038.

3. Development drilling begins in Year 7 and takes two to four years to complete depending on the number of wells drilled.
4. Production begins in Year 8.

In the cash flow model, exploration drilling costs were derived from NETL study (2007: p. 3-144).[13] Facilities and drilling capital expenditures were derived from formulas included in Attanasi and Freeman (2005: p. 34-35)[14] and pipeline capital expenses and operating expenses were derived from formulas included in NETL (2007: p. F-1). Drilling and facilities capital expenditures key determinant factors are identified in Table 2. Facilities costs were scaled based on the maximum gas throughput volume for the scenario branch of the decision tree. Similarly pipeline costs were scaled based on the expected distance from Pump Station 1 and the maximum throughput for the scenario. Costs were then adjusted for inflation and cost escalation based on work done by DNR consultants. Some operating costs are deemed to be fixed. Other operating costs were variable based on the number of wells drilled and volume of gas produced. The capital spending profile and timeline is shown in Figure 7.

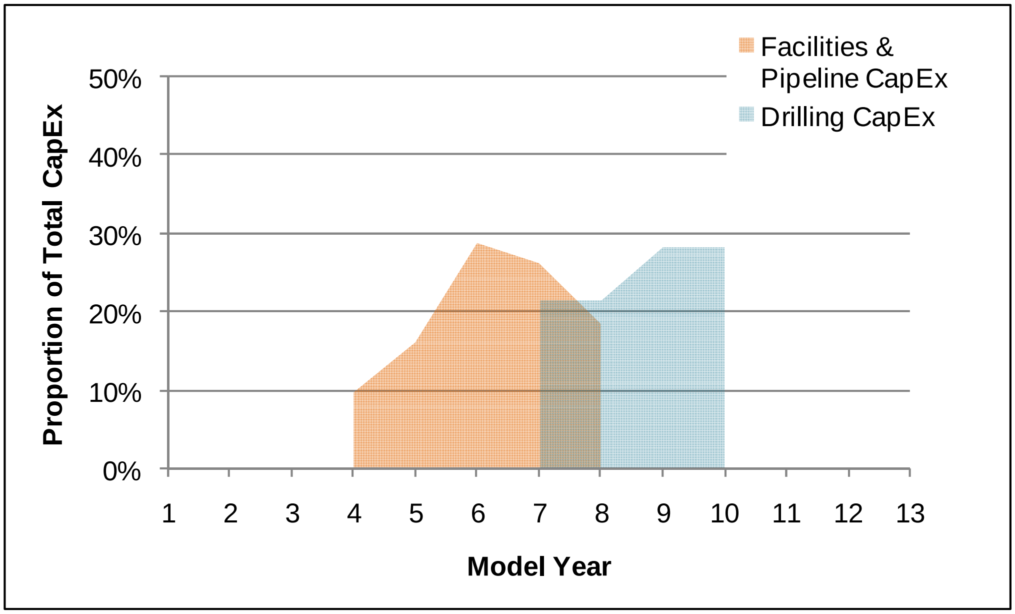
Table 2. Key Determinants of Capital Expenditures (CapEx)

	CapEx Category	**CapEx Determinant Factors**
Facilities costs	Pad and location	Cost based on remoteness
	Processing facilities	Cost scaled dynamically with estimated maximum throughput
	Feeder pipeline	Cost based on estimated length, pipeline size (diameter) scaled dynamically with estimated reserves
Drilling costs	Exploration well	Modeled with one exploration well, well cost based on estimated depth and remoteness
	Delineation well	Modeled with two delineation wells, well cost based on estimated depth and remoteness
	Development well	Well count scaled dynamically with estimated reserves, well cost based on estimated reservoir depth and remoteness

[13] Thomas, C.P., D.D. Faulder, T.C. Doughty, D.M. Hite, and G.J. White, 2007, *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?*, U.S. Department of Energy, National Energy Technology Laboratory, DOE/NETL-2007/1279, pp. 3-144.

[14] Attanasi, E.D. and P.A. Freeman, 2005, Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska; U.S. Geological Survey, Open-File Report 2005-1276, pp. 34-5.

Figure 7. Baseline Capital Expenditure Profiles for Facilities and Drilling



Note: Baseline production is assumed to begin in Year 8 after one year of development drilling.

Similar logic is used at the final node for revenues generated on the success leg. If success is achieved at all the previous branches, revenues are generated by hydrocarbon sales and value in the project is realized. Benefits represented by the final development scenarios are net of operating costs and taxes. Other scenarios simulate a delay that might be experienced by an explorer that is required to show proven reserves before an open season. To do this we rely on the base case except that we have added varying delays in time between drilling the last delineation well in Item 2 of the decision tree model node definitions, shown above (Figure A1), and start-up of pad and facilities construction in the "development" decision tree node. Effectively, this kind of delay might represent the time between proving a resource through delineation drilling and getting to an open season through existing FERC regulation as it applies in the lower-48. The logic of modeling a delay such as this is that we believe that no operator will commit to development capital expenditures that we see in the outer branches of the decision tree node definitions unless they have reasonable certainty that they will have a market available to them and that the tariff to transport their gas will be reasonable.

All project scenarios evaluated here assume the same flat market price, $8 per Mcf (real, constant 2008 dollars). Production is taxed based in the recently enacted ACES (Alaska's Clear and Equitable Share) framework, including 25% base tax rate, 20% qualified CapEx credits, 25% loss carry-forward credits. State and federal corporate income taxes are assumed to be

9.4% and 35%, respectively (Table 3). For production tax purposes, this project is assumed to be a stand-alone project and the project operator has no other production in Alaska. The cash flow model is run on an annual increment basis using real dollar value with production continuing as long as revenue (after initial development spending is complete, minus royalties and operating costs) is positive for up to 50 years. Discount factors to determine project EMVs are shown with other general model assumptions in Table 3.

Table 3. General Model Discount and Tax Rate Assumptions

Natural Gas Price Escalation (annual)	2.5%
Annual Cost Escalation – Capital Expenses	4 %
Cost Escalation – Operating Expenses	3%
Operator Discount Rate	8%
State Corporate Income Tax Rate	9.4%
Federal Corporate Income Tax Rate	35%
Ad Valorem Mill Rate	2%