



**Assessment of
Commercial Likelihood of Success
Pursuant to
AGIA Section 43.90.170(c)**

Prepared for the State of Alaska

May 22, 2008

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1.0 INTRODUCTION

Black & Veatch Enterprise Management Solutions (“B&V”) was retained by the State of Alaska’s (“State”) Department of Resources (“DOR”) to provide analytical support in the review of applications received pursuant to the State’s Alaska Gasline Inducement Act (“AGIA”). One of the components of B&V’s scope of services is an assessment of the likelihood of success (“LOS”) of the pipeline project described in each complete application. Specifically, AGIA Section 43.90.170(c) lists those factors “the commissioners shall consider” when evaluating an applicant project’s LOS. This report presents B&V’s analysis of certain of those factors and is intended to provide guidance and input to commissioners in their decisions regarding applicant projects.

Of the several applications received by the State, only one – filed by TransCanada – was deemed complete pursuant to the requirements contained in the AGIA and State’s July 2, Request for Applications (“RFA”). The intent of the AGIA was for the net present value of cash flows reflected in each applicants project proposal would be weighed by the LOS of each respective project. Since TransCanada’s application was the only complete application, the analysis and commentary in this report focuses on that project alone, and does not compare it to other proposals that were deemed incomplete.

The criteria provided in Section 43.90.170(c) seek input on a range of technical, commercial, financial and regulatory issues concerning the proposed projects. Responding to all of these requirements involved the coordinated effort of numerous advisors to the State, each of which have prepared separate LOS reports evaluating matters relevant to their subject matter expertise. Generally speaking, technical LOS factors have been addressed in a report by Westney and Associates; financing matters by Goldman Sachs; regulatory matters by Greenberg Traurig; and commercial matters by B&V.

Each advisor’s report used a similar approach to evaluate the LOS of TransCanada’s proposed project. That approach involved rating each Section 43.90.170(c) factor as either having a 1) positive impact, 2) no impact, or 3) negative impact on the project’s LOS. Key aspects of each factor were then articulated in the form of more detailed questions which were accompanied by analysis and discussion.

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The “commercial” LOS factors analyzed in this B&V report generally address the business aspects of TransCanada’s application.¹ In particular, B&V assessed matters related to TransCanada’s development plan as prescribed by Section 43.90.170(c)(1) and certain “other evidence and factors” as prescribed by Section 43.90.170(c)(6).

B&V’s discussion of “other evidence and factors” as required by Section 43.90.170(c)(6) covers only part of the issues relevant to commissioners. Goldman Sachs is providing separate analysis of the potential for TransCanada and the project to be successful in attracting the requisite equity and debt capital necessary to fund the pipeline through an operation in-service.

¹ A separate B&V report addresses net present value and revenue prospects for the State and other project stakeholders.

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2.0 EXECUTIVE SUMMARY

This report assesses whether the commercial aspects of the market and the proposed project will contribute to its likelihood of success. As detailed in the sections that follow, the results of our analysis support a finding that both would have a positive impact on the prospects for a successful project.

In particular, **forecasts show that the market needs the gas that the project can provide.** EIA forecasts expressly recognized 4-5 Bcf/day of Alaska natural gas supplies in the continental portfolio by 2021. Absent those supplies it is not known how the market would fill the void. Further supporting that need is the increasing public realization that gas demand for power generation as the result of greenhouse gas legislation could drive demand sharply higher than current forecasts. At the same time, LNG imports that figure prominently into the projected North American resource base are lagging. Each of these factors suggests that North Slope producers will find strong demand for their product.

Our review finds **TransCanada's project provides excellent access to the growing market.** TransCanada's combined Alaskan and Canadian pipeline segments would tap southern Alberta interconnects with numerous pipelines serving markets all across the eastern and western US and Canada. Pipeline capacity to these markets is expected to provide good shipper options, in part because Western Canadian Sedimentary Basin (WCSB) production that originally supported the construction of those pipes is declining. If new pipeline capacity from the region is needed, operators (including TransCanada affiliates) have consistently shown a willingness to invest in new expansions.

Natural gas market prices are highly supportive of the monetizing Alaska supplies. Long term forecasts by B&V and others all project rising prices through 2030. Current prices are already trading at significant premiums to those long term price projections. The bullish outlook for gas prices underlies the strong netback projections and net present value ("NPV") estimates presented in B&V's separate report on AGIA NPV. The outlook for strong natural gas prices also factor into the Goldman Sachs assessment of financing viability.

In addition to market conditions that are conducive for a project, our analysis finds TransCanada's plan provides a credible framework from which to begin negotiations. Notwithstanding the size of the project, **most aspects of TransCanada's proposal are consistent with industry practice as**

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seen in other large pipeline expansions. Shippers will be familiar with those projects and have the benefit of negotiating key terms for Precedent Agreements, Gas Tariffs, and transportation rates. Given the uncertainties inherent in this project, such flexibility is key to allocating risks and striking equitable deals with shippers.

AGIA specifically requires that a likelihood of success assessment consider the applicant's plan to "insulate shippers from effect of cost overruns". In general, TransCanada's proposal does not offer shippers strong protection from cost overruns. ***TransCanada does offer a commendable list of measures and negotiating options that in the aggregate could help mitigate a significant level of cost overrun risk or uncertainty.***

TransCanada's offer makes it reasonable for shippers to nominate in the planned open season. Although binding by definition, a nomination essentially only requires prospective shippers to enter into good faith negotiations for a workable Precedent Agreement. Any binding Precedent Agreement coming from those negotiations could include other "outs" for shippers if the project fails to meet milestones or other conditions. Participating in the open season is largely limited to the costs of due diligence, as TransCanada requires no financial commitment prior to concluding a Precedent Agreement. As such, TransCanada basically provides a free option for shippers – even the Denali pipeline sponsors – to compare alternatives before incurring significant expense. ***It is difficult to identify reasons why a shipper wanting to market Alaskan supplies would not take the next step of investigating the viability of TransCanada's proposal by nominating in the open season.***

Given the unknowns about Denali, it remains to be seen how that project bears on the likelihood of success of TransCanada's project. Clearly, Denali signifies its sponsor's belief in the timing and market need, but more due diligence is needed on their part before a reasonable comparison can be made with TransCanada's proposal. ***While Denali may not ultimately support the success of TransCanada's project, a settlement combining the best aspects of the TransCanada and Denali projects improves the likelihood of success of a project.***

Alaska has a long history with LNG exports and the expanding global LNG market increases the attractiveness of larger export capabilities. ***The TransCanada proposal reserves the initial North Slope gas production as support for a pipeline, but preserves the option for future LNG.*** TransCanada's rate design and expansion plans, coupled with FERC regulatory policies each facilitate future investments in pipelines and LNG export terminaling. Moreover, expert reports

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produced for the State indicate that the Pacific Market would be more receptive to a future expansion that is smaller than the initial volumes expected in the initial TransCanada project.

3.0 IS THE MARKET SUPPORTIVE OF THE PROJECT GAS SUPPLIES?

This issue addresses whether there will be a downstream market for Alaskan gas shipped on the applicant's proposed pipeline. The potential for success is increased if: 1) there is a defined need for Alaskan gas from a supply/demand perspective; 2) forecasted prices will support profitably investments in the production and transportation capacity; and 3) adequate pipeline capacity will be available to transport gas to downstream markets.

3.1 Do North American supply-demand equilibrium projections reflect a need for the Project gas supplies by 2019?

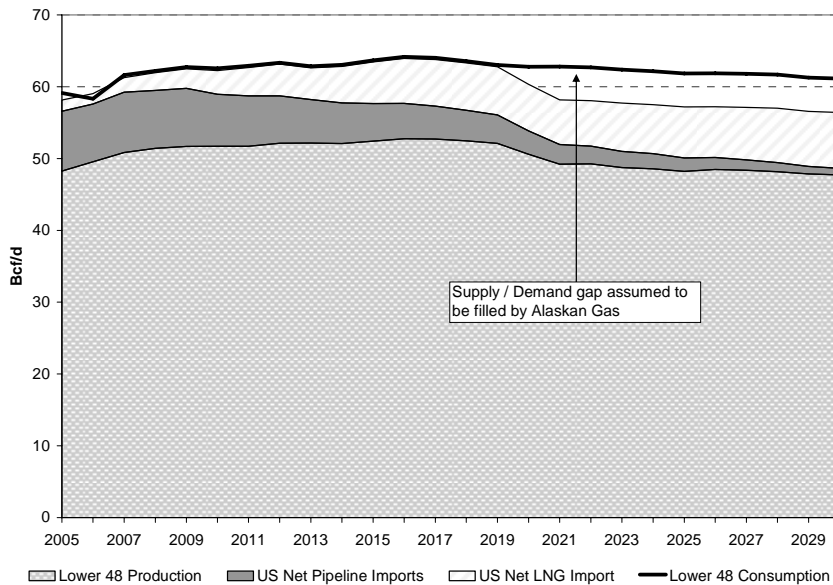
Assessment: Positive Impact

The US Energy Information Administration's (EIA) Annual Energy Outlook (AEO) Draft for 2008 projects that lower 48 natural gas consumption will grow from 62 Bcf/d in 2008 to approximately 63 Bcf/d by 2021 (Figure 1)². (EIA, 2008a: Tables 13 and 14; EIA, 2008b) This 8 Bcf/d decrease from their 2007 projection of about 71 Bcf/d by 2021 can be in part attributed to lower economic growth and the effect of price elasticities on the higher forecasted gas price level, which encourages a switch to other fuels for power generation. (EIA, 2007: Tables 13 and 14) During this same time, the National Energy Board's (NEB) Energy Future 2007 projects that Canadian demand will grow 20 percent, or roughly 2 Bcf/d (Figure 2). (NEB, 2007: Appendix Table A2.1 and Table A4.2) In all, lower 48 and Canada gas consumption increases by a total of 3 Bcf/d.

² The 5-year (2002-2006) average Alaskan gas consumption of 1.13 Bcf/d was subtracted from total US consumption to estimate lower 48 consumption.

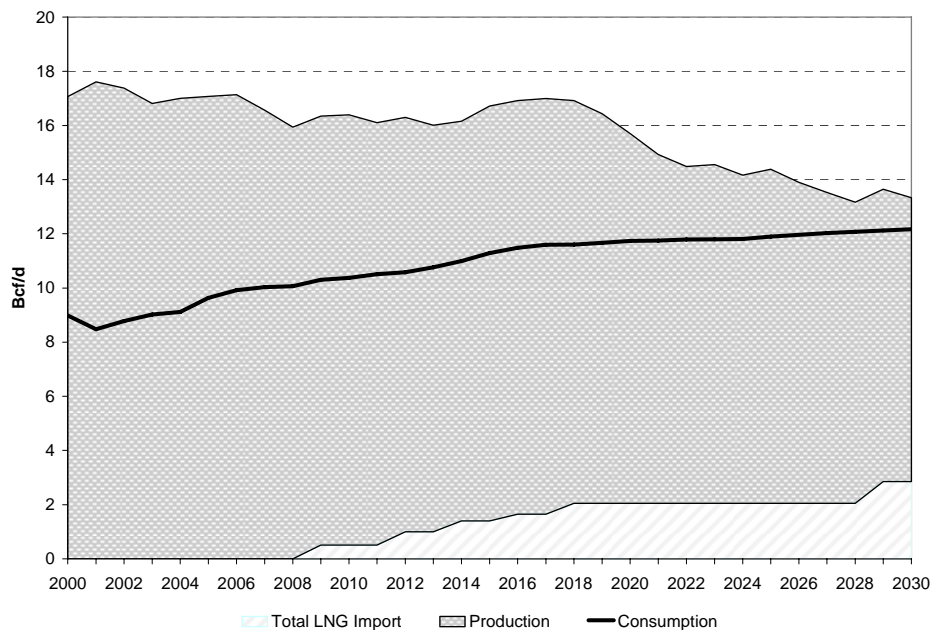
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Figure 1: EIA AEO 2008 Forecasts 4.6 Bcf/d of Alaska Supply to Lower 48 by 2021



Gas production from North American supply basins, however, is decreasing. EIA forecasts show Lower 48 production decreasing from 51 Bcf/d to 49 Bcf/d. The NEB projects that Canadian gas production declines from 16 Bcf/d in 2008 to just over 13 Bcf/d by 2021 (Figure 2). (NEB, 2007: Appendix Table A2.1 and Table A4.2) Absent LNG imports, Canadian supplies will not maintain pace with Canadian demand. Increasing demand for Canadian supplies within Canada will in turn exert pressure on exports to the Lower 48.

Figure 2: NEB 2007 Forecasts Increasing Demand and Decreasing Supply



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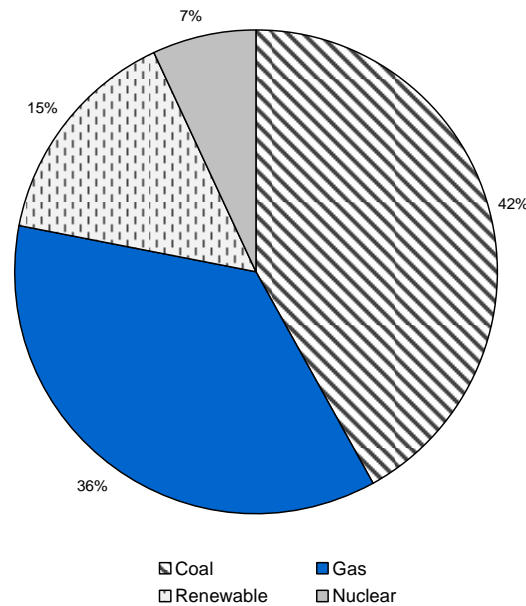
The combined effect of growing North American consumption and declining production requires increasing international LNG imports in order to satisfy demand. EIA estimates include projected import volumes at terminals across America. These estimates show that growth in imports is adequate to satisfy demand through approximately 2015. After that, Alaskan supplies are assumed to satisfy up to 4.6 Bcf/d through 2030. If there are no Alaskan supplies, it is not known where replacement gas would be sourced. (EIA, 2008a: Tables 13 and 14)

It is important to point out that Alaskan supplies are not limited to competing for 4.6 Bcf/d of market. Instead, through its Southern Alberta market (AECO) connections to the North American pipeline grid, Alaskan gas will be positioned to compete for a substantial share of the 70+ Bcf/d North America market, much the same as Western Canadian gas production is currently sold throughout Canada and the Northeast, Upper Midwest and West Coast US markets. (EIA, 2008a: Tables 13 and 14; NEB, 2007: Table A2.1 and Table A4.2) It is likely that Alaskan gas will displace more costly production in markets where it has reasonable access, particularly as the US relies on increasing volumes of non-conventional gas supplies and LNG imports. The potential to displace existing supplies in the market means that Alaskan producers are not dependent on market growth to find market. They will have substantial market sales opportunities even if consumption is flat over time.

Natural gas is expected to be a critical fuel for power generation. EIA's reference case projects an 87 gigawatt increase in gas-fired power generation capacity additions by 2030. As seen in Figure 3, this equates to 36% of total Lower 48 capacity additions. (EIA, 2008a: Table 9) EIA's reference case gas demand projections do not assume greenhouse legislation, even though many in industry expect that. For this reason, EIA's reference case can be considered a conservative projection.

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Figure 3: EIA AEO 2008 Power Generation Capacity Additions by 2030



3.2 Do market price forecasts portray opportunities for pipeline cost recovery, producer profit, and acceptable royalty netbacks?

Assessment: Positive Impact

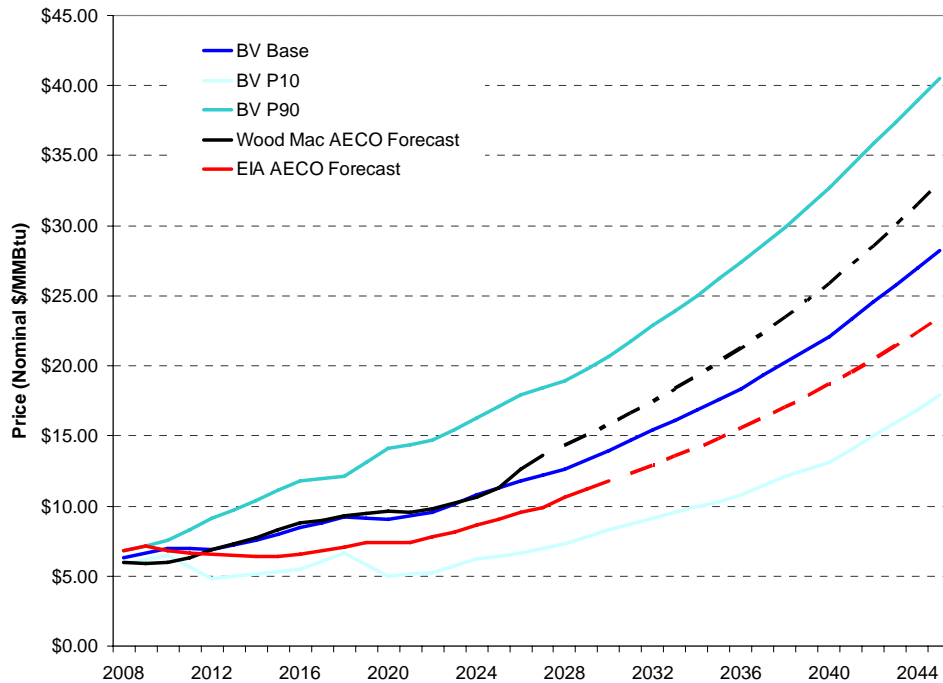
Based on a range of projected market prices, B&V's NPV model forecasts adequate opportunities for pipeline cost recovery, producer profit, and royalty netbacks.

AGIA applicants were instructed to use EIA's AEO 2007 price forecast as the reference price for their analyses. (State of Alaska, 2007: p.38) EIA's Draft 2008 release and NEB's Energy Future 2007 both project higher prices than the 2007 AEO forecast. (EIA, 2007: Table 13; EIA, 2008a: Table 13; NEB, 2007: Appendix Table A1.1) Further price increases will enhance the attractiveness of the gas market for Alaskan producers.

Figure 4 shows price forecasts at AECO Hub. (EIA, 2008a: Table 13; NEB, 2007: Appendix Table A1.1; B&V Price Model; Wood Mackenzie Base Case Price projection)

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Figure 4: Natural Gas Price Forecasts at AECO

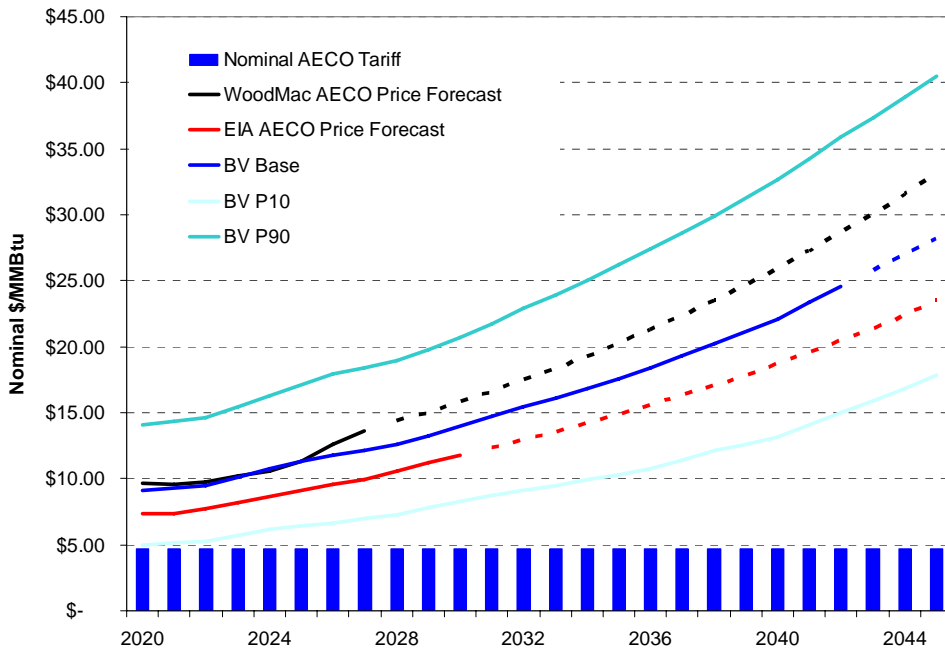


These price projections are based on specific assumptions or opinions on future market developments, such as reserve levels, finding and development costs, and LNG import volumes. Uncertainties in the assumptions could lead to changes in price projections. B&V carefully identified major fundamental drivers with significant influence over AECO prices and simulated a distribution of AECO prices related to these uncertainties

Figure 5 shows nominal AECO price projections from various sources and transportation costs from the North Slope to the AECO market. B&V P10 represents a low-end price forecast from which actual prices have only a 10% chance of falling below. Even under the P10 scenarios, the market still supports a positive netback at the inlet to the gas treatment plant. If real prices remained at a constant 2007 level throughout the analysis period they would easily cover the pipeline transportation cost.

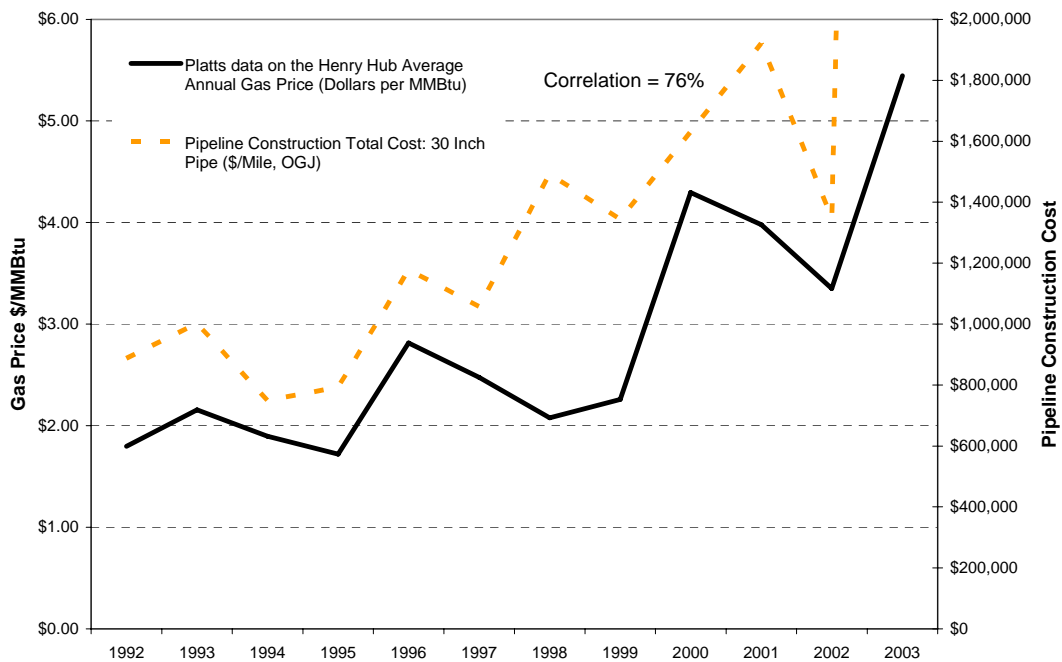
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Figure 5: Natural Gas Price Forecasts at AECO



A disastrous scenario for major project stakeholders will be the combination of high construction cost and low natural gas prices. However, this scenario is very unlikely from a historical perspective. Historical analysis shows that pipeline construction costs are very much in sync with natural gas prices, with a 76% positive correlation. (Oil & Gas Journal; Platts Gas Daily, 2007)

Figure 6: Annual Pipeline Construction Chart versus Annual Price of Gas



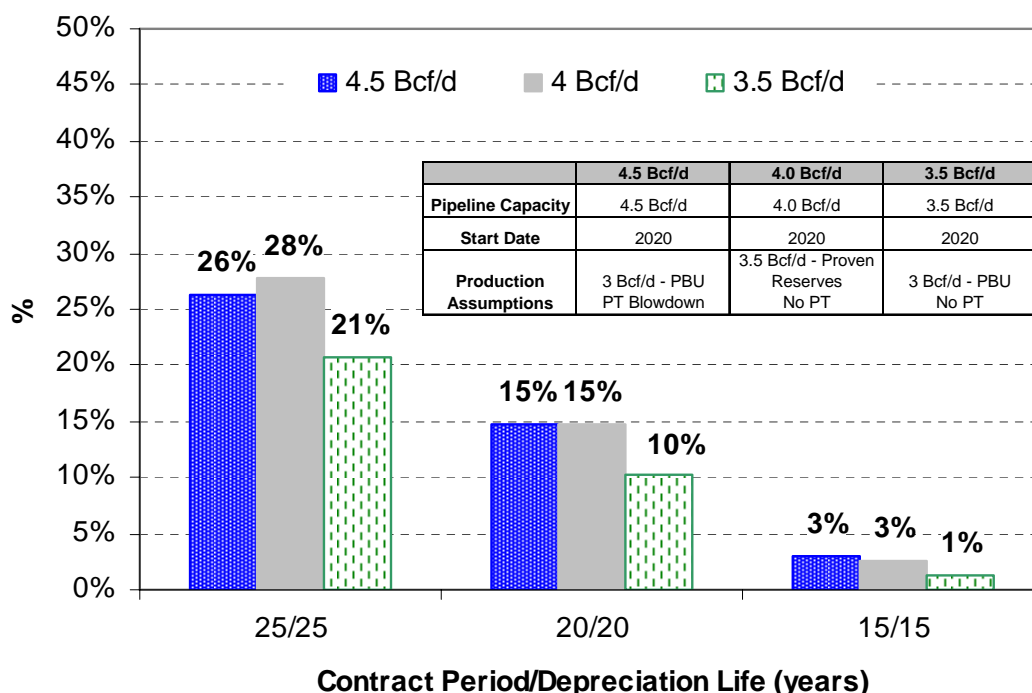
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The positive correlation extracted from historical data should not be interpreted as suggesting that a high natural gas price will definitely “cause” high construction cost or vice versa. In the historical context, continued high natural gas prices could increase the demand for pipeline materials and labor, thus raising construction costs; or, high natural gas prices might encourage construction of pipeline projects previously deemed “not-in-the-money”, therefore, reported pipeline construction costs rise higher even though building additional pipelines does not necessarily become more expensive.

Factors outside the natural gas industry, such as the price of steel and average wage or earnings from the macro-economic environment, could also affect the pipeline construction cost.

The reserve risk analysis includes an assessment of the proportion of total contracted pipeline capacity that requires yet-to-find (YTF) gas. It is calculated using future prices required to generate break-even netbacks once YTF volumes become necessary. As seen in Figure 7, the reserve risk generally decreases as the size of the pipeline and length of the contract period decreases, and is dependent on the production scenario assumed. (B&V NPV Analysis)³

Figure 7: Percent of Contract Volume that requires YTF gas

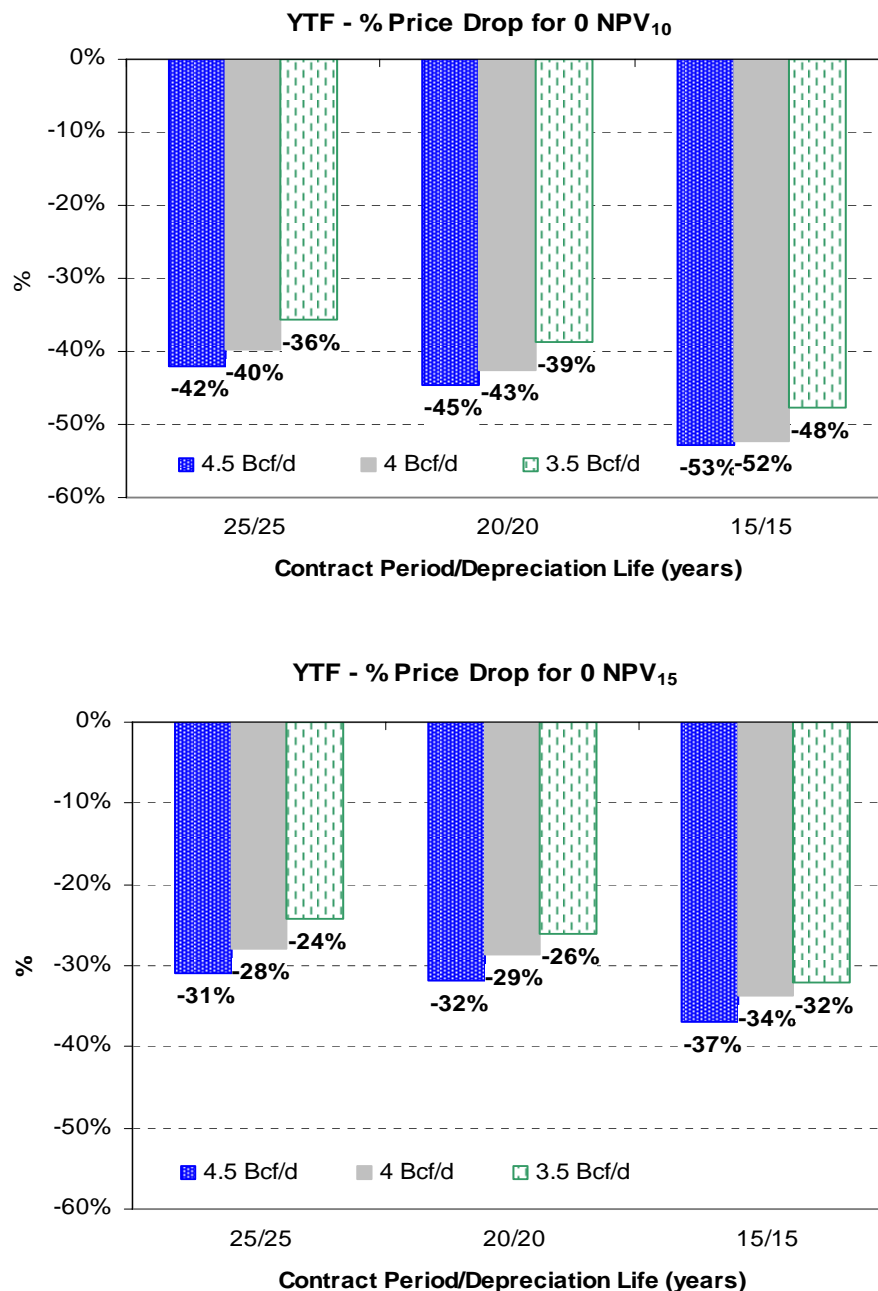


³ “PT Blowdown” case refers to a scenario where full Point Thomson gas volumes are available at blowdown production rates on the pipeline’s in-service date. “PBU” refers to Prudhoe Bay Unit production

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Assuming a conservative 4.0 Bcf/d base case, producers would start to experience break-even netbacks during the period when YTF gas is needed if the price level falls between approximately 40% and 52%, assuming a 10% discount rate. When the cash flows are discounted at a 15% rate, YTF producers would experience break-even netbacks once prices fall between 28% and 34%. Figure 8 illustrates the future price discount from the AECO base case forecast required to generate negative netbacks, assuming no YTF gas. (B&V NPV Analysis)

Figure 8: Price Discount Required for Break-Even Netbacks



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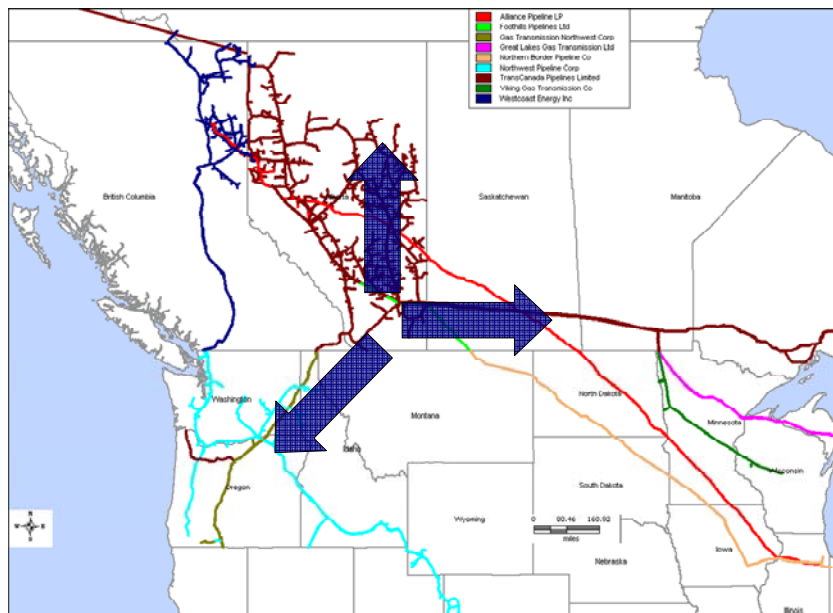
3.3 Will Alaskan gas have adequate downstream pipeline access to markets from southern Alberta?

Assessment: Positive Impact

A highly developed network of natural gas pipelines is currently in place to transport gas supplies from southern Alberta to markets across North America. Alaskan producers will have access to markets in Eastern Canada, the US West Coast, Midwest and East Coast. (B&V)

Major pipeline systems that export supplies from the area include TransCanada, WestCoast, Foothills, and Alliance. These pipelines in turn interconnect with downstream pipelines in the US that will deliver gas to market. Figure 9 shows a map of the pipeline infrastructure leaving the Alberta production area. (Velocity Suite Online, B&V)

Figure 9: Pipeline Infrastructure Exiting the AECO Hub

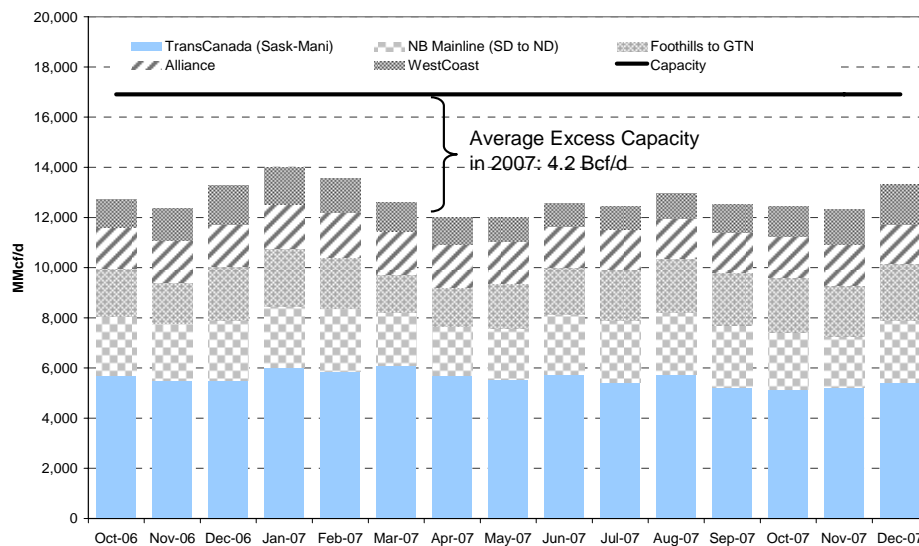


In 2007, there was an average of approximately 4.2 Bcf/d in excess capacity on pipelines exiting the southern Alberta production area. (Lippman Consulting, Inc., 2008: Reports X113, X103, X108, X152, and X118) Figure 10 summarizes the historical utilization of capacity leaving the Alberta production area.⁴

⁴ Figures are based on compressor station capacities at or near the Alberta border, as derived by Lippman Consulting from pipeline utilization reports.

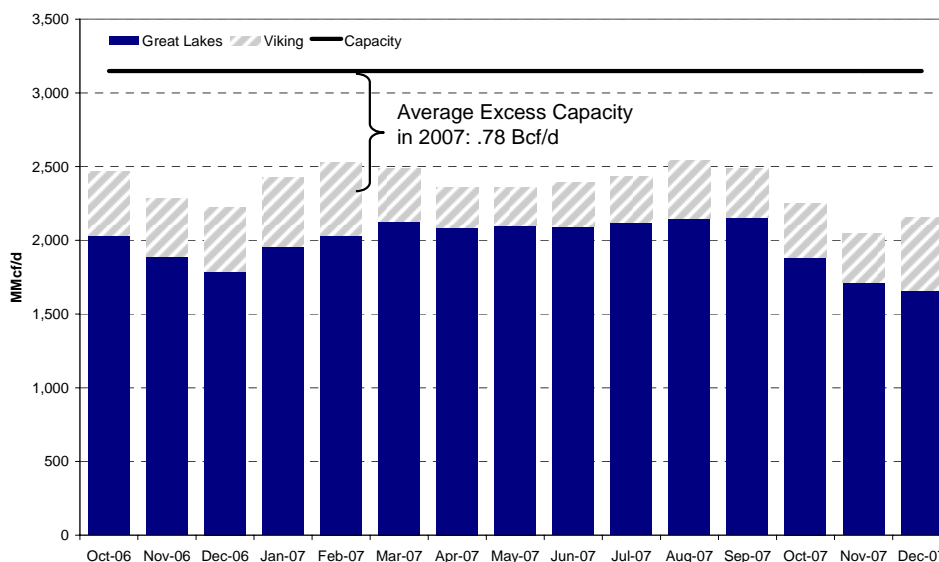
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Figure 10: Historical Pipeline Utilization leaving Southern Alberta



The majority of the excess capacity from southern Alberta results from under-utilization of the TransCanada mainline and the Foothills Pipeline, both of which supply the Midwest and east coast markets. The TransCanada system offers unused capacity to the Emerson interconnection at the Canada-US border in Minnesota, where Viking and Great Lakes pipelines ultimately transport supplies to the United States Midwest and to pipelines serving the US East Coast. The Viking and Great Lakes pipelines are also operating at well below full utilization, and in 2007 were capable of transporting an average of approximately .78 Bcf/d of extra supplies. (Lippman Consulting, Inc, 2008: Reports X119, X110) Figure 11 shows historical utilization of capacity downstream of the Emerson interconnection.

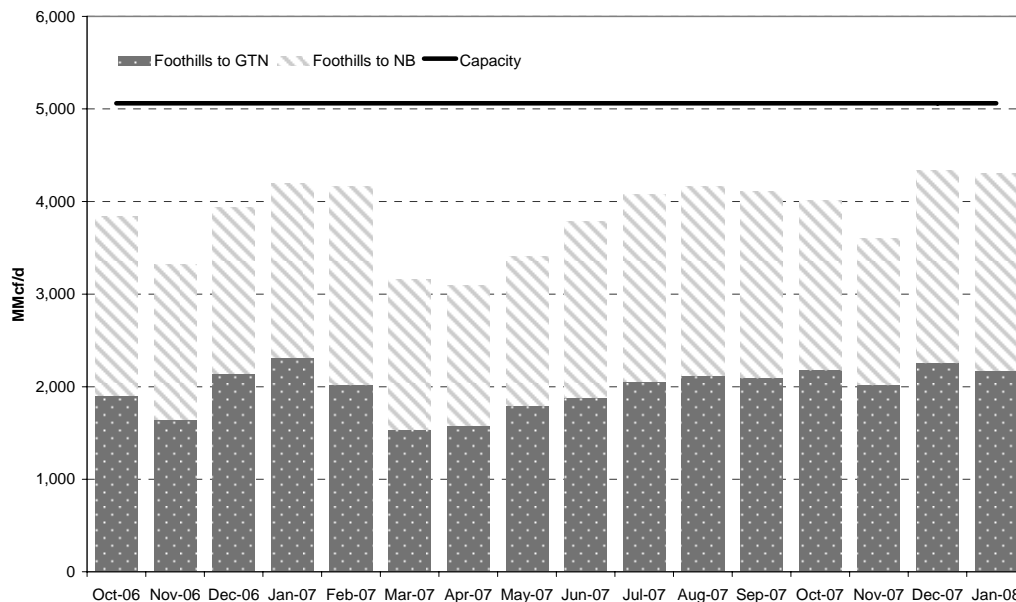
Figure 11: Historical Pipeline Utilization for Great Lakes and Viking



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The Foothills Pipeline⁵ provides access to East Coast and West Coast US markets. West Coast supplies are served through Foothills deliveries to Gas Transmission Northwest at Kingsgate, Idaho. From there volumes flow south toward the California-Oregon border. Volumes averaged about 1.99 Bcf/d in 2007, allowing for an incremental .77 Bcf/d to be transported on the system without further expansion. (Lippman Consulting, Inc, 2008: Report X103) East Coast markets are served through Foothill deliveries into Northern Border at Port of Morgan, Montana, where excess capacity averaged roughly .45 Bcf/d in 2007. (Lippman Consulting, Inc, 2008: Report X108) Figure 12 shows excess historical utilization of volumes transported on these systems.

Figure 12: Historical Pipeline Utilization for Foothills

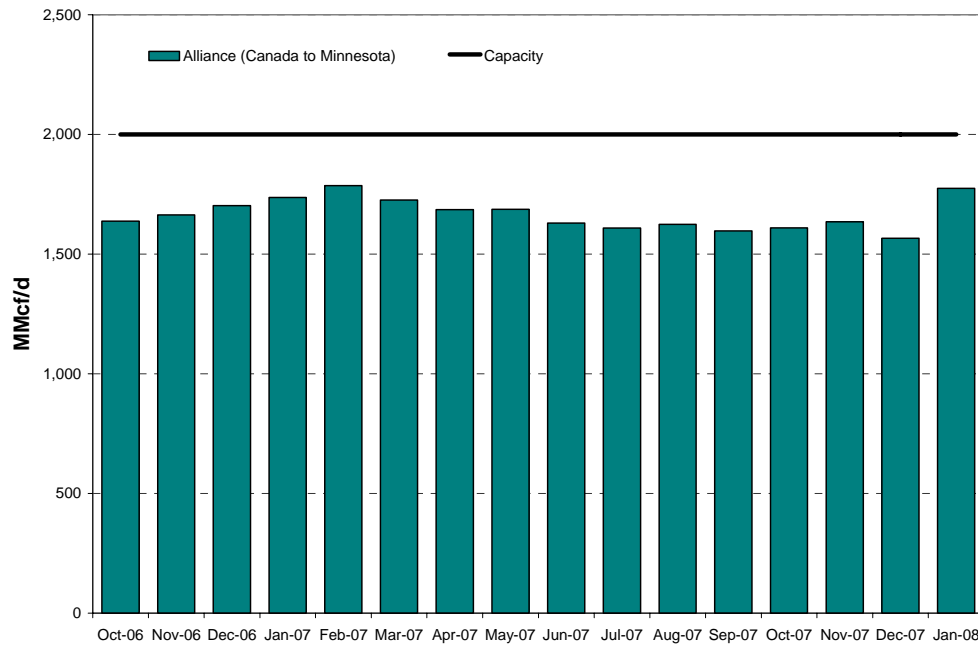


Alliance Pipeline transports British Columbia and Alberta supplies to markets in the Midwest. Alliance volumes crossing the US/Canada border into Minnesota averaged 1.66 Bcf/d in 2007 allowing for an incremental .342 Bcf/d to be transported on the system. (Lippman Consulting, Inc, 2008: Report 113) Figure 13 shows historical utilization of volumes entering Minnesota.

⁵ Used capacity utilization on Gas Transmission Northwest and Northern Border to estimate Foothills capacity utilization

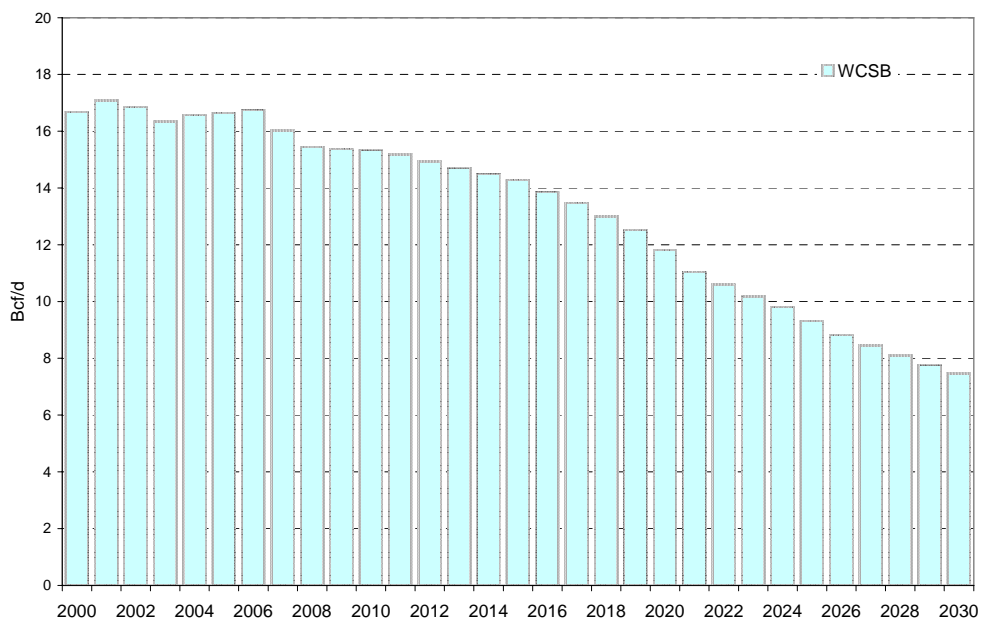
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Figure 13: Historical Pipeline Utilization for Alliance



The projected decline of gas production in the Western Canadian Sedimentary Basin (WCSB) implies increased takeaway capacity from Alberta available for Alaskan gas. The NEB projects that production will decline from 15.7 Bcf/d in 2008 down to 10.4 Bcf/d by 2023 (NEB, 2007: Appendix Table A4.2) as older fields become less productive. (NEB, 2007: p.11) This 33% decrease in production will open up additional capacity on pipelines transporting supplies from the area. Figure 14 shows NEB's forecast for WCSB production.

Figure 14: NEB WCSB Production Forecast

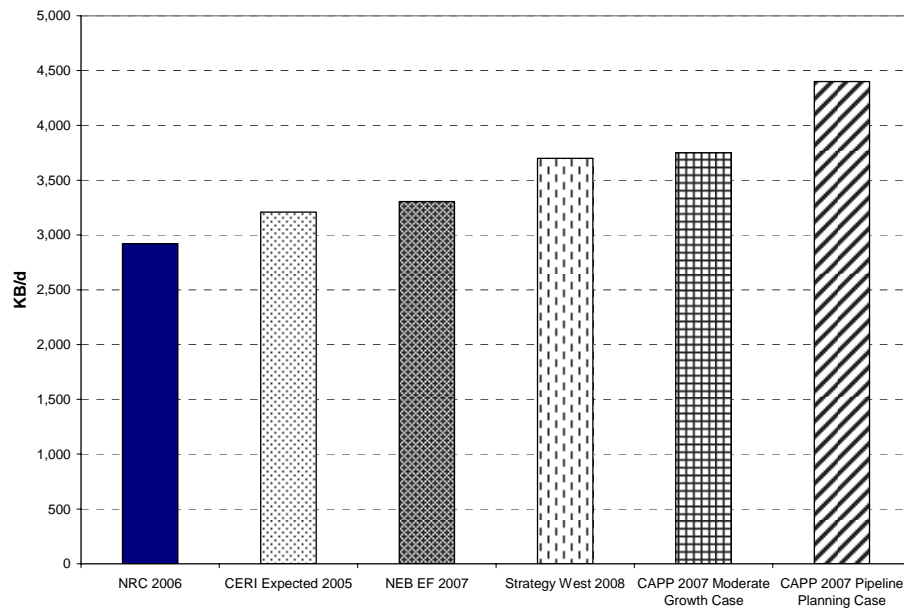


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Depending on how much if any gas pipeline capacity is converted to oil capacity, the oil sands projects could further increase take away capacity from Alberta, as gas supplies are used for production and diverted from export markets. In this event, Alaska gas would find even greater outlets to US markets.

Projections for oil sands production range from approximately 2,900 kb/d to 4,400 kb/d by 2020. (National Resources Canada, 2006: p.36; Canadian Association of Petroleum Producers, 2007: p.31) Many factors affect the feasibility of oil sands projects including prices and supply costs, the impact of escalating capital costs, changes to Alberta's royalty rates and a shortage of skilled labor. Aside from these, there are also a number of environmental concerns and uncertainties that have the potential of setting back the industry including water usage, air quality, and the possibility of provincial and federal regulations on GHG emissions. Figure 15 shows various forecasts for oil sands production in 2020. (National Resources Canada, 2006: p.36; Canadian Energy Research Institute, 2005: p.20; NEB, 2007: Figure 4.11; Strategy West Inc., 2008: Slide 32; Canadian Association of Petroleum Producers, 2007: p.32, Canadian Association of Petroleum Producers, 2007: p.31)

Figure 15: Oil Sands Production Forecasts in 2020

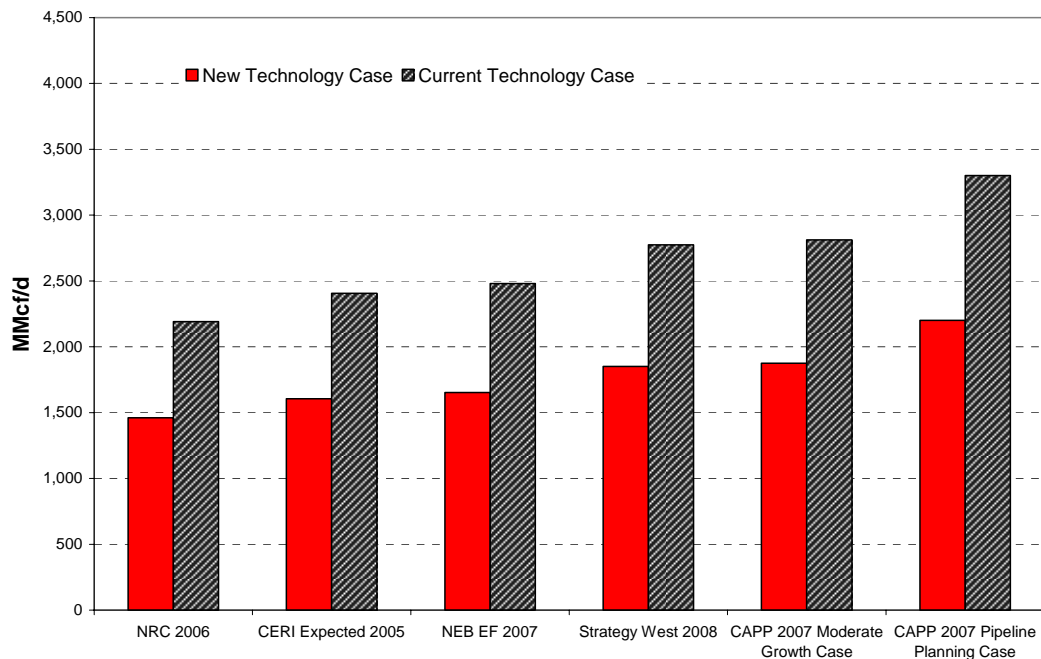


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In their January 2008 presentation at the 5th Annual Canadian Oil Sands Summit, Strategy West projects that gas intensity⁶, or the amount of purchased gas used per unit of bitumen recovery, will trend downward from current levels under new technology scenarios. (Strategy West, 2008: p.22) This downward trend can be attributed to efficiencies gained with current technologies and through the adoption of new technologies which use bitumen or bitumen residues as fuel at in situ projects, as well as the introduction of the gasification of bitumen residues at upgrading facilities. (Strategy West, 2007: p.1)

Multiplying the above oil sands projections by Strategy West's purchased gas intensity estimates in 2020 under current and advanced technology scenarios (Strategy West, 2008: slide 22) yields a purchased gas consumption range between approximately 2.2 Bcf/d to 3.3 Bcf/d assuming current technologies, or 1.5 Bcf/d to 2.2 Bcf/d assuming new technologies. Figure 16 outlines projected purchased gas consumption under current and advanced technology scenarios.

Figure 16: Purchased Gas Consumption for Oil Sands Production in 2020



Given this range of gas requirements, Alaskan gas will serve the lower 48 states even under the most stringent natural gas consumption scenario.

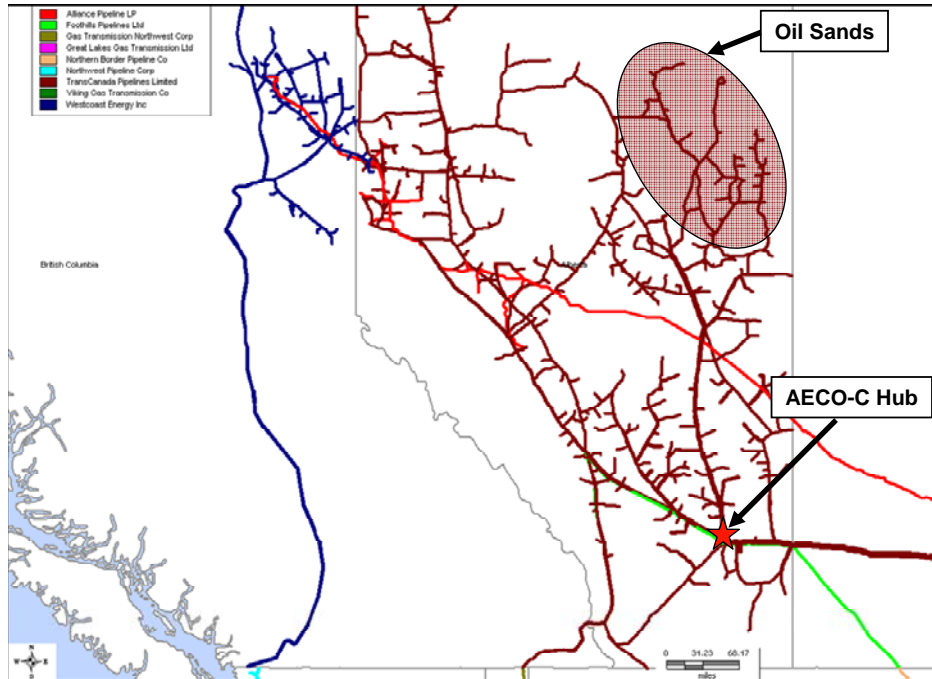
The geographic location of the Oil Sands in northeastern Alberta also suggests that gas demand might most readily be served by local Alberta production delivered via existing NOVA gathering

⁶ Strategy West's gas intensity projections do not include associated gas or gas used for production of electricity at oil sands cogeneration facilities. Estimated "Pipeline Planning Case, Existing Technologies" and "Moderate Growth Case, New Technologies" gas intensities in 2020 from chart on page 22 of report.

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system infrastructure instead of by new Alaskan gas. Figure 17 shows a map of the provincial gathering system infrastructure, as well as the general location of the oil sands. (Velocity Suite Online, B&V)

Figure 17: Alberta Infrastructure and Oil Sands



The Canadian Energy Research Institute's "The Capacity of Western Canada's Natural Gas Pipeline System" forecasts that unused take-away capacity from the southern Alberta area will increase to 6.9 Bcf/d by 2018, (Canadian Energy Research Institute, 2006a: p.2) assuming that the Alaska pipeline was in service in 2016. (Canadian Energy Research Institute, 2006b: p.13)

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4.0 PLAN TO OBTAIN SHIPPER COMMITMENTS

This factor addresses whether the applicant's service terms and conditions, as defined in the AGIA application, contracts, and preliminary terms are likely to be strong inducements to potential shippers. (Sec.43.90.170 (c)(1))

4.1 Do the applicant's plans encourage shippers to participate in the first binding open season?

Assessment: Positive Impact

A valuable feature of TransCanada's proposal is the potential for shippers to negotiate important aspects of their transportation service. (Application, pages 2.2-66-68) As required by AGIA, TransCanada proposed default services that potential shippers can consider in contemplating an open season response. Exxon Mobil, among other industry participants recognize that the proposal is in many respects an initial offer. Our assessment leads us to conclude that TransCanada's proposal provides a good starting framework and invites serious counter-offers. The flexibility for TransCanada and shippers to negotiate and conform the project to meet a variety of operating, financial and risk objectives significantly enhances its prospects for success.

Negotiated open seasons are common in the interstate pipeline industry. Respondents to an open season always retain the option to submit binding offers that differ from the service terms offered by a pipeline or are contingent on a variety of events and other factors. The strategic risk of attaching stipulations to an open season response occurs because of the potential risk that a sponsor will receive enough qualified open season responses and reject all others that do not qualify. This is unlikely in the context of the Alaska gas pipeline project since the project will likely need commitments from all shippers in order to be viable. Given the flexibilities inherent in the proposal and the likelihood that a counterproposal will not result in a prospective shipper being excluded from the project, there is little risk in pursuing alternative terms to those contained in TransCanada's default services particularly given the profits that producers stand to realize. The BV NPV team estimates that under its reference case scenario, the aggregate producers NPV totals approximately \$13.5 billion. This amount decreases from \$13.5 billion to \$11.6 billion assuming federal loans, and decreases from \$13.5 billion to \$11 billion if the overrun is funded by additional equity. Thus, assuming that producers want to monetize their North Slope gas reserves in the timeframe proposed by TransCanada, there are few rational reasons not to participate in TransCanada's first binding open season offering.

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TransCanada's proposal offers negotiating opportunities in several ways. First, the application for license describes shipper options for term differentiated rates. This feature would enable shippers to lower their unit transportation costs by extending their commitments beyond the 25-year basic term.

TransCanada also intends to offer Negotiated Rates under which numerous aspects of the service and transportation rates can be negotiated on both the Alaska and Yukon pipeline sections. (Application, pages 2.2-66-68) These include return on equity, capital structure, depreciation rates, rate base, and other factors.

TransCanada's Precedent Agreement also provides opportunities for shippers to negotiate key provisions of their otherwise binding open season commitment. As part of an Open Season announcement, project sponsors will typically provide a proforma Precedent Agreement for shipper review. If a shipper's nomination in the Opens Season is accepted, then various aspects in the Precedent Agreement are generally subject to negotiation. Key elements will often include regulatory and other termination rights, milestone dates, and mutual commitments for support and communication by all parties.

In the same aspect as the Precedent Agreement, TransCanada's shippers will have the opportunity to comment in the drafting of the Alaska and Yukon pipeline Federal Energy Regulatory Commission (FERC) and NEB Gas Tariffs. The TransCanada application provides an initial outline of the Tariff, but leaves many detailed aspects still to be written. (Application pages 2.2-61-64) These documents give detailed shape to many of the commercial and operating characteristics of a pipeline's service. Because this is a new project built for specific initial shippers, TransCanada can expect to receive comments during a collaborative drafting of the Tariff, or in regulatory motions filed in the certificate process.

Finally, TransCanada offers the ultimate negotiated term for Anchor Shippers, and that is the option for ownership in the system. (Application, pages 2.2-69-70) Ownership not only provides investor/shippers with some degree of input into the pipeline company operations, but also acts as a hedge on one-sided terms by the project sponsors. If a shipper feels that terms and conditions are too generous to owners to the detriment of shippers, that shipper can elect to be an owner.

The ability to negotiate major aspects of a transportation service enables risks to be fairly allocated between the sponsor, its customers and other stakeholders. This is valuable to all parties in the development process because each will have different risk preferences that will bear on their commitment to the project.

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4.2 Do the applicant's service offerings encourage shipper open season commitments?

Assessment: Positive Impact

Any assessment of the project likelihood of success should be predicated, in part, on the factors that constitute successful offers by other pipelines. By reviewing industry standards, a set of basic factors for evaluating the TransCanada proposal start to emerge. (B&V analysis) While industry standards represent important benchmarks, it is also necessary to recognize fundamental and significant differences between any set of new pipeline construction projects and the unique characteristics of the proposed Alaska project. In choosing new projects to review for standards, key characteristics included size of the project, expansion of shipments to new markets and recent vintage. None of the new projects are strictly comparable in size or investment. They are large in the sense of recent projects subject to FERC regulatory review in recent years. The pipeline proxy group is comprised of the following systems/projects: (Cheyenne Plains Gas Pipeline Company, Alliance Pipeline, Millennium Pipeline Company, L.L.C., Maritimes & Northeast Pipeline, Portland Natural Gas Transmission System, Rockies Express Pipeline, Iroquois Gas Transmission System, L.P.)

- Cheyenne Plains Gas Pipeline Company – A .6 Bcf/d pipeline from northern Colorado to Oklahoma, where it connects with interstate pipelines serving the northeast and Midwest. Developed by El Paso Corporation and placed into service in 2005.
- Alliance Pipeline– A 2.1 Bcf/d dense phase pipeline from British Columbia to Illinois, where it delivers gas to be processed for transport to Midwest and East Coast markets. Developed by a joint venture of Fort Chicago Partners and US and Canadian producers and pipelines, it was placed into serve in 1999.
- Millennium Pipeline Company, L.L.C. – A .525 Bcf/d pipeline originating in western New York and delivering supplies to interstate pipelines serving New York City and New England. Developed by a joint venture between NiSource, DTE Energy, and TransCanada, it will be placed into service in 2009.
- Maritimes and Northeast Pipeline– A .7 Bcf/d (now 1.2 Bcf/d) integrated Canadian-US pipeline originating in Nova Scotia and terminating in Massachusetts just north of

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Boston. Developed as a joint venture between Duke Energy (now Spectra) and Mobil (now Exxon Mobil), it was placed into service in 2002.

- Portland Natural Gas Transmission System (PNGTS) – A .25 Bcf/d pipeline originating at the Quebec-US border in New York and terminating north of Boston. The system was developed by TransCanada and Shell and placed into service in 1993.
- Rockies Express Pipeline (REX) – A 1.8 Bcf/d pipeline from Wyoming to Ohio where it will connect with pipelines serving the Midwest and East Coast. Developed as a joint venture between Sempra and Kinder Morgan, the initial phase is expected be operational in 2008, with the second phase extension complete in 2009.

In choosing these seven pipelines for developing a set of industry standards, the potential for wide variation on non-policy issues creates a range of values to use as benchmarks. As a result, we have developed the information for TransCanada and these seven pipelines for a core set of factors as shown in Figure 18 (Alliance Pipeline, L.P., 84 FERC ¶ 61,239 (1998); Alliance Pipeline, L.P., 80 FERC ¶ 61,149 (1997); Cheyenne Plains Gas Pipeline Company, Application for Certificate of Public Convenience and Necessity, Docket Nos. CP02-302-000, CP03-303-000, CP03-304-000; Colorado Interstate Gas Company and Cheyenne Plains Gas Pipeline Company, LLC., 105 FERC ¶ 61,095 (2003); Colorado Interstate Gas Company and Cheyenne Plains Gas Pipeline Company, LLC., 106 FERC ¶ 61,275; Great Lakes Gas Transmission Limited Partnership, Expansion Construction Cost Comparison Report, Docket No. CP96-647; Great Lakes Gas Transmission Limited Partnership, Notice of Intent to Prepare an Environmental Assessment for the Proposed 1998 Expansion Project and Request for Comments on Environmental Issues, Docket No. CP96-647-000; Great Lakes Gas Transmission Limited Partnership, Order Amending Certificate, Docket No. CP96-647-001; Maritimes & Northeast Pipeline, L.L.C. and Portland Natural Gas Transmission System, 80 FERC ¶ 61,346 (1997); Millennium Pipeline Company, L.P., 100 FERC ¶ 61,277 (2002); Northern Border Pipeline Company, Notice of Intent To Prepare an Environmental Assessment for the Proposed Project 2000 and Request for Comments on Environmental Issues, Docket Nos. CP99-21-000, CP99-21-001, CP99-21-002; Portland Natural Gas Transmission System, 80 FERC ¶ 61,134 (1997); Portland Natural Gas Transmission System, Notice of Application, Docket No. CP99-55-000; Rockies Express Pipeline LLC., 116 FERC ¶ 61,272 (2006); Rockies Express Pipeline LLC., 119 FERC ¶ 61,069 (2007)).

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Figure 18a: Summary Tariff/Rate Profile for Recent North American Natural Gas Pipeline Projects (p.1 of 2)

Issue	Return on Equity	Rate of Return	Depreciable Life	Rate Structure	Rate base	FL&U	Capital Structure (Debt/Equity)
Trans Canada Proposal	US 10-year Treasury Note plus 965 basis points for life of agreement	7.49% assuming 4.7% debt and 14% ROE	25 years	SFV	All costs included even if there are cost overruns, no mention of prudence reviews	Actual tracked cost	70/30 (During Construction) 75/25 (Proposed)
Cheyenne Plains	15% ROE , 9% cost of debt and subject to just and reasonable standard review after 3 years of operation proposed, 14% ROE granted, cost of debt to be updated once rates were filed	11.4% proposed, 10.5% granted assuming 14% equity and 9% debt	35 years proposed and approved	SFV	Rates based on the as filed estimate of total cost for pipeline.	Reimbursed in kind by component charge recomputed at least annually, and adjusted by actual experience proposed and later approved	60/40 (Proposed) 70/30 (Ordered)
Alliance	7.5% debt and 14% ROE	9.45%	25 years proposed and approved	Levelized	Based on ROE of 12%, but provides .5% inverse adjustment for cost overruns of 10%	Reimbursed in kind	70/30
Millennium	14% ROE and 7.5% cost of debt (proposed)	9.78% (Proposed) 9.13% (Required)	20 years	Levelized for 15 and 20 year contracts and SFV for shorter contracts	Based on as filed estimate of total cost of pipeline, Cost overruns would initially be borne by the shippers, but only up to the rate caps. Beyond that, Millennium bears cost. Millennium will need to reconcile differences between projected and actual costs 6 months later.	N/A	65/35 (Proposed) 70/30 (Ordered)
Maritimes	debt cost of 8% and ROE of 14% proposed and accepted	9.5% proposed and accepted	25 years proposed and approved	Levelized Cost of Service proposed and accepted	Rates based on as filed estimate of total cost of pipeline	Reimbursed in Kind	75/25 (Proposed and Granted)
PNGTS	Cost of equity is 14 % and the debt cost is 7.69% (Proposed and accepted)	9.26%	20 years (Proposed and accepted)	levelize its rates for the first 20 years that the proposed facilities will be in operation (Proposed)	Rates based on as filed estimate of total cost of pipeline (Proposed)	"Measurement Variance" between a minimum of down to -1.00% and a maximum of "up to +1.00%"	75/25 (Proposed)
REX	13 % based on public interest standard subject to just and reasonable standard review after three years of operation	10.19%	35 years	SFV	Rates based on the as filed estimate of total cost for pipeline	Actual tracked cost by component	45/55

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Figure 18b: Summary Tariff/Rate Profile for Recent North American Natural Gas Pipeline Projects (p.2 of 2)

Issue	Credit Requirement	Expense Recovery	Risk Profile	Open Season Requirements	Precedent Agreements	Interruptible Revenue Treatment	Minimum Contract Length
Trans Canada Proposal	Acceptable credit rating and tangible net worth greater than the capital cost of its share of the rate base over the life of the agreement	Full recovery of all expenses	Earned ROE at full rate for each year	Consistent with FERC policy-limit late bids	Requirement to support TransCanada in all regulatory applications	No IT service mentioned	25 Years
Cheyenne Plains	Minimum threshold credit standards or demonstrate creditworthiness by committing an amount equal to at least one year of reservation charges under the contract approved by Commission.	Rate recovery, may be more or less	Cost of Service recovery with regulatory risk and subject to NGA Section 5 review after three years	N/A	All customers elected negotiated rates	Proposed to not allocate costs to IT service. Proposes crediting 25% of IT revenues to firm shippers, retaining 75%. Commission ordered them to credit 100% of the revenues accrued, net of costs incurred, to provide service.	N/A
Alliance	N/A	Rate recovery, may be more or less	Cost of Service recovery with regulatory risk	Open season for its 93% of design day capacity	All customers elected negotiated rates, levelized rates	Credit 100% IT revenues to firm shippers	15 years, 5 year notice provision
Millennium	N/A	Rate Recovery, may be more or less	Cost of Service recovery with regulatory risk	Held open season	Shipper agrees to use reasonable efforts to support Millennium's applications for regulatory authorization. Millennium has entered into long-term, binding precedent agreements with eight customers that subscribe 66 percent of the capacity of its proposed pipeline.	Millennium did not propose to allocate any costs to IT services (Proposed), Commission ruled Millennium was required to either allocate costs to its interruptible services and recalculate its rates or revise its tariff to credit 100 percent of the ITS revenues net of variable costs to its firm recourse rate shippers (Ordered).	10 years
Maritimes	N/A	Rate Recovery, may be more or less	Cost of Service recovery with regulatory risk	Held open season for capacity that equals design capacity	Fully subscribed for 20 years	Allocated portion of cost to IT revenues	N/A
PNGTS	Shipper prepays for the service or supplies a letter of credit for an amount equal to the sum of the monthly reservation charges plus the usage charges for the duration of the contract	Rate Recovery, may be more or less	Cost of Service recovery with regulatory risk	N/A	Seven shippers for 20 yrs	PNGTS proposes to credit revenues from interruptible service (IT) and off-peak firm service to users not contracting for 365- day service to the regulatory asset account created for the levelized rates. (Proposed)FERC ordered them to credit 100% IT revenues to firm shippers (Ordered)	N/A
REX	BBB- credit rating and 36 months of pipeline charges (36 months of bills) less than 15% of tangible net worth	Rate recovery, may be more or less	Cost of service recovery with regulatory risk and subject to NGA Section 5 review after three years	Consistent with FERC policy	All customers elected negotiated rates and some non-conforming provisions approved	Revenue sharing per FERC policy	10 years

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We discuss conclusions relative to the standards indicated by the results of the above table in the sections below. In summary, the table illustrates that the TransCanada proposal is reasonably consistent with industry standards on the following items: SFV rate design, FL&U (fuel lost and unaccounted for gas), open season requirements and, capital structure. For the remaining items in the table our discussion is included in the response to issues addressed below.

4.3 Do the project rates and cost recovery methods reasonably allocate risks between shippers, sponsors and stakeholders?

Assessment: No Impact

As presented in its application, shippers appear to bear proportionally greater risks than TransCanada. Given recourse rates that stipulate a minimum contract term of 25-years that matches the annual depreciation rate for capital investments, initial shippers are essentially expected to fund the entire cost of the pipeline, even though it likely will have a much longer useable life. (TransCanada, pp. 2.2-65 and 66). Balanced against this are proposed recourse rates that include:

- variable equity return indexed to U. S. 10 year Treasury Note with a premium equal to 965 basis points (Op. cit. p. 2.2-67)
- inclusion of 100% of capital costs, and
- full tracking and recovery of 100% operating costs (Op. cit. p. 2.2-66),

On the one hand these provisions can be viewed as favorable to the project's LOS because they enhance the prospects of attracting the equity and debt capital that the project will need to finance the facilities. On the other hand, if judged by shippers to be too generous, these rates may discourage shipper commitments to the project as proposed and result in alternative proposals from shippers.

The summary table in Figure 19 adds useful context to the analysis and helps frame TransCanada's proposed recourse rates relative to other projects that have required cost of service and rate filings after the first three years of operation. As seen in the table and discussed in the preceding section of this report, relative to pipeline industry standards TransCanada's proposed recourse rates and associated terms trend to the upper end of the

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ranges generally accorded to sponsors. As such, they are also high relative to industry standards for the level of risks assumed by other pipelines. Examples of this include:

- A 14+% return on equity
- 100 percent recovery of operating costs represents a pipeline-favorable provision;
- 100 percent inclusion of cost overruns is favorable to the pipeline, but subject to regulatory approval, which is not a given.

TransCanada has also proposed provisions that could (partially) offset certain risks inherent in its proposal. In so doing TransCanada indicates a willingness to provide shippers with terms that are similar to other interstate pipeline projects, and otherwise mitigate the severity of its cost recovery terms. Among the notable proposed terms, TransCanada:

- Offered to absorb some of the potential impact of cost overruns for a limited term. Under this proposal, TransCanada would agree to a penalty of no more than five years and 200 basis points for large cost overruns. (in excess of 40% not subject to any further reduction) (Op. cit. p. 2.2-66) Such a provision, while providing some protections to customers, is limited in nature because it would apply to the equity component of the rates only.
- Planned to follow Canadian regulatory practice by offering the potential for negotiated rates on the Yukon-BC portion of the pipeline. (Op. cit. pp. 2.2-65, 66 and 67)
- Proposed a 75/25 debt/equity capital structure that helps to “dilute” an otherwise robust proposed cost of equity and yields a reasonable rate of return of less than 8.5 percent. In comparison, the REX pipeline received FERC approval for a 13 percent return on equity with a capital structure of 55 percent equity and 45 percent debt and a rate of return of 10.19 percent as the basis for its recourse rate. The REX rate is subject to review after three years of operation to determine the just and reasonable rate level. (Docket No. CP06-354-000, Preliminary Determination on Non-Environmental Issues, 2006: p.15)

Based on the magnitude and complexity of this project, higher returns may be warranted due to the following factors:

- The project risks associated with construction including the risk of non-completion and the uniquely large risks resulting from the challenges of the project.

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- The regulatory standard for approval of the return of and on rate base requires that the rate base be used and useful and that the costs be prudently incurred, thus there is a risk of rate base disallowance.
- The risk of relatively high leverage for the project offsets against the higher initial equity return.
- The project offers opportunities for shippers to ensure cost control by taking equity positions that permit the shippers to lower their effective transportation costs.
- At this stage in the project the number of unknown factors and the potential for unfavorable outcomes creates risks for all parties.

Certain other terms may favor the shippers such as all NGL revenues accrue to shippers (Op. cit. p.2.2-64), potential for partial ownership in the pipeline with the expected return based on the ownership share (Op. cit. pp. 2.2-69 and 70), ability to release unused capacity (Op. cit. pp. 2.2 61 and 62) (likely to be full rate at least in the early years), negotiated rates based on levelized costs over the contract term (Op. cit p. 2.2-67) avoiding the higher initial rates under the recourse option, the specific exclusion of the \$500 million State reimbursement from rate base, (Op. cit. p. 2.2-65) potential to own and control the gas treatment plant and associated costs (Op. cit. p. 2.2-64) and reduced contract terms on the Alberta segment of the line. (Op. cit. p. 2.2-64) On balance, taking into account both the risks and returns to sponsors, the recourse rates for shippers, and the breadth of negotiating opportunities available under the proposed structure, we believe that TransCanada's creates neither profound positive or negative impacts on the LOS. Stated another way, there are too many proposed terms favoring TransCanada that shippers may deem unacceptable and thus are not positive impact on the project, yet too many terms that can be negotiated providing mitigation to shippers to result in a negative impact finding. For this reason we believe the countervailing pros and cons of the proposal support a conclusion that the allocation of risks through service terms – as currently proposed – will have No Impact on the project's LOS.

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4.4 Do applicants proposed rates insulate shippers from the effect of cost overruns?

Assessment: No Impact

Section 43.90.170(c)(1) seeks an assessment of “*the reasonableness, specificity and feasibility of . . . [TransCanada’s] plan to . . . insulate shippers from the effect of cost overruns, . . .*”

In absolute terms, TransCanada’s project does not insulate shippers from cost overruns. Given the uncertainties and risks of a project of this magnitude, striking a balance of the risk allocation is likely to be critical to the ability to obtain capital commitments for the completion of the project. In its application, TransCanada clearly states that with the exception of specific and relatively modest self-imposed penalties, it expects 100 percent recovery of its capital and operating costs through recourse rates. Likewise, investors will have the expectation of recovery of all prudently incurred costs.

In relative terms, TransCanada’s proposal is not out of step with pipeline industry regulation and practices. Although some pipelines do provide rate caps for project shippers, the majority of pipelines will expect to ultimately collect their full cost of service from shippers, on terms essentially similar to those TransCanada proposes in its AGIA application.

Notwithstanding the risks this approach to cost recovery imposes on shippers, TransCanada’s application nonetheless affords opportunities to further shield shippers from overrun costs. These include:

- *TransCanada’s partial equity reduction* – TransCanada demonstrates a willingness to share construction cost risks through its proposal to reduce equity returns by up to 200 basis points on certain of its capital costs for a maximum of five years. Although this proposal ultimately offers only a negligible reduction for shippers – as Exxon Mobil notes in its comments, TransCanada’s income would still be higher with cost overruns than without – this type of voluntary concession is unusual in the pipeline industry.
- *Federal loan guarantees* – More details concerning the structure and use of Federal loan guarantees are required, but these may also partially insulate shippers from the full effect of cost overruns if they are triggered by cost overruns. By financing

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overruns with lower cost of debt (vs. equity), TransCanada would be able to partially mitigate the impact of the cost overruns passed along to shippers.

The figure below shows estimates from the NPV team regarding how the partial equity reduction and federal loan guarantees mitigate shippers from cost overruns:

Figure 19: NPV and per Unit Tariff Estimate Under Various Scenarios

Scenario			Estimates	
40% Cost Overrun	5-Year Equity Reduction	Federal Government Loans	Per Unit Tariff (\$/Dt)	NPV (\$ Billions)
			\$4.73	\$4.46
X	X	X	\$5.97	\$4.18
X	X		\$6.32	\$5.73
X		X	\$6.06	\$4.69

- *Regulator prudence reviews* – TransCanada's application does not address prudence reviews, but FERC and NEB regulators will retain jurisdictional responsibility to assure shippers and the public that all costs included in TransCanada's rates are just and reasonable. To the extent post-project reviews find certain costs were not prudently incurred, those costs may be excluded when deriving transportation rates.
- *Deferred recovery of Capital Cost Overrun Loan surcharges* – Would require Negotiated Rate Shippers to pay surcharges only when Alberta Hub prices are at or above a threshold level. When prices are lower, surcharges would be carried forward with interest until prices rise. This proposed provision would ensure a matching of shipper transport costs with supporting market revenues, and help shippers avoid the potential for negative cash flows as the result of capital cost overruns.
- *Negotiated rates* – In addition to the recourse rates, TransCanada's application expresses a willingness to negotiate major components of its cost of the service and rates including return on equity, depreciation rates, and term of contract. These factors can be structured to reduce both the timing and level of costs passed on to shippers, and in so doing partially offset the impact of cost overruns.
- *Negotiated precedent agreement terms* – TransCanada does not specifically define the terms it would be willing to negotiate in its Precedent Agreements, but shippers can reasonably expect to negotiate a range of provisions as may be needed to mitigate perceived risks. With regard to cost overruns, one example arrangement for

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allocating certain risks is a steel “tracker” similar to that found in shipper Precedent Agreements for the Rockies Express pipeline. Such a provision allows the parties to index the costs to be included for key construction cost components. Final terms for the REX Precedent Agreements are not known, but other arrangements may be employed by TransCanada and its shippers to clarify the treatment of certain types of capital costs and any associated overruns.

- *Ownership option* – TransCanada offers Anchor Shippers the opportunity to become owners in the project. Although the specific terms and equity interests available must still be defined, ownership provides one way to reduce the effective costs of any transportation service, including one burdened by cost overruns

Shippers and other stakeholders may fairly argue that TransCanada could offer greater shipper protections from cost overruns, and such terms might have provided the basis for a “Positive Impact” assessment by B&V. Such an offer may have had a negative impact on the ability to finance the project, however. Striking the critical balance between financial viability and insulating shippers will ultimately be determined by the interaction of all stakeholders. As proposed, however, we think the combination of TransCanada’s voluntary equity basis reduction and the other factors described above sufficiently exceed standard industry practice such that a “No Impact” assessment is more appropriate than a “Negative Impact” assessment.

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5.0 OTHER FACTORS PURSUANT TO SECTION 43.90.170 (C)

5.1 Is the Project supportive of or otherwise an impediment to an LNG export facility?

Assessment: Positive Impact

TransCanada's proposal reserves initial North Slope production for support of a pipeline to the Lower 48. Beyond the initial expansion, the proposal includes a number of provisions that might contribute to the development of an LNG import terminal. The capacity of an expansion in support of an LNG export project is likely to be more consistent with demand growth in the Pacific Basin than the larger initial project proposed by TransCanada. Among the provisions in TransCanada's application that support an LNG project are the following:

- *The project provides for a possible Y-line lateral to an LNG export facility on the Kenai Peninsula*

It should be recognized at the outset that the Alaskan segment of the TransCanada proposal moves North Slope gas closer to a Kenai export point than it is today. When coupled with TransCanada's proposal for regular expansions, a Y-line lateral could provide for smaller sized capacity projects (as compared to the initial TransCanada build) that are economically more competitive than a greenfield line all the way from the North Slope in serving global markets.

- *TransCanada proposes regular expansions that would facilitate getting supplies to the Y-line.*

By hosting predictable and regular expansions, TransCanada will help marketers time the needs of specific Pacific Basin suppliers more effectively. Asian LNG markets, unlike North American markets, are still heavily dependent on bilateral contracts which require greater coordination between supply and distribution legs of the value chain. The uncertainty caused by the need to synchronize several components of a supply chain can be mitigated in part by smaller and predictable expansion increments.

- *TransCanada's proposed transportation rates differentiate the cost of delivering into an LNG line versus at the Alberta terminus of the fully built project.*

TransCanada has proposed an Alaska segment rate that will not only facilitate deliveries to in-state consumers, but will also unburden LNG exporters of unneeded

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downstream transportation costs. This distance sensitive rate design and the proposal for rolled-in expansion tolls will make LNG exporters more competitive abroad.

- *FERC policy ensures that third party LNG developers will have access to TransCanada's Alaska Gasline.*

FERC open access guidelines generally require pipelines to provide interconnecting facilities to parties wanting access to interstate transmission systems. These policies effectively mean that an LNG exporter has the right to request and pay for facilities that would allow gas to flow from the Alaska Gasline into a pipeline that would feed a Kenai Peninsula LNG export facility.

Taken as a whole, the combination of TransCanada's proposal and regulatory policy preserve indefinitely the right of future Alaska gas producers to develop LNG export capabilities. The proposed TransCanada project effectively creates the critical backbone necessary for exports by leveraging the economies of scale inherent with the initial build.

5.2 Is TransCanada (as the operator) a credible developer of the project? Has applicant successfully developed other large pipeline projects?

Assessment: Positive Impact

TransCanada has built or participated in other large pipeline projects in the past. Some of the projects they have built include a series of mainline expansions, the Energia Mayakan Natural Gas Pipeline Project, and the Tamazunchale Pipeline Project. The projects they have completed required capital cost from less than 20 million up to 900 million to serve various markets such as Canada, US, San Luis Potosi, and the Yucatan Peninsula. (Alexander's Gas & Oil Connections, 1999; Catharine Davis, 2007; [Dave Schultz, 2002](#); Department of Energy, 2008; Iroquois Gas Transmission System LP., 10-Q SEC Filings, 2002; Northern Border Partners, L.P. 10-K SEC Filings 1998, 2000, 2002; Northern Border Partners, L.P. 10-Q SEC Filing 1998, 2002; Northern Border Pipeline Company, 90 FERC 61,263 (2000); Oil & Gas Journal, 1996; Pipeline & Gas Journal, 2008; Portland Natural Gas Transmission System, 2008; Portland Natural Gas Transmission System, Docket No. CP99-55-000, 1998; PR Newswire, 1999; Steve Clark, 2006; TransCanada Corporation, 2005; TransCanada Pipelines Limited Annual Reports, 1997 - 2007).

Figure 20: TransCanada Pipeline Expansions Summary

Project Name	Pipeline	Operator	Capacity (MMcf/d)	Location	In-service Date	Capital Costs (millions)	Return on Equity	Market(s) Served	Builder	Participants (TransCanada Ownership %)
Mainline Expansion	Canadian Mainline	TransCanada	287	N/A	Nov-97	\$900	11.25%	Canada	TransCanada	TransCanada (100%)
The Chicago Project	Northern Border Pipeline Company	TransCanada	700	Harper, Iowa to Manhattan, Illinois	Dec-98	\$837	12.75%	Northern Illinois	Enron Engineering and Construction Company	TransCanada (30%) & Northern Border Partners, L.P. (70%)
Mainline Expansion	Canadian Mainline	TransCanada	100	N/A	1999	\$400	11.25%	Canada	TransCanada	TransCanada (100%)
Portland Project	Portland Natural Gas Transmission System	Portland Natural Gas Transmission System	175	TQM near Pittsburg, NH and delivery points in MA	Mar-99	\$271	14.00%	Northeastern US	Portland Natural Gas Transmission System	TransCanada (21.4%)
Energia Mayakan Natural Gas Pipeline Project	Energia Mayakan	TransCanada	370	Ciudad Pemex, Tabasco to power plants in Campeche and the Yucatan	Sep-99	\$266	N/A	Yucatan Peninsula	TransCanada	TransCanada (62.5%), InterGen (32.5%), & Gutsa Constructions (5%)
Tamazunchale	Tamazunchale Pipeline	Transportadora de Gas Natural de La Huasteca[2]	170	Naranjos Veracruz to Tamazunchale, San Luis Potosi	Dec-06	\$181	N/A	San Luis Potosi	TransCanada	TransCanada (100%)
Eastchester Expansion	Iroquois Gas Transmission System	Iroquois Pipeline Operating Co	230	Long Island into NYC Market	Feb-04	\$170	14.00%	New York City	Iroquois Pipeline Operating Co	TC Pipelines (41%)
Northwest Mainline Expansion		TransCanada	415	Transported from Ladyfern BC	Early 2002	N/A		N/A	TransCanada	TransCanada
Great Lakes 1998 Expansion Project	Great Lakes Gas Transmission System	Great Lakes Gas Transmission Company	126	Emerson, Manitoba to Saint Clair, MI	Nov-98	\$149	N/A	US Midwest	Great Lakes Gas Transmission Limited Partnership	TransCanada (50%) & Coastal Corporation (50%)
Westpath Expansion	Alberta & BC Systems	TransCanada	350	Alberta and British Columbia border	2002	\$115	11.25%	California and Pacific Northwest	TransCanada	TransCanada (100%)
Project 2000	Northern Border Pipeline Company	Northern Border Pipeline	544	Manhattan, Illinois to North Hayden, Indiana	Oct-01	\$94	12.00%	Northern Indiana	Northern Border Pipeline Company	TC Pipelines[1] (10%)
Narraway Extension Project	Canadian Mainline	TransCanada	100	Transported from Narraway and Cutback of Western Alberta	2002	\$17	11.25%	Alberta	TransCanada	TransCanada (100%)
Mainline Expansion	Canadian Mainline	TransCanada	417	N/A	1998	N/A	11.25%	Canada	TransCanada	TransCanada (100%)

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5.3 What impact might the BP-Conoco announcement to develop and construct the Denali pipeline have on TransCanada's ability to secure shipper precedent agreements and the likelihood of success of their project?

Assessment: Positive Impact

More than anything, Denali legitimizes the need for the pipeline and effectively ends the debate about whether the timing or concept of TransCanada's proposal is credible.⁷ That fact alone may raise expectations for the likelihood of success like no other.

It is generally accepted, however, that two Alaskan gas pipelines are unlikely, and that the success of any one pipeline rests on shipper commitments from the North Slope's three largest gas producers.⁸ As such, the announcement by BP and Conoco to pursue an alternative project also creates uncertainties for the success of TransCanada's AGIA proposal.

One obvious uncertainty is whether BP and Conoco, as key members of the critical mass of shipper support needed for a successful pipeline, would ever opt from their announced plans and come into the TransCanada proposal or a merged version of Denali and TransCanada's proposal.

Another uncertainty is whether the Denali announcement will discourage other potential shippers from nominating capacity on the TransCanada pipeline. As the reasoning goes, if TransCanada's project does not have the Denali producers' commitment, why should others sign on to a project that lacks critical support?

In the face of these uncertainties, legislators and regulators must fairly question whether the TransCanada proposal's likelihood of success is irrevocably diminished, and by extension whether it should be denied an AGIA license for that reason. The answer is no.

⁷ "The time is right to start moving this project forward." Jim Mulva, ConocoPhillips chairman and chief executive officer. BP Press Release. 08 April. 2008.

⁸ Exxon Mobil is the third, and largest, producer. Assertions about benefits and incentives Denali sponsors effectively pertain to Exxon Mobil, even though they have announced no formal intentions in Alaska yet.

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TransCanada's prospects for success and the State's reasons for proceeding with AGIA at this point are based on the expectation that TransCanada and Denali will eventually merge into a "settlement" project. It is reasonable to expect that TransCanada's project will have many elements that are attractive to the Denali sponsors, and that those sponsors will want to integrate into a project that combines the best ideas from both projects. In the pipeline industry, such settlements among competing projects are common. Whether done through regulatory proceedings or joint ventures, settlements balance the interests of all stakeholders.

In its comments Exxon Mobil referred to TransCanada's proposal an initial offer. This is a reasonable observation that can be interpreted as meaning there are many negotiations and details to address before it can be known if TransCanada's proposal is optimal. By this standard, Denali too, must be considered an initial offer. More must be learned by all parties to compare the relative strengths and weaknesses of the two projects, before meaningful settlement discussions could take place.

The mechanics, timing and certainty of a settlement between TransCanada and Denali at this early stage are less important than recognition that for a settlement to occur, **AGIA must proceed by awarding a license**. Time must be given to shippers and regulators alike to learn whether the best of both projects can be combined into a superior solution. **Absent a licensee, the development dynamic changes materially and raises greater uncertainties for Alaskan gas reserves.**

Our likelihood of success assessment as required by AGIA considers three questions. An affirmative response to these questions supports TransCanada's likelihood of success.

- 1) Does AGIA and TransCanada's proposal support a potential settlement with the Denali sponsors?
- 2) Are there benefits to Alaska of awarding the AGIA license, despite the possibility that BP and Conoco may continue to conduct their due diligence on Denali?
- 3) Are there good incentives for BP and Conoco merge their project into TransCanada?

The first question considers whether the AGIA process leaves the door open for BP and Conoco to conduct their Denali evaluation, and then later become part of TransCanada's AGIA project. The answer is yes because AGIA affords parties both the time and the process for a merger to occur.

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TransCanada does not plan to complete its open season until 18 months after it is awarded a license.⁹ After that, it would be another 47 months before TransCanada expects to receive certificate authorization and must proceed to finance and build the project. This timeline would effectively provide the Denali sponsors with *at least* 65 months to complete their project analysis and determine whether Denali or TransCanada or a merged project is the superior alternative.

As important, AGIA provides the Commissioners with the flexibility and guidelines to approve a revised TransCanada project that includes BP and Conoco (among others) as participants. Moreover, TransCanada makes clear its willingness to offer equity positions to anchor shippers who make firm shipper commitments to the project. If BP and Conoco decide to join TransCanada's project in the future as shippers and joint venture owners, AGIA and TransCanada provide the procedural path for that to happen.

The second question that bears on likelihood of success is whether the State's interests are well-served by issuing the AGIA license despite the possibility that the Denali sponsors may become joint-venture partners in TransCanada's project. If the Denali sponsors join or merge with TransCanada (as the AGIA licensee) the State will benefit because it increases the probability that the final project will be consistent with AGIA provisions that seek to avoid a pipeline "at any price". AGIA provides guidelines on the State's values and priorities with respect to a Gasline project, and having the Denali producers in TransCanada's project shows alignment with the AGIA values and objectives. Among the benefits are:

- Project timing
- Rates and rate design
- Net present value expectations to the state
- True open access provisions, including the obligation to expand to accept third party gas

A consequential benefit of having TransCanada's proposal emerge as the prospective AGIA licensee is the improved certainty about pipeline path across Canada. Although TransCanada's certificate claims may be contestable, its previous studies and knowledge of the Canadian pipeline market will compare favorably to any alternative's sponsor. As well, TransCanada possesses right-of-way assets that may speed the process. These in turn

⁹ This is 18-months sooner than the AGIA requirements, which stipulate a 36-month maximum timeframe to host an open season.

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imply a potential for reduced cost and time requirements building across the Yukon and Alberta if it is part of a settlement project.

Finally, awarding a license to TransCanada lets their project serve as both a catalyst and benchmark for Denali. Denali sponsors have not stated that TransCanada's proposal has provided them incentive to develop their proposed pipeline. Notwithstanding, it would appear that the timing and participants in the Denali project are not independent of AGIA progress and the credibility of TransCanada's proposal. There was no mention of Denali prior to the conclusion of the AGIA's December submittal deadline, only general references to a Conoco project.¹⁰ Now, with TransCanada's application on the table, stakeholders have the benefit of evaluating Denali in context with an alternative, and against a potential joint venture that includes the best elements of both proposals. These options will not exist if AGIA does not produce a licensee.

On balance we believe the State will benefit by awarding the license. A potential of joint venture with producers on a settlement of TransCanada's project could emerge. ***Legislators should award TransCanada the AGIA license, then be patient for commercial actions to play out; both actions would enhance the TransCanada project's likelihood of success.***

The third and final question above looks at whether there are legitimate incentives for BP and Conoco to ultimately opt into TransCanada's project as a shipper and possibly joint venture owner. In other words, now that they have announced their plans, what would cause these two producers to change their minds and participate in TransCanada's AGIA project?

Notwithstanding the announcements to date BP and Conoco have much to potentially gain by forging a joint settlement with the AGIA licensee. And nothing at this point would seem to preclude the companies from exploring more options while they develop more specifics about Denali. The more information gained in the coming months, the better their decisions will be once their due diligence on Denali has advanced.

Among the things that BP and Conoco may find most attractive are the supporting factors that are unique to AGIA and cannot be easily obtained through negotiations outside the AGIA process. One important example concerns upstream fiscal terms on royalties and production taxes. Producers have indicated that finalizing pipeline terms and conditions

¹⁰ It is notable that Conoco's December pipeline "proposal" made no allusion to a partner; seemingly the progress of AGIA encouraged or accelerated BP's entrance to the process.

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without greater certainty on royalties and production taxes is counterproductive. Yet, this is what will happen with Denali.

Under AGIA, the State is precluded from negotiating terms that are competitive with the interests of the licensee. This presumably would include negotiating upstream terms with Denali shippers while TransCanada was prosecuting its AGIA application. By coming into the AGIA process through a settlement project, both the producers and the State could move more quickly to conclude upstream negotiations on fiscal terms.

The Denali producers also stand to benefit from TransCanada's presence and experience in the Canadian and downstream markets. Although not directly the product of AGIA, the fact that TransCanada may emerge as the AGIA licensee potentially confers advantages for producers in shipping gas to market. Denali's announced project offers the potential benefit of creating a competitor to TransCanada's strong presence in the market, but in the final analysis TransCanada may still offer the best combination of costs and certainty out of Canada, and optionality to market. A settlement on the Canadian path would have implications on the route across Alaska as well.

Becoming a shipper or joint venture owner with TransCanada under the AGIA process could also mitigate risks to the shippers in variety of ways. In a project of this size, any opportunities for material risk reduction could be compelling. Among those offered by working TransCanada as part of AGIA are:

- Capital cost optimization – There are certain to be project aspects where TransCanada capabilities will be superior
- Speed to market – As noted in the Denali announcement the time is right for an Alaska pipeline, and TransCanada appears to have an advantage based on years of previous work for sections of the pipeline, at least from Delta Junction forward. Experience that helps avoid project delays translates into construction interest savings and higher project (and State) net present values
- Regulatory risk – The complications of potential cross-subsidization associated with 100 percent producer ownership argues for heavy oversight and raises the potential for adverse regulatory decisions. The jurisdictional separation of ownership and use that comes with a more diverse ownership group encourages more light-handed regulation.

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- Risk diversification – The most apparent of all benefits is the opportunity to diversify the development and financing risks associated with a project this size.
- Partner risk – Although having non-producers in the pipeline's ownership structure can create competing interests, project sponsors may also find that it can provide an objective perspective when disagreements arise among producer owners.

Taking all factors into account, it is realistic to conclude that Denali will ultimately increase, and not decrease, TransCanada's likelihood of success in the project. As discussed above, Denali is evidence that the State, its gas producers and TransCanada are in greater alignment than ever before on the need and timing of the project. Even if the Producers continue to pursue Denali, in doing so they will materially improve their knowledge about the costs and challenges of their project. That knowledge serves to reduce the asymmetric distribution of information that often hinders pipeline developer negotiations with its shippers, and may ultimately serve to produce a more expeditious and balanced merged project than would otherwise be possible. The Denali sponsors have compelling reasons to ultimately enter into a settlement that produces a better project than either they or TransCanada are individually proposing today. ***If TransCanada is not the AGIA licensee, a settlement that integrates the best of all project proposals cannot happen.*** The consideration of all factors leads us to conclude that TransCanada's AGIA proposal has never shown a better potential for success than it currently does.

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