Economic, Fiscal and Workforce Impacts of Alaska Natural Gas Projects

FINAL REPORT

MAY 10, 2006

Prepared for

ALASKA DEPARTMENT OF REVENUE
P.O. BOX 110400
JUNEAU, ALASKA 99811

Prepared by

INFORMATION INSIGHTS, INC.
212 FRONT STREET, STE. 100
FAIRBANKS, ALASKA 99701
907.450.2450 | www.iialaska.com

information insights

Economic, Fiscal and Workforce Impacts of Alaska Natural Gas Projects

FINAL REPORT MAY 10, 2006

Brian Rogers, *Principal Consultant*
Doug Reynolds, *Oil and Gas Consultant*
Jana Peirce, *Consultant*

Additional staff: Charles Ermer, Nadine Hargesheimer, Cady Lister, Nancy Lowe, Sherry Modrow, Brandon Maitlen, Bobby Wilken

Prepared for

Alaska Department of Revenue
P.O. Box 110400
Juneau, Alaska 99811

Prepared by

Information Insights, Inc.
212 Front Street, Suite 100
Fairbanks, Alaska 99701
907.450.2450 *ph*
907.450.2470 *fax*

605 West 2nd Avenue
Anchorage, Alaska 99501
907.272.5074 *ph*
907.272.5076 *fax*

www.iialaska.com
info@iialaska.com

information insights

Table of Contents

Table of Figures

Executive Summary

INTRODUCTION

Alaska is in a good position to benefit from oil and gas industry strengths during the present period of record petroleum prices and profits. The State of Alaska has focused significant efforts on reaching an agreement to build a natural gas pipeline for transporting Alaska North Slope (ANS) gas to world markets.

The Alaska Department of Revenue (DOR) has asked Information Insights to analyze the economic, fiscal and workforce impacts of an Alaska natural gas project with a zero year, five year and ten year delay. Our analysis appears in two parts:

- An impact analysis of the gas pipeline proposal by the major North Slope producers [BP Exploration (Alaska), ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production, Inc.[1]] using a set of baseline assumptions provided by the department.
- A comparison of the impacts of three different scenarios for bringing Alaska gas to market based on our best estimates of costs and prices. The scenarios are based on proposals from the sponsor group and the Alaska Gasline Port Authority, but project assumptions have been adjusted to produce the best "apples to apples" comparison of all projects. The scenarios are:

    i. A 4.5 bcf/d (billion cubic feet per day) gas pipeline that parallels the Trans Alaska Pipeline to Delta Junction, Alaska, and then follows the Alaska Highway to Alberta, Canada. A 0.25 bcf/d spur line to Southcentral Alaska supplies in-state gas needs.

    ii. An Alaska LNG project based on the Alaska Gasline Port Authority (AGPA) proposal that includes a 4.0 bcf/d pipeline from Prudhoe Bay to Valdez, Alaska, where gas is liquefied and shipped as LNG to Pacific ports. A 0.25 bcf/d spur line supplies gas for in-state use to Southcentral Alaska.

    iii. A Y-line project with a 4.5 bcf/d pipeline from Prudhoe Bay to Delta Junction, where the pipeline splits into a 3.0 bcf/d pipeline to Alberta, Canada, and a 1.5 bcf/d pipeline to LNG facilities in Valdez. A 0.25 bcf/d Southcentral spur line from the Valdez line serves in-state needs.

To evaluate the impacts to the economy and employment in the State of Alaska for the baseline case and each of the scenarios, Information Insights created four economic models in Microsoft Excel, using in part economic data generated from IMPLAN economic impact modeling software. Our models calculate:

[1] Acting together as the Sponsor Group, the producers submitted a single application to the State of Alaska under the Stranded Gas Development Act (SGDA). The companies are referred to jointly in this study as the producers or the sponsor group.

- Fiscal impacts to the State of Alaska and its municipalities in annual revenues, and the net present value (NPV) of these revenues;
- Economic output, or contribution to gross state product, from the project, including effects of pipeline construction and operation, from state and local government spending of new oil and gas revenues, and from personal spending of Alaska Permanent Fund deposits generated from the project;
- The number of jobs created in the private and public sectors by the project and new economic activity brought about by the project;
- The effects of a delay in project start on these outcomes.

PART 1. BASELINE ANALYSIS OF THE SPONSOR GROUP PROJECT

We modeled the fiscal, economic and workforce impacts of an AlCan pipline project under the following baseline assumptions provided by the Department of Revenue.

Figure 1: Baseline assumptions for sponsor group project

Expected natural gas price, Chicago market	$5.50/mmBtu
Expected oil equivalent price	$33.00/Bbl
Year in which actual construction is expect to start	2011
Year in which the gas first flows	2015
Year in which last gas flows through the pipeline	2050

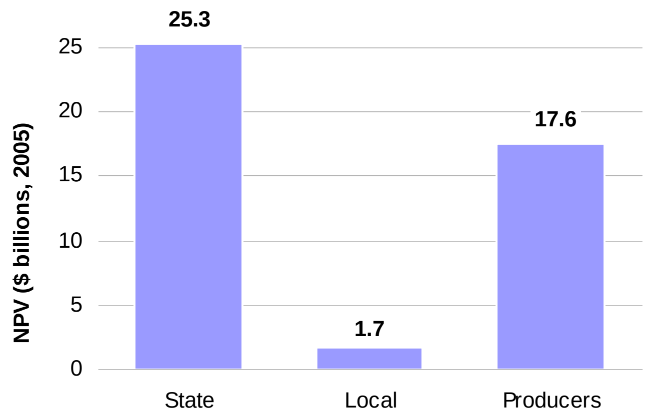
Note: All prices in real 2005 dollars

With a Chicago gas price of $5.50/mmBtu, we calculate a wellhead price of $3.43/mmBtu and a total pipeline tariff to be $2.07/mmBtu in 2005 dollars.

Based on these assumptions, our models show a net present value (NPV) of earnings to state and local governments of $27.0 billion over the life of the project[2]. The net present value of the project to the producers will be roughly $17.6 billion through 2050. Project revenues are expressed in real terms in 2005 dollars and include the effects of gains and losses in North Slope oil production due to a gas project, as well as revenues from the sale of natural gas and natural gas liquids. Our models use a 5 percent discount rate to calculate the present value of government revenue and a discount rate of 10 percent for private sector earnings.

[2] This report uses the 45-year period from 2006 through 2050 as the basis for all economic, fiscal and workforce projections.

Figure 2: Net present value of project revenues, 2010-2050

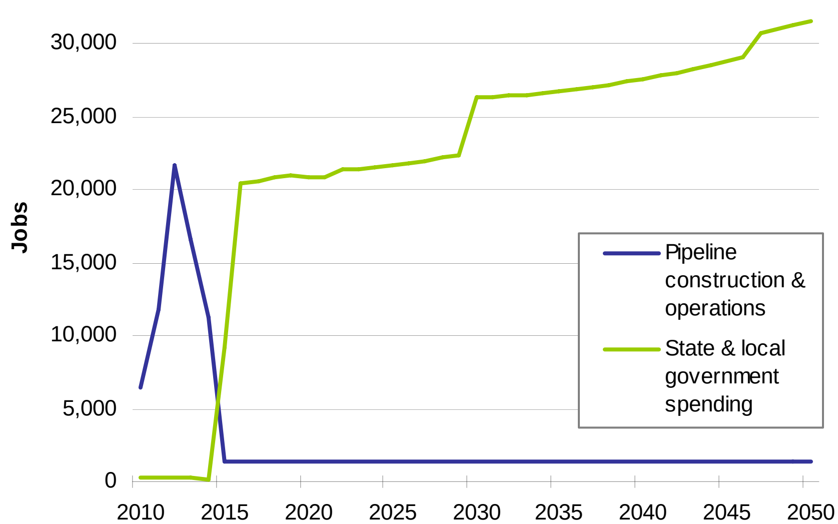


Note: Producers' NPV at 10%, government NPV at 5%

Assuming 25 percent of state royalties are placed into the Alaska Permanent Fund, annual earnings to the fund are the 7.6 percent projected by the Alaska Permanent Fund Corporation, and payouts of permanent fund dividends under current law, the project would result in a $28 billion increase to the Permanent Fund over the project's life.

The number of project-related jobs totals 68,000 job-years during construction. After construction, we expect an average of 1,300 jobs per year operating the pipeline and related facilities. State and local spending of project-related revenues will create an additional 901,000 jobs over the life of the project, for a total of just under 1 million jobs for all years from all sources.

Figure 3: Annual workforce impact of gas pipeline using baseline assumptions



Note: Direct, indirect, and induced full and part-time jobs

Figure 3 shows the annual workforce impact from a gas pipeline using the baseline assumptions. Each job represents the equivalent of one full or part-time job created through direct, indirect and induced employment impacts.

The following table summarizes the results of the sponsor group project on Alaska's economy, using baseline assumptions:

Figure 4: Impacts of sponsor group project using baseline assumptions

Wellhead and Tariff	
Wellhead natural gas price	$3.43/mmBtu
Total pipeline tariff	$2.07/mmBtu
Economic and Fiscal Impacts	
NPV (at 5%) to local governments ($ billions, 2005)	$1.7
NPV (at 5%) to state government ($ billions, 2005)	$25.3
NPV (at 10%) to producers ($ billions, 2005)	$17.6
Total NPV ($ billions, 2005) [1]	$44.6
Total construction spending ($ billions, 2005) [2]	$21.0
Estimated construction spending in Alaska ($ billions, 2005) [2]	$11.0
Ave. annual pipeline operations expenses ($ billions, 2005) [2]	$0.3
Ave. annual spending of gas revenues by state and local governments ($billions, 2005) [2]	$1.6
Total post-construction spending ($billions, 2005)[2]	$69.1
Cumulative effect on Alaska Permanent Fund balance ($ billions, 2005)[3]	$28.0
Workforce Impacts	
Total project-related jobs during constructionj[4]	68,000
Ave. annual project-related jobs during construction[4]	14,000
Total jobs from pipeline operations[4]	48,000
Average per year pipeline operations jobs[4]	1,300
Total jobs generated by state and local spending[4]	901,000
Ave. annual jobs generated by state and local spending[4]	25,000
Total jobs all sources all years[4]	1,016,000

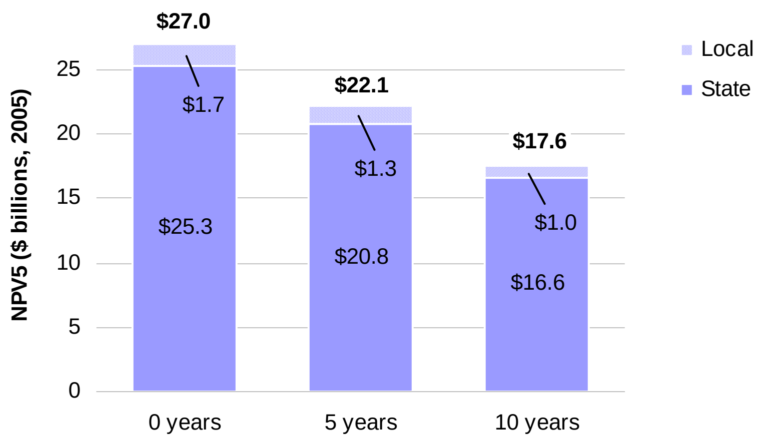
Notes:

1) 10 percent discount rate for producer earnings; 5 percent discount rate for state and local revenues.
2) Cumulative deposits and earnings less dividends, adjusted for inflation, based on 7.6 percent return and current law for dividends.
3) Direct spending in real 2005 dollars.
4) Includes direct, indirect and induced jobs, where 1 job is a full or part-time job over the course of a single year.

Impact of Delay

If the pipeline is delayed, the net present value of the project to state and local goverments will be reduced by nearly one billion dollars per year in real terms. The cumulative effect of delay on state and local revenues is shown in the figure below:

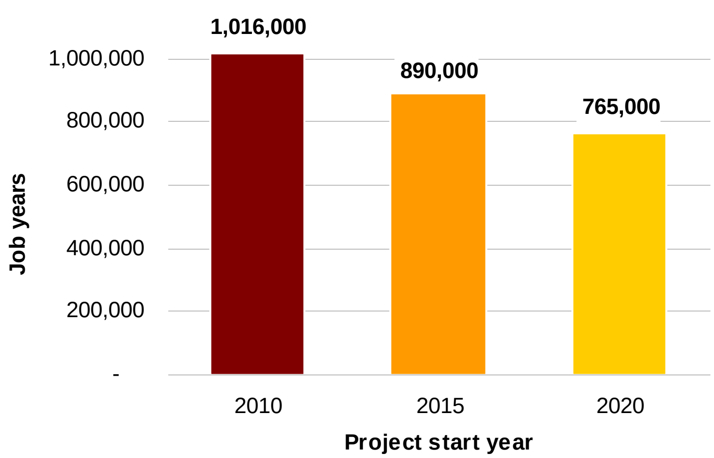
Figure 5: Impact of delay on state and local revenues



Note: NPV at 5%

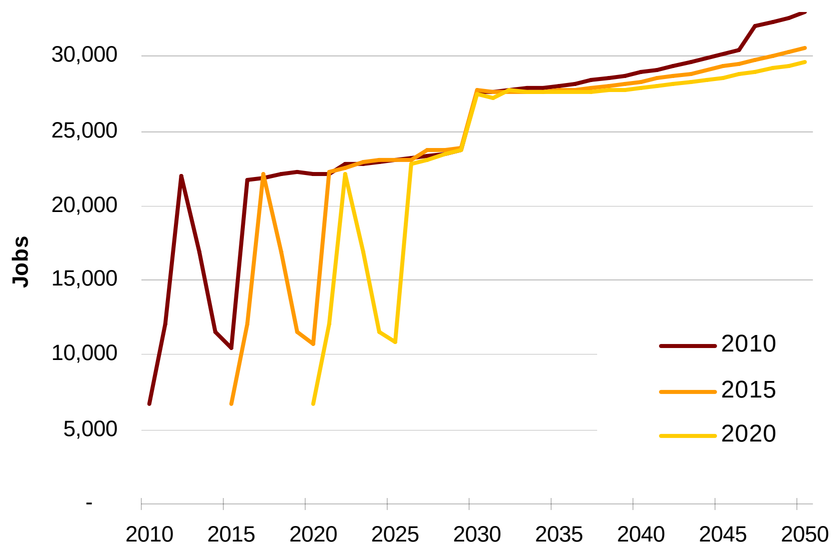
Reduced government earnings will in turn have impacts on state and local spending, Permanent Fund earnings, and job creation. The effect on total jobs from all sources from now through 2050 is substantial, with a loss of 126,000 jobs (12 percent) from five years of delay, and 250,000 jobs (25 percent) from ten years delay, as shown in Figure 7.

Figure 6: Impact of delay on total jobs from all sources



Note: Jobs shown include direct, indirect, and induced jobs, where one job is full or part-time job over the course of one year.

Figure 7: Impact of delay on annual jobs from all sources



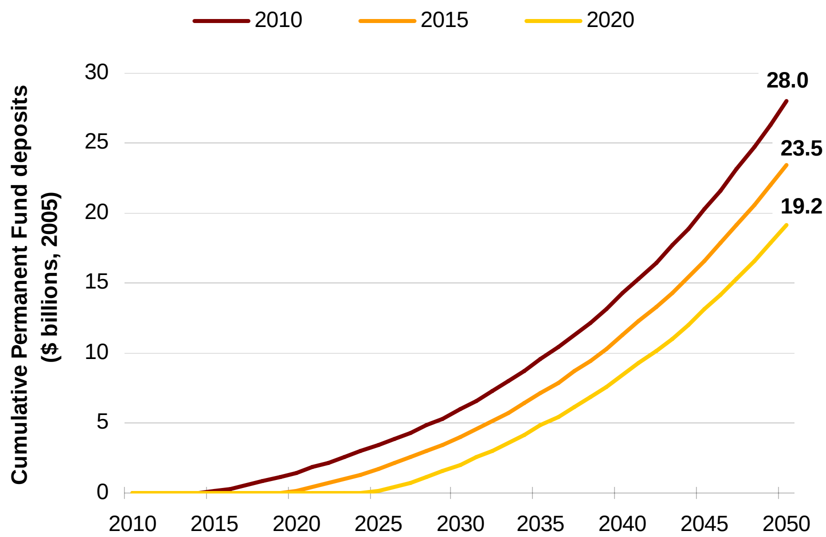
Note: Jobs shown include direct, indirect, and induced jobs, where one job is full or part-time job over the course of one year.

In addition, a delay in the start of a project could result in a significant change in resident hire rates due to the aging of Alaska's skilled construction workforce. Nearly 30 percent of Alaska construction workers were 45 years old or older in 2004 (up from 23 percent in 1994), while 17 percent were 50 years old or older. If the start of pipeline construction is delayed by five or ten years, Alaska's construction workforce may lose the experience of older workers requiring greater import of outside labor for the highest skilled jobs.[3]

Figure 8 shows the impact of a delay on the Alaska Permanent Fund. Figure 8 shows cumulative Permanent Fund deposits and earnings, less dividends paid out, adjusted for inflation. Earnings are estimated based on 7.6 percent return on investment. We assume 25 percent of the state's project-related revenues are deposited into the permanent fund.

[3] With good planning, a longer time period before start up could allow more young workers to be trained to fill expected pipeline construction jobs. Until a start-date is known, however, the state is in a Catch 22: failing to target the right crafts and train workers to fill jobs created both by retirement and pipeline construction will result in greater-than-predicted out-of-state hiring, but ramping up apprenticeship and other training programs without certain knowledge that those workers will have jobs when their training is complete will cause unnecessary expense and create an unused pool of prepared workers who may move out of state to use their training.

Figure 8: Impact of delay on Permanent Fund deposits



Summary of effects of delay on the sponsor group project

The following table summarizes the economic, fiscal and workforce impacts of delay on the sponsor group project using baseline assumptions:

Figure 9: Impacts of delay on the sponsor group project

Project Timeline	0 years	5 years	10 years
Year in which construction expected to start	2011	2016	2021
Year in which gas first flows	2015	2020	2025
Year in which last gas flows through pipeline	2050	2050	2050
Wellhead and Tariff	**0 years**	**5 years**	**10 years**
Wellhead natural gas price	$3.43	$3.50	$3.57
Total pipeline tariff	$2.07	$2.00	$1.93
Economic and Fiscal Impacts	**0 years**	**5 years**	**10 years**
NPV (at 5%) to local governments ($ billions, 2005 dollars)	$1.7	$1.3	$1.0
NPV (at 5%) to state government ($ billions, 2005)	$25.3	$20.8	$16.6
NPV (at 10%) to producers ($ billions, 2005)	$17.6	$12.2	$8.3
Total NPV ($ billions, 2005) [1]	$44.6	$34.3	$25.9
Ave. annual spending of project-related revenues by state and local governments ($billions, 2005) [2]	$1.6	$1.6	$1.6
Ave. annual pipeline operations spending ($billions, 2005)[2]	$0.3	$0.3	$0.3
Total post-construction spending, all sources ($billions, 2005)[2]	$69.1	$59.9	$50.7
Cumulative effect on Alaska Permanent Fund balance ($billions, 2005)[3]	$28.0	$23.5	$19.2

Workforce Impacts	0 years	5 years	10 years
Total project-related jobs during construction[4]	68,000	68,000	68,000
Ave. annual project-related jobs during construction[4]	14,000	14,000	14,000
Total jobs from pipeline operations[4]	48,000	41,000	34,000
Ave. annual jobs from pipeline operations[4]	1,300	1,300	1,300
Total Jobs generated by state and local spending[4]	901,000	781,000	663,000
Ave. annual jobs from state and local spending[4]	25,000	25,000	25,000
Total jobs all sources all years[4]	1,016,000	890,000	765,000

Notes:

1) 10 percent discount rate for producer earnings; 5 percent discount rate for state and local revenues.

2) Cumulative deposits and earnings less dividends, adjusted for inflation, based on 7.6 percent return and current law for dividends.

3) Direct spending in real 2005 dollars.

4) Includes direct, indirect and induced jobs, where 1 job is a full or part-time job over the course of a single year.

PART 2. COMPARATIVE ANALYSIS OF ALTERNATIVE PROJECTS FOR DEVELOPING ANS NATURAL GAS

In the second part of the study we compare the impacts from three different scenarios for bringing Alaska gas to market, based on our best estimates of costs and prices. Construction costs are based on numbers provided by the sponsor group and the Alaska Gasline Port Authority (AGPA), but where their costs for the same project components differ, we have adjusted them to produce a better “apples to apples” comparison. For this reason, the results shown for the AlCan pipeline project in the earlier section of this study vary somewhat from the impacts here. Key assumptions and results of our comparative models appear in Figure 22 through Figure 25 at the end of the Executive Summary.

We analyzed the results of our models to determine which project would bring the greatest overall economic and social benefits to Alaska. This conforms to Article 8, Sections 1 and 2 of the Alaska State Constitution, which specifies that the natural resources of the state of Alaska will be developed for the “maximum benefit of its people.”

Based on our analysis, we conclude that the AlCan pipeline proposed by the Sponsor group maximizes the value of Alaska’s North Slope natural gas resources by producing the highest revenues for the state and creating the greatest number of jobs for Alaskans over the life of the project. While any project may meet with unanticipated delays, our analysis of known delays also favors an AlCan pipeline, which is the only scenario that starts with an assured supply of gas.

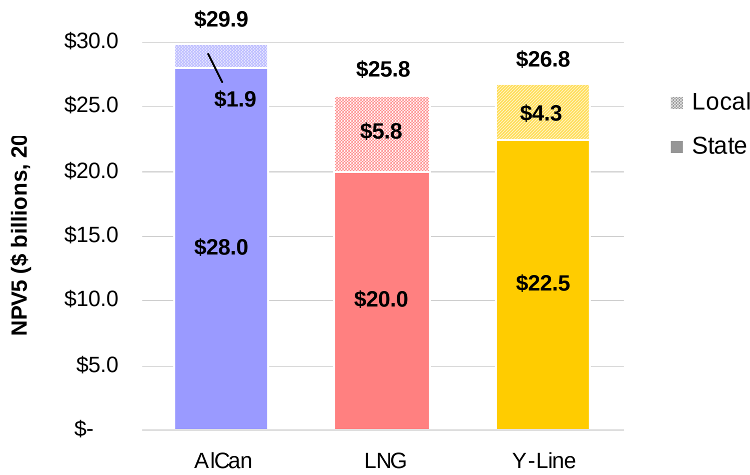
Fiscal and Economic Impact Comparison

Once a pipeline becomes operational, our model estimates the NPV of a project to Alaska state and local government to be as follows, assuming a 5 percent governmental discount rate:

- $29.9 billion or $1.6 billion per year from an AlCan pipeline;
- $25.8 billion or $1.5 billion per year from an LNG pipeline;
- $26.8 billion or $1.8 billion per year from a Y-line pipeline

As before, project revenues are expressed in real terms in 2005 dollars and include the effects of gains and losses in North Slope oil production due to a gas project, as well as revenues from the sale of natural gas and natural gas liquids.

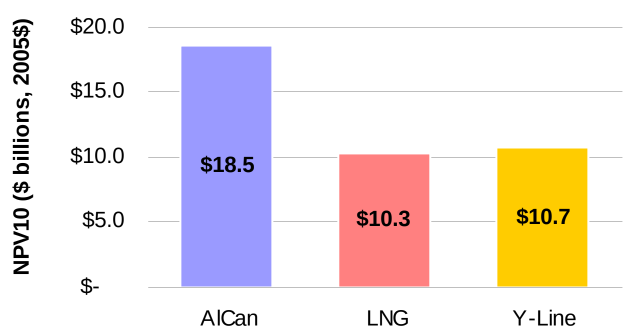
Figure 10: Present value of state and local government revenues from gas projects



Note: NPV at 5 percent

The producers currently own the leases to develop North Slope oil and natural gas. They will maximize their profits with an AlCan project as shown in the figure below. These figures show the net present value of all expected costs and profits based on our models.

Figure 11: Net present value of alternative projects to the producers



Note: NPV at 10 percent

The producers will realize greater profitability with an AlCan pipeline because this project achieves significant economies of scale that lower tariffs and other processing costs. The Chicago market is also likely to attain a premium price for natural gas liquid and for dry gas itself owning to the U.S. and Europe's strong demand and tight supplies.

Given the premium to the producers from building their own pipeline, it is unlikely they would consent to sell gas to another project without coercion. Oil and gas leases are binding contracts allowing the leaseholder to produce oil and gas in the area covered by the lease as long as they stick to the lease terms. We find it reasonable to assume that an attempt to extinguish the producers' interest in North Slope gas by taking back leases through legislative or legal means would result in protracted litigation, delaying the start of a gas pipeline project.

Alternatively, if the state wished to buy back the leases from the producers, we assume it would take two to three years to negotiate the buyout. Additional time would be required to account for all environmental and infrastructure problems and to determine a temporary owner/operator. The state would then have to set up new lease sales and solicit bids from prospective buyers who agree to participate in an Alaska LNG or Y-line project. A new lease sale might require a new environmental permitting process. In all, a buyout could take five to ten years even if the process goes smoothly and does not result in protests or further litigation. For purposes of our comparison, we assumed a five-year delay.

Value destruction

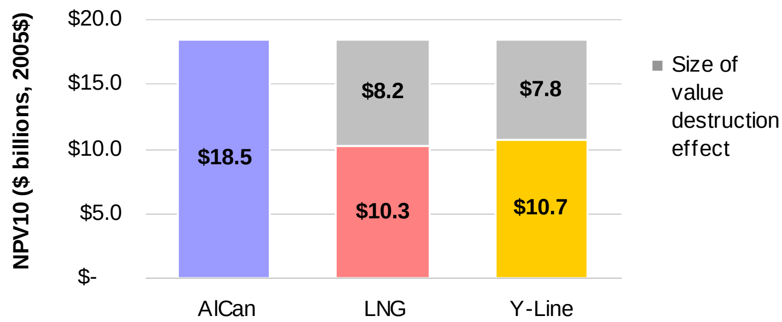
The concept of value destruction as it applies to the Alaska gas project and the importance of impacts of delay are central to understanding why the AlCan project is the superior choice for Alaska compared to an Alaska LNG or Y-line project.

We use the term value destruction to describe the loss in a project's value to the producers should natural gas be sold to an LNG or Y-line project. The value destruction effect can be illustrated by two scenarios: (a) if the producers sell gas to an LNG or Y-line project, their return from the gas declines with no comparable increase to other parties, resulting in potentially compensable loss in value of the producers' North Slope leases; or (b) if the state buys back the gas leases and reissues them with the requirement that gas be shipped to market through an Alaska LNG or Y-line project, the state's return from the leases will decline as new leaseholders reduce their bids by the amount of value destroyed.

The size of the value destruction effect is equal to the difference in the NPV to North Slope oil and gas producers of an Alaska LNG or Y-line project compared with the value of a producer-owned pipeline bringing gas to the Chicago market.

Our analysis shows that the value destruction effect is substantial for both the Alaska LNG and Y-line projects, resulting in lower state revenues and a significant reduction in jobs generated by state spending of gas revenues. Either project would result in the state losing $8 billion to $10 billion in lease sales revenue if the new leases include the stipulation that an all Alaska LNG or Y-line project be built. This estimate does not include the potential costs of litigation, contract negotiations, new permitting or costs associated with setting up the lease sales.

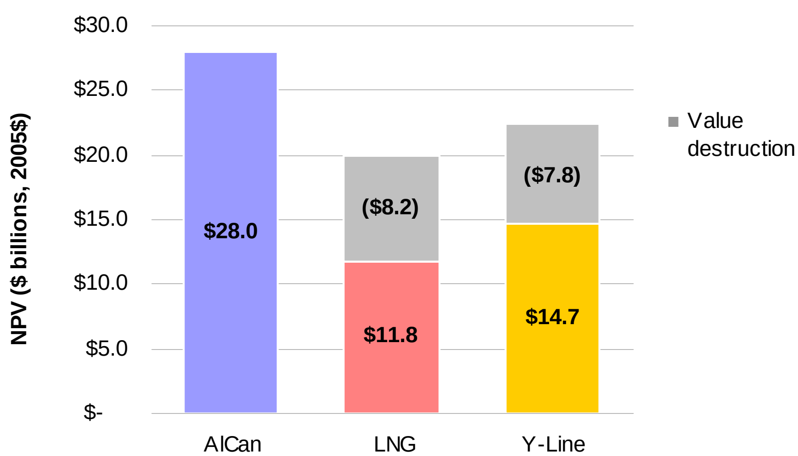
Figure 12: Size of value destruction effect for LNG and Y-line projects



Note: NPV at 10 percent

Earlier we showed the present value of an Alaska LNG project to state and local governments to be $25.8 billion. After accounting for value destruction, we expect the NPV to fall to $17.6 billion, while the NPV of a Y-line project to the state and municipalities drops from $26.8 billion to $19 billion once value destruction is taken into account. Once again, each of the NPV models uses a five percent discount rate for state and local government revenues.

Figure 13: The effect of value destruction on state revenues



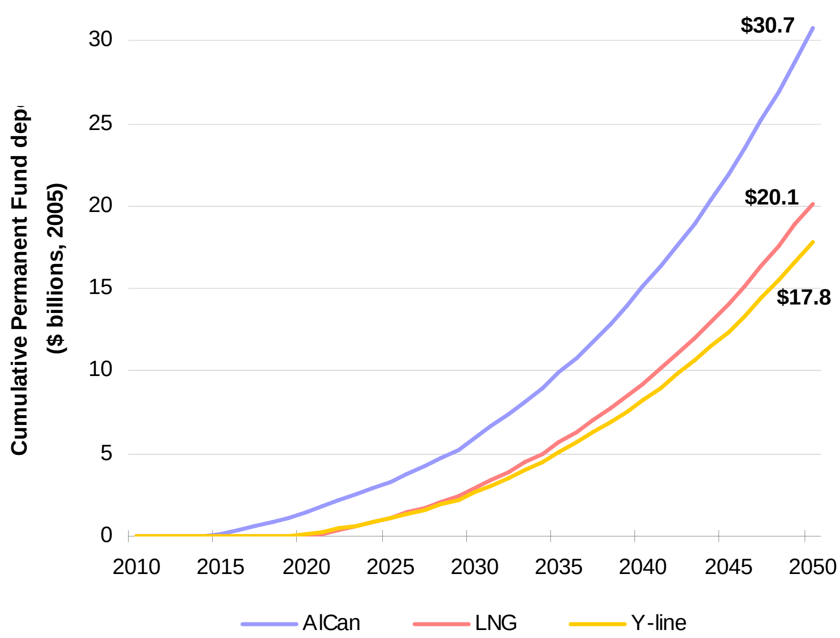
Note: NPV at 5 percent

This lost revenue would result in reduced state and local government spending and could cost Alaska the equivalent of 8,500 jobs on an annual basis due the economic multiplier effects of public and private spending. By including the lost revenue in the NPV calculations for all three projects, our model provides an accurate projection of total economic impacts and shows that the AlCan project maximizes value to Alaska.

Permanent Fund earnings

As shown, the three projects generate significant differences in revenue streams to the state. While the Alaska LNG and Y-line projects create additional municipal revenue as shown in Figure 10, it comes at the cost of a lower wellhead value, and thus lowers royalty payments to the state. Over time, the aggregate amount deposited in the Alaska Permanent Fund also suffers, with a corresponding reduction in annual Permanent Fund Dividend payments to Alaskans. The following figure shows the impact on the Alaska Permanent Fund, including deposits and cumulative earnings (less dividends paid out). Earnings are again estimated at 7.6 percent.

Figure 14: Impact of project revenues on Alaska Permanent Fund balance



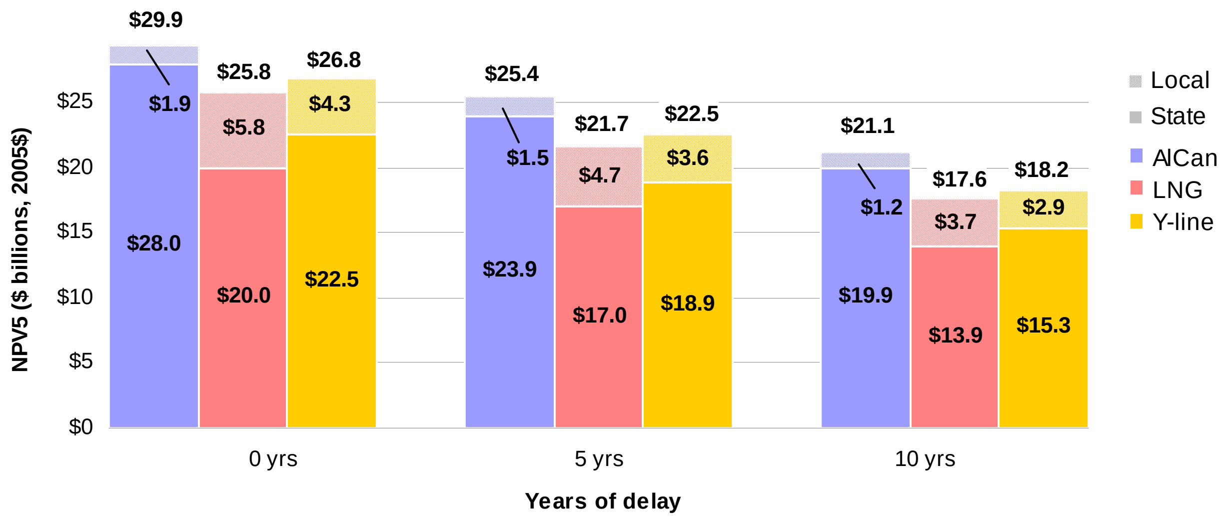
Note: Cumulative deposits plus earnings (at 7.6 percent), less dividends paid

Impact of delay

There are many reasons why a gas pipeline project might be delayed, some of which are discussed in the section on Known Challenges. Any delay in the start of construction will reduce the NPV of a project to the state and local governments as well as to the producers.

For each year of delay, we estimate the present value revenue loss to state and local governments would be approximately one billion dollars per year for any of the proposed projects.

Figure 15: Effect of delay on state and local revenues



Note: NPV at 5 percent

The state faces at least two other challenges from a delay in construction. With oil production in decline and gas revenue at least ten years off, a significant delay in project startup could result in a fiscal gap, and forcing severe budget cutbacks unless new sources of revenue or savings are found.

The second challenge stems from the aging of Alaska's skilled workforce. A five or ten year delay in the project could result in lower resident hire rates if Alaska's older skilled construction workers retire or leave the state.

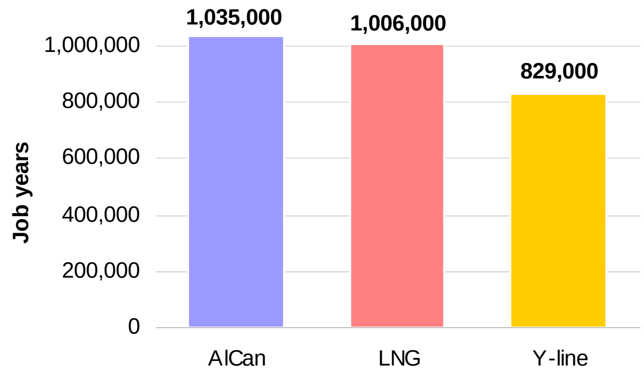
Workforce impacts

The Information Insights' model projects increased labor force needs in Alaska – direct, indirect and induced jobs – for construction of a the gas pipeline project and for project operations through 2050. (Note that in these estimates one job or job year represents one full or part-time job over the course of a single year.)

- The AlCan project increases the state's labor force needs by an average of 18,000 direct, indirect and induced workers per year during construction. The project also creates a sustained impact of about 26,000 jobs per year after construction from both pipeline operations and jobs generated by state and local spending of project-related oil and gas revenue.
- The LNG project increases the state's labor force needs by an average of 19,000 direct, indirect, and induced workers during construction, and results in a sustained increase of 27,000 jobs per year after construction. These job gains are reduced however when the effect of value destruction on state spending is taken into account. We estimate the size of the value destruction effect to be 347,000 job years.
- The Y-line project has average workforce needs of about 22,000 during construction and a sustained addition of nearly 23,000 workers thereafter. However, due to

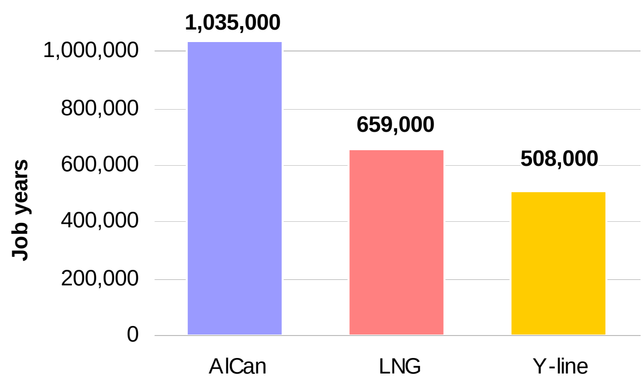
reduced spending of state revenues, the Y-line results in 321,000 fewer job years than an AlCan project when effect of value destruction is included.

Figure 16: Total jobs from all sources through 2050



Note: Includes direct, indirect and induced full and part-time jobs over the course of one year

Figure 17: Effect of value destruction on total jobs



Note: Includes direct, indirect and induced full and part-time jobs over the course of one year

The following series of figures illustrates the different job profiles the three scenarios present. One of the challenges of the Y-line profile is the large spike in jobs during the initial construction phase that could represent an unusually severe boom and bust. The spike appears during the second year of construction when building on a North Slope conditioning plant is critical, requiring extra work. At the same time, there is on-going pipeline construction, while construction on a south shore liquefaction project is in full swing, exacerbating the total Alaska labor demand. During year two of a Y-line project, the total employment effect on the state is 36,000 workers, while only 21,000 workers are needed the prior year, and only 28,000 the year after. This spike in demand will cause extra strain on the state's ability to take care of new Alaskan residents who may find themselves out of work in post-construction years.

The following charts include direct, indirect and induced labor impacts of the three projects.

Figure 18: Workforce impacts from project construction and operations

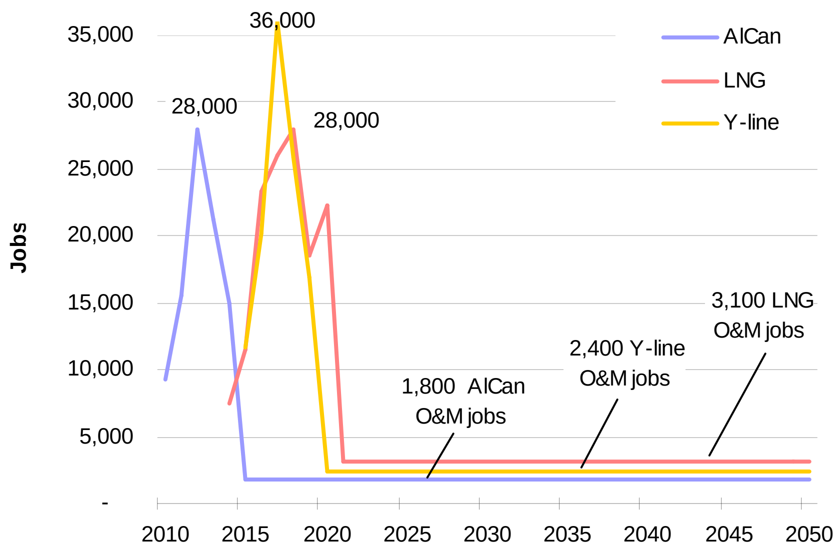


Figure 19: Workforce impact of project-related state and local spending

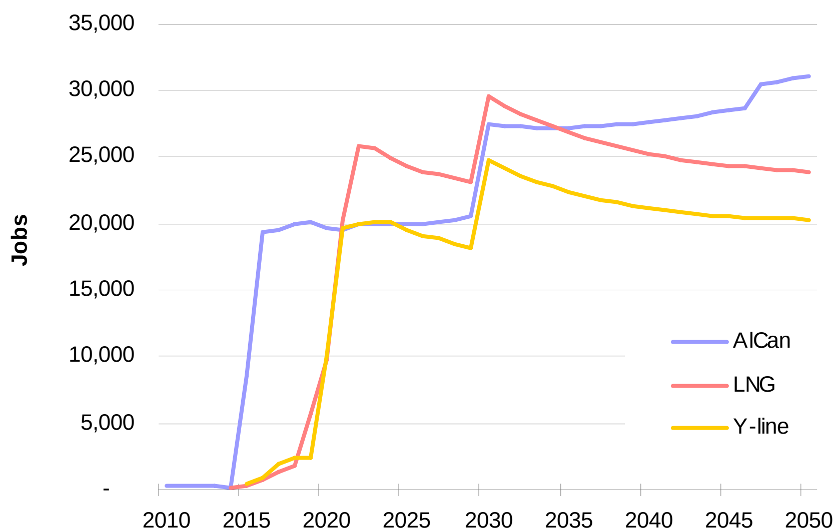


Figure 20: Total jobs from all sources through 2050

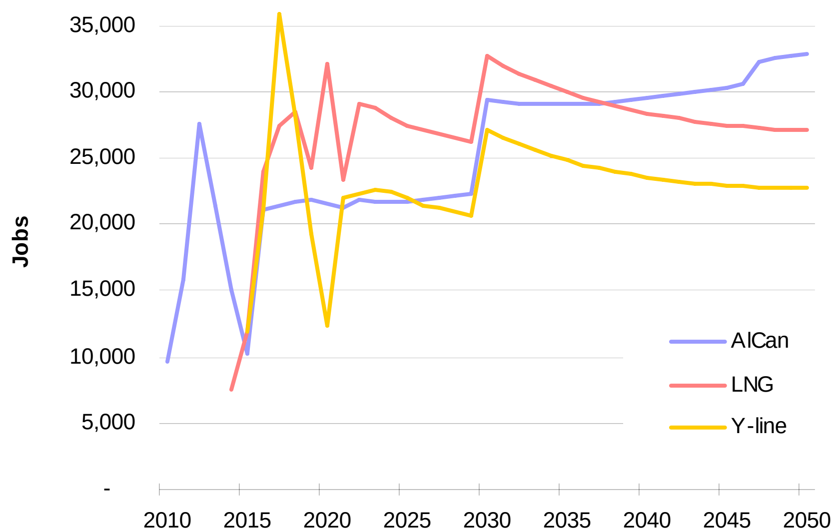
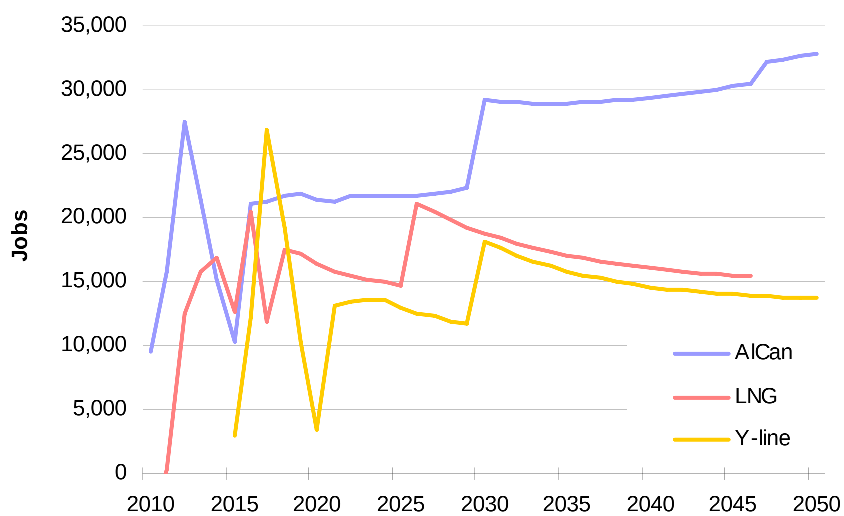


Figure 21: Total jobs showing effect of value destruction



Summary of results of comparative analysis

Figure 22 through Figure 25 summarize the assumptions, issues and impacts identified in our comparison of the three scenarios for developing Alaska North Slope natural gas.

Figure 22: Summary of project descriptions and assumptions

Project Description	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Total capacity	4.5 bcf/d	4.0 bcf/d	4.5 bcf/d
Pipeline size	52-inch to Alberta; 24-inch for the spur line to Anchorage	56-inch to Delta Junction; 48-inch Delta Junction to Valdez; 24-inch for the spur line to Anchorage	56-inch to Delta Junction; 48-inch to Alberta; 36-inch to Valdez; 24-inch for the spur line to Anchorage
In-state use	0.25 bcf/d	0.25 bcf/d	0.25 bcf/d
Market	Chicago/Alberta/Atlantic Basin	West Coast/Pacific Rim	Chicago/Alberta/Atlantic Basin West Coast/Pacific Rim
Project Assumptions	**AlCan Project (adjusted for comparison)**	**Alaska LNG Project**	**Y-line Project**
Construction start	2011	2015	2016
Construction period	4 years	6 years	4 years
First gas flows	2015	2019	2020
Project cost[1]	$21 billion to Alberta $27 billion to Chicago	$25 billion to West Coast	$26 billion to Alberta and West Coast
Market size	100 bcf/d	20 bcf/d	Combined
Gas price[1]	$5.33/mmBtu Chicago $4.33/mmBtu Alberta	$4.54/mmBtu U.S. and Canadian West Coast average LNG $4.15/mmBtu B.C. LNG	$5.33/mmBtu Chicago $5.13/mmBtu LNG
Fuel Losses	11.30% to Alberta (0.53 bcf/d)	17.6% (0.8 bcf/d)	11.50% (0.55 bcf/d)
Wellhead after tariff	$3.01	$2.50	$2.73

Figure 23: Summary of known challenges

Known Challenges	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Gas supply	Yes	Need to acquire	Need to acquire
ROW permits	Need to acquire First Nations issues Need Environmental Impact Statement	Existing permits may need updating and expanding Need to extend permits for a 30-year project Need some environmental studies and permitting	Mixed
First Nations issues	Some	None	Some plus equity issue
Tariffing issue	None	With greater municipal share, FERC may need to change methods	With greater municipal share, FERC may need to change methods
Receiving sites & LNG terminals	Pipe capacity from Alberta to Chicago exists	Poor prospects for 4 terminals	Poor prospects for 2 terminals Pipe capacity from Alberta to Chicago exists
Proposal stability	Firm	Changing	Conceptual
Construction delays	Possible Due to steel supplies, workforce issues, permitting issues	Likely Due to contract talks, tanker and terminal readiness, workforce issues, and legal challenge of obtaining gas from existing lease holders	Likely Same as Alaska LNG

Figure 24: Summary of workforce impacts

Workforce Impacts through 2050	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Project construction jobs[1] (Direct only)	53,000 Total 11,000 Ave. per year	80,000 Total 11,000 Ave. per year	66,000 Total 13,000 Ave. per year
Additional jobs during construction[1] (Indirect + induced)	35,000 Total 7,000 Annual average	55,000 Total 8,000 Annual average	43,000 Total 9,000 Annual average
Jobs from project operations[1] (Direct only)	16,000 Total 500 Annual average	22,000 Total 700 Annual average	18,000 Total 600 Annual average
Additional jobs during operations[1] (Indirect + induced)	49,000 Total 1,400 Annual average	72,000 Total 2,400 Annual average	56,000 Total 1,800 Annual average
Jobs from local and state spending of gas revenues[1,2]	882,000 Total 22,000 Annual average	776,000 Total 21,000 Annual average	646,000 Total 18,000 Annual average
Total jobs from all sources all years[1,2]	1,035,000	1,006,000	829,000
Jobs lost to value destruction[1,2]	0	347,000	321,000
Total jobs from all sources all years after value destruction[1,2]	1,035,000	659,000	58,000

Notes:

1) One job represents a full or part-time job over the course of a single year.

2) Includes direct, indirect and induced jobs

Figure 25: Summary of fiscal impacts

Fiscal Impacts through 2050	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
NPV (at 5%) to local governments[1]	$1.9 billion	$5.3 billion	$4.3 billion
NPV (at 5%) to state[1]	$28.0 billion	$20.0 billion	$22.5 billion
NPV (at 10%) to producers[1]	$18.5 billion	$10.3 billion	$10.7 billion
Total NPV[1,2]	$48.4 billion	$36.1 billion	$37.5 billion
Cost of delay to state[1]	$900 million per year	$700 million per year	$800 million per year
Average state and local spending of project-related revenue[1] (Direct spending)	$1.6 billion per year	$1.6 billion per year	$1.3 billion per year
Average project spending after construction[1]	$400 million per year	$700 million per year	$500 million per year
Total local, state and project spending after construction[1]	$71.8 billion	$69.5 billion	$57.8 billion
Reduction in NPV due to value destruction[1]	None	$8.2 billion	$7.8 billion
Alaska Permanent Fund balance in 2051 from project[1,3]	$30.7 billion	$20.1 billion	$17.8 billion

Notes:

1) 2005 dollars
2) Assumes 10 percent discount rate for producers; 5 percent rate for government
3) Cumulative earnings, net of dividends paid, based on 7.6 percent return and current dividend law

Introduction

The Alaska Department of Revenue (DOR) asked Information Insights to study economic, fiscal and workforce impacts of an Alaska natural gas project with a zero year, five year and ten year delay. In Part I of this study, we present that analysis for the project proposed by the three Alaska North Slope (ANS) producers: BP Exploration (Alaska), ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production, Inc. Acting together as the Sponsor Group, the producers submitted a single application to the State of Alaska under the Stranded Gas Development Act (SGDA). The companies are referred to jointly in this study as the producers or the sponsor group.

Our analysis of the sponsor group project is based on costs, oil and gas prices, and other assumptions provided by DOR. Using these assumptions and conventional tariff rules, we created an economic model to show the economic, fiscal and workforce impacts of the proposed project on Alaska.

In Part 2 of the report we offer a comparative analysis of alternative projects for developing ANS gas: an AlCan pipeline, a liquefied natural gas (LNG) project and a Y-line project. The projects modeled are as follows:

- AlCan pipeline – a natural gas pipeline with capacity of 4.5 billion cubic feet per day (bcf/d), expandable to 6.0 bcf/d, paralleling the Trans-Alaska oil pipeline from Prudhoe Bay to Delta Junction, Alaska, and then following the Alaska Highway to Alberta, Canada.
- Alaska LNG project – a 4.0 bcf/d capacity gas pipeline bringing North Slope gas to a liquefaction plant in Valdez, Alaska, and shipping LNG from Valdez to Pacific ports by tanker (with expandability to Delta Junction for a future Y-line).
- Y-line project – a gas pipeline with capacity of 4.5 bcf/d from Prudhoe Bay to Delta Junction, Alaska, which then splits into a 1.5 bcf/d pipeline to Valdez, Alaska, and a 3.0 bcf/d pipeline (expandable to 4.5 bcf/d) to Alberta, Canada.

As modeled, all projects include a 0.25 bcf/d spur line to Southcentral Alaska.

The comparative analysis in Part 2 is based on Information Insights' own best estimates of construction costs based on original sponsor group data, information from the Alaska Gasline Port Authority (AGPA), and estimates from PFC Energy, together with Bureau of Labor Statistics inflation calculations and private construction cost indices. Cost estimates for all three projects were then adjusted to produce a better "apples to apples" comparison. Using these assumptions we created a second set of economic models comparing the fiscal, economic and workforce impacts of the three alternative projects for developing ANS gas. Due primarily to differing assumptions on construction costs, resource prices and inflation, the results of the baseline AlCan project model in Part 1 differ slightly from the output of the AlCan project model in Part 1.

In all models, we took advantage of input data previously developed for other Alaska natural gas studies, including Northern Economic Research Associates' report to the Alaska Legislature's Joint Committee; Information Insights' study for the Municipal Advisory

Group; and Northern Economics' revenue and cost model for the Alaska Natural Gas Development Authority. We also used aspects of Roger Marks' oil gain/loss model and Pedro van Meurs' PPT model.

We constructed all models in Microsoft Excel. We applied the economic multiplier model and input data developed by the IMPLAN Group to analyze effects of construction and state spending on employment and the economy.

It is important to note that the primary purpose of these models is to show the difference in Alaska's workforce and economic output created by a gas pipeline project, including state and local spending of project proceeds, and to compare three potential gas pipeline projects. The models do not address the potential interaction between gas pipeline construction and operation and other economic activity that may take place in Alaska, including new oil and gas exploration and development. The models do take into account the anticipated shutdown of the Trans-Alaska Pipeline System (TAPS) in about 25 years.[4]

Finally, the models are not intended to answer the question of whether a gas pipeline is economically viable or not, or whether ANS gas is really stranded. Such questions depend on a risk analysis of future natural gas and oil prices as well as other market changes, and are outside the scope of this study. The models presented here are intended only to estimate the economic, fiscal and workforce impacts that the State of Alaska is likely to encounter from construction and operation of an ANS natural gas project.

[4] Existing DOR models anticipate that TAPS shutdown will occur in about 2030, when oil production from Prudhoe Bay declines to approximately 150,000 barrels per day. We believe that technological changes may allow pipeline flow to continue until production falls to about 100,000 barrels per day, several years later. In either case, absent a gas pipeline the TAPS shutdown will result in a sharp reduction in the Alaska workforce – in oilfield and pipeline jobs, and in jobs created by the spending of state and municipal revenues from royalties and taxes. As noted elsewhere in the report, construction of a gas pipeline would extend the production from Prudhoe Bay indefinitely, keeping oil flowing through TAPS and moving gas to market, and would avoid the loss of oilfield, pipeline, state and municipal jobs. The graphs produced for this report, showing the difference in net Alaska jobs between a gas pipeline and no gas pipeline, all therefore show a jump in the number of jobs caused by the gas project. Consequently, portions of these increases are avoided job losses rather than new jobs.

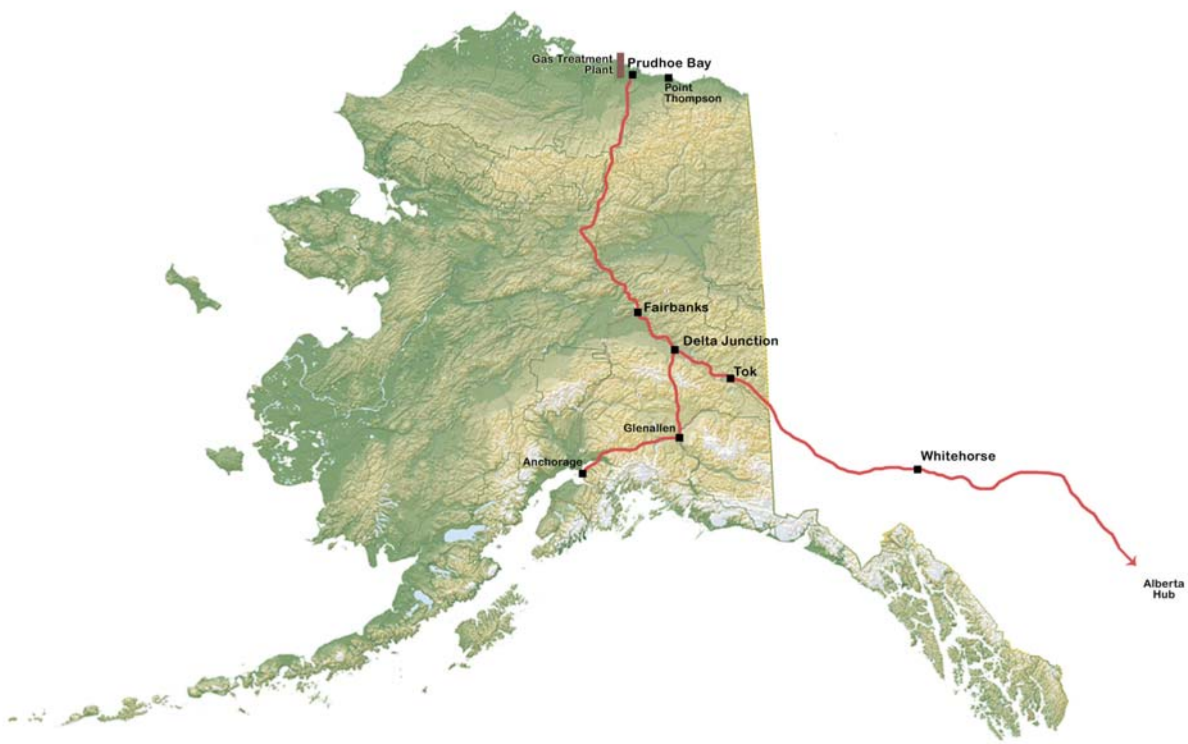
Part 1. Baseline Analysis of the Sponsor Group Project

The Alaska Department of Revenue asked Information Insights to study economic, fiscal and workforce impacts of an Alaska natural gas project with a zero year, five year and ten year delay. In this part of the study, we present that analysis for the project proposed by the three major North Slope producers, acting jointly as the sponsor group. The state has negotiated a contract with the sponsor group under the SGDA to build the proposed project.

Our analysis of the sponsor group project is based on costs, oil and gas prices, and other assumptions provided by DOR, as well as other assumptions and conventional tariff rules, outlined in the section on key issues and assumptions. The results of our economic model are presented at the end of part one.

PROJECT DEFINITION

Figure 26: Route of proposed AlCan project



The North Slope producers propose to build a 4.5 bcf/d gas pipeline, expandable to 6.0 bcf/d, paralleling the TAPS oil pipeline from Prudhoe Bay to Delta Junction, Alaska, within the existing right of way (ROW), and then following the Alaska Highway to Alberta, Canada. The project includes construction of a gas treatment plant (GTP) at Prudhoe Bay to clean, compress and chill the gas before it enters the pipeline and to remove heavier natural gas liquids (NGLs), which will be added to the oil pipeline. The producers anticipate building a high strength steel pipeline with a diameter of 52 inches. This will allow an initial throughput of 4.5 bcf/day of natural gas and natural gas liquids in the pipeline under very high pressure. The pipeline will be expandable to 6 bcf/day with the placement of additional compressors along the pipeline. From Alberta, Alaska natural gas will travel the additional 1,500 miles to Chicago, Illinois, through new or existing pipelines to be sold on the Midwest market, which is part of the very large Atlantic Basin regional market extending all the way to Europe.[5]

After a year of planning and engineering activities, the project will be constructed over a four-year period, with construction of Alaska sections concentrated in winter when soils are frozen to minimize environmental impact. Ramp up to full production will occur within one year of completion. Based on the producers' 2001 study, we estimate that pre-construction could begin in 2010, with construction completed in 2015 and full production beginning in 2016.

A spur line with capacity of 0.25 bcf/d will follow the TAPS line from Delta Junction to Glennallen and then run westward to Anchorage to bring North Slope gas to Southcentral gas facilities and provide for in-state use. (The spur line could also run from Tok to Anchorage, but the costs for a Tok spur line would not differ enough to change the analysis.)

Our assumptions about the project are based primarily on the sponsor group's application to the state under the Stranded Gas Development Act, incorporating confidential data provided by the companies.

The route of the AlCan pipeline appears on the previous page.

KEY ISSUES AND ASSUMPTIONS

This section explains the terms and issues necessary to understand the economic models and model results. It defines the default values assigned to key parameters and explains the assumptions behind the values.

Baseline Assumptions

We modeled the fiscal, economic and workforce impacts of an AlCan pipline project under the following baseline assumptions (Figure 27 provided by the Department of Revenue.

[5] Pipeline from Alberta to Chicago is not included in the model because capacity already exists to get Alaska natural gas to Chicago using current infrastructure. Tariffs from Alberta to Chicago are included in the model.

Figure 27: Baseline Alcan pipeline model assumptions

Expected natural gas price, Chicago market (2005$)	$5.50/mmBtu
Expected oil equivalent price (2005$)	$33.00/Bbl
Year in which actual construction is expect to start	2011
Year in which the gas first flows	2015
Year in which last gas flows through the pipeline	2050
Project cost to Chicago (2005$)	$21 billion
General inflation	2%
Annual operating cost	2-4% of initial capital cost

Oil Production Gains and Losses

To estimate the net effect of a gas project on North Slope oil production, we analyzed many factors. They include: accelerated oil decline due to the loss of reinjected gas[6]; the likelihood of increased exploration; greater development of Point Thomson oil reserves; and the extended profitability of the Prudhoe Bay oil field itself. Any gains or losses in oil production due to a gas project will have revenue consequences for the state and TAPS producers that must be taken into account when assessing the economics of a gas development proposal.

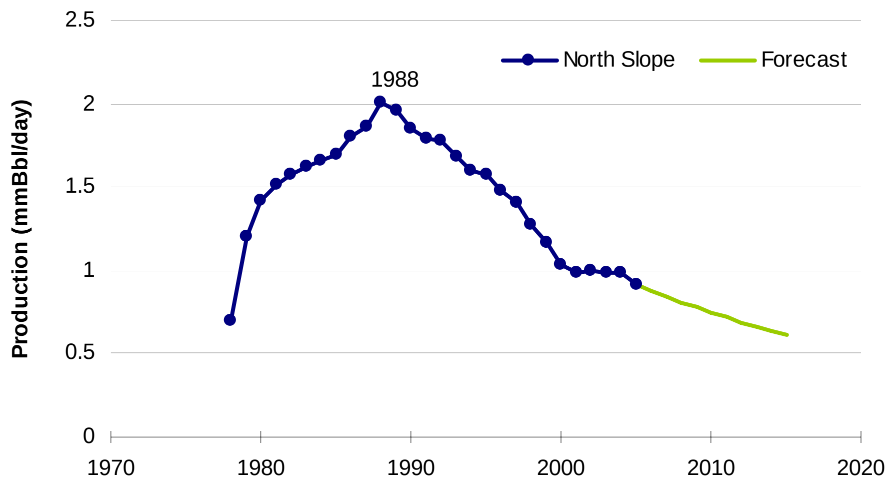
North Slope decline

Without a gas pipeline project, we assume North Slope oil production will continue to decline at rates similar to the recent past for main Prudhoe Bay fields. Once a pipeline is built, we expect oil production to decrease more rapidly, especially for Prudhoe Bay, due to the removal of natural gas that would otherwise be reinjected into wells. Each year of delay in starting a natural gas project pushes back the expected decline in oil production. Offsetting this loss is a smaller gain in North Slope oil production from oil reserves at Point Thomson.[7] With or without a project, the model assumes continuing North Slope oil exploration resulting in new discoveries, all of which have been factored into the decline rate.

[6] With no way to get it to market, gas produced as a secondary product from oil wells is now reinjected into the oil wells. This practice increases pressure in the reservoirs and helps push oil up to the surface. Once a pipeline is built, the gas going to market will no longer be available for reinjection. The result will be lower reservoir pressure and slower flow rates from each producing well.

[7] The assumptions of Point Thomson oil reserves in the model are derived from Roger Marks' model for the Department of Revenue; we believe they represent a very conservative estimate. Assuming a less conservative estimate would moderate the negative effect of a gas pipeline project on overall North Slope oil production and on state oil revenues.

Figure 28: North Slope oil decline, actual and forecast



Without a gas pipeline project, we assume North Slope oil production will decline at a rate of four percent per year based on a weighted average of the 1990s decline rate and the decline rate over the last five years. Figure 28 shows North Slope decline in mm Bbl/year. Expected losses and gains resulting from a gas project are added on top of the four percent decline.

Changes in oil production have an inverse effect on the TAPS tariff. The change in the tariff will contribute to the state's gain or loss in oil revenue due to a gas pipeline project. A decrease in oil production will impact the variable portion of the tariff resulting in a lower wellhead price and lower state revenues.

Prudhoe Bay Unit (PBU)

Based on the past five years of performance, we assume that Prudhoe Bay and its satellite fields will have a loss of six percent per year without a gas project until production declines to 100,000 Bbl/day. At that point we assume Prudhoe Bay Unit will shut down without a gas project, because the producers will have stretched the technology and the expansion of peripheral fields as far as possible and continued production will be unprofitable. Figure 29 shows Prudhoe Bay unit production declines in mm Bbl/day, absent a gas pipeline.

After a gas project starts, we estimate that oil production at PBU will decline at a faster rate of 12 percent per year because of the absence of gas for reinjection. Oil production at PBU will continue indefinitely due to the availability of oil produced as a secondary product from natural gas wells. The trend for Prudhoe Bay oil production differs markedly with and without a gas pipeline, as displayed in Figure 30.

Figure 29: Prudhoe Bay oil production, actual and forecast

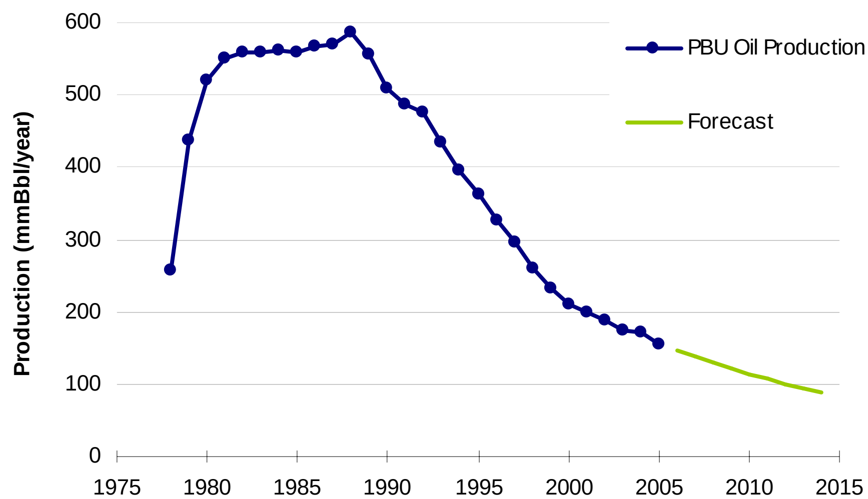
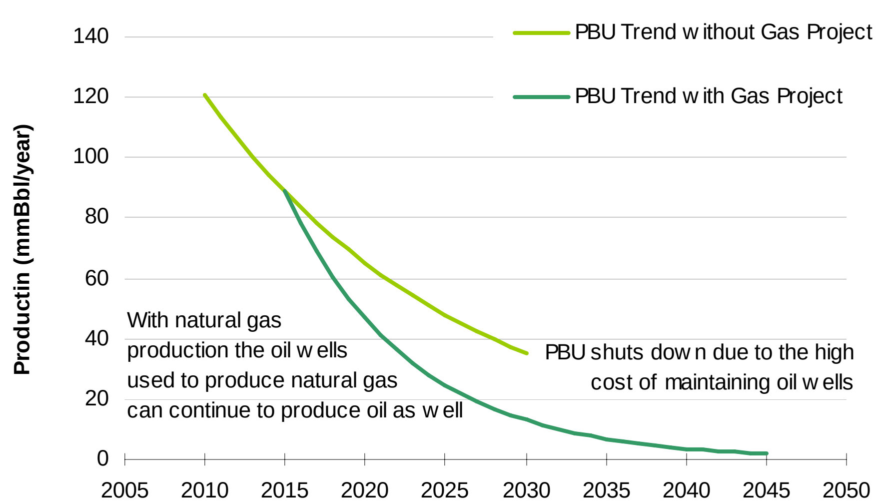


Figure 30: Prudhoe Bay production trend with and without gas project

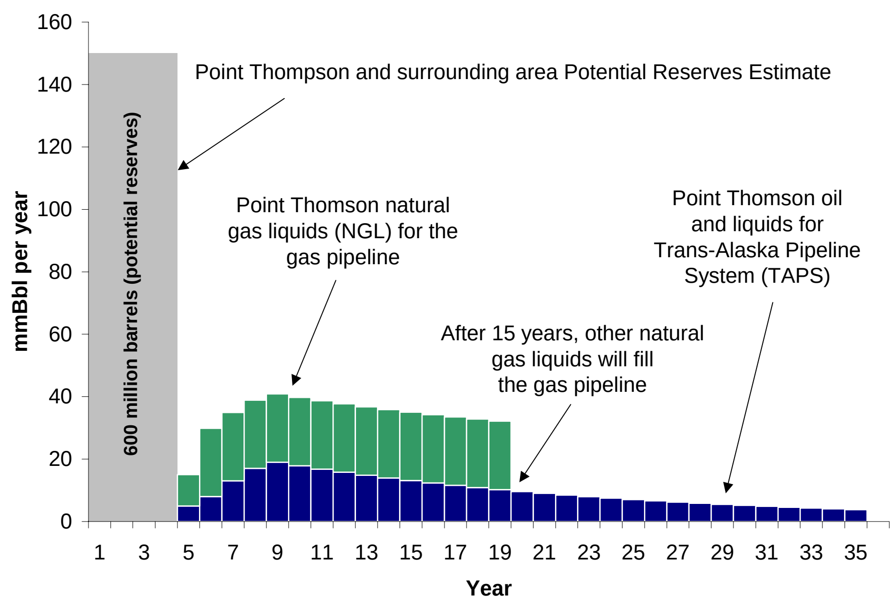


Point Thomson Unit (PTU)

Construction of a natural gas pipeline will allow greater development of the Point Thomson Unit, which will increase ANS oil production. Current reserves at Point Thomson are estimated at “hundreds of millions of barrels” in the Department of Natural Resources’ PTU decision document. We put the number at 600 million barrels since we know 200 million exists in the main Point Thomson Unit and 200 million were found in previously explored surrounding sands, with more discoveries expected.

Out of those 600 million barrels of liquids, we expect 60,000 Bbl/day to be placed in the natural gas pipeline for about 15 years.[8] See Figure 31. That requires a total of 300 million barrels of PTU liquids. After 15 years, we assume other liquids found at other fields will fill the gas pipeline. The rest of PTU oil will go into TAPS.

Figure 31: Pt. Thomson and surrounding area estimated production



Project Life

The model assumes a 45-year project life, beginning with 10 years of permitting, pre-construction, and construction, followed by 35 years of production through the year 2050. We expect that once a gas pipeline is in place, even if natural gas from Prudhoe Bay and Point Thomson cannot fill the pipeline for the entire 35 years, new exploration will yield other fields with natural gas that can fill the pipeline for that lifespan. New gas supplies could come from the National Petroleum Reserve-Alaska, the Arctic National Wildlife Refuge, and/or the Chukchi Sea, among other possibilities. The model calculates project impacts through 2050, regardless of the date the project actually begins delivering gas.

Fuel Losses

Fuel losses associated with each project are shown in Figure 32. Our assumptions mirror conventional losses for natural gas projects. In addition to normal processing losses, fuel losses are incurred when gas is taken off to run compressor stations, to fuel LNG tankers, and

[8] Natural gas liquids can be placed in a gas pipeline because under extreme pressure the liquids revert to a gaseous state and will mix with methane, the main component of natural gas.

to be burned in other industrial processes along the way. Because gas undergoes more processing in an LNG project, routine fuel losses are greater.

Figure 32: Conventional fuel losses associated with similar projects

Conditioning plant	4%
Pipeline	2%/1,000 mi.
Separation	3%
Liquefaction	–
LNG shipping & regasification	–
LPG shipping	–
Total loss of saleable commodity	**.51 bcf/d**

In-state Use

We estimate that the demand for ANS natural gas within Alaska will be about 0.25 bcf/d based on the Econ One report, *Alaska Natural Gas In-State Demand Study*. Currently, Southcentral Alaska uses upwards of 0.5 bcf/d. Because manufacturing fertilizer at the Agrium plant in Nikiski requires cheap energy, we expect that plant to shut down or use alternative sources of gas such as coal gas. The Nikiski LNG plant and Kenai oil and gas operations will reduce their gas needs as well. We expect in-state demand for industrial uses in Southcentral Alaska to be weak in the early years of a North Slope gas project, with Kenai oil and gas fields continuing to provide substantial quantities of natural gas for some time to come. There is still interest in new exploration and development in the Kenai and Southcentral region, some of which is likely to be successful and could fill much of the remaining demand in the region. As a result, Southcentral may need substantially less than 0.5 bcf/d from the North Slope for the foreseeable future. We estimate that demand at 0.25 bcf/d.

Demand for gas from Interior Alaska also will account for some in-state use. Although much of the Interior will switch from fuel oil to natural gas if gas is available at attractive prices, consumption of gas from the region will have a relatively small effect on total in-state demand. This is because the population and industrial base of the Interior is about one-tenth the size of Southcentral.

Another potential source of in-state demand comes from new industries that may start up to take advantage of relatively inexpensive natural gas or natural gas liquids such as ethane or butane. The creation of new industries (e.g. a petrochemical plant or an Internet server farm) could be feasible only if natural gas and other costs were lower than elsewhere. Given Alaska's high labor and transportation costs, such new in-state uses would face significant challenges even with a North Slope pipeline.[9]

[9] The challenge of predicting with any accuracy the needs of industries that don't yet exist was discussed in the Anchorage Chamber of Commerce's 2005 report *Natural Gas and Alaska's Future*: "Any predictions for new demand of this type would necessarily be results only of the assumptions that are made about the size, scope

To foster industries that are nationally or globally competitive, it is likely that gas would have to be sold at below market rates to in-state industries to offset our relatively higher labor and transportation costs. We believe any attempt to sell energy at below world prices will only reduce the value that Alaska receives for its energy sales.

Revenues

Wellhead cost

The wellhead cost is the total cost of extracting oil and gas, including exploration, development and production of the resource. We use simple wellhead cost assumptions in order to calculate state and federal income tax and a project's net value to producers. We estimate the entire cost of producing natural gas at $0.25/mmBtu, and the entire cost of producing oil at $9.00/Bbl.

Royalties

The state receives a royalty for all natural gas produced which averages 12.5 percent of the wellhead value minus a processing fee.

Petroleum Production Tax (PPT)

The models were run both with a simplified Petroleum Production Tax (PPT), based on the PPT as introduced in the legislature, and with a severance tax and Economic Limit Factor (ELF). However, only the PPT results are shown here. Similar results were obtained with the severance tax and ELF. Because the PPT is a highly complex mechanism to model, we used a simplified estimate based on a model by Pedro van Meurs.

Corporate Income Tax (CIT)

The federal corporate income tax rate is assumed to be the standard 35 percent rate. Pipeline and other project tax deductions were assumed to have an accelerated depreciation schedule over seven years. Alaska state income tax is set at 4.7 percent, which is half of the normal income tax rate because Alaska uses modified inter-state apportionments that spread the tax among the states where oil producers operate.

Property Tax

The oil and gas property tax rate for Alaska is usually set at 20 mills, or two percent. However, the SGDA provides the option of a payment in lieu of taxes (PILT) to economically impacted and revenue-impacted municipalities. The PILT would provide the state flexibility to lower or remove the property tax in the early years of constructing and operating a gas project. This creates a benefit to the owners of the project by creating a higher return on their investment, while it can benefit the state by evening out revenue to local municipalities.

---

and nature of the new industry(s), which could be almost anything the modeler making the prediction wants." This was said about predictions on the impact on in-state demand for natural gas from new industries, but the statement could apply equally to attempts to predict the workforce needs of future industries.

The proposed SGDA contract for the AlCan pipeline provides for two separate PILTs, one during construction to compensate municipalities for the impacts of pipeline construction (such as increased road maintenance, police protection, and protection of subsistence resources), and one during operation of the pipeline. The construction PILT is set at $125 million, spread over a six-year period. The other operating PILTs are throughput based, and set at:

- $0.003/mcf per mile for upstream pipeline property
- $0.01/mmBtu for GTP property
- $0.024/mcf for mainline pipeline property

Figure 33 shows the rates used in the models for federal, state and provincial oil and gas taxes:

Figure 33: Applicable tax and royalty rates

	Income Tax	Property Tax	Royalty Rate	Other
Federal Taxes				
U.S.	35.0%			14% income tax depreciation rate
Canada	22.0%			
State and Provincial Taxes				
Alaska – existing law	4.7%	2.0%	12.5%	7.25% estimated PPT for gas 10.4% estimated PPT for oil
Alaska – SGDA contract property tax PILT		$0.0003 /mcf / mi for upstream pipe $0.01/mmBtu for GTP $0.024/mcf for mainline pipe		
Alaska – LNG project		1.0% 10 yrs 1.5% 5 yrs 2.0% after		
Yukon Territory	15.0%	1.0%		
British Columbia	13.5%	2.5%		
Alberta	13.5%	1.5%		

State equity interest

Under the SGDA contract negotiated with the producers, the state will own an approximately 20 percent equity share in the gas treatment plant, pipeline, and associated properties, from which the state will earn revenue. For simplicity in the models, we assume that all capital the state uses to pay for its equity share in a gas project is borrowed. The cost of the borrowed money is 6.4 percent while the equity revenue is based on typical FERC levelized tariff formulas.

State Spending and Saving

Permanent Fund

Any gas project will produce significant new revenues for the state from royalties, an oil and gas production profits tax and the return on any state equity share in a project. We assume that 25 percent of all state royalty revenues will be deposited in the Alaska Permanent Fund. Based on history, we also assume that all remaining revenue will go to increased state spending and none will be used to fill the Constitutional Budget Reserve. We assume an earnings rate on the Alaska Permanent Fund of 7.6 percent, the target set by the fund trustees.

Taxes and royalties

Tax and royalty assumptions used in the models follow existing law, as modified by the PPT proposal currently before the legislature. The model assumes that the state will not set its royalty rate to zero for gas sold in Alaska as proposed by AGPA for the purpose of selling cheaper energy in order to develop new business. If the state were to reduce its royalty rate for in-state gas to zero, selling in-state gas for the cost of transporting it, the state would effectively be giving away that portion its royalty share. While we have not modeled this option, we believe that the loss of jobs (direct, indirect and induced) from lower state revenues would exceed the potential gain of jobs from reduced costs of gas to business and consumers.

Multiplier effects of state spending

Alaska has a lower spending and jobs multiplier than other states because a large proportion of Alaska's goods and services are imported, such as automobiles, food, and household appliances. For this reason the earnings multiplier is between 1.5 to 2.5 times any spending. Jobs multipliers are about 1.5.

Discount rate

The discount rates used to determine the present value of a gas project to the state and to the producers are assumed to be a five percent nominal discount rate for government and a ten percent nominal rate for the private sector. Northern Economics Research Associates conducted a study of typical earnings for oil companies through the 1990s and found their discount rate to be 12 percent. However, because the private sector in general has an average discount rate of 10 percent and because the pipeline risks are less than risks associated with exploration and development, we use a 10 percent rate.

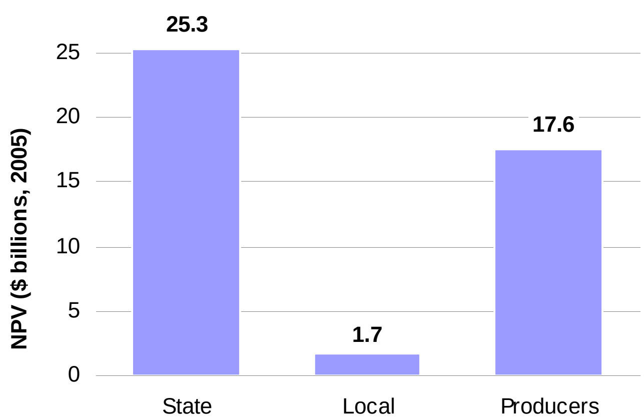
BASELINE MODEL RESULTS

This section presents the economic, fiscal and workforce impacts to the state of the sponsor group project using baseline assumptions. It also shows the effect of delay on project outcomes and the value of the project to the producers.

Economic and Fiscal Impacts

Our models show the value to state and local governments of a sponsor group project to be $27.0 billion over the life of the project[10]. The value of the project to the producers will be roughly $17.6 billion through 2050. Project revenues are calculated on a net present value (NPV) basis, using a 5 percent discount rate for government and a 10 percent rate for private sector earnings. In addition to the revenues from the sale of natural gas and natural gas liquids, project revenues include the net effect of gains and losses in North Slope oil production that occur as a result of a gas project. All monetary values in the report are given in real 2005 dollars unless otherwise noted.

Figure 34: Net present value of project revenues, 2010-2050



Note: Producers' NPV at 10%, government NPV at 5%

Assuming 25 percent of state royalties are placed into the Alaska Permanent Fund, annual earnings to the fund are the 7.6 percent projected by the Alaska Permanent Fund Corporation, and payouts of permanent fund dividends under current law, the project would result in a $28 billion increase to the Permanent Fund over the project's life.

[10] Project life is defined as a 45-year period from 2006 through 2050, which mirrors the DOR period of fiscal certainty in the SGDA contract with the sponsor group, and includes time spent on permitting and construction and any pre-construction delays. Economic, fiscal and workforce projections are calculated from Year 0 (pre-construction) through 2050 for each model.

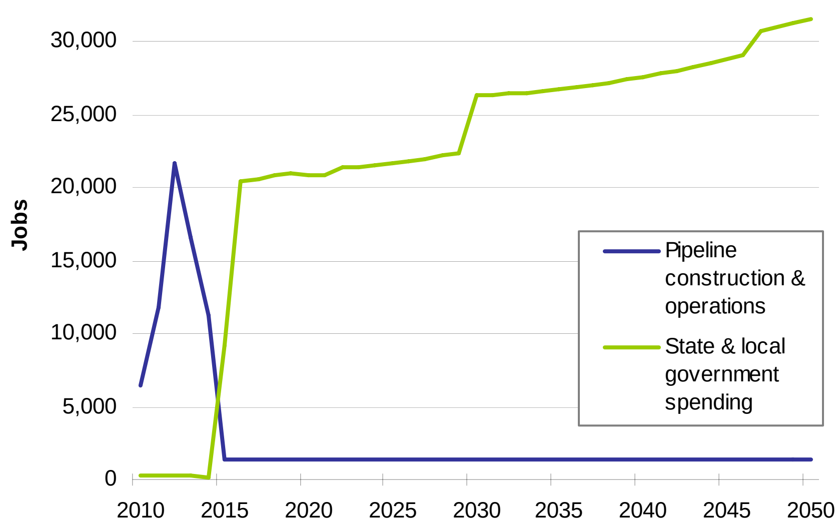
Workforce Impacts

The model is designed to show the net change in jobs in Alaska – direct, indirect and induced – brought about as a result of gas pipeline construction and operation, and the spending of state and local government revenues brought by the project.[11]

The number of project-related jobs totals 68,000 job-years during construction. After construction, we expect an average of 1,300 jobs per year operating the pipeline and related facilities. State and local spending of project-related revenues will create an additional 901,000 jobs over the life of the project, for a total of just under one million jobs for all years from all sources.

Figure 35 shows jobs created by the sponsor group project from all sources by year – with pre-construction employment (direct, indirect and induced) beginning in 2010 and construction employment from 2011 to 2015. Once full operations begin in 2016, employment (direct, indirect and induced) generated by the spending of state and municipal project revenues quickly outpaces jobs from operation of the GTP and pipeline. The effect of new spending on economic activity and employment in the state is discussed in the section on economic multipliers in Part 3.

Figure 35: Annual workforce impact of gas pipeline using baseline assumptions



Note: Direct, indirect, and induced full and part-time jobs

---

[11] As noted earlier, the base case for Alaska workforce assumes a 2030 shutdown of the Trans-Alaska Pipeline System and the Prudhoe Bay oil field, absent a gas pipeline project. The presence of a gas pipeline project extends the economic life of the field, which effectively becomes a gas field incidentally producing oil. The increase in net jobs that occurs in 2031 therefore represents the TAPS- and Prudhoe Bay-related direct, indirect and induced jobs that are preserved by continued operations on the oil side.

The following table summarizes the results of the sponsor group project on Alaska's economy, using baseline assumptions:

Figure 36: Impacts of sponsor group project using baseline assumptions

Wellhead and Tariff	
Wellhead natural gas price	$3.43/mmBtu
Total pipeline tariff	$2.07/mmBtu
Economic and Fiscal Impacts	
NPV (at 5%) to local governments ($ billions, 2005)	$1.7
NPV (at 5%) to state government ($ billions, 2005)	$25.3
NPV (at 10%) to producers ($ billions, 2005)	$17.6
Total NPV ($ billions, 2005) [1]	$44.6
Total construction spending ($ billions, 2005) [2]	$21.0
Estimated construction spending in Alaska ($ billions, 2005) [2]	$11.0
Ave. annual pipeline operations expenses ($ billions, 2005) [2]	$0.3
Ave. annual spending of gas revenues by state and local governments ($billions, 2005) [2]	$1.6
Total post-construction spending ($billions, 2005)[2]	$69.1
Cumulative effect on Alaska Permanent Fund balance ($ billions, 2005)[3]	$28.0
Workforce Impacts	
Total project-related jobs during constructionj[4]	68,000
Ave. annual project-related jobs during construction[4]	14,000
Total jobs from pipeline operations[4]	48,000
Average per year pipeline operations jobs[4]	1,300
Total jobs generated by state and local spending[4]	901,000
Ave. annual jobs generated by state and local spending[4]	25,000
Total jobs all sources all years[4]	1,016,000

Notes:

5) 10 percent discount rate for producer earnings; 5 percent discount rate for state and local revenues.
6) Cumulative deposits and earnings less dividends, adjusted for inflation, based on 7.6 percent return and current law for dividends.
7) Direct spending in real 2005 dollars.
8) Includes direct, indirect and induced jobs, where 1 job is a full or part-time job over the course of a single year.

Effects of Delay

A project delay has a negative impact on the present value of a project to state and local governments because the time value of money causes the income streams to lose value. The impact is greater on the gas producers, since the model uses a higher discount rate for private than for public revenue flows because of lower public sector borrowing costs.

With each year of delay, we assume the project will be subject to declining North Slope oil production, while facing higher construction costs due to inflation. A delay in project start impacts the models in several ways:

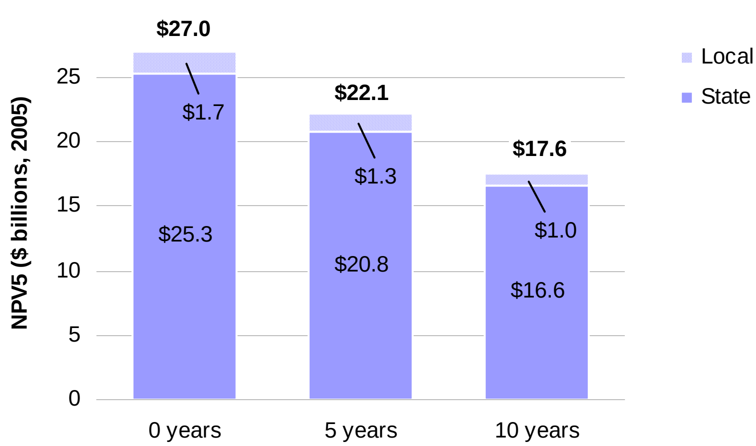
- Inflation impacts project costs, affecting property taxes
- The delay in gas production differentially impacts the Prudhoe Bay oil production and revenue decline caused by Prudhoe Bay gas production
- The changing project cost effects change the tariff calculation, and thus netback value,
- Changes in netback value affect royalties, PPT and income taxes, and royalty effects change the permanent fund deposits
- Changes in royalty, tax, and permanent fund income affect the amount of revenues received by, and therefore spent by, state and local governments
- Changes in spending affect the economic output and workforce impacts from the project

The baseline year for preconstruction activities (Year 0) for the Alcan pipeline is set at 2010. The model shows a delay reduces the NPV of revenues to state and local governments by close to one billion dollars for each year of delay.

Impact of delay on state and local revenue

If the pipeline is delayed, the net present value of the project to state and local goverments will be reduced by nearly one billion dollars per year in real terms. The cumulative effect of delay on state and local revenues through year 2050 is shown in the figure below:

Figure 37: Impact of delay on state and local revenues

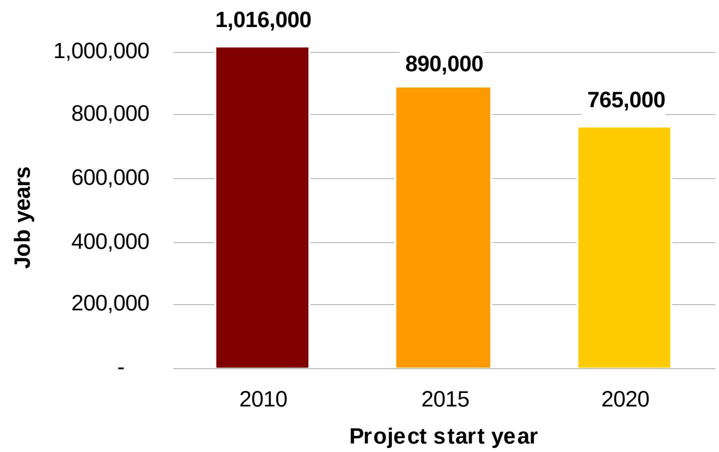


Note: NPV at 5%

Impact of delay on jobs

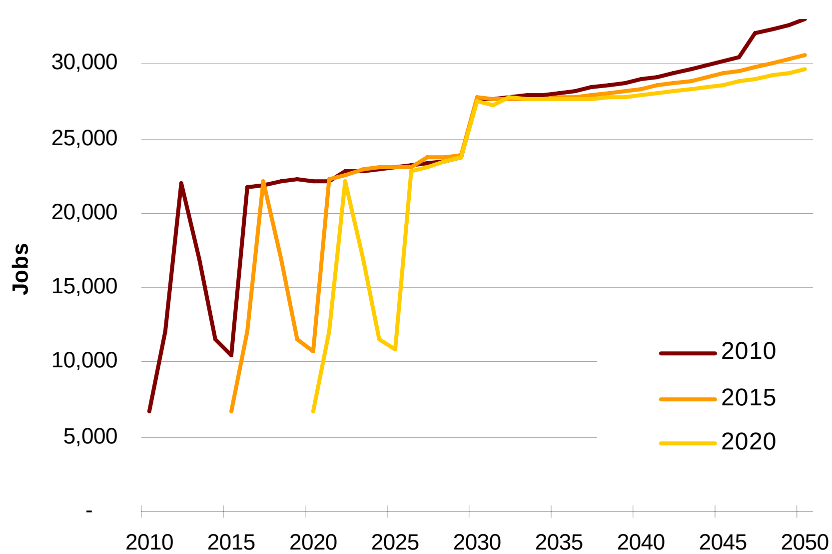
Reduced government earnings will in turn have impacts on state and local spending, Permanent Fund earnings, and job creation. The effect on total jobs from all sources from now through 2050 is substantial, with a loss of 126,000 jobs (12 percent) from five years of delay, and 250,000 jobs (25 percent) from ten years delay, as shown in the following figure.

Figure 38: Impact of delay on total jobs from all sources



Note: Jobs shown include direct, indirect, and induced jobs, where one job is full or part-time job over the course of one year.

Figure 39: Impact of delay on annual jobs from all sources



Note: Jobs shown include direct, indirect, and induced jobs, where one job is full or part-time job over the course of one year.

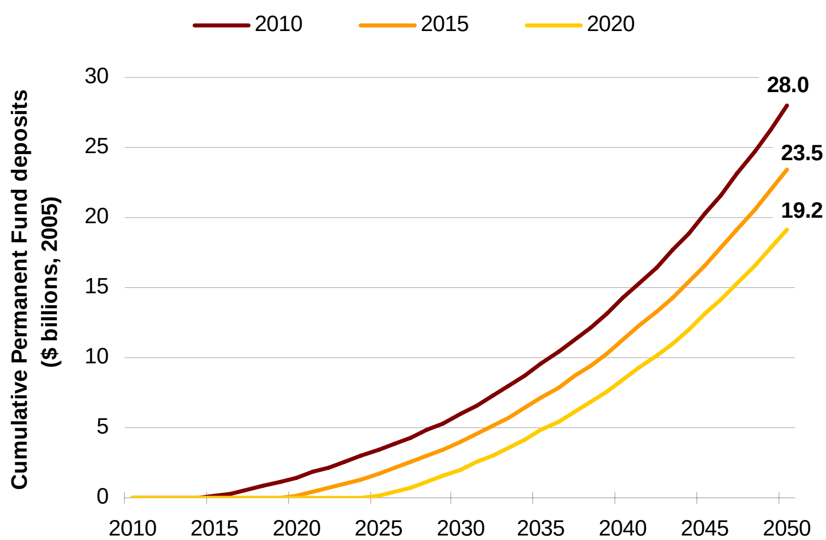
In addition, a delay in the start of a project could result in a significant change in resident hire rates due to the aging of Alaska's skilled construction workforce. Nearly 30 percent of

Alaska construction workers were 45 years old or older in 2004 (up from 23 percent in 1994), while 17 percent were 50 years old or older. If the start of pipeline construction is delayed by five or ten years, Alaska's construction workforce may lose the experience of older workers requiring greater import of outside labor for the highest skilled jobs.[12]

Impact of delay on the Alaska Permanent Fund

Figure 40 shows the impact of a delay on the Alaska Permanent Fund balance. The project impact on the fund balance is calculated as project-related deposits plus earnings, less dividends paid out, adjusted for inflation. We assume 25 percent of the state's project-related revenues are deposited into the fund. Earnings are estimated using a 7.6 percent return on investment, the target used by fund managers.

Figure 40: Impact of delay on Permanent Fund deposits



Summary of Baseline Model Results

The following table summarizes the economic, fiscal and workforce impacts of the sponsor group project using baseline assumptions and shows the impacts of delaying the start of the project by five or ten years.

---

[12] With good planning, a longer time period before start up could allow more young workers to be trained to fill expected pipeline construction jobs. Until a start-date is known, however, the state is in a Catch 22: failing to target the right crafts and train workers to fill jobs created both by retirement and pipeline construction will result in greater-than-predicted out-of-state hiring, but ramping up apprenticeship and other training programs without certain knowledge that those workers will have jobs when their training is complete will cause unnecessary expense and create an unused pool of prepared workers who may move out of state to use their training.

Figure 41: Impacts of delay on the sponsor group project

Project Timeline	0 years	5 years	10 years
Year in which construction expected to start	2011	2016	2021
Year in which gas first flows	2015	2020	2025
Year in which last gas flows through pipeline	2050	2050	2050
Wellhead and Tariff	**0 years**	**5 years**	**10 years**
Wellhead natural gas price	$3.43	$3.50	$3.57
Total pipeline tariff	$2.07	$2.00	$1.93
Economic and Fiscal Impacts	**0 years**	**5 years**	**10 years**
NPV (at 5%) to local governments ($ billions, 2005 dollars)	$1.7	$1.3	$1.0
NPV (at 5%) to state government ($ billions, 2005)	$25.3	$20.8	$16.6
NPV (at 10%) to producers ($ billions, 2005)	$17.6	$12.2	$8.3
Total NPV ($ billions, 2005) [1]	$44.6	$34.3	$25.9
Ave. annual spending of project-related revenues by state and local governments ($billions, 2005) [2]	$1.6	$1.6	$1.6
Ave. annual pipeline operations spending ($billions, 2005)[2]	$0.3	$0.3	$0.3
Total post-construction spending, all sources ($billions, 2005)[2]	$69.1	$59.9	$50.7
Cumulative effect on Alaska Permanent Fund balance ($billions, 2005)[3]	$28.0	$23.5	$19.2
Workforce Impacts	**0 years**	**5 years**	**10 years**
Total project-related jobs during construction[4]	68,000	68,000	68,000
Ave. annual project-related jobs during construction[4]	14,000	14,000	14,000
Total jobs from pipeline operations[4]	48,000	41,000	34,000
Ave. annual jobs from pipeline operations[4]	1,300	1,300	1,300
Total Jobs generated by state and local spending[4]	901,000	781,000	663,000
Ave. annual jobs from state and local spending[4]	25,000	25,000	25,000
Total jobs all sources all years[4]	1,016,000	890,000	765,000

Notes:

1) 10 percent discount rate for producer earnings; 5 percent discount rate for state and local revenues.
2) Cumulative deposits and earnings less dividends, adjusted for inflation, based on 7.6 percent return and current law for dividends.
3) Direct spending in real 2005 dollars.
4) Includes direct, indirect and induced jobs, where 1 job is a full or part-time job over the course of a single year.

Part 2. Comparative Analysis of Alternative Projects for Developing ANS Natural Gas

INTRODUCTION AND OVERVIEW

The Department of Revenue also asked Information Insights to analyze and compare the economic and employment impacts to the State of Alaska of several gas pipeline development scenarios. This part of the study looks in particular at the effects on employment and state and local government revenue of three alternative projects and on the sensitivity of each to varying periods of delay prior to the start of construction.

The study models the following three scenarios for getting ANS gas to market:

- AlCan pipeline – with capacity of 4.5 billion cubic feet per day (bcf/d) (expandable to 6 bcf/d) carrying gas from Prudhoe Bay, Alaska, to Alberta, Canada.
- Alaska LNG project – a 4.0 bcf/d capacity gas pipeline bringing North Slope gas to a liquefaction plant in Valdez, Alaska, and shipping LNG from Valdez to Pacific ports by tanker (with expandability to Delta Junction for a future Y-line).
- Y-line Project – a gas pipeline with capacity of 4.5 bcf/d pipeline from the North Slope to Delta Junction, Alaska – then splitting into a 1.5 bcf/d pipeline to Valdez, Alaska and a 3.0 bcf/d pipeline (expandable to 4.5 bcf/d) to Alberta, Canada.

As modeled, all projects include a 0.25 bcf/d spur line to Southcentral Alaska.

The first two scenarios were modeled on projects proposed by the sponsor group and the Alaska Gasline Port Authority (AGPA) respectively. Project details for the AlCan project come from the sponsor group's SGDA application, from confidential data provided by the companies, and from DOR. The sponsor group's 2001 cost projections have been adjusted for inflation. Project details and costs for the Alaska LNG project are based on the *Project Definition* released by AGPA in December 2005, as well as on private conversations with the Port Authority's economist and directors, and on updated plans provided by AGPA to DOR. The Y-line model is based on AGPA's most recent proposal and uses cost assumptions derived from the first two scenarios.

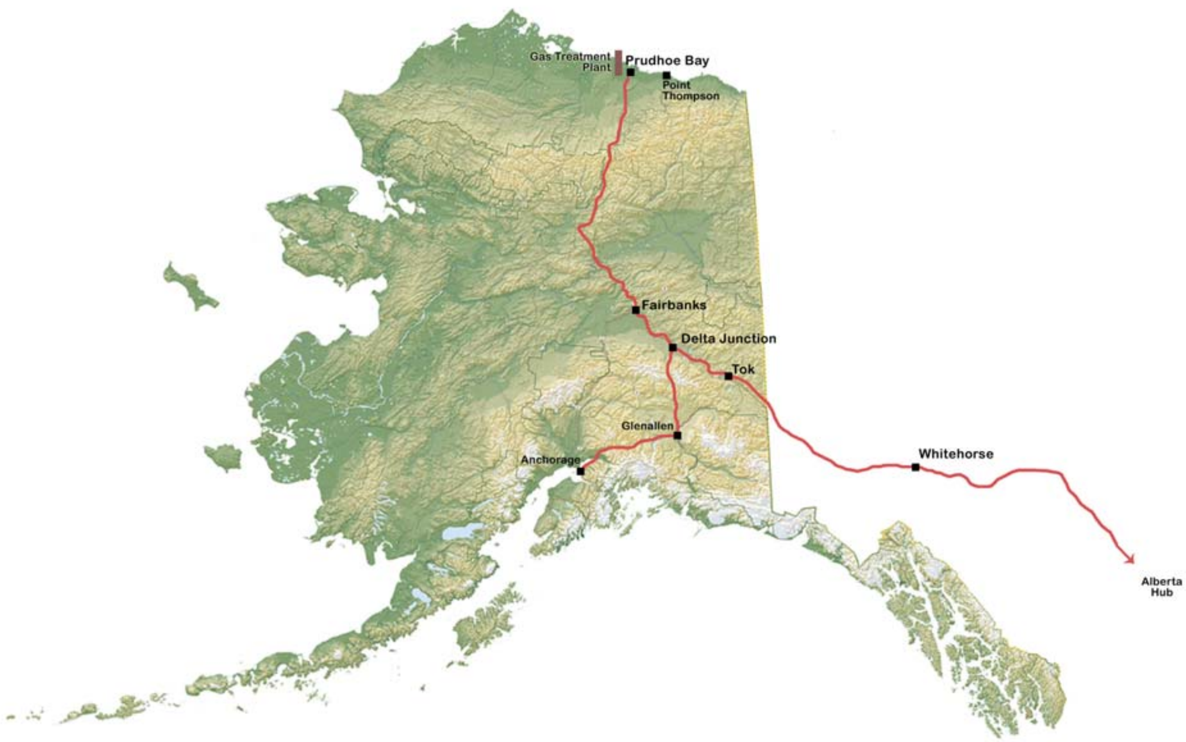
All of the assumptions used in this portion of the study (including assumptions on the sponsor group project) are based on our team's best estimates of costs, prices and impacts, and then adjusted as appropriate to create a better "apples to apples" comparison of all projects. For this reason the results of the baseline analysis of the sponsor group project in Part 1 of the report will vary slightly from the results for the same project in this comparative analysis.

The economic model of any energy project must accurately predict the future price of energy and must estimate the costs involved for building and operating such a project. To have an unbiased price forecast, we used the Energy Information Administration's (EIA) 2006 long-term price forecast average for oil and gas. Because natural gas is segmented into regional markets and into different products such as propane and ethane, we also based our price forecasts on a market analysis conducted by PFC Energy.

Based on the costs, forecast prices, and conventional tariff rules, we created economic models of each project and used the models to determine economic and workforce impacts on Alaska. Where necessary, we simplified project assumptions to more directly compare economic effects of the competing proposals. The text at the end of the section includes side-by-side comparisons of the economic, fiscal and workforce impacts of the three projects.

PROJECT DEFINITIONS

Figure 42: Route of proposed AlCan project



AlCan Pipeline Project

The North Slope producers propose to build a 4.5 bcf/d gas pipeline, expandable to 6.0 bcf/d, paralleling the Trans-Alaska oil pipeline (TAPS) from Prudhoe Bay to Delta Junction, Alaska, within the existing right of way (ROW) and then following the Alaska Highway to Alberta, Canada. The project includes construction of a gas treatment plant (GTP) at Prudhoe Bay to clean, compress and chill the gas before it enters the pipeline and to remove heavier natural gas liquids (NGLs), which will be added to the oil pipeline. The producers anticipate building a high strength steel pipeline with a diameter of 52 inches. This will allow an initial throughput of 4.5 bcf/day of natural gas and natural gas liquids in the pipeline under very high pressure. The pipeline will be expandable to 6 bcf/day with the placement of additional compressors along the pipeline. From Alberta, Alaska, natural gas will travel the additional 1,500 miles to Chicago, Illinois, through new or existing pipelines to be sold on the Midwest market, which is part of the very large Atlantic Basin regional market extending all the way to Europe.[13]

After a year of planning and engineering activities, the project will be constructed over a four-year period, with construction of Alaska sections concentrated in winter when soils are frozen to minimize environmental impact. Ramp up to full production will occur within one year of completion. Based on the producers' 2001 study, we estimate that pre-construction could begin in 2010, with construction completed in 2015 and full production beginning in 2016.

A spur line with capacity of 0.25 bcf/d will follow the TAPS line from Delta Junction to Glennallen and then run westward to Anchorage to bring North Slope gas to Southcentral gas facilities and provide for in-state use.

Our assumptions about the project are based primarily on the sponsor group's application to the state under the Stranded Gas Development Act, incorporating confidential data provided by the companies as well as an analysis of industry inflation rates over the past five years.

The route of the AlCan pipeline appears on the previous page.

Alaska LNG Project

AGPA's project design for an "all-Alaska pipeline" and LNG project has evolved through several iterations. We modeled a 4.0 bcf/d project based primarily on the *Project Definition* released by the Port Authority in December 2005. As modeled, the project consists of a gas treatment plant in Prudhoe Bay; an 800-mile pipeline that parallels the TAPS oil pipeline all the way to Valdez; and an LNG plant in Valdez consisting of three 1.1 bcf/d liquefaction trains, LPG extraction facilities, and storage and loading facilities for both LNG and LPG. From Valdez, the liquefied gas will be shipped by super-insulated tanker to West Coast LNG terminals in the U.S. and Canada, where it will be regasified and sold primarily on the smaller Pacific Rim market. A 0.25 bcf/d spur line will bring gas from Glennallen to Anchorage to supply Southcentral gas facilities and other in-state demand.

The AGPA project, as detailed by Bechtel, anticipates building a 56-inch diameter pipeline from the North Slope to Delta Junction, and a more conventional 48-inch pipeline from Delta Junction to Valdez with a 24-inch spur line from Glennallen to Anchorage. The 56-inch pipeline is a necessary element in the project design because it is the most likely method for possible further expansion should ANWR open up and new large gas fields be found.

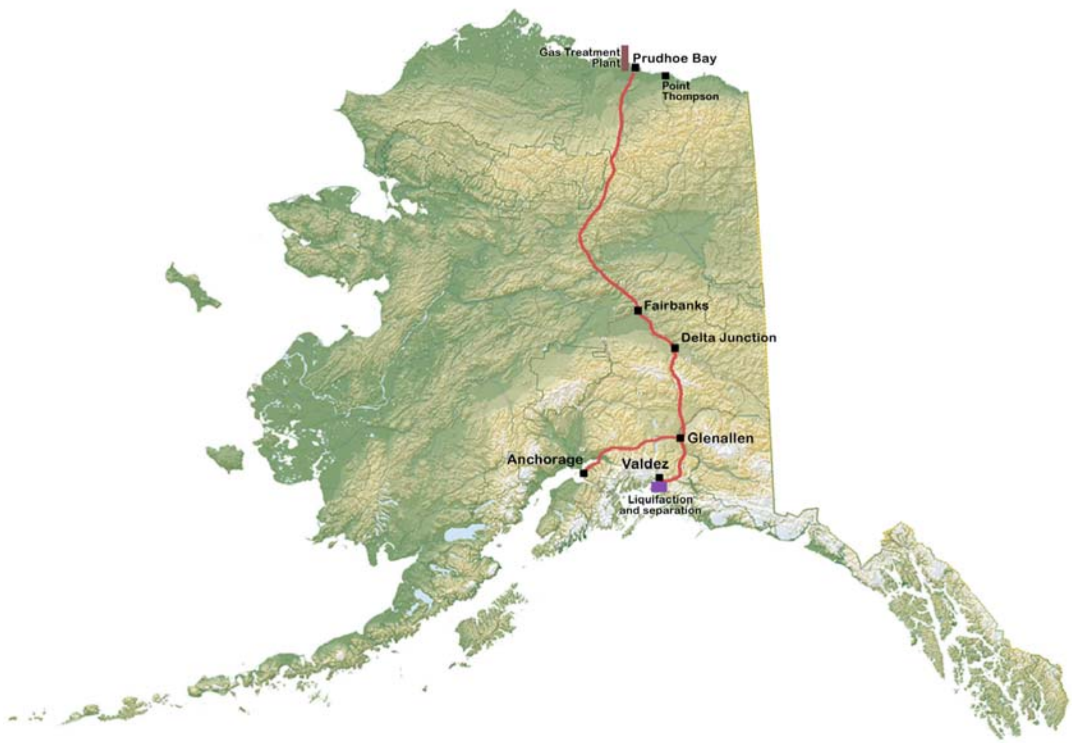
In addition to the information provided by AGPA, we considered PFC Energy's independent assessment of the Alaska LNG project, and compared information from both sources with our own analysis and with other LNG projects around the world to arrive at the cost, timing and market assumptions used in the model. AGPA's models assume that preconstruction

[13] Pipeline from Alberta to Chicago is not included in the model because capacity already exists to get Alaska natural gas to Chicago using current infrastructure. Tariffs from Alberta to Chicago are included in the model.

activities could begin in 2009 if gas contracts were in place today; our model assumes it would take at least two years to negotiate such contracts for the acquisition of gas and a total of five years of litigation or lease re-acquisition time, so pre-construction activities would begin in 2016.

A more likely construction start date is 2021 or later because the state would have to litigate or negotiate a repurchase to acquire the gas for a new project. Furthermore, even if the state were to take back the leases, there would likely be a protracted period to take care of new environmental permits, conduct new lease sales and renegotiate all aspects of pipeline construction and oil and gas production. The 2016 date is simply the earliest possible date that construction could begin.

Figure 43: Route of proposed Alaska LNG project

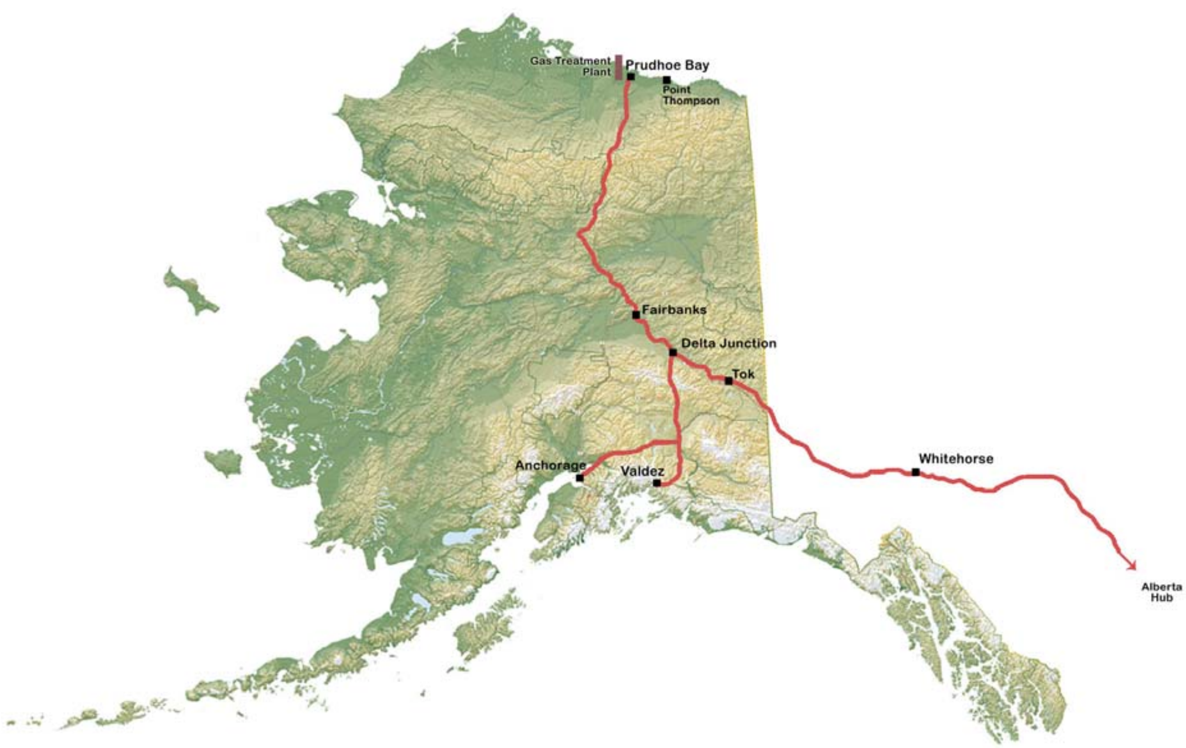


Y-line Project

We modeled a conceptual Y-line scenario consisting of a 4.5 bcf/d pipeline running from a GTP at Prudhoe Bay to Delta Junction, Alaska, along the TAPS right of way, and then splitting into a 1.5 bcf/d pipeline to an LNG plant in Valdez and a 3.0 bcf/d (expandable to 4.5 bcf/d) pipeline to Alberta, Canada. The 3/1.5 Y-line scenario represents our best guess as to the requirements of a Y-line project that would make the most economic sense given initial estimates of North Slope gas reserves and other constraints. Like the previous projects, the model includes a 0.25 bcf/d spur line from Glennallen to Anchorage for in-state use. The project includes a 56-inch diameter pipeline to Delta Junction, with a more conventional 48-inch pipeline from Delta Junction to Alberta Canada. Those lines are therefore expandable. The line from Delta Junction to Valdez is a 36-inch diameter line, and the spur line is 24 inches in diameter.

Our Y-line model uses construction costs, market prices, and timing assumptions developed for the previous models. A conceptual map of the Y-line project appears below:

Figure 44: Route of Y-line project with spur to Southcentral Alaska



We model the construction start date as 2017 also because of the time needed for negotiating an agreement with the producers to buy back leases and negotiate permits for the Canadian portion of the project. Again, this is not the most likely start date but is the fastest start date conceivable.

KEY ISSUES AND ASSUMPTIONS

This section explains the terms and issues necessary for understanding the economic models and model results. It defines the default values assigned to key parameters and explains the assumptions behind the values used.

Oil and Gas Prices

Long-term oil and gas price forecasts

The latest Energy Information Administration (EIA) forecast[14] projects oil prices to average over $50 per barrel over the next 25 years. The EIA forecast for natural gas prices predicts an average over $5 per million British thermal unit (mmBtu) over the same period.

In the short term, EIA predicts that the Lower 48 price for natural gas will fall below $5/mmBtu within 5 years as increased drilling brings on new supplies and new import sources become available. Eventually natural gas prices will slowly increase to $6.00/mmBtu by 2030 (in 2006 dollars), because Alaska natural gas production and Lower 48 production from unconventional sources will not be able to offset the impacts of resource depletion and increased demand. EIA estimates put the average future price of Lower 48 natural gas in inflation adjusted dollars at $5.33/mmBtu. In our economic models we assume the average price of natural gas will be $5.33/mmBtu and that this will be the price for gas sold in Chicago.

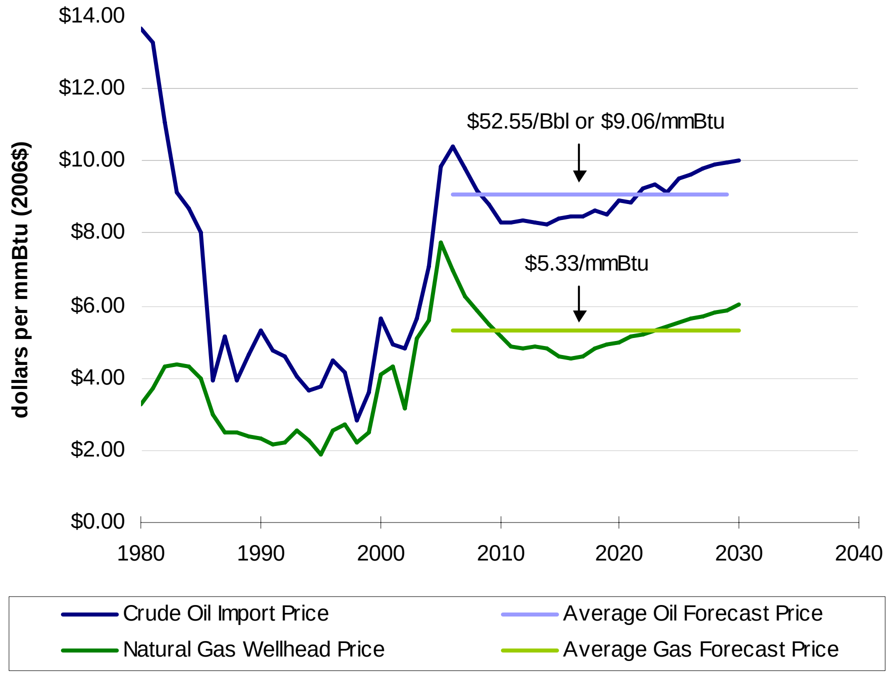
The expected price for natural gas in Alberta is $1 less than the Chicago price, which includes separation costs.

The 2006 EIA forecast for oil in the Lower 48 starts at about $60/Bbl, before dropping below and then climbing above $50/Bbl. The long-term average oil price is expected to be $52.55/Bbl. We find no benefit to using EIA's exact forecast model since EIA forecasts change often, so our models use the average price. The oil equivalent price, which is the price of oil in BTUs, is $9.06/mmBtu.

---

[14] Energy Information Administration. February, 2006.
http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

Figure 45: Oil and gas prices and forecasts, 2006 dollars



Energy inflation rate

We assume energy prices will stay constant in real terms in the model while general inflation for all costs and prices will increase at 2.5 percent. These assumptions are discussed further in the section on general inflation below.

Natural gas liquids

We assume propane will be sold at a price between oil and gas, but closer to the price of oil. The model uses a propane price of $30/Bbl or $7.83/mmBtu, which is two-thirds of the difference between gas and oil.

Regional Markets

Unlike the oil market, the natural gas market is fragmented into separate regional markets. These include the Pacific Rim, West Coast, Midwest, and Atlantic Basin markets. Natural gas liquids such as propane and ethane also have different values in different markets. This affects the value and jobs creation potential of any pipeline project and must be evaluated.

PFC Energy conducted an evaluation of gas markets for the Department of Revenue to determine the economic value of natural gas. We used their work in our models together with EIA price forecasts.

The price Alaska receives for its natural gas depends on where it is sold. Natural gas transported by pipeline to Alberta with connecting pipe to Chicago will be sold on the

Atlantic Basin market. Natural gas piped to Valdez, liquefied, and shipped to West Coast ports will be sold on the Pacific Rim market. The price for gas in the regional markets is determined by supply and demand in each market. Historically, natural gas prices in the Pacific Rim have been higher than the Atlantic, where sufficient North American supplies have kept gas prices low. Long-range forecasts, however, now show the potential for market prices to reverse, with Atlantic Basin prices topping Pacific Rim prices.

Chicago Market

Because trade and arbitrage of natural gas supplies create an interconnected market all the way across the Atlantic Basin to Europe, the Chicago market is much broader than that created by supply and demand forces in the Midwest alone. For example, Nigeria, Algeria, Trinidad and Tobago, and Venezuela can sell natural gas to either Europe or the U.S. via LNG tankers. Since they are most likely to sell to the country that pays more, gas markets on both sides of the Atlantic are tightly bound to each other; therefore, Alaska would effectively be selling gas to the entire Atlantic Basin region by selling to Chicago. That region is a large market with a demand of about 100 bcf/d in total. For this reason, we do not anticipate that Alaska gas will flood the market or cause a precipitous decline in Midwest natural gas prices.

Due to a projected North America decline of natural gas production, the Atlantic Basin including Chicago will see tight supplies and relatively higher prices for the next 20 years. Prices will remain relatively high until new LNG supplies come on line fast enough to replace North America's anticipated natural gas supply decline, but that may take a long time due to political uncertainties in a number of LNG producer countries.

Although we use the EIA forecast price for the Lower 48 of $5.33/mmBtu, we believe this is a conservative forecast and that future gas prices will be much higher.

Alberta Price

If the pipeline projects go only to Alberta, they will sell gas in Gordondale, Alberta. The price for natural gas there has been consistently $0.85 less per mmBtu than the Chicago market since the Alliance pipeline was completed in 2000. An additional fee for separation is included in the models that sell gas in Gordondale.

Pacific Rim Market

Despite its vast size, the Pacific Rim, including China, Japan and California, represents a much smaller market for natural gas sales with current consumption of natural gas at about 20 bcf/d. Some of the current supply comes from within the region, including China, the western U.S., Indonesia, Australia, and Sakhalin (Russia). In addition, Russia is considering a new gas pipeline to either Japan or China from its most western Siberian fields. The addition of significant new supplies of LNG into the market will cause a decline in price because this market is already thin, and because current regional supplies are "hard wired" into the region and difficult to change.

LNG shipped from Valdez will be sold on the West Coast and will therefore be more vulnerable to Pacific Rim price drops as new Mid-East and Asian supplies become available. For the purposes of the LNG model, we assume that the future price of natural gas in California's southern region will be the same as the EIA forecast for the country as a whole at $5.33/mmBtu. However, markets on the west coast away from southern California will have lower prices due to too much supply coming into these regions. Nevertheless, Alaska needs to be concerned that if too much natural gas floods the Pacific Rim market as a whole, prices may be substantially lower.

California will want to buy Alaska LNG based on flexible terms, as Japan has done in the past. If there is competition from new gas due to building new West Coast LNG regasification facilities, California will be able to pay less for its gas. Alaska can find itself competing with gas from Sakhalin (Russia), Australia and Indonesia on a very thin Pacific Rim market and stands to lose billions of dollars. With so much gas going into the Pacific Rim at one time, a price decline of 20 percent for ten years is possible.

AGPA's December 2005 report specifies at least 600 mcf/d of new Alaska LNG production will be sold to Kitimat, British Columbia, where it will be piped to the Alberta natural gas hub and on to Chicago. We assume this gas will be sold in Chicago at the EIA forecast price minus the pipeline tariff to Kitimat, which is estimated at $1.05. Another 1 bcf of supply will be sold to the North Star LNG facility in Oregon. Since Oregon is halfway between Alberta, Canada (a huge natural gas hub), and Southern California (another hub), the price obtained in Oregon will be the average between the two. The rest of the LNG will be sold to Southern California at the national average price. PFC Energy estimates the price loss by selling to these combined markets of Kitimat, Oregon, and Southern California at $.45/mmBtu.

LNG must, however, be regasified before it can be sold as natural gas. PFC Energy estimates regasification costs, including storage, at between $0.20/mmBtu and $0.90/mmBtu depending on location. We therefore assume that the West Coast cost for LNG regasification, before it comes onshore, will be $0.34. Accordingly, the average price for the LNG on board the tanker before it gets to shore is $0.79 less than the EIA forecast price for natural gas, or $4.54/mmBtu.

We estimate that a little over 3 bcf/d will be sold in the Pacific Rim after accounting for Kitimat sales, in-state use, propane sales, and pipeline and processing losses.

For the Y-line we estimate the LNG regasification cost will be $0.20/mmBtu. Since the Y-line only has 1 bcf/d of gas sales to the West Coast, those sales are assumed to be direct to Southern California and will receive the average U.S. price of $5.33/mmBtu. The LNG price before regasification is therefore $5.13. This still leaves Alaska with risk of revenue loss should other LNG supplies come into the market and lower the price.

State and Local Government Equity Interests

As stated under SGDA, the state will own a 20 percent equity share in an AlCan project. Under the LNG project proposal, AGPA would own a 100 percent equity share in the pipeline project and liquefaction plant, and may own a 100 percent equity share in the gas treatment plant. In the Y-line model, we have assumed AGPA would own a 100 percent equity share in the gas treatment plant, the pipeline from Prudhoe Bay to Valdez, and the liquefaction plant, while the line from Delta Junction to the Alaska border and on to Alberta would be privately owned with the state investing 20 percent in that portion of the project.

Construction Costs

Construction spending costs are based on estimates provided by the sponsor group and AGPA[15] [adjusted for inflation using producer price indices (PPI)], and on comparisons with similar projects around the world. Upstream costs including well development and feeder lines to Prudhoe Bay are estimated to be about $4.1 billion. These costs are not included in any tariff, but are included in the labor impact model. These costs are spread out in the production costs of the model.

Pipeline costs for each project are estimated at $156,000 per inch mile in Alaska and $133,000 per inch mile in Canada.[16] Gas treatment plant (GTP) costs for all projects are estimated at $3.1 billion. In order to compare separate elements of construction, we used the same cost per mile and GTP cost for each of the proposed projects.

Figure 46: Estimated construction costs for an AlCan pipeline project

Item	Cost Estimate ($ billion, 2005)	Percent of total project cost to Alberta	Percent of total project cost to Chicago
Upstream development including feeder lines (only for labor impact)	$4.1	N/A	N/A
GTP	$3.1	18%	13%
Alaska pipeline (to border)	$6.1	35%	26%
Canadian pipeline	$7.0	41%	30%
Spur line to Anchorage	$1.0	6%	4%
Total Cost to Alberta (excluding upstream development)	**$17.2**	**100%**	
Estimated cost Alberta to Chicago	$6.5		27%
Total Cost to Chicago (excluding upstream development)	**$23.7**		**100%**

The AlCan project has the advantage of using only one size of pipe for the entire 2,000 miles to Alberta. This creates economies of scale for production, trenching and laying of pipe.

The LNG project estimates include the cost of conditioning natural gas to a higher standard of CO_2 removal necessary for liquefaction. A portion of the pipeline route will have 56-inch pipe to allow for a possible Y-line project in the future. Another portion will have 48-inch pipe, and the spur line will be 24-inch pipe.

[15] In its independent review of the economics of the LNG project, PFC Energy estimated that costs would be 5 to 8 percent higher than AGPA's published cost estimates from Bechtel. Its analysis was based on standard project requirements in terms of materials, site development, utilities, labor costs, location factors, etc.

[16] The difference in cost between Alaska and Canada reflects labor differences, terrain differences and differences in transportation access.

The liquefaction trains for the LNG project will be among the world's largest. Although AGPA says that the facilities have been designed using a proven technology, as of 2005 no trains of this size had been completed. Based on a comparison with similar projects now being built, we assume each train will cost $2.1 billion.

Jones Act-compliant tankers are estimated at $300 million each or a total of $3 billion for a fleet of 10 ships (the fleet size we estimate will be needed to take the gas to West Coast markets).[17] In addition, we estimate that three tankers will be needed to ship Liquid Petroleum Gases (LPG) to West Coast or Asian destinations.

Figure 47: Estimated construction costs for an Alaska LNG project

Item	Cost Estimate ($ billion, 2005)	Percent of Total
Upstream development including feeder lines (only for labor impact)	$4.1	N/A
GTP	$3.1	15%
Alaska pipeline (Prudhoe Bay to Valdez)	$6.7	33%
Spur line	$0.5	2%
Gas separation facility	$0.5	2%
Single liquefaction train	$2.1	10%
Total for 3 Trains	**$6.3**	**31%**
Single Jones Act-compliant tanker	$0.3	1%
Total for all ships including LPG	**$3.5**	**17%**
Total (excluding upstream costs)	**$20.6**	**100%**

For the Y-line proposal, GTP costs are estimated at $3.1 billion, which includes the cost of conditioning natural gas to the higher standard of CO_2 removal required for liquefaction. The pipeline to Delta Junction will be constructed of 56-inch pipe, while the rest of the pipeline down the Alaska Highway to Alberta will be 48 inches in diameter and will use high-strength steel for the high pressure needed.

The Y- or spur line to the South Shore will be a 36-inch pipeline – big enough to handle one bcf/d for liquefaction and in-state usage at .25 bcf/d. The cost for a one bcf/d liquefaction plant is estimated at $2.1 billion. Jones Act-compliant tankers are estimated at $300 million each or a total of $1.2 billion for a fleet of four ships (the fleet size we estimate will be needed to take the gas to market in southern California). At least one tanker will be needed for shipping liquid petroleum gas (LPG).

[17] PFC Energy estimates a U.S. built LNG tanker with a capacity of 160,000 cu. ft. will cost $308 million, or 54 percent more than a typical South Korean-built tanker.

Figure 48: Estimated construction costs for a Y-line project

Item	Cost Estimate ($ billion, 2005)	Percent of Total
Upstream development including feeder lines (only for labor impact)	$4.1	N/A
GTP	$3.1	14%
Alaska pipeline (Prudhoe Bay to Valdez)	$5.9	27%
Canadian pipeline (plus pipeline from Delta Junction to border)	$8.5	39%
Spur line	$0.5	2%
Gas separation facility	$0.5	2%
Single liquefaction train	$2.1	10%
Single Jones Act-compliant tanker	$0.3	1%
Total for all ships	**$1.3**	**6%**
Total (excluding upstream costs)	**$21.9**	**100%**

Potential Y-line cost savings to Anchorage

One way that a Y-line can create significant savings is to bypass Valdez and route the line directly to Anchorage. There are two potentially significant cost savings. Southcentral Alaska will already need a 24-inch spur line for in-state use from Glennallen to Anchorage. A Glennallen to Anchorage line expanded to 36 inches adds approximately $385 million to the total cost, while providing the capacity to ship all of the 1.5 bcf/d of gas to Southcentral. The project saves money by not building a pipeline from Glenallen through the Chugach Mountains and over Thompson Pass to Valdez, which is estimated to cost $1.15 billion. There is therefore $770 million in savings to be had by going straight to Anchorage, and Anchorage is already connected to Nikiski's LNG facilities by existing pipelines.

A second cost savings for a Y-line direct to Anchorage would be to allow the project to use and expand on Nikiski's existing LNG facilities. The cost of expanding an existing LNG plant should be significantly less than building a greenfield plant. A Valdez site would need high cost infrastructure development, such as siting costs, port costs, road costs, the costs of acquiring and delivering massive amounts of gravel, and labor camp costs that a Nikiski site would not need. The Nikiski site may more easily obtain permit upgrades, also making it a quicker option. Therefore, a Y-line straight to Anchorage rather than to Valdez should save an Alaska port authority an estimated $1.5 billion and create an estimated 1,500 extra jobs per year through increased state spending. This can also reduce the price of natural gas in Anchorage.

Figure 49: Map of alternate Y-line route.

Operating Costs

Operating and maintenance costs in Figure 50 show the percent of the initial capital expenditure that is needed every year to operate and maintain facilities. These costs are used to determine tariffs.

Figure 50: Operating costs as a percent of capital costs

Operating Costs	Percent of Capital Costs
Conditioning plant	3.0%
Pipeline	2.2%
Separator plant	4.0%
Liquefaction plant	4.0%
LNG ships	3.0%
LPG ships	3.0%

Fuel Losses

Fuel losses associated with each project are shown in Figure 51. Our assumptions mirror conventional losses for natural gas projects. In addition to normal processing losses, fuel losses are incurred when gas is taken off to run compressor stations, to fuel LNG tankers, and to be burned in other industrial processes along the way. Because gas undergoes more processing in an LNG project, routine fuel losses are greater.

Figure 51: Conventional fuel losses associated with similar projects

Fuel Losses	AlCan Pipeline	Alaska LNG	Y-line
Conditioning plant	4%	4%	4%
Pipeline	2%/1,000 mi.	2%/1,000 mi.	2%/1,000 mi.
Separation	3%	3%	3%
Liquefaction	–	5%	5% for LNG
LNG shipping & regasification	–	3%	3% for LNG
LPG shipping	–	1%	1% for LNG
Total loss of saleable commodity	**.51 bcf/d**	**.62 bcf/d**	**.51 bcf/d**

Inflation

The models used for the comparative analysis assume an inflation rate of 2.5 percent for the overall economy, whereas the analysis of the sponsor group project in Part 1 used a two percent inflation rate at the request of DOR. We believe that current information suggests a higher rate of general inflation. In the past year consumer price inflation has been as high as five percent. While we don’t expect five percent inflation to persist, we do believe inflation will continue to be slightly higher than past rates.

In our cost estimates, we have taken account of the recent rise in the price of steel and project specific labor and management costs. Although these have been substantial, we do not foresee a continuation of these cost increases. Steel prices appear to have stabilized, and relatively looser labor markets will moderate labor and other costs in the construction industry in the future, especially if we are in the midst of a housing and real estate bubble.

Construction Schedule

Our estimates of the length of time needed to construct the Alaska LNG and the AlCan pipeline project are shown in Figure 52. Year 0, the pre-construction year, would begin after all planning, design, and permitting activities are completed. Projects are not at 100 percent capacity at completion of construction. The ramp-up period accounts for time needed to bring on line and test all components of the pipeline and upstream and downstream facilities.

The producers estimate the AlCan pipeline project will take four years to construct. We assume a one-year ramp up during which production will average 50 percent of total project capacity.

We assume a similar construction schedule to build a pipeline from the North Slope to Valdez, a gas treatment plant and upstream infrastructure, including a pipeline to Point Thomson. The Alaska LNG project also requires construction of three large liquefaction trains. Typical trains in the past have taken three years to build. We assume concurrent but staggered construction of the three trains in order to lower construction costs by spacing workforce needs in Valdez. This also will allow time for West Coast markets to develop, with each train operating at 70 percent during its first year.

We assume the construction schedule for a Y-line would require four years to construct, with a single liquefaction train built in Valdez. We assume a one-year ramp-up on the AlCan section of the pipeline, at 50 percent capacity, and a one-year ramp-up on the LNG portion of the project, operating at 70 percent capacity its first year.

Figure 52: Estimated construction schedules for AlCan pipeline project

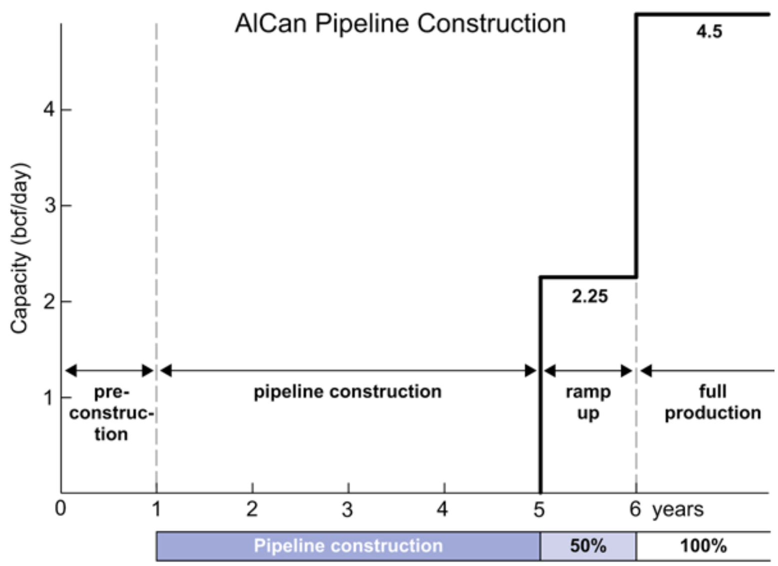


Figure 53: Estimated construction schedules for Alaska LNG project

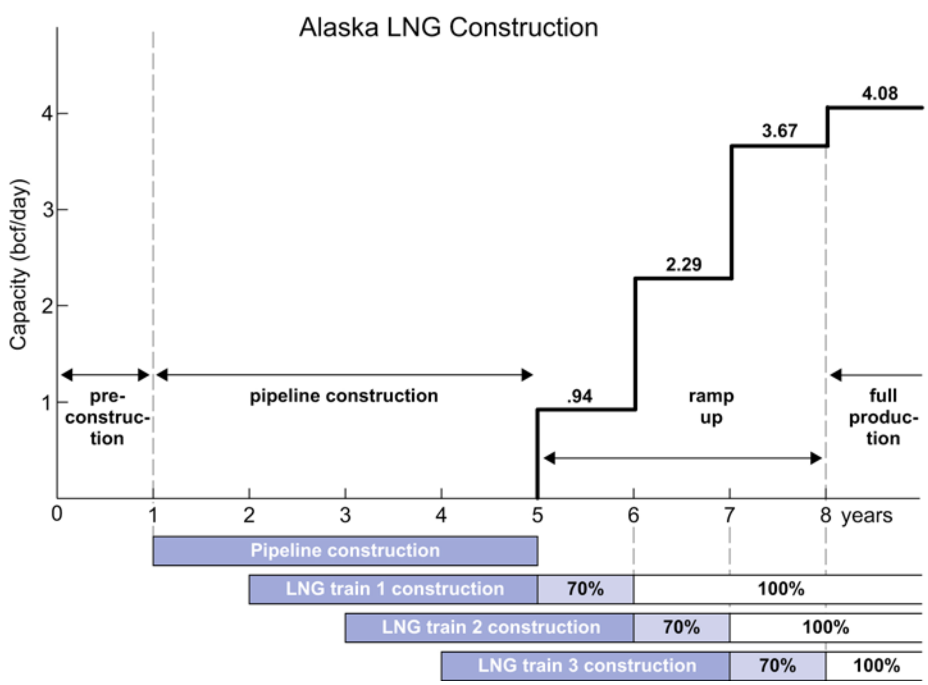
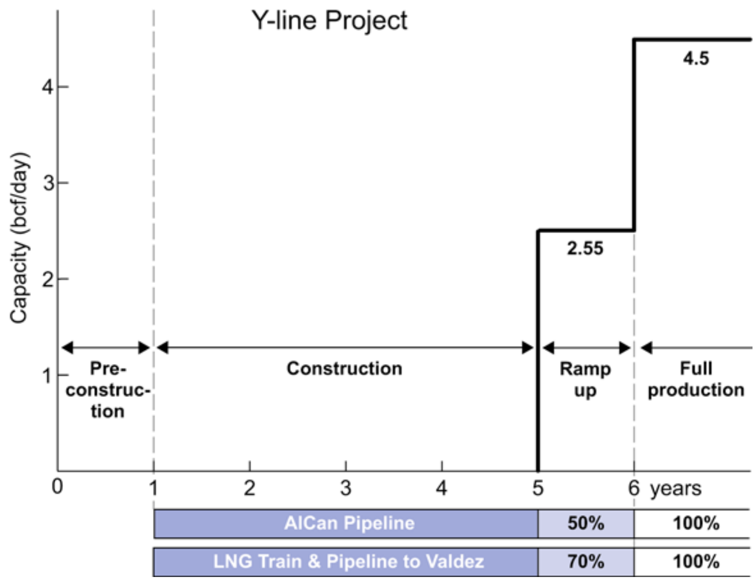


Figure 54: Estimated construction schedule for Y-line project

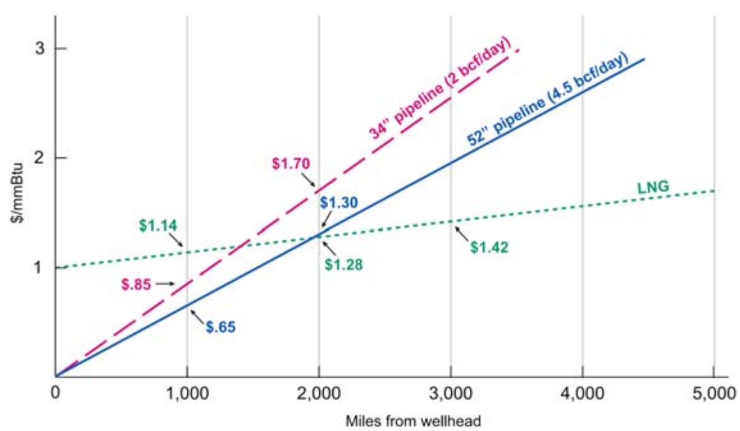


Tariff Calculation

Tariffs are calculated based on costs of construction, taxes and standard ratemaking formulas. The Federal Energy Regulatory Commission (FERC) is responsible for setting pipeline tariffs in the United States. In the economic models, we use a levelized tariff formula, where the tariff fee does not change as prices and costs increase with inflation.

The tariff normally includes any federal taxes. An LNG project may receive a federal tax exemption that would reduce tariffs, while a producers' project will not be eligible for such an exemption. Figure 55 illustrates representative costs for transporting natural gas by pipeline and by LNG as a function of distance for a typical natural gas project.

Figure 55: Representative transportation costs for natural gas projects



The following figures show how estimated tariffs for different Alaska natural gas pipeline projects compare to each other.

Figure 56: Tariff profile for AlCan pipeline project

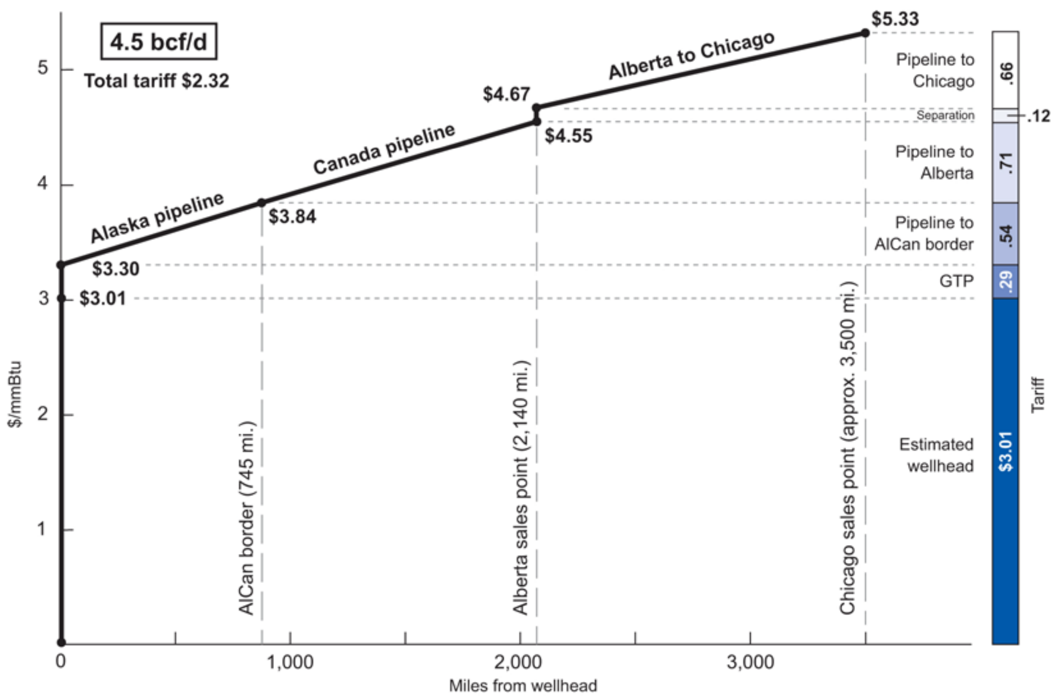


Figure 57: Tariff profile for Alaska LNG project

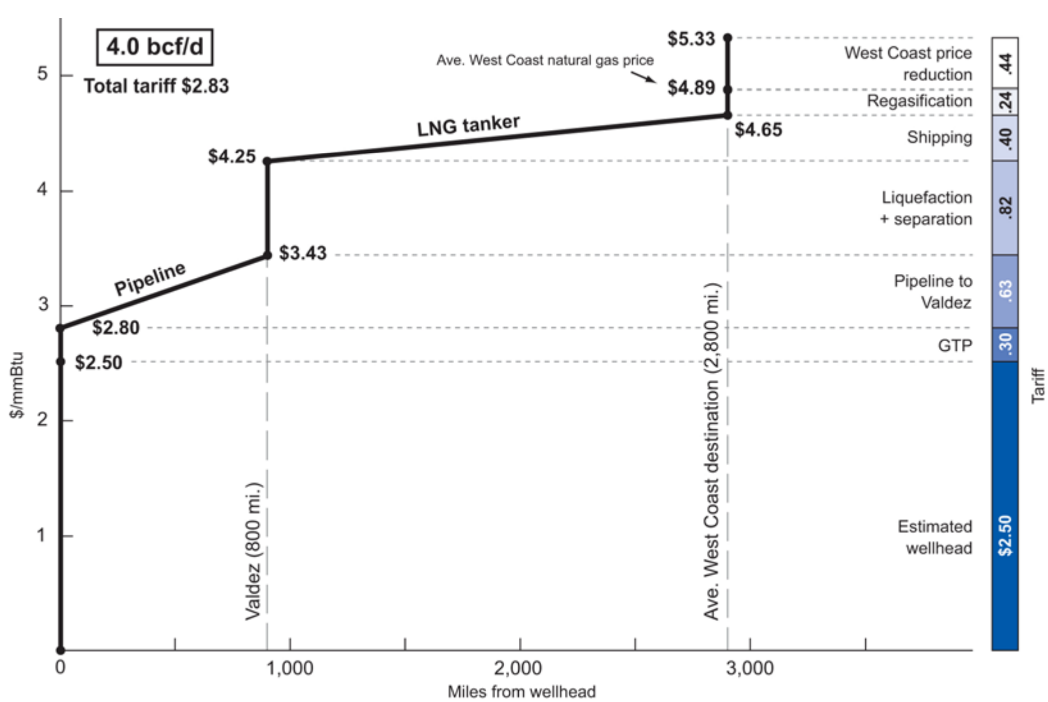


Figure 58: Tariff profile for Y-line project

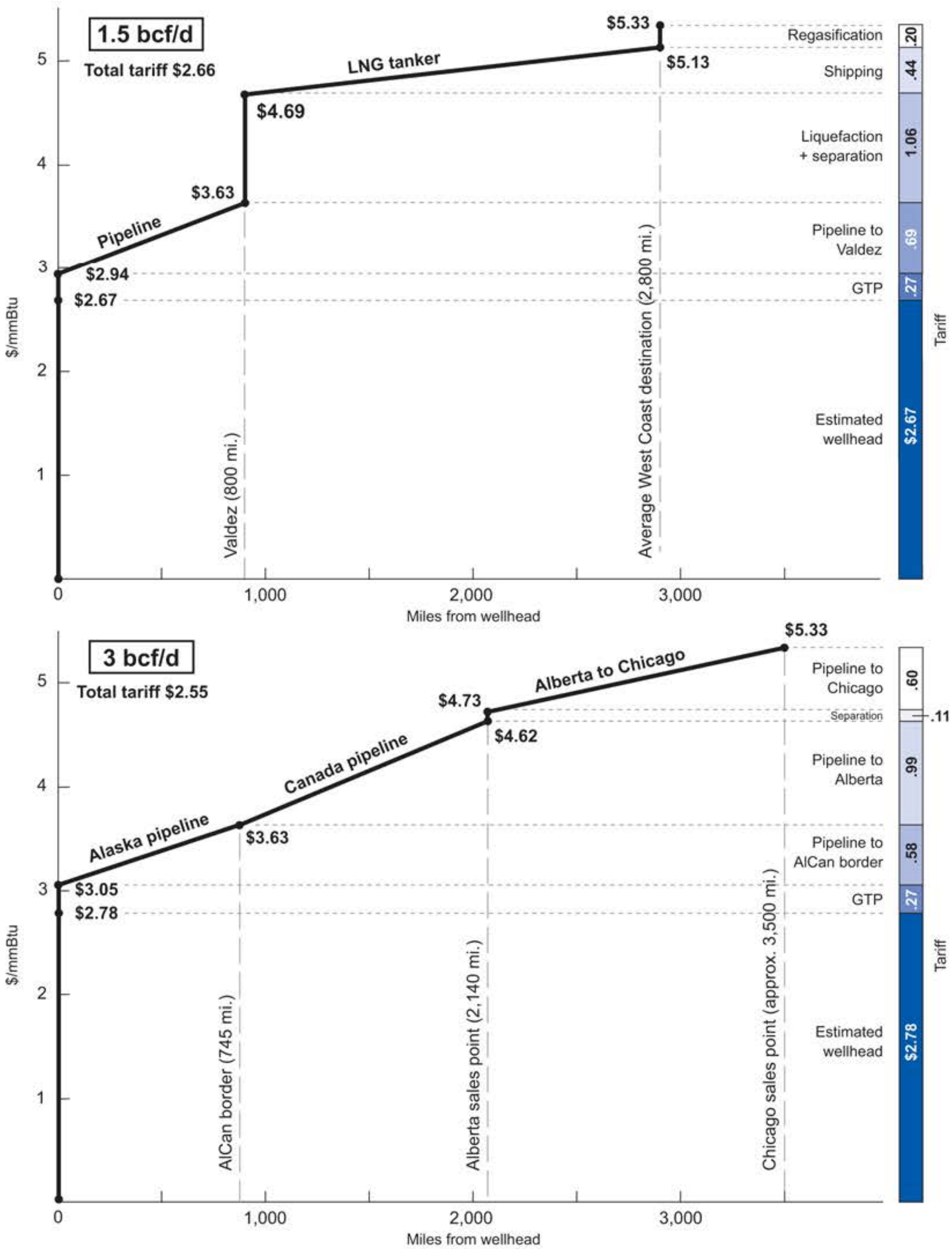


Figure 59 shows estimated tariffs for each of the projects. All tariffs are given in 2005 dollars.

Figure 59: Estimated tariffs for Alaska natural gas projects

Tariffs	AlCan Pipeline ($/mmBtu)	Alaska LNG ($/mmBtu)	Y-line ($/mmBtu)	
			Canada	LNG
Year 0 (first tariff date)	2015	2019	2020	2020
Wellhead value	$3.01	$2.50	$2.78	$2.67
GTP	0.29	0.30	0.27	0.27
Alaska pipeline	0.54	0.63	0.58	0.69
Canadian pipeline	0.71	–	0.99	–
Separation	0.12	0.06	0.11	0.19
Alberta to Chicago	0.66	–	0.60	–
Liquefaction	–	0.76	–	0.87
Shipping	–	0.40	–	0.44
Regasification	–	0.24	–	0.20
West Coast price reduction	–	0.44	–	–
Total Tariff	**$2.32**	**$2.83**	**$2.55**	**$2.66**
Final Sale Value	**$5.33**	**$5.33**	**$5.33**	**$5.33**

Property Tax

In our comparison models, we use different state and municipal property tax structures for the three projects.

The Alcan model assumes that state and municipal property tax revenues will be a throughput-based payment in lieu of taxes (PILT) of 2.4 cents per mcf, allocated among municipalities as set out in the SGDA contract.

The LNG model follows AGPA's recommended PILT. The LNG pipeline project as proposed by AGPA would be municipally owned and exempt from property taxation. AGPA has proposed a property tax PILT for this project based on undepreciated replacement cost of project property at:

- 10 mills for the first 7 years
- 15 mills for the next 7 years
- 20 mills thereafter

The Y-line model assumes state and municipal property tax revenues would be similar to the LNG line for the Prudhoe Bay to Valdez section (and GTP and liquefaction plant), and similar to the AlCan line for the Delta Junction to Canadian border section.

Municipal Revenues

The model calculates municipal revenues from the projects, and shows the workforce impacts of municipal spending of those revenues. Based on AGPA's *Project Definition*, we assume 60 percent of revenues from AGPA equity earnings and local gas property taxes will accrue to the state, and 40 percent to municipalities. The distribution of the municipal share follows AGPA's proposal, with 15 percent paid to the three AGPA member municipalities and the remaining 85 percent to all other Alaska municipalities. The model assumes that all municipal revenues will be spent.

Summary of Project Definitions and Assumptions

The following table provides a summary of the project assumptions and definitions used in Part 2 of the study.

Figure 60: Summary of project descriptions and assumptions

Project Description	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Total capacity	4.5 bcf/d	4.0 bcf/d	4.5 bcf/d
Pipeline size	52-inch to Alberta; 24-inch for the spur line to Anchorage	56-inch to Delta Junction; 48-inch Delta Junction to Valdez; 24-inch for the spur line to Anchorage	56-inch to Delta Junction; 48-inch to Alberta; 36-inch to Valdez; 24-inch for the spur line to Anchorage
In-state use	0.25 bcf/d	0.25 bcf/d	0.25 bcf/d
Market	Chicago/Alberta/Atlantic Basin	West Coast/Pacific Rim	Chicago/Alberta/Atlantic Basin West Coast/Pacific Rim
Project Assumptions	**AlCan Project (adjusted for comparison)**	**Alaska LNG Project**	**Y-line Project**
Construction start	2011	2015	2016
Construction period	4 years	6 years	4 years
First gas flows	2015	2019	2020
Project cost[1]	$21 billion to Alberta $27 billion to Chicago	$25 billion to West Coast	$26 billion to Alberta and West Coast
Market size	100 bcf/d	20 bcf/d	Combined
Gas price[1]	$5.33/mmBtu Chicago $4.33/mmBtu Alberta	$4.54/mmBtu U.S. and Canadian West Coast average LNG $4.15/mmBtu B.C. LNG	$5.33/mmBtu Chicago $5.13/mmBtu LNG
Fuel Losses	11.30% to Alberta (0.53 bcf/d)	17.6% (0.8 bcf/d)	11.50% (0.55 bcf/d)
Wellhead after tariff	$3.01	$2.50	$2.73

KNOWN CHALLENGES AND ASSUMPTIONS

Each project faces known challenges that are hard to quantify in models, but which could significantly affect the overall viability of the project. Some challenges, such as the risk of delay due to unfinished road and bridge projects, will affect all projects more or less equally and are not included in the discussion. Instead we focus on serious issues that could make or break a project, as well as on challenges that may impact projects disproportionately.

Transportation infrastructure upgrades

Existing Alaska highways and bridges along some routes will require upgrading prior to the start of construction to support the heavy loads of high-density pipe, and some ports will need to be expanded to handle the large volume of construction equipment and supplies. Funding will need to be secured almost immediately once a project is approved to allow the necessary work to be completed prior to construction of the gas project, according to Information Insights' *Stranded Gas Development Act Municipal Impact Analysis*, prepared for the Municipal Advisory Group in 2004 under the SGDA. Upgrades may be eligible for federal funding with a state match through the federal transportation programs, however there is already a large backlog of projects in the State Transportation Improvement Plan (STIP) that are designed or ready to start and are awaiting funding. Without earmarks for the projects outside the STIP process or increased levels of federal funding, it will challenging to fund the needed upgrades without displacing existing road projects of high importance to municipalities and other entities across the state.

We assume that roads and bridges will be upgraded in time to move heavy pipe.

AlCan Pipeline

Getting a pipeline built

A project to bring Alaska gas reserves to market has not ranked well compared to other projects open to North Slope producers, according to a 2004 study by PFC Energy. Based on a comparison of NPV/barrels of oil equivalent (BOE) and the internal rates of return for projects in the companies' global portfolios, an Alaska gas pipeline project ranked as follows at the time of the study:

ExxonMobil:	74 out of 100 projects
BP Exploration:	61 out of 77 projects
ConocoPhillips:	41 out of 61 projects

Until recently, it has been in the interest of the companies to delay the development of North Slope reserves while pursuing other global opportunities with lower risk and higher profit potential. While recent state and federal legislation have helped improve the policy environment for development, the recent rise in world energy prices has been the single biggest factor changing the economics of an Alaska gas pipeline. The producers' expectation of future prices will continue to be a factor impacting the timing of construction.

Permitting challenges

The sponsor group faces several permitting challenges before construction can begin. In addition to successfully negotiating the environmental permitting processes in both countries, rights-of-way will be needed to cross state, federal and private lands in Alaska; and federal, provincial, territorial and tribal lands in Canada, all of which are expected to take years to acquire.

TransCanada Pipelines Limited (TransCanada). TransCanada owns right-of-way and environmental permits for the Canadian portion of an AlCan pipeline, and also holds permits for the federal ROW in Alaska. TransCanada acquired its Canadian permits with its purchase of Foothills Pipe Lines Ltd., which was authorized to construct the Canadian portion of a natural gas pipeline under Canada's Northern Pipeline Act (NPA) of 1978. However, because these permits are for a specific project using specific technology under the NPA, there is speculation that TransCanada's permits are not valid for this substantially different project. Unfavorable economics stalled the Foothills project, but in 2004 TransCanada filed its own application under Alaska's Stranded Gas Development Act, with the intention of building at least the Canadian portion of a pipeline. TransCanada has said it would be willing to sell its Alaska permits to a partner who would build the U.S. portion. It is unclear whether TransCanada would be willing to relinquish them without a partnership deal, or whether a different project can be built along the same route with new permits.

To build a pipeline along the proposed AlCan route, therefore, the producers will need to either partner with TransCanada, acquire its ROW permits, or challenge the exclusive nature of the permits in Canadian court. There are, however, other legal questions over use of the nearly 30-year-old NPA certificates held by TransCanada. While TransCanada maintains that NPA is in full force and effect, Enbridge has questioned that status. The act specifies both route and technical details for the pipeline, some of which may no longer make sense with current technology. The sponsor group believes this could open the project to legal challenges as project requirements have substantially changed since 1978 and may necessitate more complex regulatory processes.

First Nations. Canadian First Nations' opposition has increased costs and may stall the Mackenzie Valley natural gas pipeline now being permitted in northwest Canada. In the Northwest Territories a large number of tribes have backed the project, forming the Aboriginal Pipeline Group (APG) with a one-third ownership interest in the pipeline. However the Deh Cho, whose lands cover the southern third of the pipeline route, have skillfully used the courts and the regulatory process to hold up permitting. According to Shell Oil, the project is behind schedule because pipeline owners have filed more than 6,500 pages of documents in response to regulatory appeals and public information requests by First Nations' groups.

The Deh Cho's demands have created grassroots pressure on leaders of the Aboriginal Pipeline Group to go back to their corporate partners with increased demands, including broad taxation powers and $40 million in additional compensation. The Deh Cho may be using their opposition as leverage in negotiations with the government over unresolved land claims issues. In April 2005 the oil companies stopped all engineering work on the pipeline and threatened to call off the project in response to what they saw as excessive First Nations' demands.

The DeneTha, an Alberta tribe that has sued to stop the pipeline, filed an additional legal challenge to the Mackenzie pipeline, claiming that they have been left out of both environmental hearings and benefits negotiations. A negotiator for a coalition of First Nations tribes whose lands surround the Alaska gas pipeline right of way warns that Alaska producers should see the Mackenzie situation as a wake-up call.

Alaska LNG Project

Obtaining gas from North Slope producers

Obtaining gas from the producers who hold North Slope oil and gas leases is the largest single challenge for any Alaska LNG project. Our analysis concludes the Alaska LNG project reduces profits to the producers by roughly one-fourth from those expected from the AlCan pipeline project, even if an LNG project could start without delay. It would not be in the best interest of the producers or their shareholders to sell gas to AGPA or, quite likely, to any alternate pipeline developer. Without a gas reserves tax or other mechanism to substantially change project economics for North Slope lease owners, we believe it is unlikely the producers would ever sell gas to a competing project. Any change in the law that affects the status of existing leases would be likely to result in protracted litigation. Even if litigation were successful, the additional delay in construction would result in a lower NPV to the producers and the state. An analysis of this issue is provided in the appendix.

Contract negotiations. Assuming the producers were willing to sell natural gas to an LNG or Y-line project, we posit that negotiating a contract with the producers could take several years to negotiate.

Value destruction. If the producers are not willing to sell gas to a project that provides less economic return to them, the state could seek to buy back the leases or attempt to take them through legislative or legal means with the intention of reselling them to a buyer willing to participate in an Alaska LNG project. Even assuming the state could avoid a lengthy and costly court battle, there are compelling economic arguments against this approach.

If the condition of a new lease sale were that the buyer must agree to sell natural gas to an Alaska LNG project, the sales price of the leases would be approximately $8 billion less than the sales price without the condition and the difference could be much greater. In economic terms, this loss of value is called value destruction. The $8 billion amount represents the difference in NPV to North Slope producers of an Alaska LNG project compared with an 80 percent producer-owned AlCan pipeline project. In other words, if the net present value of an LNG project is lower to a potential new producer, that difference in value would be reflected in a lower bid to buy the leases. Since Alaska would receive less upon reselling the leases, a portion of the value of the gas to Alaska is destroyed.

Our models show that the state would forfeit roughly $8 billion in lease sales revenue by requiring an Alaska LNG line to move gas to market. If deducted from project revenues, that sum translates into a $2 billion reduction in Alaska Permanent Fund deposits and a $6 billion reduction in state spending. That money could be used for generating infrastructure, jobs, and services in the state. It would create an estimated 90,000 jobs if spent over a short period of time or as many as 250,000 jobs if the money were invested and the earnings spent by the state over the life of the project.

Despite the challenges that an Alaska LNG project would have in obtaining gas for shipment, for the purposes of the model we adopt AGPA's assumption that an Alaska LNG project will be able to obtain gas from North Slope producers, but assume a five-year delay in project start as the minimum time required to obtain gas.

Gas conditioning facilities

We assume the same cost of GTP for all projects $3.1 billion – a figure provided by DOR and based on producer estimates.

There are, however, several reasons why an LNG project may have higher gas treatment costs than an AlCan project:

1. Gas that will eventually be liquefied needs to be conditioned to a higher standard.
2. AGPA may need to seek a higher-cost, fixed price contract to secure financing.
3. An LNG or Y-line project may not be able to take advantage of existing gas conditioning facilities on the North Slope if a cooperative agreement cannot be reached with the producers.

AGPA acknowledges that while it could reuse existing gas conditioning infrastructure at Prudhoe Bay, it may have to build entirely new facilities. For the purposes of the model, we assume a cooperative agreement can be reached that allows North Slope gas conditioning infrastructure to be used by an LNG project and that no additional capital expenses are required to replicate existing facilities.

Point Thomson development

If an Alaska LNG project is selected over a project that includes a producer-owned pipeline, it is unknown whether North Slope producers will develop their Point Thomson oil and gas reserves. We estimate potential reserves at Point Thomson Unit at 600 million barrels. Three hundred million barrels of natural gas liquids (NGLs) under high pressure would fill a natural gas pipeline for about 15 years, while PTU oil (which accounts for the rest of the liquids) would extend the life of the TAPS oil pipeline, offsetting the revenue loss from the accelerated decline in oil production that will occur once gas is no longer reinjected into wells. If the producers were to choose not to invest in the wells, feeder lines and associated infrastructure required to develop Point Thomson's reserves, the life of an Alaska natural gas project would be shorter, the state's oil and gas revenues would be lower, and state spending of oil and gas revenues would generate fewer jobs.

For the purposes of the models, we assume that Point Thomson oil and gas reserves would be developed if any gas project goes forward.

Jones Act-compliant tankers

The Jones Act is the 1920 federal law requiring the use of U.S.-owned and -built ships with U.S. crews for the transport of all cargo between domestic ports. To comply with the law, AGPA has agreed to purchase Jones Act-compliant tankers for shipments to West Coast destinations, although gas transported to Kitimat, British Columbia, and continuing on to U.S. terminals may not be subject to the Act if sufficiently altered. We assume all ships are Jones Act compliant to avoid any risk of delay in a project. AGPA has stated that it has an MOU and competitive price quote from the American Shipping Group's Totem Ocean Trailer Express (TOTE) subsidiary to provide U.S.-built LNG carriers that are fully Jones Act compliant.

The Port Authority has not revealed the details of the MOU or its cost estimates for acquiring Jones Act-compliant ships. Since there are currently no U.S.-flagged LNG tankers and no U.S. shipyard has built an LNG tanker in the last two decades, we believe it could take at least four or five years for a shipyard to ramp up and build the number of tankers required to ship all the Alaska LNG destined for West Coast terminals.

Our Alaska LNG model assumes that Alaska LNG shipments will not be exempt from the Jones Act, but that the number of tankers needed by AGPA can be built in time to ship 100 percent of the capacity of each LNG train as it comes on line. Our model assumes a price of $300 million per tanker.

West Coast LNG import terminals

LNG terminal development on the West Coast of the United States will be a challenging process, as they will have to be permitted and developed as a part of the completion of an LNG project. Development and permitting of adequate LNG receiving capacity on the West Coast will add another variable in the development of an Alaska LNG project. Proposals to build LNG facilities on the West Coast could run into local opposition due to environmental, security and perceived community impacts. No projects have been permitted so far.

In its March 17, 2006 *Assessment of The Alaska Gasline Port Authority LNG Project*, PFC Energy evaluated the prospects of specific LNG import terminal projects on the West Coast that have been identified as potential buyers. They analyzed the likelihood of four principle project criteria, any of which could undermine a project's viability, to determine if any were likely to be developed within the next 10 years. PFC Energy found that, even for the two projects (Kitimat and Northern Star) whose prospects for quick permitting were good, their distance to the premium natural gas markets in southern California makes it only a poor bet that they will be ready to receive Alaska LNG within the next ten years. The price received in British Columbia or Oregon will be lowered by the cost of transporting regasified LNG to main consumption centers in California. PFC Energy estimates the netback to Kitimat to be nearly $2/mmBtu below the PG&E citygate price in San Francisco.

Figure 61: Evaluation of West Coast LNG terminal development prospects

Likelihood of:	**Kitimat LNG** (Kitimat, BC)	**Northern Star** (Bradwood, OR)	**Clearwater Port** (Offshore Oxnard, CA)	**Port Penguin** (Offshore CA)	**Sound Energy Solutions** (Long Beach, CA)
Obtaining a federal/provincial permit	Likely	Good	Mediocre	Negligible	Good
Obtaining state and local permits	Likely	Good	Fair	Negligible	Poor
1st project in the area ready for financing	Excellent	Likely	Poor	Negligible	Excellent
Financing and construction	Poor	Poor	Poor	Negligible	Likely
Conclusion: Likelihood of construction in next 10 years	Poor	Poor	Poor	Negligible	Poor

Source: PFC Energy, 2006

Our model staggers the construction of LNG trains to allow more time for development of West Coast LNG terminals. For the purposes of the model we adopt AGPA's assumption that sufficient West Coast terminal capacity will exist to receive all of Alaska's LNG supply as it comes on line.

Construction scheduling

Any delay during construction adds significantly to costs both because of high interest rate payments for borrowed capital and because of the time value of money for costs previously incurred. For an Alaska LNG project, one of the challenges in determining tariffs is that a pipeline has to be built early in the project, but will not initially be able to run completely full because it will take time to build the large liquefaction facilities in Valdez and develop West Coast contracts for the entire supply. The delay in tariff earnings for the pipeline will add to interest payments as well as the time value of money for costs already incurred. This significantly reduces the NPV of an LNG project to the natural gas leaseholders.

Tax exemption

AGPA is eligible for tax-exempt status as a political subdivision according to a private letter ruling issued by the Internal Revenue Service. Tax exemption means bonds issued by the Port Authority would be tax-exempt, and the Authority would not be required to pay federal income tax on its earnings. The I.R.S. will eventually rule formally on whether the federal tax exemption is valid for the final project specifications. If the exemption were not granted, it would reduce revenues for the producers and the state from an Alaska LNG project, but would do so asymmetrically. Gas lease owners would lose 20 percent of the NPV of a project, while the state would lose as little as two percent.

For the purposes of the model we assume that an I.R.S. exemption is secured.

LNG plant space and workforce needs

Two major LNG projects were recently completed, one in Qatar and one in Trinidad and Tobago. Each covers one square mile of land. The Alaska project calls for a similar size plant with three 1.1 bcf LNG trains. The mountainous terrain around Valdez could make siting an LNG plant of that size challenging and expensive. For the purposes of the model we assume there will be adequate space to build the necessary processing facilities at the costs published by AGPA.

Likewise, peak workforce needs in Valdez may create challenges when several LNG trains are built concurrently. AGPA estimates a peak workforce of 2,500 for construction of the LNG plant and associated facilities. Our calculation of work force, based on implementation of similar projects, indicates there could be a peak work force as high as 7,500 workers in Valdez in year four of the project. This may strain available housing and support services and may overwhelm in-state labor resources requiring a higher percentage of out-of-state labor. We assume that workforce needs can be met with creative housing solutions and a staggered schedule for train construction, but the risks of labor cost overruns need to be acknowledged.

Permitting challenges

AGPA has acquired options from Yukon Pacific Corporation on the major permits and ROW leases needed to build an Alaska LNG project. Most of the permits were issued in 1987-88 for a period of 30 years and will need to be renewed. The Port Authority asserts that all are currently valid, though they anticipate updating key permits with new environmental and technical information and making adjustments to market LNG on the U.S. West Coast instead of Asia. To the extent that the project is substantially larger than originally permitted, and will go thirty years past the original permits length of use, new permits or substantial modifications to existing permits may be required.

Our base model assumes no project delay will occur, nor will financing delay occur due to the short time left on the permits as issued to YPC.

FERC requirements

An Alaska LNG project that has the potential to become a Y-line in future may be subject to FERC tariffing rules. Since a Y-line will go to Canada, and Canada may be able to change its tariffing rules if the U.S. changes its rules, FERC would likely require the Port Authority to follow standard tariffing practices, including the structure of a PILT, to avoid the possibility of a pipeline tariff war with Canada.

Y-line Project

A Y-line project is a hybrid of an AlCan pipeline and an Alaska LNG project and would face all of the same challenges mentioned above that those projects face. In some cases the scale of the potential impact is different for a Y-line project, and these differences are noted below. In addition, a Y-line faces some unique challenges which are discussed here.

Obtaining gas and value destruction

A Y-line project also would experience reluctance on the part of current North Slope lease holders to sell gas to a project that would be much less profitable to them than their own pipeline to midwest markets. We estimate that a Y-line would return roughly one-fourth less to the producers than a single pipeline to Alberta over the life of the project if a Y-line could be built with no delay. If we assume a delay of five years is needed to negotiate or litigate for access to gas, the loss in NPV to the producers increases to 42 percent. (See the appendix for a review of the analysis.) However, for the purposes of the model, we assume that current North Slope produers would be willing participate in a Y-line project.

Construction scheduling

One of the challenges of any Y-line is to coordinate the various parts of the project. The Y-line has to simultaneously organize the pipeline building and marketing of gas to Alberta, while doing the same via LNG to California. If, for example, a California regasification terminal is delayed due to permitting problems, it could either delay the entire project or it could create an extra tariff cost due to the pipeline not being full right from the start. Also because a Y-line will involve complex engineering management of compressors stations, nautral gas liquifaction facilites and gas conditioning plants, a delay in any one part of the project may cause the need to re-calibrate or re-engineer all the other parts of the project, increasing costs.

Tariff disputes

The Federal Energy Regulatory Commission (FERC) is likely to scrutinize very closely any municipally owned Y-line project, or an LNG project that has the expectation of expanding into a Y-line project, because there is an opportunity for the owner to use its taxation powers (or payment in lieu of taxes) to affect the real return to the pipeline owning municipalities. While FERC rules provide that tariffs provide a return on investment, municipal owners may receive their return in both the equity return and a tax or PILT return.

In addition, there could be tariff disputes due to different tax treatment in Alaska and Canada. For example, if Alaska increases its tax share to local municipalities in a manner substantially different from the Canadian process, any later pipeline that carries Alaska natural gas through Canada may be subject to similar tariffing schemes by the Canadian Energy Board (CEB), FERC’s counterpart in Canada. What may ensue is a “tariff” war where Canadian municipalities try to gain higher tariff revenue at Alaska’s expense, which would lower wellhead prices in the state and thus lower state revenues. Trade disputes between Canada and the U.S. have already emerged with fishing and timber; it is not out of the question to see similar disputes with natural gas.

Nikiski advantage

A Y-line that takes 1.5 bcf/d directly to Anchorage will enjoy a significant cost savings by using existing pipeline to Nikiski for shipping to West Coast destinations. We estimate savings in pipeline and LNG facility construction costs to be on the order of $1.5 billion for a project that bypasses Valdez and re-engineers the spur line to Anchorage from 24 inches to a 36-inch size, and then upgrades and expands the exisiting Nikiski LNG facility. We believe this is an important engineering approach that AGPA should fully analyze and present to state policy-makers.

Summary of Known Challenges

Figure 62: Summary of known challenges

Known Challenges	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Gas supply	Yes	Need to acquire	Need to acquire
ROW permits	Need to acquire First Nations issues Need Environmental Impact Statement	Existing permits may need updating and expanding Need to extend permits for a 30-year project Need some environmental studies and permitting	Mixed
First Nations issues	Some	None	Some plus equity issue
Tariffing issue	None	With greater municipal share, FERC may need to change methods	With greater municipal share, FERC may need to change methods
Receiving sites & LNG terminals	Pipe capacity from Alberta to Chicago exists	Poor prospects for 4 terminals	Poor prospects for 2 terminals Pipe capacity from Alberta to Chicago exists
Proposal stability	Firm	Changing	Conceptual
Construction delays	Possible Due to steel supplies, workforce issues, permitting issues	Likely Due to contract talks, tanker and terminal readiness, workforce issues, and legal challenge of obtaining gas from existing lease holders	Likely Same as Alaska LNG
Delay for road and bridge upgrades	Possible	Possible	Possible

COMPARATIVE ANALYSIS MODEL RESULTS

Based on the comparative analysis of all three projects, we conclude that the AlCan pipeline proposed by the sponsor group maximizes the value of Alaska's North Slope natural gas resources by producing the highest revenues for the state and creating the greatest number of jobs for Alaskans over the life of the project. While any project may meet with unanticipated delays, our analysis of known delays also favors an AlCan pipeline, which is the only scenario that starts with an assured supply of gas.

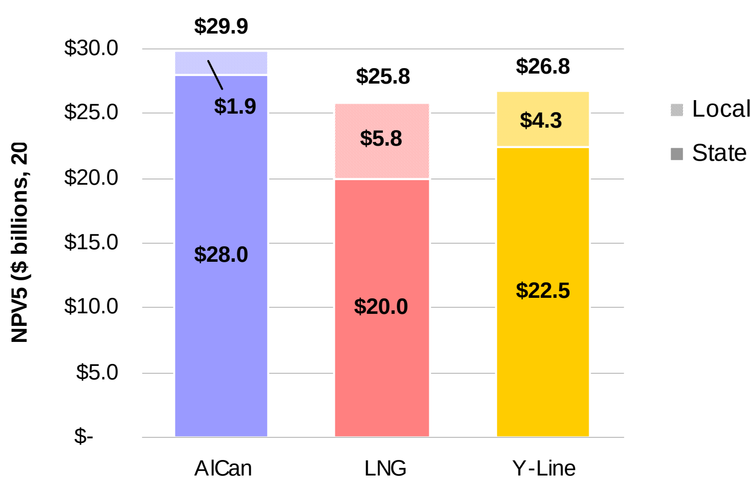
Fiscal and Economic Impact Comparison

Once a pipeline becomes operational, our model estimates the NPV of a project to Alaska state and local government to be as follows, assuming a 5 percent governmental discount rate:

- $29.9 billion or $1.6 billion per year from an AlCan pipeline;
- $25.8 billion or $1.5 billion per year from an LNG pipeline;
- $26.8 billion or $1.8 billion per year from a Y-line pipeline

As before, project revenues are expressed in real terms in 2005 dollars and include the effects of gains and losses in North Slope oil production due to a gas project, as well as revenues from the sale of natural gas and natural gas liquids.

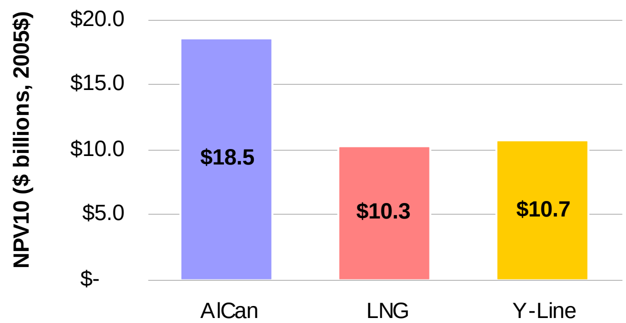
Figure 63: Present value of state and local government revenues from gas projects



Note: NPV at 5 percent

The sponsor group owns the rights to develop the ANS gas reserves. They will maximize their profits with an AlCan project as shown in the figure below. These figures show the net present value of all expected costs and profits based on our models.

Figure 64: Net present value of alternative projects to the producers



Note: NPV at 10 percent

The producers will realize greater profitability with an AlCan pipeline because this project achieves significant economies of scale that lower tariffs and other processing costs. The Chicago market is also likely to attain a premium price for natural gas liquid and for dry gas itself owning to the U.S. and Europe's strong demand and tight supplies.

Given the premium to the producers from building their own pipeline, it is unlikely they would consent to sell gas to another project without coercion. Oil and gas leases are binding contracts allowing the leaseholder to produce oil and gas in the area covered by the lease as long as they stick to the lease terms. We find it reasonable to assume that an attempt to extinguish the producers' interest in North Slope gas by taking back leases through legislative or legal means would result in protracted litigation, delaying the start of a gas pipeline project.

Alternatively, if the state wished to buy back the leases from the producers, we assume it would take two to three years to negotiate the buyout. Additional time would be required to account for all environmental and infrastructure problems and to determine a temporary owner/operator. The state would then have to set up new lease sales and solicit bids from prospective buyers who agree to participate in an Alaska LNG or Y-line project. A new lease sale might require a new environmental permitting process. In all, a buyout could take five to ten years even if the process goes smoothly and does not result in protests or further litigation. For purposes of our comparison, we assumed a five-year delay.

Value destruction

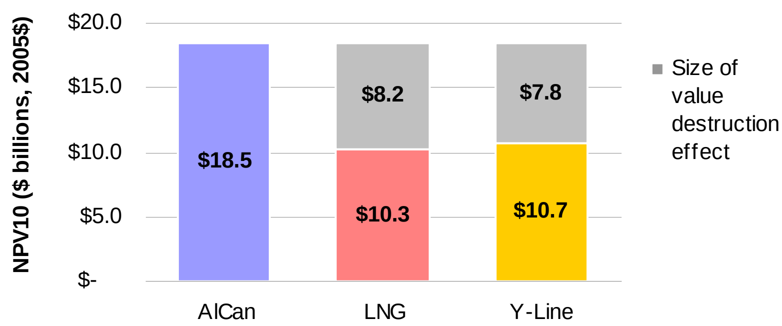
The concept of value destruction as it applies to the Alaska gas project and the importance of impacts of delay are central to understanding why the AlCan project is the superior choice for Alaska compared to an Alaska LNG or Y-line project.

We use the term value destruction to describe the loss in a project's value to the producers should natural gas be sold to an LNG or Y-line project. The value destruction effect can be illustrated by two scenarios: (a) if the producers sell gas to an LNG or Y-line project, their return from the gas declines with no comparable increase to other parties, resulting in potentially compensable loss in value of the producers' North Slope leases; or (b) if the state buys back the gas leases and reissues them with the requirement that gas be shipped to market through an Alaska LNG or Y-line project, the state's return from the leases will decline as new leaseholders reduce their bids by the amount of value destroyed.

The size of the value destruction effect is equal to the difference in the NPV to North Slope oil and gas producers of an Alaska LNG or Y-line project compared with the value of a producer-owned pipeline bringing gas to the Chicago market.

Our analysis shows that the value destruction effect is substantial for both the Alaska LNG and Y-line projects, resulting in lower state revenues and a significant reduction in jobs generated by state spending of gas revenues. Either project would result in the state losing $8 billion to $10 billion in lease sales revenue if the new leases include the stipulation that an all Alaska LNG or Y-line project be built. This estimate does not include the potential costs of litigation, contract negotiations, new permitting or costs associated with setting up the lease sales.

Figure 65: Size of value destruction effect for LNG and Y-line projects

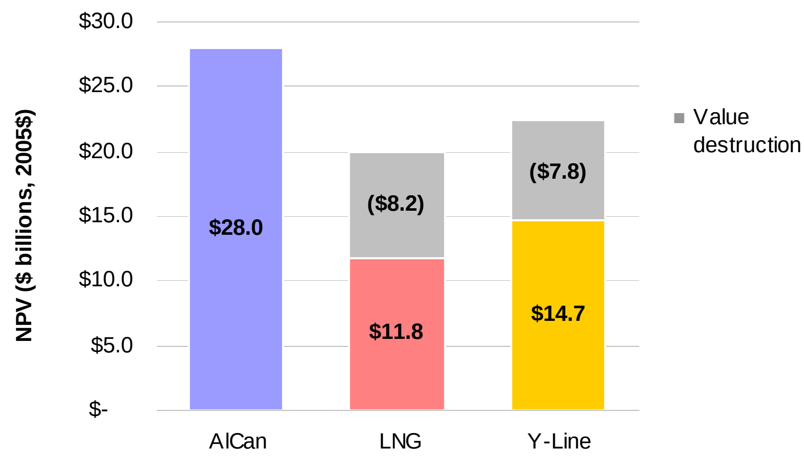


Note: NPV at 10 percent

Earlier we showed the present value of an Alaska LNG project to state and local governments to be $25.8 billion. After accounting for value destruction, we expect the NPV to fall to $17.6 billion, while the NPV of a Y-line project to the state and municipalities drops from $26.8 billion to $19 billion once value destruction is taken into account. Once again, each of the NPV models uses a five percent discount rate for state and local government revenues.

This lost revenue would result in reduced state and local government spending and could cost Alaska the equivalent of 8,500 jobs on an annual basis due the economic multiplier effects of public and private spending. By including the lost revenue in the NPV calculations for all three projects, our model provides an accurate projection of total economic impacts and shows that the AlCan project maximizes value to Alaska.

Figure 66: The effect of value destruction on state revenues



Note: NPV at 5 percent

Alaska Permanent Fund effects

The three projects generate significant differences in revenue streams to the state. While the Alaska LNG and Y-line projects create additional municipal revenue as shown in Figure 63, it comes at the cost of a lower wellhead value, and thus lowers royalty payments to the state. Over time, the aggregate amount deposited in the Alaska Permanent Fund also suffers, with a corresponding reduction in annual Permanent Fund Dividend payments to Alaskans. The following figure shows the impact on the Alaska Permanent Fund, including deposits and cumulative earnings (less dividends paid out). Earnings are again estimated at 7.6 percent.

Figure 67: Impact of project revenues on Alaska Permanent Fund balance

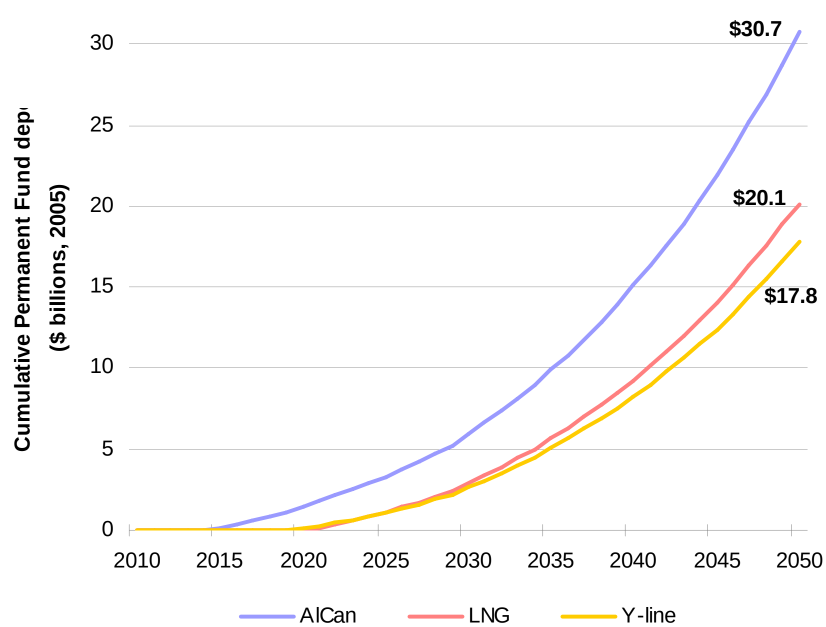
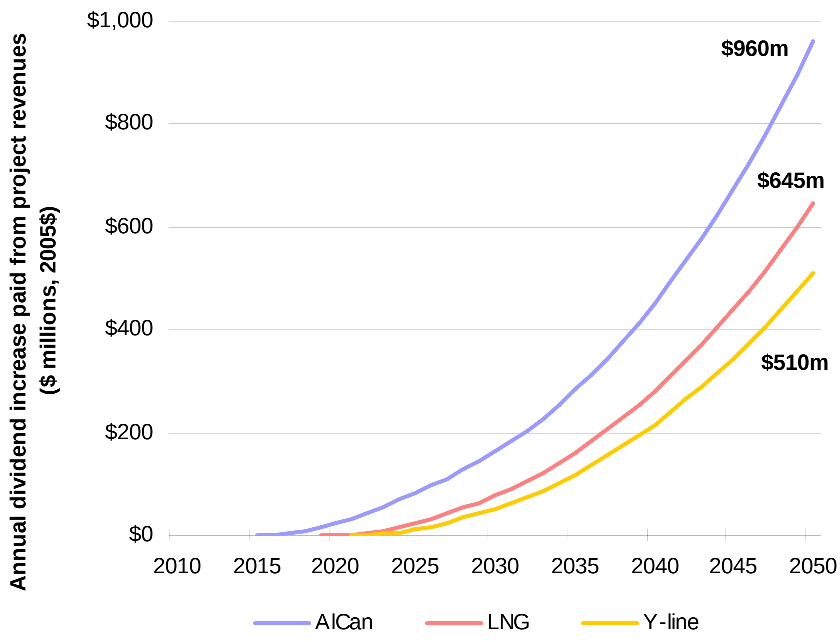


Figure 68 Project effect on annual Alaska PFD payments

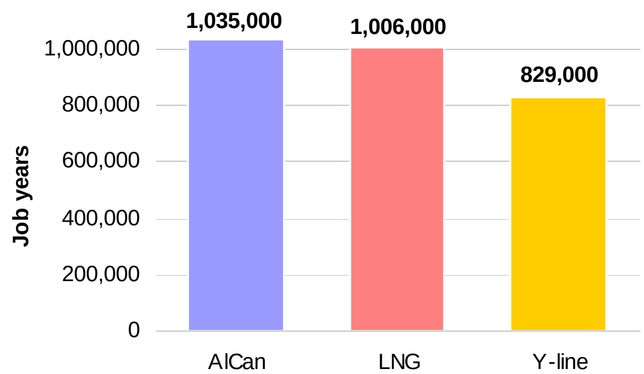


Comparison of Workforce Impacts

The Information Insights' model projects increased labor force needs in Alaska – direct, indirect and induced jobs – for construction of a the gas pipeline project and for project operations through 2050. (Note that in these estimates one job or job year represents one full or part-time job over the course of a single year.)

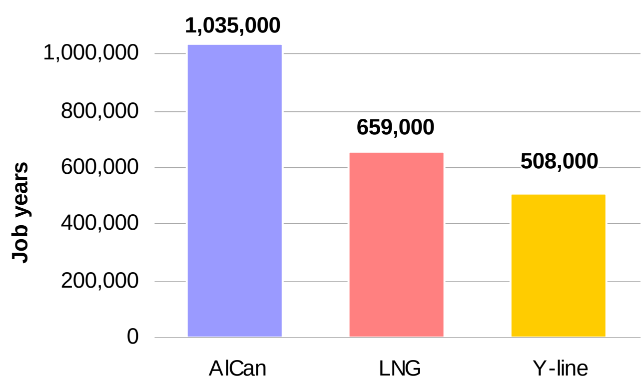
- The AlCan project increases the state's labor force needs by an average of 18,000 direct, indirect and induced workers per year during construction. The project also creates a sustained impact of about 26,000 jobs per year after construction from both pipeline operations and jobs generated by state and local spending of project-related oil and gas revenue.
- The LNG project increases the state's labor force needs by an average of 19,000 direct, indirect, and induced workers during construction, and results in a sustained increase of 27,000 jobs per year after construction. These job gains are reduced however when the effect of value destruction on state spending is taken into account. We estimate the size of the value destruction effect to be 347,000 job years.
- The Y-line project has average workforce needs of about 22,000 during construction and a sustained addition of nearly 23,000 workers thereafter. However, due to reduced spending of state revenues, the Y-line results in 321,000 fewer job years than an AlCan project when effect of value destruction is included.

Figure 69: Total jobs from all sources through 2050



Note: Includes direct, indirect and induced full and part-time jobs over the course of one year

Figure 70: Effect of value destruction on total jobs



Note: Includes direct, indirect and induced full and part-time jobs over the course of one year

The following series of figures illustrates the different job profiles the three scenarios present. One of the challenges of the Y-line profile is the large spike in jobs during the initial construction phase that could represent an unusually severe boom and bust. The spike appears during the second year of construction when building on a North Slope conditioning plant is critical, requiring extra work. At the same time, there is on-going pipeline construction, while construction on a south shore liquefaction project is in full swing, exacerbating the total Alaska labor demand. During year two of a Y-line project, the total employment effect on the state is 36,000 workers, while only 21,000 workers are needed the prior year, and only 28,000 the year after. This spike in demand will cause extra strain on the state's ability to take care of new Alaskan residents who may find themselves out of work in post-construction years.

The following series of charts shows the total (direct, indirect and induced) labor impacts of each project from project construction and operations as well as those generated by state and local spending of project revenues through the year 2050.

Figure 71: Workforce impacts from project construction and operations

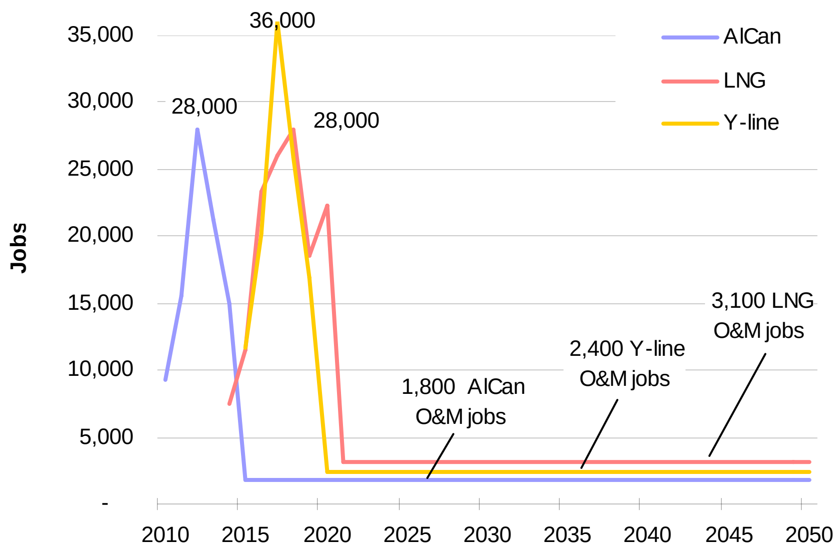


Figure 72: Workforce impact of project-related state and local spending

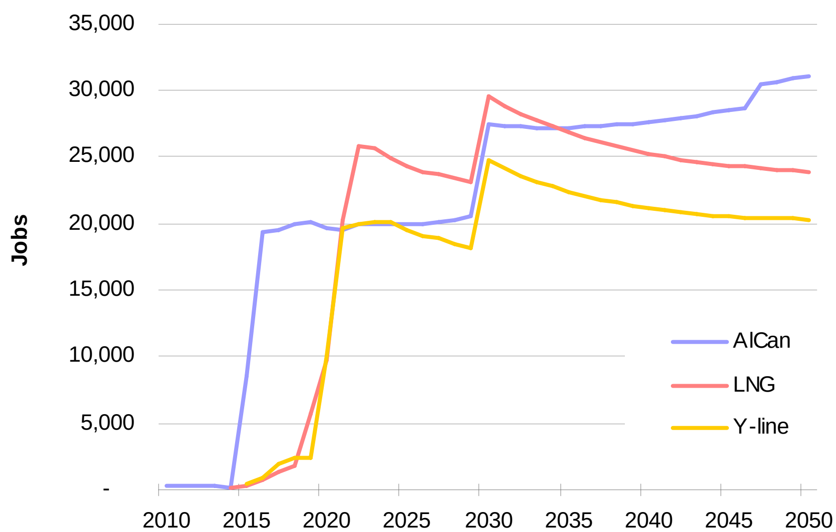


Figure 73: Total jobs from all sources through 2050

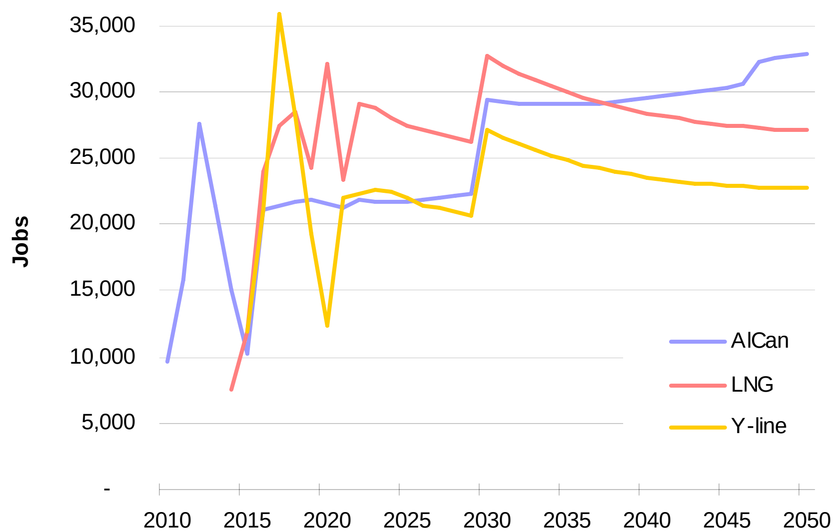
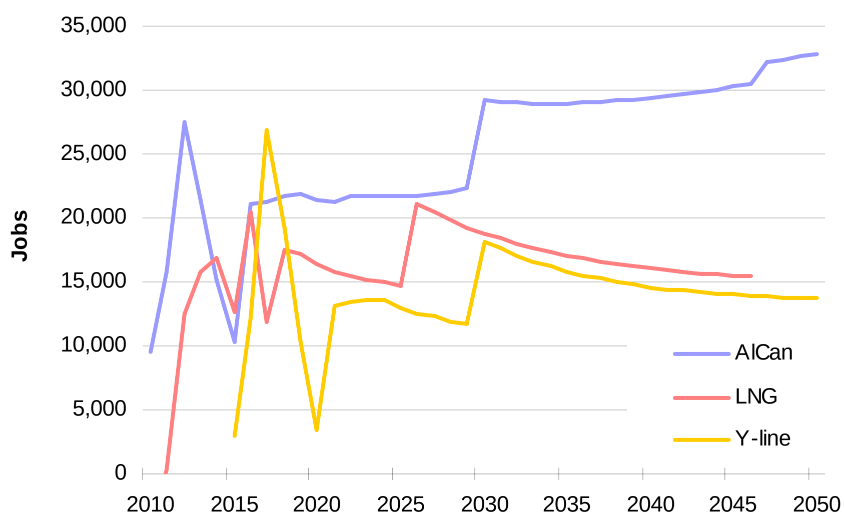


Figure 74: Total jobs showing effect of value destruction



The gross number jobs picture fails to tell the whole story, however. The pipeline projects are the largest currently under construction in the U.S., and will require a workforce in excess of the number of Alaskans eligible to fit those jobs.

Our earlier work for the Alaska Department of Revenue's Municipal Advisory Group examined the existing Alaska workforce, employment and unemployment, and types of jobs generated by the AlCan pipeline project. We estimated that Alaskans could fill 50 percent of the direct and indirect jobs, and 100 percent of the induced jobs.

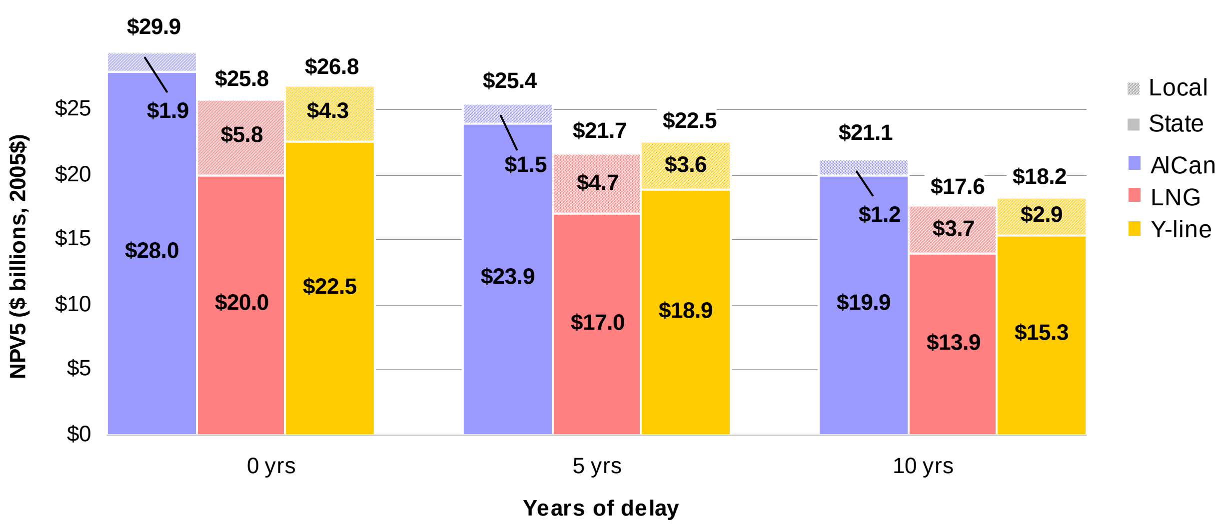
We have not conducted a comparable analysis of the LNG or Y-line pipeline projects, but believe it is reasonable to anticipate no greater proportion of Alaska hire for those projects. In fact, it is likely that the large labor force needed to construct LNG facilities at the same time a pipeline is being built would require a higher percentage of imported labor.

Impact of Delay

As discussed already, a project delay has a negative impact on the present value of a project to state and local governments. The impact is greater on the gas producers, since the model uses a higher discount rate for private and than for public revenue flows because of lower public sector borrowing costs.

There are many reasons why a gas pipeline project might be delayed, some of which are discussed in the section on known challenges. For each year of delay, we estimate the present value revenue loss to state and local governments would be approximately one billion dollars per year for any of the proposed projects.

Figure 75: Effect of delay on state and local revenues



Note: NPV at 5 percent

The state faces at least two other challenges from a delay in construction. With oil production in decline and gas revenue at least ten years off, a significant delay in project startup could result in a fiscal gap, and forcing severe budget cutbacks unless new sources of revenue or savings are found.

The second challenge stems from the aging of Alaska's skilled workforce. A five or ten year delay in the project could result in lower resident hire rates if Alaska's older skilled construction workers retire or leave the state.

Summary of Comparison Model Results

The following tables summarize the results of our comparative analysis of the economic economic, fiscal and workforce impacts of alternative proposals to develop North Slope gas.

Figure 76: Summary of workforce impacts

Workforce Impacts through 2050	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Project construction jobs[1] (Direct only)	53,000 Total 11,000 Ave. per year	80,000 Total 11,000 Ave. per year	66,000 Total 13,000 Ave. per year
Additional jobs during construction[1] (Indirect + induced)	35,000 Total 7,000 Annual average	55,000 Total 8,000 Annual average	43,000 Total 9,000 Annual average
Jobs from project operations[1] (Direct only)	16,000 Total 500 Annual average	22,000 Total 700 Annual average	18,000 Total 600 Annual average
Additional jobs during operations[1] (Indirect + induced)	49,000 Total 1,400 Annual average	72,000 Total 2,400 Annual average	56,000 Total 1,800 Annual average
Jobs from local and state spending of gas revenues[1,2]	882,000 Total 22,000 Annual average	776,000 Total 21,000 Annual average	646,000 Total 18,000 Annual average
Total jobs from all sources all years[1,2]	1,035,000	1,006,000	829,000
Jobs lost to value destruction[1,2]	0	347,000	321,000
Total jobs from all sources all years after value destruction[1,2]	1,035,000	659,000	58,000

Notes:

1) One job represents a full or part-time job over the course of a single year.

2) Includes direct, indirect and induced jobs

Figure 77: Summary of economic and fiscal impacts

Fiscal Impacts through 2050	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
NPV (at 5%) to local governments[1]	$1.9 billion	$5.3 billion	$4.3 billion
NPV (at 5%) to state[1]	$28.0 billion	$20.0 billion	$22.5 billion
NPV (at 10%) to producers[1]	$18.5 billion	$10.3 billion	$10.7 billion
Total NPV[1,2]	$48.4 billion	$36.1 billion	$37.5 billion
Cost of delay to state[1]	$900 million per year	$700 million per year	$800 million per year
Average state and local spending of project-related revenue[1] (Direct spending)	$1.6 billion per year	$1.6 billion per year	$1.3 billion per year
Average project spending after construction[1]	$400 million per year	$700 million per year	$500 million per year
Total local, state and project spending after construction[1]	$71.8 billion	$69.5 billion	$57.8 billion
Reduction in NPV due to value destruction[1]	None	$8.2 billion	$7.8 billion
Alaska Permanent Fund balance in 2051 from project[1,3]	$30.7 billion	$20.1 billion	$17.8 billion

Notes:
1) 2005 dollars
2) Assumes 10 percent discount rate for producers; 5 percent rate for government
3) Cumulative earnings, net of dividends paid, based on 7.6 percent return and current dividend law

Part 3. Alaska Construction Workforce Issues

The gas pipeline project will require a large construction workforce, but the effect of the project on Alaska's employment picture will be far different from the Trans-Alaska Pipeline System (TAPS). At the peak of TAPS construction activity in 1976, over 28,000 people worked on the project in direct construction craft jobs, compared to projected peak employment for the current gas pipeline projects (including gas treatment and liquefaction facilities) of 7,000 to 15,000 direct project jobs. Meanwhile, the population of the state along with baseline employment has more than doubled, so the relative impact of the project on Alaska will be one-fourth to one-seventh as large.

Baseline Alaska Construction Workforce

Estimates prepared by the University of Alaska Anchorage Institute for Social and Economic Research (ISER) peg total construction spending for 2005 at more than $5.0 billion. Construction industry employment in Alaska has grown steadily since 1989. In 2002, over 28,000 people listed construction work as their majority source of yearly income and 35,000 individuals reported that at least part of their income came from construction industry work.

Alaska DOLWD reported the average number of construction jobs for 2002 approached 16,000, and that number grew to over 18,500 by 2005. The construction industry employs Alaskans not just in building but also in government, oil and gas, mining, transportation, utilities, manufacturing, and engineering.

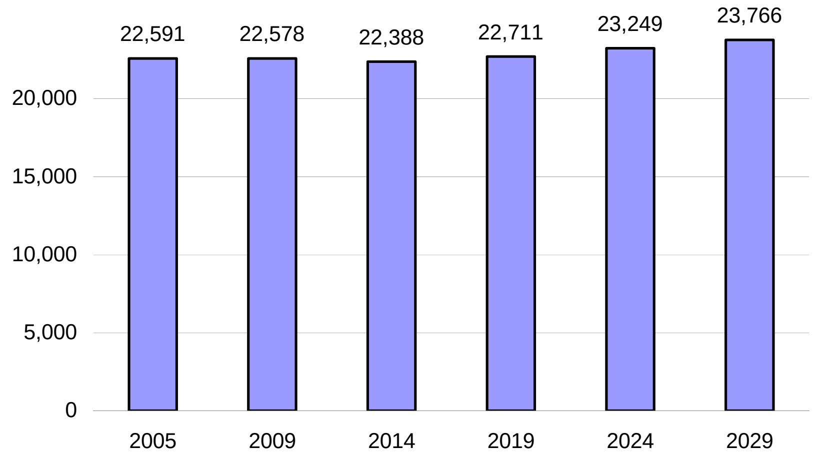
Figure 78: Average annual construction jobs

Annual average jobs	2001	2002	2003	2004	2005
Construction	14,900	15,800	16,900	17,600	18,530

Source: Alaska Department of Labor and Workforce Development

Looking forward, however, we project a construction workforce that will not grow substantially. The graph in Figure 79 below shows the number of Alaskans working in the construction industry at present and provides estimates through 2029. Not all of these people work full time and/or year round. Estimates are based on population projections provided by the Alaska DOLWD and on the current rate of participation in the construction industry of 7.27 percent of the Alaska workforce age 18 to 49 years old.

Figure 79: Projected Alaska construction workforce



Source: ADOLWD

The Challenge

Regardless of which project gets built, training workers for jobs that apply only to gas pipeline construction would mean sending many of those specialty workers outside Alaska to seek work following completion of the pipeline project. There are however, many construction workers in other crafts who are Alaska residents – and they should have the opportunity to fill needed positions during construction.

Figure 80: AlCan pipeline trade demand and apprentice completions

Trade	Skilled craft demand – AlCan pipeline project: Line-wide	Skilled craft demand – AlCan pipeline project: Alaska portion	Training time (years)	Training time (OJT hours)	Reported annual completions (2002)
Welders and helpers	1,650	565	2 – 4	6,000	135
Teamsters	755	258	3	3,000	156
Laborers	1,250	428	3 – 4	4,000	52
Operating Engineers	2,000	685	4	4,000 + 8 wks training	302
Inspectors	418	143			237
Surveyors	135	46	4	4,000	19

Source: Alaska Works Partnership; Producers' Stranded Gas Act application; Information Insights, Inc

In January 2006 the Alaska Office of Apprenticeship Training, USDOL, reported 206 active registered apprenticeship programs with 2,018 active participants (apprentices). The Office estimates that 80 to 90 percent of these apprentices are involved in programs that provide training for work in the construction industry. In real numbers this means there are currently between 1,600 and 1,800 construction industry trade apprentices being trained in Alaska. Figure 80 breaks out demand and annual completions by trade.

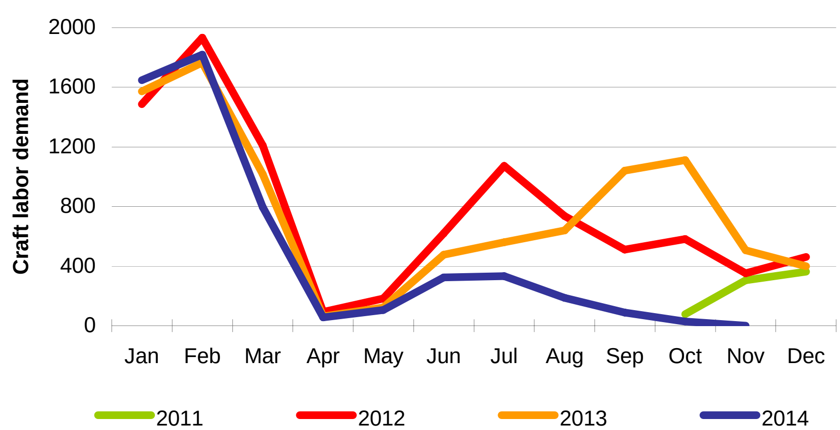
Labor Force Impacts

Alaska Economic Trends in November 2003 reported that construction comprised five percent of Alaska employment, while it made up between eight and ten percent of all employment in the state in 1983. The most seasonal of Alaska industries, construction employment nearly doubles from its winter low to the peak months.

A gas pipeline project, however, will see its workforce peak during the winter months, as reported in the sponsor group's SGDA application. The AlCan project anticipates significant portions of actual pipeline construction will be during the winter, shown by the following chart based on information contained in the.

The majority of workers engaged directly in construction of the gas pipeline will be required during the months of January, February and March, although there will be a moderate level of employment demanded during all months of the year. Because much of the terrain along the route consists of tundra with underlying permafrost, the potential for damage from brining heavy equipment across this delicate landscape will be minimized by the winter work schedule. During the second and third years of construction there will be moderately high demand for trade workers in the summer months as well as high demand in the peak winter months.

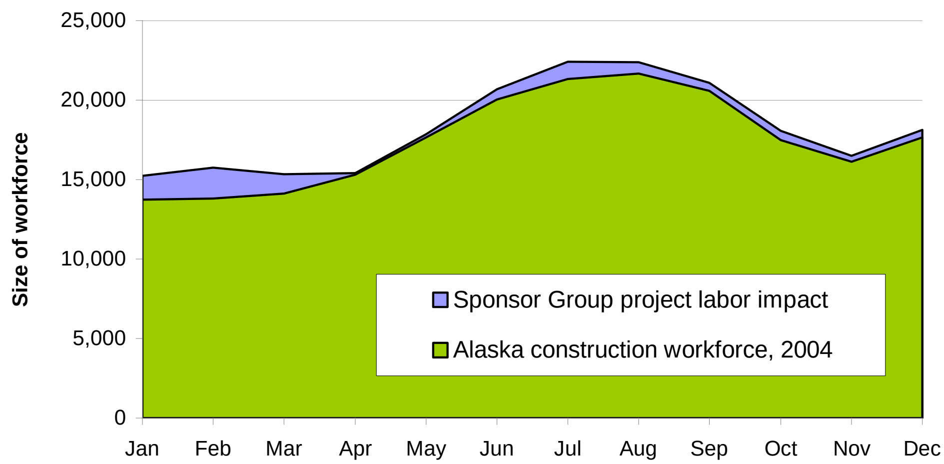
Figure 81: Sponsor Group project craft demand by month



The following graph shows the seasonality of existing Alaska construction employment, which in 2004 peaked at 21,655 in August, compared with a January low of 13,743. The blue area shows what the impact of the Sponsor Group project demand for craft labor in the first full year of construction would be on the 2004 baseline construction employment. The effect of construction of the LNG pipeline on Alaska employment would be considerably different, since a larger, year-round workforce would be required to build the LNG trains. We do not know the extent to which LNG train modules would be constructed outside Alaska, but do know considerable in-state construction effort would be required.

Either the AlCan or LNG gas pipeline project would have workforce demands exceeding current construction employment. The most significant opportunities for local hire come during the peak season of pipeline construction, provided that the skills needed by the project are available in the Alaska workforce.

Figure 82: Project impacts on Alaska construction workforce



The table below (Figure 83) breaks out by trades the total craft trade workforce needed for the construction phase of the AlCan gas pipeline project:

Figure 83: Projected Alaska employment from an AlCan pipeline

Trade	Projected Employment: Prudhoe Bay to Alberta	Estimated Employment: Alaska pipeline segment only
Welders/Helpers	1,650	565
Operators	2,000	685
Surveyors	135	46
Laborers	1,250	428
Teamsters	755	258
Inspectors	418	143
UT Technicians	90	31
Salaried Foreman	170	58
Total craft labor	**6,468**	**2,214**

Source: Producers data; Information Insights, Inc.

Effect of Delay

Despite a lengthy period of growth and stability in Alaska, the construction industry continues to report rates of non-resident hire that are higher than other industry averages. Wages to nonresident workers represent a loss for the state's economy, with the majority of those earnings spent outside of Alaska. In 2002, nonresident workers comprised 18.2 percent of all workers statewide, and 20 percent of construction jobs.

There is heavy competition for skilled labor in the construction industry in Alaska, where the market remains relatively tight especially in the summer. An aging construction workforce combined with several large-scale projects on the horizon and the possibility of continued delay on construction of a gas pipeline creates the potential for increased non-resident hire.

The current construction workforce in Alaska reflects the rest of the nation in that it is, as a whole, growing older. Although the average for construction trade labor is 37, the same as the average for all workers, a larger percentage of construction workers are nearing retirement. Retirement age for trades that require physical work tends to be younger than for other jobs. Many of the individuals employed in the construction industry today came to Alaska 30 years ago to build the Trans Alaska Pipeline System. In 2004, 29 percent of the state's construction workforce was 45 years or older (up from 23 percent in 1994), and 17 percent was 50 or over. The relative lack of young people with the skills to fill positions in the construction industry means skilled workers (who receive the highest wages) are staying on the job more years, driving up the cost of construction labor.

Figure 84: Average age of construction workers by trade, 1999

Trade	Average age in 1999	Percent 45 years & older	Percent 50 years & older
Pipelines, except natural gas	46.6	60.8%	35.7%
Operating Engineers	42.1	42.4%	24.0%
Truck Drivers, Heavy and tractor-trailer	42.0	41.2%	24.9%
Heavy construction other than building	40.1	36.7%	21.1%
Electricians	40.0	34.1%	21.2%
Plumbers, pipefitters and steamfitters	38.5	29.4%	14.5%
Carpenters	38.4	29.5%	15.6%
Construction – special trade contractors	36.5	24.4%	13.5%
Construction Laborers	34.5	21.0%	10.9%
Freight, Stock and Material Movers	32.9	15.7%	8.0%

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

The aging of Alaska's workforce, in concert with the nation's workforce, creates additional challenges for an Alaska gas pipeline project. If the start of pipeline construction is delayed considerably, Alaska's construction workforce may lose the experience and numbers of workers from the baby-boom generation, requiring greater import of outside labor for the higher skilled jobs.

As Alaska's older construction workers wait to see whether to plan for retirement or hang on for a pipeline that appears to be just around the corner, their continued presence in the workforce has a dampening effect on efforts to further expand apprenticeship programs. Until a start-date is known, this standoff may continue, and it places the state in a double jeopardy: failing to target the right crafts and train workers to fill jobs created both by retirement and pipeline construction will result in greater-than-predicted hiring of out-of-state workers for pipeline construction; but ramping up apprenticeship and other training programs now, without certain knowledge that those workers will have jobs when their training is complete will cause unnecessary expense and create an unused pool of prepared workers.

Economic Multiplier

We used the IMPLAN Group's economic impact model to examine the economic and employment impacts of state spending increases in specific sectors of the Alaska economy. While IMPLAN is commonly used for economic impact analysis, there are some challenges, especially for projects that substantially change a region's economy.

In any economic sector, new economic activity generates new direct jobs in that sector. In addition to direct jobs being created by spending in each sector, additional jobs and earnings are created throughout the state's support sector through economic multiplier effects. In Alaska, multipliers are typically between 1.25 and 2.5, meaning that for every direct job, one-half to one-and-a-half additional jobs are created in the support sector. So for example, the total employment impact of a factory that employs 100 workers creates between 50 and 150 support and service sector jobs.

To allow ready comparison between gas pipeline projects under differing assumptions, we simulated the results of new spending in the following sectors of the Alaska economy:

- Drilling oil and gas wells
- New construction
- Water, sewer, and pipeline construction
- Pipeline transportation
- Natural gas distribution
- Industrial gas manufacturing
- Petroleum refineries
- Support activities for pipeline operations
- State and local government non-education

Multipliers can also be applied to earnings. As money is directed through a sector and spent on goods and services, new earning are created.

Figure 85: Multiplier effects of $100,000 in new spending

	Number of Jobs created by $100 million in project spending			
Economic Sector	**Direct**	**Indirect**	**Induced**	**Total**
Drilling Oil and Gas Wells	354.5	155.8	265.0	775.3
New Construction	751.9	267.3	404.5	1423.7
Water, Sewer, and Pipeline Construction	965.1	166.5	459.4	1591.0
Pipeline Transportation	140.1	349.8	290.6	780.5
Natural Gas Distribution	135.8	145.5	191.5	472.8
Industrial gas manufacturing	102.2	211.7	170.8	484.7
Petroleum Refineries	26.0	162.3	138.9	327.2
State and Local Government Non-education	1102.5	61.5	381.0	1545.0
Support Activities for Pipeline Operations	537.1	50.9	354.8	942.8

	Economic Activity created by project spending ($ thousands)			
Economic Sector	**Direct**	**Indirect**	**Induced**	**Total**
Drilling Oil and Gas Wells	$100,000	$19,118	$25,655	$144,773
New Construction	100,000	29,124	39,153	168,277
Water, Sewer, and Pipeline Construction	100,000	19,287	44,466	163,752
Pipeline Transportation	100,000	68,294	28,126	196,420
Natural Gas Distribution	100,000	55,427	18,539	173,966
Industrial gas manufacturing	100,000	50,788	16,531	167,319
Petroleum Refineries	100,000	65,212	13,442	178,654
State and Local Government Non-education	100,000	8,488	36,880	145,367
Support Activities for Pipeline Operations	100,000	7,072	34,346	141,418

Source: IMPLAN Group, 2003 data.

Workforce Impact Conclusion

State and local government spending of their project revenues is a major factor in the number of jobs created by a pipeline project, dwarfing over time the jobs created during project construction. The effect, therefore, of value destruction on state and local revenues cannot be downplayed.

Glossary

$/Bbl	Price per barrel, the unit in which world oil prices are typically quoted.
$/mmBtu	Price per million British thermal units – the unit in which natural gas prices are typically quoted. British thermal units (BTUs) provide a convenient basis for comparing the energy content of various grades of natural gas and other fuels. One cubic foot of natural gas produces approximately 1,000 BTUs, so 1,000 cu. ft. of gas is comparable to one mmBtu.
AGPA	Alaska Gasline Port Authority, comprised of the North Slope Borough, the Fairbanks North Star Borough, and the City of Valdez, was created in 1999 by local referenda in the three municipalities for the purpose of building a natural gas pipeline to Valdez for LNG production and shipping to market.
bbl/d	Barrels per day – a measure of oil production.
bcf/d	Billion cubic feet per day – a measure of natural gas production. Similarly mcf designates a million cubic feet of natural gas.
FERC	Federal Energy Regulatory Commission (FERC) is the federal agency responsible for permitting and setting tariffs for oil and gas pipelines in the United States. Although FERC's jurisdiction is over interstate transportation, it is expected that FERC would exercise its authority to regulate an Alaska gas pipeline even if an all Alaska route is chosen, preempting the Regulatory Commission of Alaska (RCA) to set intrastate rates and terms.
GTP	Gas treatment plant, also called a conditioning plant, which will be built on the North Slope as part of any gas pipeline project.
Job-year	One full or part-time job over the course of a single year
Jones Act	The Jones Act, part of the Merchant Marine Act of 1920, requires that all cargo moving between U.S. ports be carried in ships, which are U.S.-owned, -built and -crewed.
LNG	Liquefied Natural Gas is natural gas that is kept at -260° F or below at atmospheric pressure. Liquefying natural gas reduces its volume by a factor of 610, making LNG more practical to store and ship. LNG must be regasified before it can be used.
LNG tanker	LNG must be transported by sea in specially built double-hulled ships super insulated to keep LNG at temperatures below -260° F.
LNG train	An individual module in a gas liquefaction plant where gas is turn it into a liquid using a refrigeration process. A liquefaction plant typically consists of multiple large trains to achieve economies of scale.

Levelized tariff	A pipeline tariff set at a constant rate, which doesn't change with inflation.
Lower 48	A common phrase used in Alaska to indicate the contiguous 48 U.S. states, which excludes Alaska and Hawaii.
LPG	Liquid Petroleum Gases, which are composed mostly of propane.
Natural gas	The main component of natural gas is methane (CH_4).
Natural Gas Liquids	Natural gas liquids (NGLs) are other hydrocarbons that are by-products of natural gas processing, such as ethane, propane, butane, and iso-butane. NGLs can be sold for a variety of uses, including enhancing oil recovery in oil wells, providing raw materials for petrochemical plants, and as sources of energy. They can either be shipped with the natural gas or separated before shipping and sold separately.
Net Present Value	Net Present Value (NPV) is the present value of future cash flows including capital investment.
Nominal dollars	The price given at the value of the dollar at the time the cost is incurred (not adjusted for inflation).
Oil Equivalent Price	The price of oil in British Thermal Units (BTUs) so that oil prices can more easily be compared to the price of other fuels such as natural gas.
PPI	Producer Price Index
Prudhoe Bay Unit	The oil and gas in and around Prudhoe Bay, Alaska.
Pt. Thomson Unit	The oil and gas fields in and around Point Thomson, Alaska.
Real dollars	The price or cost of something when adjusted for inflation. In this study real dollars are 2006 dollars unless noted otherwise.
RIK or GIK	Royalty in Kind or Gas in Kind – The state can take some of its tax and royalty revenue in kind as oil or gas, which could improve the economics of a project for the producers.
Stranded gas	Known reserves that have not been developed, because it has been uneconomic to bring the gas to market.
Tariff	A fee to pay for the use of a pipeline.
Wellhead cost	The costs of extracting oil and gas, including the cost of exploration, development and production of the resource.

References

Anchorage Chamber of Commerce, *Natural Gas and Alaska's Future*, Vol. 1: The Facts. Report by State/National Affairs Committee, November 2005.

Anchorage Chamber of Commerce, Natural Gas and Alaska's Future, Vol. 2: Alaskan Goals and Priorities. Report by State/National Affairs Committee, February 2006. http://www.anchoragechamber.org/cms/RunScript.asp?Article_type=General&p=ASP\Pg0.asp

Alaska Gasline Port Authority, *Project Definition*, December 2005.

Alaska Gas Pipeline Construction Cost Risks, Testimony of Tony Palmer, VP Alaska Business Development TransCanada. June 16-17, 2004

Cattaneo, Claudia, *Mackenzie Deal Imminent*. Financial Post, November 17, 2005 http://www.mvapg.com/articles/article/2013161/37539.htm

Cho, Joseph H. et al., Kellogg Brown & Root Inc., *Large LNG carrier poses economic advantages, technical challenges*. Oil and Gas Journal, http://ogj.pennnet.com/Articles/Article_Display.cfm?Section=ARTCL&ARTICLE_ID=237513&VERSION_NUM=3&p=94

Colgan, Ryan, Alaska Gasline Port Authority, presentation to the Fairbanks Republican Luncheon on Friday, February 3, 2006

Collier, Robert, San Francisco Chronicle, *Fueling America Canadian Oil Showdown. Frozen pipeline: Tribe's success at blocking natural gas delivery system threatens development of oil-sands mines*, May 23, 2005.

Energy Information Administration, Annual Energy Outlook 2006, December 2005, http://www.eia.doe.gov/oiaf/aeo/index.html

Energy Information Administration, LNG industry costs declining, Report Released December 2003. http://www.eia.doe.gov/oiaf/analysispaper/global/lngindustry.html

Econ One Research, Inc., *Alaska Natural Gas In-State Demand Study - Volume 1* ASP 2001-100-2650, Alaska Department of Natural Resources, January 23, 2002.

Federal Energy Regulatory Commission, Report to Congress on progress made in licensing and constructing the Alaska natural gas pipeline, February 2006.

Finizza, Anthony, *Investment Decision-Making by Oil and Gas Companies.* Presenation before the Legislative Budget & Audit Committee Interim Hearings on Alaska Natural Gas Pipeline Economics. Econ One Research, Inc., August 31, 2005.

Information Insights, Inc., Stranded Gas Development Act Municipal Impact Analysis. November, 2004.

Murkowski, Frank H., Speech to the Resource Development Council, November 16, 2005.

Nelson, Kristen, "Unit in default," Petroleum News, week of October 9, 2005. "Hundreds of millions" of barrels PTU.

Persily, Larry. “Mixing Gas in Mexico Way around Jones Act,” Petroleum News, week of October 19, 2003. http://www.petroleumnews.com/pntruncate/359480809.shtml

Palmer, Tony, Alaska Business Development TransCanada, *Pacific NorthWest/Western Canada Energy Forum, Mackenzie Valley & Alaska Highway Pipelines*. Undated presentation.

PFC Energy, *Assessment of The Alaska Gasline Port Authority LNG Project* Draft Report. Prepared for the Alaska Department of Revenue, February 10, 2006.

Pulliam Barry, *Net Present Value, Rate of Return, and Profitability Index on Producer Investments.* Presentation before the Legislative Budget & Audit Committee Interim Hearings on Alaska Natural Gas Pipeline Economics. Econ One Research, Inc., August 31, 2005.

Reynolds, Douglas B. et al, Northern Economic Research Associates, *The Alaskan Natural Gas Transmission System*, Report to the Alaska State Legislature’s Joint Committee on Natural Gas, August 2002.

Rogers, Brian et al., Information Insights, *Stranded Gas Development Act Municipal Impact Analysis*. Report to the Alaska Department of Revenue, Municipal Advisory Group, November 2004.

Weber, Bob, *Legal challenge to pipeline review returns to court as hearing reveal aboriginals split*. CNEWS Canada, February 19, 2006. http://cnews.canoe.ca/CNEWS/Canada/2006/02/14/1442900-cp.html

Appendix

VALUE DESTRUCTION ANALYSIS

While it is interesting to consider how the state fares for different pipeline projects, it is important to first understand why the producers may be unwilling to sell natural gas to an LNG or Y-line project. Here we show the results of an apples-to-apples comparison using the above assumptions from the producers' point of view. In this analysis we assume that the producers are determined to pursue each project as quickly as possible. Then we examine how the projects compare on a net present value basis.

The following table shows the outcome for the producers if each project were started with no delay for acquiring gas:

Figure 86: Producers' NPV with earliest possible start dates

Project	AlCan	LNG	Y-line
Year in which construction expected to start	2010	2010	2011
Year in which gas first flows	2015	2014	2015
Year in which full throughput achieved	2016	2017	2016
NPV (at 10%) to producers assuming tax incentives are valid ($ billions, 2005)	$18.5	$13.9	$14.6
Loss to producers	0	$4.6	$3.9
Percent loss	0%	24%	21%
NPV (at 10%) to producers without tax incentives ($ billions, 2005)	$18.5	$13.0	$13.9
Loss to producers	N/A	$5.5	$4.6
Percent loss	N/A	30%	25%

Based on this analysis, it is clear that the producers gain the most by pursuing an AlCan pipeline project. The producers would lose at least 21 percent of the value of the gas by pursing an alternative project.

However, real losses could be greater if market differences are taken into account. If a large volume of Alaska gas is sold on the relatively thin Pacific Market in general, or the U.S. West Coast market in particular, it is more likely to cause a significant reduction in the price of gas than if it is sold in Chicago on the larger Atlantic market. Any softening in price would result in a loss to producers greater than what our models show.

How quickly West Coast LNG terminals could be permitted and built is another crucial factor affecting the relative profitability of an LNG project, since any delay lowers the present value of a project. If sufficient terminal capacity is not available to receive ANS gas, the proposed early start modeled here would be delayed and any advantage the LNG project has from having permits in hand would be reduced.

Once it is clear that the producers lose money in a project other than an AlCan pipeline, the state has to consider its options for pursuing a different project to develop North Slope gas.

The sponsor group holds leases to lands that contain 94 percent of proven ANS gas reserves. The leases constitute a property right to develop the natural gas on these lands. If the state wants the producers to participate in a different project, one that is not in the producers' best interest, the state has at least two options available:

1. The state can try to extinguish the producers' property right through administrative action and litigation.
2. The state can buy back the leases with a lump sum payment or other terms.

Each of these options poses interesting questions and challenges: How long would litigation take? Who would prevail? What is the appropriate price to pay to buy back the leases?

Our models in the main body of the report assume that in order to build one of the alternative projects, one of these options is necessary to reacquire ANS gas leases, and that a minimum of five years will be needed to do so. For example, if the state were to buy back the leases, time would be required to negotiate the sale, establish interim producers, and resell the leases to a buyer willing to build an alternative project. The five year delay further reduces the net present value of an alternative project to the producers, as shown in Figure 87.

Based on these assumptions, year 0 (the pre-construction year) in our comparison models in the main body of the report is 2010 for an AlCan project, 2014 for an LNG project, and 2015 for a Y-line project. We believe these are the *earliest* likely start dates for each project, though not necessarily the *most* likely. In analyzing the impacts of delay in our models, we calculated five and ten year delays from this adjusted year 0 start date. Other potential sources of delay are discussed in the section on known challenges and assumptions.

Figure 87: Producers' NPV with adjusted year 0

Project	AlCan	LNG	Y-line
Year in which construction expected to start	2011	2015	2016
Year in which gas first flows	2015	2019	2020
Year in which full throughput achieved	2016	2022	2021
NPV (at 10%) to producers ($ billions, 2005)	$18.5	$13.0	$13.9
Loss to producers	N/A	$8.2	$7.8
Percent loss	N/A	44%	42%