Written Findings and Determination by the Commissioners of Natural Resources and Revenue for Issuance of a License under the Alaska Gasline Inducement Act (AGIA)

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Preface ES-1
Executive Summary ES-2
Acronyms and Abbreviations
Glossary

CHAPTER ONE INTRODUCTION AND AGIA

A. Introduction 1-1
B. History of Alaska Natural Gas Pipeline Efforts 1-3
   1. The Stranded Gas Development Act 1-3
   2. Alaska Gasline Inducement Act 1-4
C. Summary of Projects 1-7
   1. The TC Alaska Application 1-7
   2. The LNG Project Options 1-7
   3. The Producer Project 1-7
   4. The Bullet Line 1-8
   5. LNG and an Overland Pipeline 1-8
D. Maximizing Benefits for Alaskans 1-9
   1. Getting a Natural Gas Pipeline, Quickly 1-10
   2. Jobs and Long-term Careers for Alaskans 1-12
   3. Affordable Energy for Alaskans 1-14
   4. Sufficiently Maximizing Revenues to the State and Its Citizens 1-16
E. Summary 1-19
F. References 1-20

CHAPTER TWO TECHNICAL BACKGROUND

A. Natural Gas Primer 2-1
   1. Natural Gas Markets 2-1
   2. LNG Basics 2-3
   3. History of LNG 2-3
   4. Asian Gas Quality Demands 2-4
B. Pipeline Primer 2-5
   1. Natural Gas Pipeline Project Development 2-5
   2. Project Analysis 2-6

3. Pipeline Regulation 2-7
4. The Alaska Natural Gas Pipeline Act and Impacts on the Regulation of an Alaska Natural Gas Pipeline 2-9
5. Alaska's Natural Gas Resources 2-10
C. Analysis Team....................2-11
D. References....................2-14

CHAPTER THREE ANALYSIS OF TC ALASKA'S APPLICATION

A. Introduction and Summary 3-1
B. Who is TC Alaska?....................3-3
1. History and Company Description....................3-3
a. TransCanada in Alaska....................3-3
C. Summary of Proposed Project 3-5
1. Gas Treatment Plant (GTP) 3-6
a. Potential Equity Partners....................3-7
b. Management Challenges 3-7
c. Regulatory Challenges....................3-8
d. Transportation Challenges 3-9
D. TC Alaska's Project Would Produce a Significantly Positive Net Present Value for the State of Alaska 3-10
1. Summary of Methodology and Results of NPV Analysis....................3-11
2. NPV Methodology 3-17
a. General Approach 3-17
b. Natural Gas Prices 3-20
c. EIA Price Forecast 3-23
d. Wood Mackenzie Price Projection....................3-25
e. Projection Based on Forward-Looking North American Supply and Demand Model 3-27
f. Estimated Volumes of Natural Gas Sold....................3-35
g. Estimated Pipeline and GTP Costs, Schedule, and Tariffs 3-44
h. Pipeline Cost and Schedule Analysis, Including Cost and Schedule Ranges....................3-46
i. Nominal Dollar Cost Ranges and Tariffs: Escalation Risk 3-54
j. Upstream Costs....................3-61
3. Estimated NPV Produced by the Project—Results of the NPV Analysis 3-61
a. Estimated NPV under the Proposal Base Case 3-62
b. Estimated NPV Under the Conservative Base Case and Low Volume Sensitivity Case Remain Favorable. 3-69
c. The Project Would Produce a Positive NPV Even If No Point Thomson or YTF Gas Is Ever Produced. 3-75
4. Impact of $500 Million Match 3-79
5. Availability of Low Cost Expansion 3-80

E. Analysis of the Likelihood of Success of TC Alaska's Project 3-83
1. Introduction and Summary 3-83
2. Methodology for Analyzing the Project's Likelihood of Success 3-84
3. Analysis of Likelihood of Success Criteria Under AGIA Section 170 3-85
a. TC Alaska Has Submitted a Plan for its Project That is Technically Feasible, Reasonable, and Specific. 3-85
b. TC Alaska Has Demonstrated the Technical and Financial Ability To Construct the Project. 3-98
c. TC Alaska Has Submitted a Reasonable Commercial Plan Which, Coupled With Economic and Political Factors, Should Help To Encourage Firm Shipping Commitments 3-106
d. TC Alaska's Ability To Overcome Barriers To Obtaining Firm Shipping Commitments 3-119
e. Other Factors Which Indicate TC Alaska's Project Has A Reasonable Prospect of Securing Firm Shipping Commitments 3-153
F. Summary 3-160
G. References 3-161

CHAPTER FOUR LNG

A. Introduction and Summary of Analysis of LNG Project Options 4-1
B. Background 4-3
C. The LNG Project Options 4-7
D. The Y Line Option 4-9
E. Analysis of the NPV of the LNG Project Options 4-12
1. Calculation of LNG Prices 4-12
2. LNG Volumes 4-20
3. Costs and Schedule Related to LNG Scenarios 4-20
4. Comparison of LNG and TC Alaska Costs and Tariffs 4-28
5. Estimated State NPV_5 4-34
6. Comparison of Estimated NPVs Produced by the TC Alaska Project and the LNG Options. 4-35
F. TC Alaska's Project Has a Greater Likelihood of Success Than Any of the LNG Options. 4-43
1. An LNG Project Would Be Significantly More Complex, and Thus More Risky, Than an Overland Route. 4-43
2. An LNG Project Would Be More Difficult To Finance Than an Overland Route 4-46
3. There Is a Significant Risk LNG Would Not Provide Open Access to Future Explorers, In Contrast With the TC Alaska Project 4-47
4. The Major North Slope Producers Have Indicated Their Preference for An Overland Route Over the LNG Options. 4-48
5. An LNG Project Will Require Proven and Committed Reserves (Certified by Experts) to be Dedicated to the Project. 4-50

6. Exporting LNG To Asia Presents Regulatory and Political Barriers That the TC Alaska Project Would Not Face....4-50
7. An Overland Route Has a Better Opportunity than an LNG Project To Spur a Petrochemical Industry....4-52
G. Conclusion....4-54
H. References....4-56

CHAPTER FIVE COMPARISON OF THE TC ALASKA PROPOSAL WITH THE PROPOSAL BY BP/CONOCOPHILLIPS

A. Introduction and Summary of Conclusions....5-1
B. The History of SGDA and TAPS Illustrates the Risks Posed by a Producer-Owned Pipeline....5-4
1. The State's Experience Under SGDA....5-4
2. TAPS....5-7
C. TC Alaska—Commitments; Producer Project—No Commitments....5-9
1. Capital Structure....5-9
2. Expansion....5-13
3. Rolled-in Rates....5-14
4. Commitments To Hold an Open Season and File at FERC, and Other Issues That Could Result in a Delay of the Producer Project....5-17
D. A Producer-owned Pipeline Has an Incentive to Act in Ways That Are Contrary to the Best Interests of the State....5-20
E. Both TC Alaska and the Producer Projects Lack Firm Shipping Commitments....5-24
F. Comparison of the Costs to the State Following the TC Alaska Project Path or the Producer Project Path....5-26
G. TC Alaska's Offer of Equity Partnership....5-29
H. The Upstream Inducements Provided by AGIA are Valuable and Incentivize the Producers to Commit Gas to the TC Alaska Project....5-30
I. It is in the State's Interest to Pursue the TC Alaska Project....5-32
J. Conclusion....5-33
K. References....5-34

CHAPTER SIX FINDINGS AND DETERMINATION

Commissioners' Findings....6-1
Commissioners' Determination....6-2

Figures

Figure 2-1: Pipeline Flow 2-2
Figure 2-2: Natural Gas Production 2-2
Figure 2-3: Potential LNG Trading Routes from Alaska 2-4
Figure 3-1. Map of TransCanada Pipeline Operations 3-4
Figure 3-2. Present Value of $100 Cash Flow in Future 3-14
Figure 3-3. Present Value of $100 Cash Flow in Future Years 3-15
Figure 3-4. Sensitivity of State NPV to Discount Rates 3-17
Figure 3-5. NPV Modeling 3-18
Figure 3-6. Annual Henry Hub Price 3-21
Figure 3-7. EIA-Based Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars) 3-24
Figure 3-8. Wood Mackenzie-Based Henry Hub Forecast to 2045 (Nominal dollars) 3-25
Figure 3-9. Wood Mackenzie Basis Forecast 3-26
Figure 3-10. Wood Mackenzie-Based Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars) 3-27
Figure 3-11. Black and Veatch Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars) 3-29
Figure 3-12. U.S. Gas-fired Power Generation Demand Distribution Range 3-30
Figure 3-13. WCSB Finding and Development Cost Curve (Real 2008 $) 3-31
Figure 3-14. U.S. Lower 48 Industrial Demand Distribution Range 3-32
Figure 3-15. Relative Impact of Price Drivers on AECO HUB Price Formation, 2022 (Nominal $) 3-33
Figure 3-16. Distribution Range of AECO Price Forecasts over Time (Nominal $) 3-34
Figure 3-17. AECO Price Forecasts (Nominal $) 3-35
Figure 3-18. Production Profile for Proposal Base Case 3-42
Figure 3-19. Production Profile for Conservative Base Case 3-43
Figure 3-20. Subproject Component Cost Ranges—Derivation Process 3-47
Figure 3-21. Proposal Base Case Cost Distribution—Alaska Pipeline 3-49
Figure 3-22. Proposal Base Case Cost Distribution—Yukon-BC Pipeline 3-50
Figure 3-23. Proposal Base Case Cost Distribution - GTP 3-51
Figure 3-24. Proposal Base Case Cost Distribution—Integrated Project 3-52
Figure 3-25. Project Cost Risk: Comparing Project Escalation with Project Scope Risks Showing Cost Uncertainty and Risk Increasing With Escalation Rates 3-54
Figure 3-26. Tariff Distributions by Project Throughput:Smaller Projects Give Higher Tariffs 3-57
Figure 3-27. State NPV5 Tornado Diagram: The Relative Importance of Different Project Risks 3-64
Figure 3-28. State NPV5 Sensitivity to Price 3-65
Figue 3-29. Comparing TC Alaska Pipeline Tariff (Nominal $) with Various AECO Price Forecasts 3-66

Figure 3-30. Producer NPV_{10} Tornado Diagram: The Relative Importance of Different Project Risks 3-68
Figure 3-31. Pipeline Tariffs Under Proposal, Conservative, and Low Volume Cases 3-70
Figure 3-32. State NPV5 Under Proposal, Conservative, and Low Volume Cases 3-72
Figure 3-33. Aggregate Producer NPV Under Proposal, Conservative, and Low Volume Cases 3-73
Figure 3-34. Impact of Contract and Depreciation Periods on AECO Tariff 3-74
Figure 3-35. Reserve Risk: Producer NPV Assuming No YTF Gas 3-76
Figure 3-36. Reserve Risk: Yearly Net Back Cash Flow 3-77
Figure 3-37. State of Alaska NPV5 with and without $500m match 3-79
Figure 3-38. AGIA Roll-in-Rate Provision 3-82
Figure 3-39. Schedule Risk of Proposal Base Case 3-92
Figure 3-40. Impact of Commercial Terms of Transportation Contracts to AECO Tariff 3-109
Figure 3-41. Impact of Commercial Terms of Transportation Contracts to Producer NPV_{10} and NPV_{15} 3-110
Figure 3-42. Tariff Consequences of Cost Overruns With and Without 100% Debt Financing 3-115
Figure 3-43. TransCanada NPV8.8 Sensitivity Consequences of Cost Overruns With and Without 100% Debt Financing 3-116
Figure 3-44. TransCanada NPV8.8 For Different Project Configurations 3-123
Figure 3-45. U.S. Government NPV_5 For Different Project Configurations 3-127
Figue 3-46. State NPV_5 For Different Project Configurations 3-128
Figure 3-47. Percentage Price Drop Necessary to Generate NPV of Zero For Producers' Proved Reserves 3-131
Figure 3-48 Aggregate Producers NPV_{10} - 4.5 BCF/d Proposal Base Case With and Without Price Uncertainty 3-132
Figure 3-49. Real AECO Price Forecasts vs. Tariff + Fuel 3-133
Figure 3-50. Aggregate Producers NPV_{10} Uncertainty for the 3.5, 4.0, and 4.5 Bcf/d Cases 3-134
Figure 3-51. Impact of Different Periods of Fiscal Uncertainty for Producer NPV_{10} 3-139
Figure 4-1. Asian LNG Price Formula: The Historical Period 4-13
Figure 4-2. Japanese 'S' Curve for LNG Pricing: The Historical Period 4-14
Figure 4-3. More Recent Japanese, Korean, Tawainese, and Chinese LNG Prices Related to Crude Oil Price 4-15
Figure 4-4. Asian LNG and Henry Hub Prices in the Different Scenarios (Real 2007) 4-17
Figure 4-5. Historical Oil to Gas Price Ratio 4-18
Figure 4-6. Cost-Risk Profile for the LNG Base Case GTP Plant Construction 4-21
Figure 4-7. Cost-Risk Profile for the LNG Base Case Delta Junction to Valdez Pipeline Construction 4-22
Figure 4-8. Cost-Risk Profile for the LNG Base Case LNG Plant Construction 4-24
Figure 4-9. Execution Cost Probability Distribution for a 4.5 Bcf/d Integrated LNG Project 4-26
Figure 4-10. Tariff Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case 4-28

Figure 4-11. Fuel Loss Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case....4-29
Figure 4-12. Tariff Comparison Including Estimated Incremental Fuel Costs: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case..4-30
Figure 4-13. Tariff with Incremental Fuel Costs and Shipping Costs..................................4-31
Figure 4-14. Tariff Build Up..4-33
Figure 4-15. State Net Present Value Under Different LNG Project Configurations............4-34
Figure 4-16. Margins of LNG Project versus a Pipeline Project..4-35
Figure 4-17. State NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions.....4-36
Figure 4-18. Major North Slope Producers' NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions..4-37
Figure 4-19. Price vs. Tariff for a 4.5 Bcf/d LNG Project and the 4.5 Bcf/d Proposal Base Case Pipeline Project...4-38
Figure 4-20. Comparative State NPV_5 Distributions Associated with Project Cost Risk.......4-39
Figure 4-21. Comparative Producer NPV_{10} Distributions Associated with Project Cost Risk 4-40
Figure 4-22. State NPV Under LNG and TC Alaska Pipeline Cases..................................4-42
Figure 5-1: Impact of Capital Structures on Tariff Rates...5-11
Figure 5-2: Impact of 50/50 debt to equity ratio 5-12

Tables

Table 2-1: Contractor Expertise...2-11
Table 3-1. NETL's Estimate of Economically Recoverable Natural Gas Reserves...........3-41
Table 4-1. Liquefaction Plant Cost Ranges 4-25
Table 4-2. Stakeholder NPV for 4.5 LNG Project Under Alternative Scenarios-Base Case LNG 4-41

APPENDICES

Appendix A: Public Comments and Responses

Appendix B: AGIA Statute

Appendix C: AGIA Overview and Completeness Review

Appendix D: TransCanada Correspondence Post Completion

Appendix E: Consultant Qualifications

Appendix F: Technical Team Analysis of the TransCanada AGIA Application

Appendix G1: AGIA NVP Report

Appendix G2: Assessment of Commercial Likelihood of Success (LOS) pursuant to AGIA Section 49.90.170(c)

Appendix H: Analysis and Findings Regarding TransCanada's AGIA Application

Appendix I: Potential LNG Production from North Slope Gas

Appendix J: Regulatory Issues Report

Appendix K: Expected Returns and Approval Economics

Appendix L: The Prospect Exploration Economics

Appendix M: Outlook for Yet-to-Find North Slope Natural Gas Resources

Appendix N: Briefing Paper on Wood Mackenzie Long Term Outlook

Appendix O: Summary of Findings for Resource Assessment and Field Development Study of the Thomson Sand, in the Point Thomson

Appendix P: Alaska Natural Gas Pipeline - Employment Impacts Modeling

Appendix Q: AGIA Training Strategic Plan - A Call to Action

Appendix R1: Summary Analysis of TransCanada Contingent Liability Issues

Appendix R2: Export License Considerations for LNG Export Terminal

Appendix R3: Lack of Open Access for LNG Export Terminal

Appendix R4: Competitive Analysis of Producer - Owned Alaska Natural Gas Pipeline

Appendix R5: Review of TransCanada's Corporate Integrity and Good Business Ethics as Required by AGIA

Appendix R6: Examples of Approved Capital Structure and Return on Equity (ROE) for Major New/Expansion Projects

Appendix R7: New Pipeline Projects that have used Negotiated Rates to Allocate the Risk of Potential Cost Overruns

Appendix R8: Producer-owned Pipeline

Appendix S1: Bennett Jones Report

Appendix S2: Comments on TransCanada's Business Ethics

Appendix S3: Rolled-in vs. Incremental Tolls

Appendix T: Applicable State and Federal Statutes

Appendix U: AGIA License

Acronyms and Abbreviations

AEO	Annual energy outlook
AGIA	*Alaska Gasline Inducement Act, AS 43.90 et. seq.*
AMEC	AMEC-Paragon Engineering Company
ANCSA	*Alaska Native Claims Settlement Act, 43 U.S.C. § 1601*
ANGPA	*Alaska Natural Gas Pipeline Act, 15 U.S.C. §§ 720 et. seq.*
ANGTA	*Alaska Natural Gas Transportation Act, 15 U.S.C. §§ 719 et. seq.*
ANGTS	Alaska Natural Gas Transportation System
ANNGTC	Alaska Northwest Natural Gas Transportation Company
AS	Alaska Statute
BC	British Columbia
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BMP	Best Management Practices
Btu	British thermal unit
BV	Black and Veatch
cf	cubic foot
CO_2	carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
C.F.R.	Code of Federal Regulations
DNR	Alaska Department of Natural Resources
DO	designated officer
DOE	U.S. Department of Energy
DOG	Alaska Division of Oil & Gas
DOT	Department of Transportation
DOT-PHMSA	Department of Transportation, Pipeline and Hazardous Materials Safety Administration
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPC	engineering, procurement and construction
EPCM	engineering, procurement and construction management
ERR	Economically recoverable reserves
°F	degrees Fahrenheit
FEED	front end engineering design
FERC	Federal Energy Regulatory Commission
FID	Final Investment Decision
FPC	Federal Power Commission
GAAP	generally accepted accounting principles
GHV	gross heating value
GTP	gas treatment plant
H_2S	hydrogen sulfide
H_2O	Water
HSE	health, safety and environment
IRR	Internal Rate of Return
IOS	International Organization for Standardization

LNG	liquefied natural gas
LOS	Likelihood of Success
LSCC	Little Susitna Construction Company
MAGTC	MidAmerican Energy Holdings Company and MEHC Alaska Gas Transmission Company, LLC
MAOP	maximum allowable operating pressure
m^3	cubic meters
Mbpd	Million barrels per day
mcf	thousand cubic feet
mmBtu	million British thermal unit
mmcf	million cubic feet
MMS	US Department of Interior Minerals Management Service
NARG	North America Regional Gas Model
NBP	Northern Border Pipeline
NEB	National Energy Board (Canada)
NEB Act	*National Energy Board Act*
NEPA	*National Environmental Policy Act*
NETL	National Energy Technology Laboratory
NGA	*Natural Gas Act, 15 U.S.C. § 717 et. seq.*
NGL	natural gas liquid
NPA	*Northern Pipeline Act, 1977-78, c. 20, R.S., 1985, c. N-26*
NPRA	National Petroleum Reserve - Alaska
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
OFI	Office of the Federal Inspector
OGIP	Original gas in place
O&M	operations and maintenance
OSHA	Occupational Safety and Health Administration
PA	Precedent Agreement
PDF	Portable Document Format
PFC	Petroleum Finance Company
psi	pounds per square inch
psig	pounds per square inch gauge
QP	Qatar Petroleum
RCA	Regulatory Commission of Alaska
RFA	Request for Applications
RIK	Royalty-in-Kind
RIV	Royalty-in-Value
ROW	right-of-way
SCF	standard cubic feet
SGDA	Stranded Gas Development Act AS 43.82
SME	Subject matter expert
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TCAlaska	TransCanada Alaska Company, LLC and Foothills Pipe Lines, Ltd.
tcf	trillion cubic feet
TransCanada	TransCanada Corporation
TRR	Technically recoverable reserves

TSM	TAPS Settlement Methodology
U.S.C.	United States Code
USGS	United States Geological Survey
WCSB	Western Canada Sedimentary Basin
YESEAA	*Yukon Environmental and Socio-Economic Assessment Act*
YPC	Yukon-Pacific Corporation
YTF	Yet to Find
YTG	Yukon Territorial Government

Glossary

TERM	DEFINITION
Acceptable Credit Rating	A Credit Rating not lower than any of the following: “BBB-” from Standard & Poor’s, a division of the McGraw-Hill Companies, Inc. and its successors and assigns (S&P), “Baa3” from Moody’s Investors Service, Inc. and its successors and assigns (Moody’s), “BBB-” from Fitch Ratings Ltd. and its successors and assigns (Fitch), or “BBB (low)” from Dominion Bond Rating Service Limited and its successors and assigns (DBRS). In the event an entity is rated by two or more of S&P, Moody’s, Fitch and DBRS, the lowest rating shall prevail.
Actual Capital Cost	The capital cost that is approved by FERC in the U.S. and the Northern Pipeline Agency and National Energy Board in Canada as the final capital cost of the Project following the In-Service Date and which TransCanada is authorized to include in the Project rate base for the recovery and return calculation pursuant to such approvals.
AECO	The Alberta Energy Company (AECO) hub was originally a storage facility in Alberta where natural gas was bought and sold. As suppliers and customers increasingly used this storage facility to buy and sell natural gas, the location was quickly established as the point at which the benchmark Alberta price was established in the marketplace. While this storage facility still exists, AECO today generally refers to the Alberta gas price and Alberta pricing point. When gas is said to be traded at the AECO hub, it is actually being traded on a notional (non-physical) point on the Nova Inventory Transfer pipeline system.
AGIA Commissioners	Commissioner of Revenue and Commissioner of Natural Resources
Agreement on Principles	Agreement Between the United States and Canada on Principles Applicable to a Northern Natural Gas Pipeline, September 20, 1977, U.S. – Can., 29 U.S.T. 3581.
Alaska Open Season	The process that complies with 18 C.F.R. Part 157, Subpart B (Open Seasons for Alaska Natural Gas Transportation Projects) pursuant to which TransCanada shall solicit initial binding commitments from potential Shippers for capacity on the Alaska Section, and the GTP in the event TransCanada is the sponsor for the GTP, which shall take place concurrently with the Yukon-BC Open Season and the Alberta Open Season.
Alaska Section	The section of the Pipeline System located in Alaska which runs from the outlet of the GTP near Prudhoe Bay, Alaska to the Alaska/Yukon border near Beaver Creek, and which would include related pipeline, compression, measurement and other permanent and temporary facilities located in Alaska.
Alaska Shippers	Those Shippers that commence service at a receipt point on the Pipeline System in Alaska.
Alberta Hub	The natural gas trading hub on TransCanada’s Alberta System, where natural gas and natural gas liquids are traded and which trading activities are facilitated by the NOVA Inventory Transfer (NIT).
Alberta Open Season	The process pursuant to which TransCanada shall solicit initial binding commitments from potential shippers for capacity on the

TERM	DEFINITION
	Alberta Section and TransCanada's Alberta System from the British Columbia/Alberta border near Boundary Lake to the Alberta Hub and further downstream for deliveries to the Alberta border, which shall take place concurrently with the Alaska Open Season and the Yukon-BC Open Season.
Alberta Section	The existing Foothills Pre-Build System located in Alberta and any new pipeline required to be built and owned by Foothills in Alberta in order to provide access to the Alberta Hub from the Yukon-BC Section, including related pipeline, compression, measurement and other permanent and temporary facilities owned by Foothills and located in Alberta.
Alberta System	TransCanada Corporation's wholly-owned, 15,000 mile natural gas transmission system in Alberta which gathers natural gas for delivery to end users and to liquids extraction facilities within the province and for delivery through provincial export locations to major natural gas market areas across North America. The Alberta System is a significant component of the Alberta Hub.
Anchor Shipper	A shipper who has reached an agreement with the pipeline sponsor, generally through one-on-one negotiation to support the project, by making a large early commitment to capacity on the proposed pipeline.
Antitrust	Opposing or intended to regulate business monopolies, such as trusts or cartels, especially in the interest of promoting competition.
ANS	The Alaska North Slope, which is the portion of Alaska north of sixty-eight degrees North latitude.
ANS Explorers	Those companies that have been or will be exploring for natural gas on the North Slope of Alaska.
ANS Producers	BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc. and ExxonMobil Alaska Production Inc.
Base Capital Cost	The capital cost of the Pipeline System that is approved by FERC in the CPCN in Alaska and by the Northern Pipeline Agency and National Energy Board in the Leave to Construct in Canada.
Basin Control	The ability of the Major North Slope Producers to control the North Slope basin and discourage competitor producers from initiating and/or increasing their exploration and production activities in the area due to potentially high tariffs and uncertain access to essential pipeline capacity to move new production to markets.
Basis Point	One hundredth of a percentage point, or 0.01%. This term is usually used to discuss small fluctuations in equity indexes, interest rates, and yields on fixed annuities.
Blow Down	The rapid production of either oil or natural gas from a hydrocarbon reservoir. In terms of the Prudhoe Bay Unit and other mature reservoirs on the North Slope, blow down will signal a shift from a production approach that is designed to maximize the production of oil to an approach that is focused on the production of natural gas.
Bridge Shipper	An entity, usually governmental, that temporarily covers some of the unused capacity or commitments in the event that the new pipeline fails to attract enough paying customers to fill it.

TERM	DEFINITION
Canada Open Season	The combined Yukon-BC Open Season and the Alberta Open Season.
Canada Section	The Yukon-BC Section and the Alberta Section.
Capital Cost Overrun	That amount, if any, by which the Actual Capital Cost of the Pipeline System exceeds the Base Capital Cost or other agreed to amount.
Capital Cost Overrun Loan	The project loan which credit is proposed to be enhanced by the U.S. Loan Guarantee, and pursuant to which a Capital Cost Overrun would be financed.
Capital Cost Overrun Surcharge	The provisional toll which Surcharge Shippers are required to pay, when the market gas prices at the Alberta Hub are above a pre-determined threshold, for servicing the Capital Cost Overrun Loan.
Central Gas Facility	Existing facility at Prudhoe Bay that provides initial processing of the wet natural gas that has been separated from the ANS crude oil stream. Some natural gas liquids are extracted and the remaining gas stream is, for the most part, discharged for re-injection.
Collateral	(i) an irrevocable standby letter of credit from a financial institution acceptable to TransCanada with a Credit Rating of at least A by S&P and A2 by Moody's; or (ii) unencumbered cash collateral in a form satisfactory to TransCanada; or (iii) other collateral which may be mutually acceptable to the shipper and TransCanada.
Commission or FERC	Federal Energy Regulatory Commission
Contingent Liability	Liabilities that may or may not be incurred by an entity depending on the outcome of a future event such as a court case.
Credit Rating	The respective rating assigned to the long-term senior unsecured debt (not supported by third party credit enhancement) of an entity by S&P, Moody's, Fitch or Dominion Bond Rating Service and their respective successors and assigns. If an entity does not have a long-term senior unsecured debt rating, the corporate Credit Rating (or deemed equivalent) shall be used as a substitute.
Cure Period	A provision in a contract allowing a defaulting party to fix the cause of a default, for example a repayment grace period.
Decision to Proceed	The transition point between the Development Phase and the Execution Phase of the Project; the major Project milestone at which the final decision is made with respect to whether to proceed to execution of the Project or not.
Definition Sub-Phase	That portion of the Development Phase that begins with the conclusion of the Open Season and ends when all major Project approvals are in place and the final Decision to Proceed has been made.
Delivery Point	Any point on the Pipeline System where gas may be taken off the Pipeline System.
Discount Rate	AGIA specifies various discount rates to be analyzed in considering the NPV of future cash flows to the state. The discount rates specified are zero, five, six, and eight percent.
Divisible Income	The net cash flow from the proposed project.
Dry Gas	Natural gas that does not contain significant condensates or liquid hydrocarbons.
End User	The ultimate consumer of a product, especially the one for whom the

TERM	DEFINITION
	product has been designed.
FERC Open Season Regulations	The FERC regulations as set forth in 18 C.F.R. § 157, Subpart B (Open Seasons for Alaska Natural Gas Transportation Projects).
Firm Transportation Service	The transportation service provided to a Shipper on a pipeline system pursuant to a Transportation Services Agreement (TSA) between the Shipper and a pipeline whereby the pipeline agrees to make available to the Shipper on a firm basis the capacity on the pipeline system subscribed for in the TSA and the Shipper agrees to pay for such capacity as per the TSA whether the Shipper uses such capacity or not.
First Nations peoples	The Indian peoples of Canada, both Status and non-Status, as defined in the Indian Act, R.S., 1985, c. I-5.
Foothills System or Foothills Pre-Build or Pre-Build	The existing natural gas pipeline system built under certificates issued pursuant to Canada's Northern Pipeline Act that starts at Caroline, Alberta that branches into two legs, with one leg running south-east to Monchy, Saskatchewan and the other leg running south-west to Kingsgate, British Columbia, which is owned by Foothills Pipe Lines Ltd., a wholly-owned subsidiary of TransCanada Corporation.
Gas Cap	An oilfield term indicating the condition which occurs as oil is removed; the gas becomes mobilized and accumulates as a "gas cap" on the oil formation. Also, the portion of a reservoir occupied by free gas (gas not in solution).
Gas Treatment Plant (GTP)	In the TransCanada application, the GTP is necessary for treating some natural gas that is to be shipped via pipeline from the Alaska North Slope (ANS). The GTP will process over 5 billion cubic feet per day (bcf/d) of residue gas from the existing Central Gas Treatment Facility located at Prudhoe Bay. This residue gas would be treated by removing the undesirable constituents (e.g., CO2) by dehydration and filtration processes. The 4.5 bcf/d of sales gas would be chilled to 28°F and compressed to 2500 pounds per square inch gauge (psig) prior to shipping. The CO2 would be returned to the residue gas stream and re-injected into the Prudhoe Bay reservoir.
Guarantee	A financial guarantee in the form acceptable to TransCanada from a party with an Acceptable Credit Rating.
Henry Hub	The Henry Hub is a pipeline interchange located near Erath, Louisiana. The Henry Hub is the designated delivery point for the NYMEX Natural Gas futures contract. The Henry Hub is also a highly liquid trading point, with numerous buyers and sellers of both physical natural gas and financial derivatives. The Hub provides access to more than a dozen interstate and intrastate pipeline interconnects
Hub	A major natural gas receipt and delivery and/or trading point.
Hurdle Rate	The minimum rate of return producers must achieve to pursue a project.
In-Service Date	The date for Commencement of Commercial Operations of the Pipeline System.
In-State Shippers	Those Shippers that subscribe for transportation services with the Alaska Section for natural gas delivery to a delivery point within the

TERM	DEFINITION
	State of Alaska.
Internal Rate of Return	The internal rate of return (IRR) is a metric used to determine the efficiency of an investment, as opposed to the net present value (NPV), which indicates value or magnitude. The IRR is the annualized effective compounded return rate which can be earned on the invested capital, i.e., the yield on the investment.
Investment Grade	Applies to an assessment of a shipper's creditworthiness and means a long term senior unsecured debt rating of at least BBB- by Standard & Poor's (S&P); Baa3 by Moody's Investor Services (Moody's); BBB- by Fitch Ratings (Fitch); or BBB (Low) by Dominion Bond Rating Service (DBRS).
Leave to Proceed	Has the meaning ascribed to it in Section 2.2.4.2(2) "Canadian Regulatory Approvals".
Levelized cost	The present value of the total cost of building a pipeline over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).
License	The license to be granted under the Alaska Gasline Inducement Act, AS 43.90 et. seq.
Line Pack	A quantity of gas purchased for operational (non-commercial) use by the pipeline entity to fill and pressurize the pipeline prior to the commencement of commercial operations. The line pack quantity is generally considered a permanent part of the pipeline's asset base (and its cost is included in the tariff), allowing the pipeline to deliver gas for a shipper at a pipeline delivery point at the same time the shipper delivers that quantity of gas to a pipeline receipt point.
Lower 48	The contiguous states of the United States, i.e. not including Alaska or Hawaii.
Mainline	The large diameter pipeline that is routed generally along the TAPS pipeline and the Alaska Canada Highway, compressor stations and related facilities, including any additions, improvements, expansions, extensions or renewals or replacements to the pipeline, compressor stations, or related facilities, designed to transport gas from the ANS to off-take points and to connect with other pipelines.
Major NS Producers	Phrase used to describe major North Slope producers including Exxon, British Petroleum, and ConocoPhillips
Management Committee	A committee of senior representatives of TransCanada who direct the organization and who will provide executive guidance to senior management of the Project and will consider approvals for significant Project scope and budget changes.
Midstream Capital Costs	The capital costs of the pipeline, GTP, compressor stations, and (as applicable) LNG liquefaction facilities are a key input into the Midstream Model, and significantly affect Midstream tariffs.
Midstream Divisible Income	Consists of profits for the pipeline owner as well as property and corporate income taxes.
Midstream Element	Means a gas transmission pipeline, a gas treatment plant, the main pipeline (mainline), compressor stations, or a NGL plant.

TERM	DEFINITION
Natural Gas Liquids	Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied.
Net Present Value (NPV)	Net Present Value is an economic calculation used to appraise the financial value of long-term projects. An NPV calculation figures the present value of an investment that may generate returns for many years; in short, the AGIA NPV calculation allows us to understand, in terms of today's money, the profits (or losses) that an Offeror's AGIA Application offers the State.
Negotiated Rate Shippers	Those Shippers that have elected to pay the transportation tariff/toll in accordance with the Negotiated Rate has the meaning ascribed to it in Section 2.2.3.7 "Negotiated Rates"
Net Back value	The net back value is defined as the unit price or value of a product such as natural gas at a particular point on the pipeline (or upstream of the pipeline such as at the point of production.) The net back value is calculated by subtracting from the downstream sales price of that product all the costs incurred to deliver the product to the point of sale.
Net Cash Flow	The net cash flow from gas, or "Upstream Divisible Income", is: (1) the final destination price of the gas, times (2) the volume of gas transported, minus (3) total tariff payments and (4) out of pocket production costs.
NOVA Inventory Transfer or NIT	A notional point on TransCanada's Alberta System that acts as a market hub, where the transfer of title to gas transported on such system occurs, and which transfer can only occur following payment by the shipper of the receipt toll. NIT functions as both a market and supply hub by providing direct access to over 300 bcf of connected storage, a large (3 bcf/d) intra-Alberta market and multiple pipelines which transport approximately 17 bcf/d to major markets across North America.
Off-take Point	A delivery connection location, consisting of necessary valves, flanges and fitting, where gas flows out of a mainstream pipeline to other pipelines for distribution.
On Spec	On speculation, or speculatively.
Open Season	An open season is the process during which a pipeline company seeks customers to make firm transportation commitments (usually long-term) to a project, e.g., the concurrent initial binding Alaska Open Season, Yukon-BC Open Season and Alberta Open Season. An open season is the process during which a pipeline company seeks customers to make long-term firm transportation commitments to a project.
P_x	Indicates that an outcome or proposed action has a X% likelihood of occurring. For example and outcome of proposed action of P_{50}, has a 50% likelihood of occurring.
Precedent Agreement	An agreement between a Shipper and TransCanada entered into following the completion of the Alaska Open Season, the Yukon-BC Open Season or the Alberta Open Season, as applicable, pursuant to which such Shipper agrees to commit a certain amount of gas to the Alaska Section, the Yukon-BC Section or the Alberta Section and

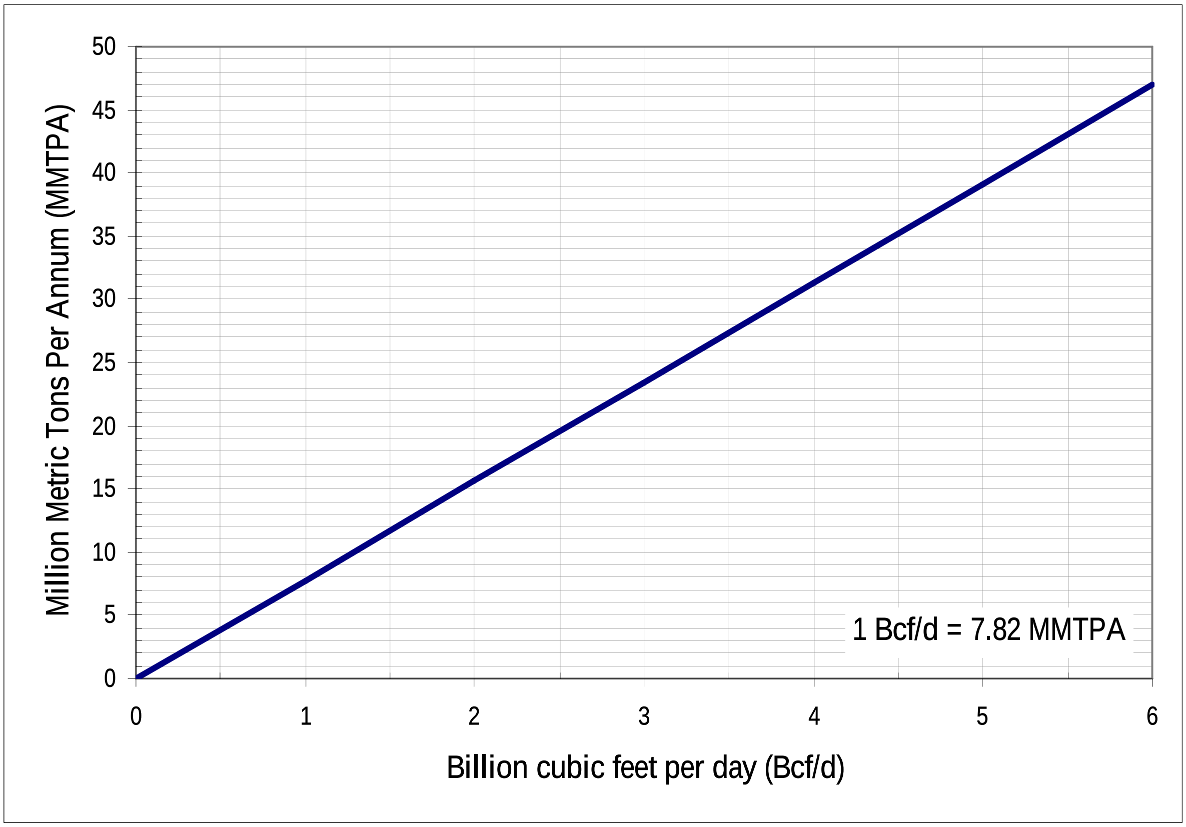
TERM	DEFINITION
	TransCanada's Alberta System, as applicable, which shall be superseded and replaced by the Transportation Services Agreement prior to the In-Service Date.
Proposal Sub-Phase	That portion of the Development Phase that begins with the award of the AGIA license and ends with the conclusion of the Open Season
Proved Reserves	Reserves of natural gas that are claimed with reasonable certainty (80% to 90% confidence) to be recoverable in future years by specified techniques.
Ratemaking	The practice of establishing rates of payment for services, as for public transportation or utilities.
Rebuttable Presumption	An assumption made by a court, one that is taken to be true unless someone comes forward to contest it and prove otherwise.
Receipt Point	Any point on the Pipeline System where gas may be put into the Pipeline System.
Receipt Shippers	Those Shippers that enter into a Transportation Services Agreement with TransCanada's Alberta System pursuant to which the Shippers agree to deliver gas into the Alberta System and pay the receipt toll.
Recourse Rate	Recourse rates are cost-based rates set by FERC under conventional public utility rate-making methods. In Section 2.2.3.5(1) of TransCanada's application Recourse Rate is used to describe that the 100% load factor for the Alaska section would be $1.06/mmBtu in constant 2007 dollars.
Recourse Rate Shippers	Those Shippers that have elected to pay the transportation tariff/toll for the Alaska Section in accordance with the Recourse Rate as described in Section 2.2.3.5 "Rate Structure and Supporting Information".
Regasification	The practice of converting liquefied natural gas back into gaseous form to send to market, often after moving it into cold storage tanks.
Rolled-in rates	Is a term used by FERC to differentiate between rolling-in the construction costs of new pipeline expansion with the existing facilities or developing costs on an incremental basis (establishing separate cost-of-services and separate rates for the existing and expansion facilities).
Royalty In-Kind	Royalty is a share of production. When taken "in-kind" the State of Alaska physically takes custody of the oil or gas produced.
Royalty In-Value	When taken "in-value" the royalty share is left with the producer, who must sell 100 percent of the oil or gas, and pay the State of Alaska its royalty share of the net proceeds from the sale of 100 percent of the oil or gas, or the market value of the oil or gas, whichever is higher.
Sealift	The barging of large oil and gas field equipment from where it is built to where they are installed.
Shippers	Those entities that contract for gas processing and transportation services on the GTP and the Pipeline System.
Sovereignty	Supremacy of authority or rule as exercised by the State.
Spend-Curve	A component of calculating cost and schedule range data that shows when in the process the dollars will be spent to develop and construct the project.
State	State of Alaska
Surcharge Shippers	Those Negotiated Rate Shippers that elect the Capital Cost Overrun

TERM	DEFINITION
	Surcharge option.
Take or Pay Contracts	Agreements between a buyer and a seller that obligate the buyer to pay a minimum amount of money for a product or service, even if the product or service is not utilized or purchased.
Tangible Net Worth	Total assets (exclusive of goodwill and other intangible assets) minus total liabilities, as reported in the provider's unqualified audited annual financial statements and unaudited quarterly financial statements in accordance with generally accepted accounting principles in the country in which the provider is organized, consistently applied.
Tariff	The rate and terms of service materials associated with operations of the pipeline. Frequently, this term only refers to the rates to be charged for particular services.
Term-differentiated Rates	Rates that that vary by the length of the contract term. These rates allow the pipeline to recover its capital costs from shippers over a longer period, thus lowering the rates paid by shippers that sign longer-term contracts.
Transportation by Others or TBO	Commercial arrangements whereby one pipeline system contracts for capacity on another pipeline system. The pipeline system taking the capacity uses it to provide integrated service to parties on its system.
Transportation Services Agreement	The agreement between a Shipper and TransCanada pursuant to which TransCanada agrees to provide natural gas transportation services on the Alaska Section, the Yukon-BC Section, the Alberta Section or TransCanada's Alberta System, as applicable, to the Shipper and the Shipper agrees to abide by the terms and conditions of the agreement and pay the applicable tariff/toll for subscribing for capacity on the Alaska Section, the Yukon-BC Section, the Alberta Section or TransCanada's Alberta System, as applicable.
Twenty (20) Must Haves	The twenty statutory requirements of the Alaska Gasline Inducement Act as specified in AS 43.90.130
Upstream Divisible Income	The net cash flow from gas, or "Upstream Divisible Income", is: (1) the final destination price of the gas, times (2) the volume of gas transported, minus (3) total tariff payments and (4) out of pocket production costs. Upstream Divisible Income is shared between the Producers, the State of Alaska, and the federal government through royalty, and state production taxes.
Wet Gas	Natural gas that contains methane and natural gas liquids such as butane, propane and ethane.
Work Commitments	A promise on the part of the participants to the fiscal contract to take the steps necessary to implement the gas pipeline project. With regard to the SGDA contract, work commitments refer to a promise on the part of the participants to the fiscal contract to take the steps necessary to implement the gas pipeline project
Yet-to-find (YTF) area	Production areas which, according to the NETL Alaska Gas Study and other sources, have a significant amount of economically recoverable reserves, but which have not yet been discovered.

Units

Bcf/d	billion cubic feet per day
Btu	British thermal unit (Btu). The term "Btu" is used to describe the heat value (energy content) of fuels.
Calorific Content	The heating value or calorific value of a fuel is the amount of heat released during combustion.
Decatherms	A decatherm is a measure of heat energy equal to 1,000,000 British thermal units (Btu). It is approximately the energy equivalent of burning 1000 cubic feet (often referred to as 10 Ccf) of natural gas
Ft	feet
In	Inches
M	Meter
MMBTU	**MMBTU** represents one million BTU, which can also be expressed as 1 decatherm (10 therms)
MMTPA	Million Metric Tons Per Annum. 1Bcf/d = 7.82 MMTPA
psig	pounds per square inch gauge
Tcf	trillion cubic feet

Billion cubic feet per day (Bcf/d) – Million Metric Tons per Annum (MMTPA) Conversion Chart



PREFACE

This document contains the Findings and Determination of the Commissioners of Natural Resources and Revenue concerning whether to issue a license under the Alaska Gasline Inducement Act ("AGIA") to TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd. Throughout this document, the AGIA applicant is referred to as "TC Alaska." TC Alaska is a subsidiary of TransCanada Corporation ("TransCanada"). TransCanada, through its independent pipeline company affiliates, owns and operates one of the largest natural gas pipeline transportation networks in North America. TransCanada has pledged all support necessary, both financial and otherwise, to TC Alaska to achieve completion of the project.

The basis for this Determination is explained in detail in the written Findings and supporting documentation that follows:

- *Executive Summary*: The Executive Summary contains a short, simple discussion to provide the reader with a sketch of the more important aspects of the Findings document. The reader can obtain additional, more-detailed information from the actual text of the Findings and Determination.
- *Chapter One — Introduction and AGIA*: Chapter One serves as an introduction to the process used to develop this Findings document and presents information that guides the reader through the evaluation conducted by the Commissioners of the Departments of Natural Resources and Revenue under AGIA. Chapter One also presents information on how the commissioners examined and compared three natural gas projects in order to determine the type of project that most sufficiently maximizes benefits to Alaskans.
- *Chapter Two — Technical Background*: Chapter Two provides a simplified explanation of the many components of a major natural gas pipeline project—what physical and engineering components comprise a natural gas pipeline, what regulatory processes govern the development and operation of a pipeline, what commercial factors drive the economics for the various pipeline stakeholders, and what methods are traditionally used to evaluate a pipeline project's technical and commercial viability.
- *Chapter Three — Analysis of TC Alaska's Application*: Chapter Three contains the commissioners' evaluation of the TC Alaska Project as proposed in its AGIA Application.
- *Chapter Four — LNG:* Chapter Four contains the commissioners' comparison of the TC Alaska Project with liquefied natural gas (LNG) project options.
- *Chapter Five — Producer Project*: Chapter Five consists of the commissioners' comparison of the TC Alaska Project with the proposal ConocoPhillips and BP recently submitted, labeled "Denali™ - the Alaska Gas Pipeline" ("the Producer Project").
- *Chapter Six — Findings and Determination*: Chapter Six contains the Findings and Determination of the commissioners.
- *Appendices*: The appendices contain information that supplements or further explains the Findings document. The appendices include the summary of public comments and the responses to those comments, as well as expert reports.

EXECUTIVE SUMMARY

This Executive Summary contains a short, simple discussion of the more important aspects of the Findings document. The reader can obtain additional, more detailed information from the actual text of the Findings and Determination. As discussed in these Findings:

- *Issuance of the AGIA license to TC Alaska will maximize benefits to Alaskans because it will provide the best opportunity to achieve a gas pipeline that encourages full exploration of Alaska's natural gas resources, generates long-term jobs for Alaskans, maximizes state revenues, provides affordable in-state gas opportunities, and realizes other important state goals.*
- *Although liquefied natural gas ("LNG") project options are likely economic, they would provide the state with less revenue than the TC Alaska Project. Exclusive LNG projects are significantly less likely to succeed compared to TC Alaska because they are more complex, more costly, more difficult to finance, and would face potential regulatory barriers in exporting LNG to Asia. The TC Alaska Project provides Alaska with its best opportunity for a successful LNG project, as a "Y-line" option. The TC Alaska Project proceeding first will reduce costs and lessen financial and contracting hurdles associated with an LNG project. Coming after gas is already bound for U.S. markets, a Y-line may be able to overcome political opposition to exporting gas. Accordingly, the commissioners believe that the best route to an Alaska LNG project runs through the TC Alaska proposal.*
- *Although the TC Alaska Project would generate billions of dollars of profits for the Major North Slope Producers, BP and ConocoPhillips have opposed the TC Alaska Project and touted their own pipeline proposal ("the Producer Project"). Unlike TC Alaska's Project, the Producer Project contains no commitments to a project timeline, fails (similar to TAPS) to ensure tariff and expansion terms that will maximize North Slope exploration and development, suffers from potential antitrust problems, and in order to result in a pipeline will likely (similar to the failed Stranded Gas Development Act contract) require the state to provide the Producers with massive additional fiscal concessions.*

Purpose of this Finding and Determination

AGIA, AS 43.90, requires the Commissioners of Natural Resources and Revenue to issue a determination with written findings if they decide that a proposed gasline project will sufficiently maximize the benefits to the people of Alaska and merits issuance of an AGIA license. This document constitutes the commissioners' Finding and Determination. Following an extensive evaluation process and consideration of public comments, the commissioners have determined that the TC Alaska Project will sufficiently maximize the benefits to Alaskans and merits issuance of the AGIA license.

Benefits for Alaska of a TC Alaska Gas Pipeline Project

The pipeline project proposed by TC Alaska offers significant benefits to Alaska. Alaska's economy will benefit from short-term construction jobs, but will benefit more significantly from long-term careers, as new natural gas fields are developed because the pipeline to market has been built. Alaska will benefit from a pipeline that can be expanded to accommodate additional natural gas supplies that can be dedicated to meet Alaska's energy needs. Alaska will benefit from a pipeline tariff structure that maximizes state revenues, provides true open access to all potential shippers, provides the lowest reasonable transportation rates, and accommodates expansions. Alaskans will benefit from the opportunity the TC Alaska Project creates for a "Y line" liquefied natural gas project and the "bullet line" to Southcentral Alaska. Alaska will benefit from the potential for lower energy costs as natural gas is made available to communities throughout Alaska via off-take points along the pipeline route and associated spur lines. The construction of a natural gas pipeline is an exciting start to a new era in the Alaska economy, one where more Alaskans have careers in natural gas exploration and development, where the state and its citizens enjoy a continuing stream of tax and royalty revenues, and where local energy costs are reduced.

Because of the commitments to expansion and real open access that will open the North Slope basin to competition, the TC Alaska Project will generate long-term jobs more effectively than either an LNG option or the Producer Project.

Constructing a natural gas pipeline will generate thousands of construction jobs that will last for three to four years. After the pipeline is operating, employees will be needed to operate compressor stations and other pipeline facilities. The demand for skilled workers trained to drill wells and build new production facilities will increase as the availability of a path to market enhances the economics of exploring for Alaska's vast undiscovered gas resources. Because of its commitments to expansion and real open access that will open the North Slope basin to competition, the TC Alaska Project will generate long-term jobs more effectively than either an LNG option or the Producer Project.

The TC Alaska Project will not interfere with a smaller "bullet line" from the North Slope to Southcentral Alaska. Rather, moving both projects forward simultaneously may produce unique synergies. There are adequate amounts of natural gas on the entire North Slope to fill both pipelines. Because of its smaller scale, the "bullet line" project may be designed and constructed more quickly than the TC Alaska Project. The two projects may provide benefits to each other: the construction work force may gain experience working on the "bullet line;" and the TC Alaska Project may attract experts to the state who would not otherwise be available to work on the "bullet line" project.

The TC Alaska Project would not preclude an LNG project. Indeed, approving the TC Alaska Project will enhance the prospects for a successful "Y line" LNG project as it will reduce the costs, financing challenges, and commercial coordination challenges unique to LNG projects. TC Alaska offers to construct or transport gas to a "Y line" from Delta Junction to an LNG processing facility in Prince William Sound if shippers express sufficient demand for that project as the work on the overland project progresses.

The TC Alaska Project provides several opportunities to address Alaska's need for low-cost energy. TC Alaska's proposed distance-sensitive transportation rates ensure that Alaskans will pay just the costs incurred to ship gas within Alaska. The TC Alaska Project also offers the potential for construction of spur lines that will make natural gas available to communities throughout the state. Most importantly, because the true open access and tariff provisions promote gas exploration and development, Alaskans will benefit from an environment in which companies compete to meet Alaskans' energy needs.

The cost of transportation on the TC Alaska pipeline (its "tariff") will protect the state's interests throughout the years of pipeline operation. Lowest reasonable tariffs are essential to ensure genuine open access and maximize opportunities for development of Alaska's North Slope natural gas resources. TC Alaska commits to the requirements of AGIA that are designed to ensure the lowest possible tariffs. When tariffs are too high, explorers and developers are discouraged from investing in North Slope natural gas exploration and development. Low tariffs improve the economics of finding and developing additional natural gas resources on the North Slope, which encourages additional exploration and development work that will provide for long-term, stable employment for Alaskans.

Low Tariffs

- Encourage exploration
- Increase long-term employment opportunities
- Produce higher revenues to the state
- Strengthen the Permanent Fund

Low tariffs also mean that the state can earn a greater return on its natural gas resources. As the owner of the natural gas resources, the state gets a share of the natural gas production, its "royalty" share. As a sovereign, the state taxes the profit on natural gas production. Tariffs are deducted from the market price at the destination where the natural gas is delivered before the royalty amount and production taxes are calculated. This means the higher the tariff, the lower the return to Alaska for its natural gas resource. These returns are an important future revenue stream for the state that can be used to fund government services and capital projects, defray the cost of energy to Alaskans, and maintain the strength of and protect the Permanent Fund.

TC Alaska has committed to regularly expand its pipeline to meet the need for transporting additional gas on reasonable commercial terms. This is essential to opening the North Slope to competitive natural gas exploration and development. New explorers and producers need confidence that if their efforts are successful, they will be able to get their natural gas into the pipeline and to market at a fair rate for transportation.

Alaska's experience with TAPS (which is owned by the Major North Slope Producers) demonstrates how the terms of ownership and operation of a pipeline can adversely affect the state's economic interests and the exploration efforts of developers who do not own a share of the pipeline. When the Regulatory Commission of Alaska reviewed the tariffs on the TransAlaska oil pipeline twenty-six years after it began to operate, it found that the tariffs were excessive. The Superior Court, and eventually the Alaska Supreme Court, affirmed the Commission's finding that the TAPS owners had collected pipeline tariffs from shippers that were an average of 57 percent too high. Decades of excessive tariffs reduced the state's royalties and production tax, and hindered competitive development of the state's oil resources by non-owner companies.

Alaska cannot afford to repeat the TAPS experience. The state must maximize development of the natural gas resources on the North Slope to realize economic growth through increased jobs, revenues and other benefits that will flow from increasing gas production. TC Alaska's commitments to a lower tariff structure will ensure that the state does not repeat the problems experienced with TAPS.

The commissioners recognize the Producer Project may be pursued to completion outside the AGIA process and without state fiscal concessions. The Producers have an obligation to market their gas when it is reasonably profitable to do so; they do not have an obligation to transport the gas through any particular project. If the Producer Project proceeds to an open season, the TC Alaska Project would compete with the Producer Project for gas commitments. However, the Producers have stated that they need concessions from the state to enable them to commit gas to any gas pipeline project. AGIA ties upstream incentives to gas committed at the initial open season of the AGIA project, to provide the state with the benefits Alaskans require. The state will have opportunities throughout this process to evaluate the need to increase the value of the AGIA upstream incentives, when justified.

> Awarding a license to TC Alaska will ensure that any additional upstream incentives are provided in exchange for the benefits inherent in an AGIA project. In addition, awarding a license to TC Alaska reduces the likelihood that the state will need to provide unwarranted concessions to the Major North Slope Producers.

The TC Alaska Project offers significant benefits to the state and its citizens. As a pipeline company which increases its profits by expanding its system, TC Alaska has the incentive to foster timely development of the state's natural gas resources to their maximum potential. This also serves the state interests. The TC Alaska Project sets the stage for an open and competitive North Slope natural gas basin during and after pipeline construction. TC Alaska is unique in its willingness to commit to actions that will realize this future.

Background

Development of Alaska's natural resources is the cornerstone of Alaska's economy. Alaska's North Slope is a world-class natural gas basin. Recent studies estimate that there are 224 trillion cubic feet ("Tcf") of undiscovered, technically recoverable natural gas resources throughout the Alaskan Arctic. Of this amount, 137 Tcf are categorized as undiscovered, economically recoverable resources. These resources are in addition to the approximately 24.5 Tcf of natural gas reserves within Prudhoe Bay plus 9 Tcf of natural gas reserves discovered in other existing fields on the North Slope, including Point Thomson. Although there has been considerable debate about who should build a pipeline and when it will be built, there is unanimous agreement that Alaska needs a pipeline to get its huge volumes of natural gas to market.

When natural gas was discovered on the North Slope, the search began for a way to get Alaska's substantial natural gas resources to market. State and federal laws were passed to encourage natural gas pipeline construction. Potential developers spent millions of dollars on plans and studies. However, the low prices in natural gas markets forestalled the commitments necessary to support the tremendous cost of what would be the largest construction project in North America. As dynamic changes occurred in the natural gas market within the last decade, the viability of, and interest in, an Alaska natural gas pipeline increased.

In 1998, when the Stranded Gas Development Act ("SGDA") was passed, the average price for natural gas in the Lower 48 was under $2 per million British thermal unit (mmbtu). The first half of this decade was marked by discussions of what type and amount of government subsidies and concessions were needed to make the project viable. Within Alaska, those discussions came in the context of contract negotiations conducted by the previous Governor and his administration with the three primary oil and gas leaseholders on the North Slope: BP, ConocoPhillips, and ExxonMobil ("Major North Slope Producers"). The debate surrounding the proposed contract centered on how much value the state would need to transfer to the Major North Slope Producers and how much risk the state would be required to accept.

By 2006, the natural gas markets had changed dramatically. The average price of natural gas in the Lower 48 was more than $6 per mmbtu. Large government subsidies no longer appeared necessary to make the project economically viable. In addition, the state had become much better educated on natural gas pipeline economics. The State learned that if it was not careful to protect its interests, billions of dollars in value could be transferred unnecessarily from the state to the Major North Slope Producers. These changes shifted the public debate from what state concessions would be necessary to what the state government could do to most effectively advance the project and maximize the interests of Alaskans. The legislature did not accept the contract that had been negotiated with the Major North Slope Producers under the SGDA. The Major North Slope Producers continued to insist that large concessions from the state were needed, without demonstrating the need for those concessions. Alaska's natural gas pipeline project was at an impasse.

When the Palin Administration proposed AGIA in early 2007, it was based on the understanding that an Alaska natural gas pipeline project was economically viable and that the Major North Slope Producers would continue their efforts to negotiate commercial terms to maximize their strategic position in Alaska and obtain maximum value from any natural gas pipeline project. To protect the state's interests, AGIA used free market competition to move the project through the current impasse. All interested companies were eligible to propose any type of project they determined to be economically and technically viable. The Major North Slope Producers would need to decide whether they were going to get the enormous reserves of Alaska natural gas in the fields they now operated to market in a pipeline they built and owned, or one constructed by

> AGIA uses free market competition to move the project through the current impasse. All interested companies were eligible to propose any type of project they determined to be economically and technically viable.

a third party. AGIA presumed that the Major North Slope Producers would act as reasonable commercial players who would comply with their lease obligations and participate in a project with positive economics. Furthermore, AGIA established that if incentives are provided to a natural gas pipeline project they are given in exchange for genuine open access and other provisions necessary to protect the state's interests.

AGIA established a competitive process to allow companies to compete for a license. The companies submitting applications to construct and operate Alaska's natural gas pipeline were required to commit to the tariff and expansion terms that were designed to protect the state's interests and to develop the state's economy by providing employment during the construction of the pipeline and (more importantly) providing long-term careers in a new natural gas exploration and development industry. AGIA was based on the understanding that competition could drive companies to make those commitments. All who recognized that the project economics were positive would compete for the commercial opportunity to build the natural gas pipeline and earn some of those profits. The competition was open to everyone willing to operate within the parameters established by the AGIA "must haves." All competitors, including natural gas pipeline companies, natural gas producers, and LNG projects were eligible to compete.

In exchange for the commitments required in AGIA, the Alaska legislature offered a package of inducements. These include: reimbursement of up to $500 million of the costs incurred to obtain a regulatory approval from the Federal Energy Regulatory Commission ("FERC") to construct a pipeline; an AGIA project coordinator to facilitate the process; and a stable production tax rate for ten years and fixed royalty valuation methods to anyone who committed to purchase capacity to ship natural gas on the AGIA gasline during its first binding open season. The legislature recognized the state's vital interests in encouraging exploration and development of Alaska's natural gas resources by ensuring a genuine open access pipeline and the lowest reasonable transportation rates. AGIA license applicants were required to commit to a tariff structure that would assure the lowest possible transportation rates and expansion terms to encourage natural gas explorers and prospective developers to compete to explore for and develop Alaska's North Slope natural gas resources and bring them to market. The legislature made the inducements available to an AGIA licensee if the licensee would agree to meet the requirements and make the commitments that the legislature deemed necessary to protect the state's interests.

A Request for Applications ("RFA") was released on July 2, 2007. Applications were due November 30, 2007. The applications covered a variety of projects including both overland natural gas pipelines and LNG projects. After a thorough review, only the application from TC Alaska was found to have met all the threshold application "completeness" requirements of the AGIA statute and RFA. Although none of the applications proposing an LNG application was complete, the commissioners nevertheless compared several LNG options with the TC Alaska Project before making a decision due to the need to resolve the long-standing public debate over which route is preferable. A public review process was held on the TC Alaska application, and more than 350 public comments were received. The comments were considered in development of the Findings and are summarized in Appendix A along with responses.

The commissioners assembled a team of experts to provide analysis to help the commissioners evaluate the TC Alaska application, examine LNG options, and review the Producer Project. The team included numerous experts whose names and contributions are presented in Chapter 2. Their reports, compiled and attached as Appendices, were evaluated in developing these Findings and Determination.

How a Natural Gas Pipeline Project will Progress

Construction of a natural gas pipeline to bring Alaska's natural gas to market is a complex undertaking. There is no single event that will take the state from not having a pipeline to having a pipeline. Rather it is a series of steps, spanning a number of years, with each step affecting the next and requiring significant expenditures. Benchmarks define these steps, and at each one a pipeline developer must re-evaluate the project economics and decide whether to proceed. A successful Alaska natural gas pipeline requires much more than a proposal to build a pipeline; it requires a company that will move through each of the steps to completion. The state's evaluation process considered how likely it is that the TC Alaska Project, various LNG options and the Producer Project will complete the progression from an exciting idea to an operating pipeline.

The first step for the TC Alaska Project is issuance of an AGIA license. That license will make TC Alaska's commitment to obtain a FERC certificate legally enforceable. TC Alaska will not earn any revenues until natural gas begins to flow through the pipeline; approximately ten years after an AGIA license is awarded. In exchange for the state's commitment match of up to $500 million of the costs of taking the project through FERC certification, the state gets a commitment from TC Alaska to move the project forward to that benchmark. TC Alaska has committed to submit an application to the FERC by December 2011.[1]

After the AGIA license is issued, the next step for TC Alaska is holding an open season. Open season is the term used in the natural gas industry to describe the process a pipeline builder uses to solicit firm shipping commitments for natural gas. Producers that commit to ship natural gas get reserved capacity on the pipeline and fixed transportation rates. The pipeline company gets commitments to transport natural gas that will help it finance construction of the natural gas pipeline.

A natural gas pipeline ultimately needs shipping commitments to be successful. In order to attract shipping commitments, a project must provide positive economic opportunity for gas shippers. The commissioners' analysis shows that the Major North Slope Producers can expect billions of dollars in profits if they commit gas to the TC Alaska Project.

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After an open season, regardless of results, TC Alaska will apply for a FERC certificate. An interstate pipeline must have a certificate of public convenience and necessity from FERC before constructing new pipeline facilities. Among other things, FERC reviews the project, approves the proposed tariff terms, and sets recourse rates based on its review of the costs of construction and operation. Recourse rates are available to all shippers, but any company willing to commit to ship a defined volume for a specific period of time can negotiate better terms. FERC commonly approves negotiated rates. FERC has the authority to impose certificate conditions on the pipeline company that it believes are necessary to protect the public interest.

The proposed transportation rates described in TC Alaska's application are a reasonable first step in allocating the risks and rewards among the parties who will be involved in this project. However, nothing in the AGIA license prevents the state from protecting its interests in front of FERC by arguing for different terms. As the project moves forward and the project costs and

[1] In its Application, TC Alaska premised this and other dates on receiving the AGIA License by April 1, 2008. According to TC Alaska, if the License is issued later this year, these dates may need to be adjusted. However, for ease of reference in these Findings we will continue to refer to the original dates used by TC Alaska in its Application.

expected revenues are better defined, the negotiations between TC Alaska and potential shippers will continue. If, after they have negotiated their cost of transportation, the Major North Slope Producers can demonstrate that some change in the state's fiscal regime is necessary to enable them to earn a fair return, then the legislature can consider changes to the state's fiscal system.

After a FERC certificate is awarded, the complex process of pipeline construction begins. Because of the remote location and large size of this pipeline, the process of ordering materials and bringing them to the site will require extensive logistical planning. Construction of the pipeline and the associated processing plant will take at least three years.

Throughout the process, TC Alaska will continue to evaluate if there is demand for more capacity in the pipeline. Capacity can be added by including additional compressor stations (“compression”) or adding parallel pipe (“looping”). As additional natural gas fields are discovered and brought into production, the TC Alaska pipeline will add capacity and continue to create more jobs in Alaska’s natural gas industry.

TC Alaska Project Proposal

TC Alaska proposes to build a 48-inch diameter, high-pressure pipeline capable of carrying between 3.5 and 5.9 billion cubic feet per day (bcf/d). The project would run 1,715 miles from a natural gas treatment plant at Prudhoe Bay on the North Slope to interconnect with the Alberta Hub in Canada. This is the second largest natural gas trading center in North America, which interconnects with pipelines that carry more than 10 bcf/d of gas into U.S. markets. The Alaska section will be approximately 750 miles long with six compressor stations at startup and five natural gas delivery points in Alaska.

The net present value (“NPV”) calculation methodology used to assess TC Alaska’s application allows the State to consistently and transparently assess its future value in common terms. Because TC Alaska’s application, the LNG options, and the Producer Project are based on a variety of assumptions and projections, it is essential to use common terms to assess the impacts of these assumptions and projections on

> Net Present Value – NPV is an economic calculation used to determine the value of long-term projects. It recognizes that a dollar today is worth more than a dollar in the future. Future income (or “net value”) is measured by its “present” value through discounting. The NPV calculation allows assessment of profits that will be spread over decades.

the value to the state. With the basic assumptions rendered into common terms, the state can evaluate whether the TC Alaska Project serves the best interests of the state and compare it to LNG options and the Producer Project.

The path offered by TC Alaska's plan is likely to succeed. TC Alaska provided a work plan that is technically reasonable, feasible and specific. It includes the use of technology that TransCanada is now using to operate pipelines in climates similar to Alaska's. The schedule, including the timing of U.S. and Canadian regulatory approvals, is aggressive but reasonable and appropriate. TransCanada has the financial ability to contribute equity to the project and to obtain the financing necessary for construction. TransCanada has a strong record of performance in developing other large projects and a positive record of integrity and business ethics.

The commissioners also considered whether sufficient natural gas exists on the North Slope to fill the capacity of TC Alaska's proposed pipeline for 25 years. Alaska has enough natural gas resources to fill the TC Alaska pipeline for 25 years and for decades longer. This is true even though Point Thomson natural gas may not be available for any project during its initial years due to the operator's failure to develop the Point Thomson Unit in a timely manner, and the significant potential that the Unit must first be developed for liquid condensate and oil. The unavailability of Point Thomson gas, however, is more than offset by the unique profitability of the natural gas at Prudhoe Bay. In fact, despite the unavailability of Point Thomson gas, the state and the Major North Slope Producers stand to receive significantly positive cash flows and NPVs from the Project even if the Prudhoe Bay gas is the only gas ever produced on the North Slope. If, in addition to the Prudhoe Bay gas, natural gas from Alaska's other vast resources is also produced (including Point Thomson gas—which is very likely), then the Project will be even more profitable.

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Additionally, the commissioners considered the claim by the Major North Slope Producers that TC Alaska cannot succeed because of the risk that, if it builds the Project, it would be sued by former partners that worked with other TransCanada affiliates to try to advance an Alaska gasline project more than two decades ago. As discussed in Chapter 3, the commissioners find that the potential claims against TC Alaska and its affiliates are extremely weak, and that the Producers have failed to support their speculative theory. As a result, the commissioners conclude that the risk of litigation over this issue does not present a significant barrier to the TC Alaska Project's likelihood of success, including its ability to obtain financing.

The commercial terms proposed by TC Alaska are reasonable. TC Alaska's plan for managing cost overruns will reduce the risk for shippers of tariff increases. The TC Alaska proposal provides the Major North Slope Producers with several significant commercial opportunities. They can construct and own the gas treatment plant on the North Slope. They can also own an equity share in the TC Alaska pipeline. Further, the terms may become even more attractive through negotiations with the Major North Slope Producers.

Although there are project risks, none of them are significant enough to outweigh the TC Alaska Project's likelihood of success. Natural gas prices are not likely to decline enough to make the project uneconomic. The risk that there are insufficient resources on the North Slope to fill the proposed pipeline is low. The commissioners anticipate that the state's current fiscal structure will allow companies that develop North Slope gas and transport it on the TC Alaska pipeline to earn a significant profit.

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The TC Alaska Project is viable. TransCanada has successfully constructed many natural gas pipelines and now operates 36,000 miles of natural gas pipelines in North America. The TC Alaska Project will provide positive economics to the state and federal governments, the Major North Slope Producers and to TC Alaska. It is likely to succeed because all of the stakeholders will benefit from success and risk losing a lot if the project fails.

Alternatives to the TC Alaska Proposal

There were no applications found complete that proposed an instate pipeline and LNG project. In addition, although the Major North Slope Producers did not submit an AGIA application, BP and ConocoPhillips recently announced the Producer Project. To help determine whether TC Alaska's pipeline proposal maximizes benefits and is in the best interest of the state, the commissioners evaluated LNG project options from the North Slope to an LNG plant in Valdez and the Producer Project.

The LNG project options examined were guided by the LNG project proposals submitted under AGIA. Under the same assumptions used to analyze the TC Alaska Project, all LNG project options resulted in less value to the state and the Major North Slope Producers. Although an LNG project would be able to tap the higher prices, that we expect to be available in the Asian market, the LNG projects have significantly higher costs and thus result in lower NPV to the state or Major North Slope Producers. The commissioners' analysis does not reveal comparative benefits in either timing or costs associated with an LNG project.

Even if LNG had demonstrated comparable NPV to the TC Alaska Project, the LNG projects would still not be preferable to the TC Alaska Project. The commissioners' analysis reveals that LNG projects have a much lower likelihood of success compared to the TC Alaska Project. An LNG project will face unique financing and commercial challenges for several reasons. These include the need to negotiate multiple and concurrent agreements for the purchase, pipe transport, liquefaction, shipping, re-gasification, and sale of natural gas. An LNG project also faces significant challenges because the Major North Slope Producers have made it clear that the Asian market is not their preferred market. In addition, an LNG project will face significant risk of not being permitted to export the gas to its primary market in Asia.

> The primary markets for Alaskan LNG are in Asia, thus an LNG project would not address North American energy security and likely faces significant political opposition to exporting the gas.

The gas quality (specifically, requirements for higher heat content) required to fulfill long-term contracts to an Asian buyer is likely to preclude the development of a petrochemical industry in Alaska associated with an LNG project. Some propane can be removed from the natural gas stream to meet Alaskan energy needs. However, the other natural gas liquids would need to remain in the stream to satisfy the expected contract requirements of the Asian market.

In addition, LNG projects create concerns about genuine open access at the liquefaction plant. FERC cannot impose open access requirements on a liquefaction plant. Just as pipeline tariff terms can create disincentives for exploration, so can the processing terms at the liquefaction plant. The lack of genuine open access at the liquefaction plant will increase risks for explorers and limit the incentive for new natural gas exploration and development on the North Slope. The career opportunities and revenues associated with future development and expansions offer great value to Alaska; the limitations on those factors associated with an LNG project make it less attractive.

When compared to an exclusive LNG project, the overland gasline project proposed by TC Alaska provides an opportunity for a successful LNG "Y line" project or "spur line." The likelihood of success of an LNG project is greatest when it is constructed as a "Y line."

Approving the TC Alaska Project will enhance the prospects for a successful "Y line" LNG project as it will reduce costs, financing challenges, and commercial coordination challenges unique to LNG.

The dynamics of a producer-owned and operated pipeline are very different from those of a third-party owned pipeline. An entity that both produces natural gas and owns the pipeline, like the Producer Project, earns revenues through sales of natural gas and shipment of the natural gas. Such an entity is not necessarily as driven to keep costs low—a producer who owns a pipeline and the natural gas shipped through the pipeline, is essentially paying itself to ship the natural gas, and so is less sensitive to the transportation rate. And because they own or produce the natural gas, there is a reduced economic driver to explore for and develop additional resources until such time as it is necessary to maintain shipping volumes through the pipeline. As the state's experience with TAPS has shown, combining pipeline and shipper responsibilities can harm the state's interests. For many of these same reasons, the Producer Project suffers the risk of being stalled by anti-trust challenges.

Any Alaska natural gas pipeline project can proceed without state assistance. AGIA is not the exclusive vehicle for construction of an Alaskan natural gas pipeline; rather it was created to ensure that a natural gas pipeline is constructed that meets Alaska's needs. It was not designed to preclude the Major North Slope Producers from owning and operating the natural gas pipeline. Instead, its goal was to ensure that if they did, they would act like an independent pipeline company rather than an integrated gas producer and pipeline company. The state's interests would be protected through commercial tariff terms that ensure the lowest possible tariffs, guarantee genuine open access and expansion of the pipeline to encourage continued development of Alaska's vast natural gas resources.

On the day before the AGIA applications were due, ConocoPhillips publicly announced their desire to pursue a natural gas pipeline outside the AGIA process. Negotiations of fiscal conditions were a pre-condition of moving forward with the project. The administration chose to continue the competitive AGIA process in favor of exclusive negotiations. Recently, BP and ConocoPhillips announced the pursuit of another natural gas pipeline project: "Denali™ - the Alaska Gas Pipeline" ("Producer Project"). Negotiations over fiscal conditions are no longer seen as a pre-condition of forward movement, but are now seen as a pre-requisite to a successful open season.

None of the important commercial terms of the Producer Project are defined and, unlike TC Alaska, the Producer Project makes no enforceable commitments. There is no enforceable commitment to adhere to their stated timeline or to achieve additional milestones, such as applying for a FERC certificate. There is no information on the tariffs the Producer Project would offer, let alone an enforceable commitment to provide genuine open access. This makes the option currently presented by the Producer Project extremely risky for the state. The Producer Project was offered outside of the AGIA process, and may continue in parallel to TC Alaska's efforts.

None of the important commercial terms of the Producer Project are defined and, unlike TC Alaska, the Producer Project makes no enforceable commitments.

Some have suggested that the state should "save" its $500 million, and exclusively pursue the Producer Project rather than the TC Alaska Project. However, no company would turn down $500 million unless it expected to extract even greater concessions later from the state. Indeed, during the SGDA process the Major North Slope Producers demanded the state provide billions of dollars in fiscal concessions—far more than the $500 million provided under AGIA. In addition, the Producers demanded numerous other concessions which would have required the state to relinquish a large portion of its sovereignty. There is no reason to expect BP and ConocoPhillips would not demand similar concessions if the state rejects the TC Alaska application. In addition, these objections to AGIA ignore the fact that the state will receive numerous benefits for the $500 million, including lower rates that more than offset the $500 million and enforceable commitments to move the project forward.

In sum, the TC Alaska Project will enhance the likelihood of success of an LNG "Y line" project. Facilitating a "Y line" may protect the state against future price changes in North American and LNG markets. The Producer Project, because of its undefined commercial terms, offers enormous risks and uncertain rewards to Alaska.

In sum, the TC Alaska Project will enhance the likelihood of success of an LNG "Y line" project. Facilitating a "Y line" may protect the state against future price changes in North American and LNG markets. The Producer Project, because of its undefined commercial terms, offers enormous risks and uncertain rewards to Alaska.

Summary of the Findings

- The TC Alaska Project is economically viable. At expected natural gas prices, the project will generate billions of dollars and substantial rewards for Alaskans, the Major North Slope Producers, the state and federal governments, and TC Alaska.
- TransCanada has a proven track record in pipeline design, construction, and operation and currently operates more than 36,000 miles of gas pipeline in North America. It has the financial resources to meet the challenge of financing this project.
- The TC Alaska Project plan is technically sound and feasible, and the project schedule is appropriately aggressive but reasonable.
- The extremely positive economics of TC Alaska's Project, combined with the legal and political context, provide favorable conditions for attracting shipping commitments for the project.
- Overall, the TC Alaska Project is likely to succeed.
- Exclusive LNG project options would most likely result in lower NPV to the state than the TC Alaska Project, would not easily accommodate expansions and the open access terms that would cause more long-term jobs to be added to the state's economy, and have a lower likelihood of success than the TC Alaska Project.
- A "Y-Line" addition to the TC Alaska Project is more likely to succeed than other LNG project options.
- The key for adding long-term jobs for Alaskans is a pipeline that encourages exploration and development of North Slope natural gas. The TC Alaska Project makes legally enforceable commitments that will result in such a pipeline.
- Alaskans need low-cost energy. This can be provided by an Alaskan gas pipeline project that has a low transportation cost (tariff), is committed to expansion to accommodate new found natural gas, provides access for natural gas off-take and spur lines in Alaska, ensures that natural gas delivered in Alaska only pays transportation costs for the mileage that the natural gas has traveled, and results in maximum revenue to the state and its citizens. The TC Alaska Project meets these objectives.

- The TC Alaska Project will not preclude construction of a smaller pipeline from the North Slope to Southcentral Alaska. Issuing a license to TC Alaska may increase the likelihood that plans for a “bullet line” or “spur line” will become reality.
- Similar to the failed SGDA contract, the Producer Project is not guaranteed to continue to advance the project to construction or even FERC certification and will likely require undefined concessions from the state. Similar to TAPS, the Producer Project will likely result in commercial terms that do not protect Alaska’s interests.
- The TC Alaska Project provides opportunities for significant Producer ownership. If the state determines that additional concessions are needed, they can be added to the TC Alaska Project to ensure that any concessions result in a pipeline that maximizes benefits for Alaskans.

Determination

The commissioners found TC Alaska’s application to be complete and in compliance with the AGIA statute and Request for Applications. Following an extensive evaluation process, the commissioners determine that the natural gas pipeline project from the North Slope to Canada proposed by TC Alaska is the project that will sufficiently maximize the benefits to the people of this state. The commissioners further determine that the TC Alaska Project merits the award of a license under AGIA. These Findings and Determination will be submitted to the presiding officers of each house of the Alaska Legislature for approval of the license.

The license will be issued to TC Alaska as soon as practicable after the effective date of a bill approving the license proposed by the commissioners. If a bill is not passed within 60 days of the date that the legislative presiding officers receive this Determination, the commissioners may not issue the proposed license and may request new applications.

This Executive Summary presents an overview of the Written Findings and Determination by the Commissioners of the Alaska Departments of Natural Resources and Revenue for issuance of a License under the Alaska Gasline Inducement Act (AGIA). It summarizes the commissioners’ process for evaluating TC Alaska’s proposed natural gas pipeline project and the commissioners’ determination as provided by AGIA. This Executive Summary is part of the commissioners Written Findings and Determination that is anticipated to be published on May 28, 2008. This document is a summary only, and is not the commissioners’ final determination under AGIA and is not a final agency action.

Chapter One — Introduction and AGIA

Table of Contents

A. Introduction 1-1
B. History of Alaska Natural Gas Pipeline Efforts 1-3
  1. The Stranded Gas Development Act 1-3
  2. Alaska Gasline Inducement Act 1-4
C. Summary of Projects 1-7
  1. The TC Alaska Application 1-7
  2. The LNG Project Options 1-7
  3. The Producer Project 1-7
  4. The Bullet Line 1-8
  5. LNG and an Overland Pipeline 1-8
D. Maximizing Benefits for Alaskans 1-9
  1. Getting a Natural Gas Pipeline, Quickly 1-10
  2. Jobs and Long-term Careers for Alaskans 1-12
  3. Affordable Energy for Alaskans 1-14
  4. Sufficiently Maximizing Revenues to the State and Its Citizens 1-16
E. Summary 1-19
F. References 1-20

A. Introduction

Alaska's North Slope is a world-class natural gas basin. Recent studies estimate that there are 224 trillion cubic feet (Tcf) of undiscovered, technically recoverable natural gas resources throughout the Alaskan Arctic. Of this amount, 137 Tcf are categorized as undiscovered, economically recoverable resources. These resources are in addition to the approximately 24.5 Tcf of natural gas reserves within Prudhoe Bay plus 9 Tcf of natural gas reserves discovered in other existing fields on the North Slope, including Point Thomson (USGS 2005; NETL 2007; Appendix O). Since the discovery of the Prudhoe Bay reserves, numerous entities have looked for ways to get gas to market. These efforts included state and federal laws designed to encourage gas pipeline construction, and millions spent on plans and studies by government sponsored authorities, North Slope oil and gas producers and various pipeline companies.

A natural gas pipeline from the North Slope could meet more than five percent of the United States' current annual consumption of natural gas for decades.

The drafters of the Alaska State Constitution recognized both Alaska's vast resource potential and the importance of resource exploitation. The State Constitution enshrined the principle that the state's resources be managed for the benefit of Alaskans through the following two provisions:

- It is the policy of the state to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest. (Constitution of the State of Alaska, Article VIII, Section 1)
- The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the state, including land and waters, for the maximum benefit of its people. (Constitution of the State of Alaska, Art. VIII, Sec. 2)

The Alaska State Constitution says it is essential for the future of Alaska that our state's vast natural gas resources be developed in a way that makes a lasting contribution to the state and its citizens and that maximizes benefits to Alaskans as envisioned by the state's founders.

The Alaska Gasline Inducement Act (AGIA) established an open and competitive process for developing a natural gas pipeline on terms that maximize benefits for the people of Alaska.

In 2007, the Alaska Gasline Inducement Act (AGIA) established an open and competitive process for developing a natural gas pipeline on terms that maximize benefits for the people of Alaska. Any pipeline will provide thousands of short-term construction jobs for Alaskans. But not just any pipeline will provide long-term jobs and careers, meet Alaska's energy needs, and sufficiently maximize state revenues with minimal state concessions. Getting a gas pipeline constructed is one element necessary to meet these needs—another is maximizing gas resource development in order to provide for a secure future that benefits Alaskans now and for generations.

B. History of Alaska Natural Gas Pipeline Efforts

For decades, Alaska has sought construction of a pipeline to develop and market the state's natural gas resources. In the 1970s, three proposals were considered for federal authorization: an "over the top" pipeline; an in-state liquefied natural gas (LNG) pipeline; and an overland route from the North Slope to Canada. The overland route was selected and a consortium of U.S. and Canadian pipeline companies began acquiring financial backing. The economics of the time thwarted the pipeline effort and by 1982 the project was indefinitely stalled (FERC 2001).

Starting in 1982, the state began taking a more active role in working toward a natural gas pipeline when then-Governor Hammond appointed a committee to guide the state efforts toward marketing North Slope gas. The committee examined an all-Alaska pipeline combined with an LNG terminal in Southcentral Alaska as the marketing point for the gas, known as the Trans-Alaska Gas System (TAGS). The Yukon Pacific Corporation acquired the pipeline right-of-way and other permits for the TAGS project but never moved forward with construction. Various other proposals for an Alaska-Canada overland pipeline and an all-Alaska LNG project have been put forward over the course of the past 20 plus years, but none resulted in construction of a gasline.

Alaska has sought construction of a pipeline to develop and market the state's natural gas resources for more than three decades.

1. The Stranded Gas Development Act

In 1998, the Stranded Gas Development Act (SGDA) was passed by the Alaska legislature, and amended in 2003. The Act provided the legal basis for developing a fiscal contract between the state and pipeline project sponsors. In 2004, five groups submitted pipeline proposals under the SGDA: BP, ConocoPhillips, and ExxonMobil (Major North Slope Producers or the Producers); TransCanada Corporation; Alaska Gasline Port Authority; Enbridge, Inc.; and MidAmerican Energy Holdings Company.

The previous administration decided that the fastest way to getting a pipeline was through a contract on resource production terms that provided "fiscal certainty" to the Producers.[1] (Alaska Department of Revenue 2006). The previous administration ultimately negotiated exclusively

[1] "Fiscal certainty" under the SGDA included "a commitment not to change the agreed upon rates for gas and oil severance or production taxes, corporate income tax, and property taxes, and to protect against imposition of other new taxes, such as a reserves tax, for the term of the contract." (Alaska Department of Revenue 2006, p. ES-5) The tax freeze on oil and gas was from 35 to 45 years.

with the Major North Slope Producers, resulting in public release of a draft fiscal contract with the Producers in May 2006.

The proposed SGDA contract consisted of an unbalanced set of state concessions and so-called Producer "commitments." The concessions made by the state under the contract were broad, material, long-term, and binding. They swept across fiscal and regulatory authorities and surrendered multiple aspects of the state's sovereign rights and prerogatives. Furthermore, the terms harmed and frustrated the state's interests in promoting the full exploration and development of natural gas resources in Alaska, limiting the potential for the creation of new exploration and development jobs on the North Slope. Nothing in the contract ensured development or construction of a gas pipeline.

In 1998, when the Stranded Gas Development Act (SGDA) was passed, the average price for natural gas in the Lower 48 was under $2 per million British thermal units (MMBtu). The first half of this decade was marked by discussions of what type and amount of government subsidies and concessions were needed to make the project viable. By 2006, the natural gas markets had changed dramatically. The average price of natural gas in the Lower 48 was more than $6 per MMBtu. Large government subsidies no longer appeared necessary to make the project economically viable. In addition, the state had become much better educated on natural gas pipeline economics. It learned that, if the state was not careful to protect its interests, billions of dollars in value could be transferred unnecessarily from the state to the Major North Slope Producers.

To accommodate the draft fiscal contract terms, the Alaska legislature would have needed to change the SGDA law as written. These changes were not passed by the legislature, and the negotiations between the state and the Major North Slope Producers ended in 2006, without approval of the proposed contract.

2. Alaska Gasline Inducement Act

In 2007, the Alaska Gasline Inducement Act (AGIA) was passed by the Alaska Legislature with a nearly unanimous vote. The purpose of AGIA is to encourage, through an open and transparent process, expedited construction of a natural gas pipeline that:

- Facilitates commercialization of North Slope gas resources in the state.
- Promotes exploration and development of oil and gas resources on the North Slope.
- Maximizes benefits to the people of the state from the development of oil and gas resources in the state.

- Encourages oil and gas lessees and other persons to commit to ship natural gas from the North Slope to a gas pipeline system for transportation to markets in this state or elsewhere. (AS 43.90.010)

In July 2007, the state issued a Request for Applications for a license to be issued under AGIA. Five applications for an AGIA license were received and submitted to a multi-step licensing process that included:

The net present value of the anticipated cash flow to the state, the project sponsor, and Major North Slope Producers were calculated to determine the overall economics of the project.

- An evaluation of the completeness of each application.
- Solicitation and review of public comment on each complete application.
- An evaluation of the net present value (NPV) of each complete application weighted by its likelihood of success (LOS).
- An evaluation of whether any complete application maximizes benefits to Alaskans.
- If an application maximizes benefits to Alaskans, provide public notice of and forward a Findings and Determination to the legislature of intent to award an AGIA license.

A detailed explanation of each of these steps can be found in Appendix C.

Only the TC Alaska Application was found complete. (A discussion of the process used to determine an application's completeness can be found in Appendix C.) Following the completeness evaluation, TC Alaska's proposed project was evaluated for the net present value of the anticipated cash flow to the state weighted by the likelihood of success for the proposed project.[2] (See Chapter Three) The net present value of the anticipated cash flow to the state, Major North Slope Producers, and the project sponsor were all calculated to determine the overall economics of the project.

Public comment on TC Alaska's complete Application was solicited and considered. Following the evaluation of the complete Application and consideration of public comment on the

[2] If more than one application were found to be complete, the NPV and LOS evaluation would have been used to determine which application ranked the highest and whether that project sufficiently maximizes benefits to Alaskans. (AS 43.90.170) If, as in this case, only one application was found complete, the evaluation was used to determine whether the proposed project maximizes benefits to Alaskans sufficiently to merit issuance of an AGIA license. (AS 43.90.180)

Application, the Commissioners of the Departments of Natural Resources and Revenue compared the TC Alaska Application with the Producer Project and LNG options and evaluated whether the TC Alaska project sufficiently maximizes the benefits to the people of Alaska and merits issuance of an AGIA license.

C. Summary of Projects

Comments on the TC Alaska Application identified pipeline project alternatives including:

- An export-oriented liquefied natural gas (LNG) project that would ship natural gas from the North Slope to a processing and shipping facility in Valdez.
- A producer-owned overland pipeline from the North Slope to Canada.

In order to fully evaluate whether TC Alaska's proposed project would provide the maximum benefit to Alaskans, the commissioners compared the TC Alaska project with LNG options and the Producer Project.

1. The TC Alaska Application

The TC Alaska Application proposes a 1,715-mile long, 48-inch diameter, mostly buried pipeline running from a gas treatment plant at Prudhoe Bay on the North Slope to the Alberta Hub in Canada. This is the second largest natural gas trading center in North America, which interconnects with pipelines that carry more than 10 Bcf/d of gas into U.S. markets. This overland pipeline's base design is capable of carrying between 3.5 and 5.9 billion cubic feet per day (Bcf/d) of natural gas. The gas treatment plant will be constructed by a third-party or by TC Alaska. The Alaska section of the pipeline will be approximately 750 miles long with six compressor stations at startup and five gas delivery points in Alaska. The Application includes an initial expansion capability of up to 6.5 Bcf/d. Further expansions would include a combination of additional compression and pipeline looping. (See Chapter Three)

2. The LNG Project Options

The commissioners evaluated the technical, commercial, and economic features of LNG options. These options were all based on a large-volume pipeline running from the North Slope to a new liquefaction facility located on Prince William Sound. The commissioners evaluated a number of pipeline configurations and throughput volumes to ensure that a comprehensive suite of LNG options were considered. (See Chapter Four)

3. The Producer Project

On April 8, 2008, BP Alaska and ConocoPhillips announced "Denali™ - The Alaska Gas Pipeline" project (the Producer Project), an overland pipeline from the North Slope to Alberta, Canada. At this point, the only public information provided is contained in a 12-page PowerPoint presentation and press release. The Producer Project recommends a 4 Bcf/d, large-diameter pipeline to the Alberta Hub, with extension of the pipeline to the Lower 48 if an extension is necessary. The project includes a gas treatment plant on the North Slope near the Prudhoe Bay facilities. The Denali™ PowerPoint presentation says that the project will support in-state gas distribution efforts and will provide at least five Alaskan natural gas delivery points, including one at Fairbanks (See Chapter Five).

4. The Bullet Line

During the public comment period, many Alaskans raised concerns and asked questions about a small-diameter "bullet line" natural gas pipeline running from the North Slope to Fairbanks (and then presumably to a terminus in Southcentral Alaska). This bullet line would be designed and operated to meet the energy needs of Alaskans along the railbelt.

The bullet line concept has been the subject of state review and evaluation in the recent past. In 2008, based on a request by the Governor, the Alaska legislature appropriated $4 million to the Alaska Natural Gas Development Authority to investigate in-state natural gas options. The AGIA legislation explicitly ensures that the state's pursuit of a high-volume, large-diameter, pipeline from the North Slope to markets outside Alaska will not interfere with parallel efforts to build a smaller-volume (500 million cubic feet per day or less), small-diameter, in-state energy-oriented pipeline. Development of the two are separate, and AGIA ensures that neither will be negatively impacted by the other; thus, a bullet line was not evaluated for inclusion in these Findings.

5. LNG and an Overland Pipeline

An overland pipeline to Alberta does not preclude an LNG project. TC Alaska has stated a willingness to offer gas treatment and pipeline transportation services to Delta Junction or Valdez in support of an LNG project, if a shipper requests such services. An overland pipeline and a pipeline delivering gas to an LNG facility are not mutually exclusive undertakings; there are economies of scale to be realized from a large-diameter overland pipeline that can make the economics of an LNG Y Line project more attractive. An overland pipeline project may facilitate the development of an LNG Y Line project within Alaska. (See Chapter Four)

An overland pipeline project may facilitate the development of an LNG Y Line project within Alaska.

D. Maximizing Benefits for Alaskans

The first goal for the state is getting a natural gas pipeline. The next goal is getting a pipeline that protects Alaska's interests. Taken together, the state's application requirements under AS 43.90.130, project development inducements under AS 43.90.110, .250-.260, 300-.330, and the project net present value and likelihood of success evaluation criteria under AS 43.90.170 effectively address protecting Alaskans' interests by encouraging a pipeline project that maximizes the following benefits:

- Getting a natural gas pipeline, quickly.
- Jobs and long-term careers for Alaskans.
- Affordable energy for Alaskans.
- Sufficiently maximizes revenue to the state and its citizens from development of its natural gas resources.

A pipeline that maximizes benefits to the state and Alaskans will:

- Be predictably expandable. Predictable capacity expansions are key to encouraging new exploration and development of Alaska's gas resources, which in turn will lead to new long-term jobs and careers for Alaskans, and opportunities for economic in-state use of North Slope gas.
- Offer effective open access and reasonable transportation rates to all Alaska gas producers in order to encourage continued exploration and development of Alaska's gas reserves and the generation of new long-term jobs and careers for Alaskans, and opportunities for economic in-state use of North Slope gas.
- Make commitments, to the maximum extent permitted by law, to provide job opportunities for Alaskans, so that the benefits of pipeline construction and operation and new jobs in exploration and development stay in Alaska rather than being shipped Outside.
- Commit to provide in-state natural gas delivery points and distance-sensitive transportation rates to help meet Alaskans' energy needs.
- Commit to take the necessary steps to develop a pipeline, including seeking the required approvals to construct the pipeline, so that the jobs and in-state energy benefits of the

right pipeline can be realized sooner, and so that the state can begin to receive revenue from the commercialization of its natural gas resources.

The commissioners, in their evaluation of the pipeline projects, have considered factors that assist in understanding whether and how each project will meet the needs of Alaskans and the state. These factors are explained below and examined in Chapters Three, Four, and Five.

1. Getting a Natural Gas Pipeline, Quickly

With more than 85% of the state's unrestricted revenue funded by oil production, continued oil production declines over the next decade may result in budget shortfalls that will have to be made up by (a) cutbacks in state services; (b) raising taxes or instituting new taxes; (c) use of Permanent Fund earnings or principle; or (d) a combination of the three. Given the robust economics of an Alaska gas pipeline project, the time to commercialize Alaska's natural gas resources is now.

An initial step to getting a pipeline project going is determining whether the project is economically viable and can obtain sufficient customer commitments and the necessary debt and equity financing for construction. Other early steps to be taken include an assessment of the technical viability of the project and consideration of the legal, regulatory, or other impediments to pipeline project development. Among other things, firm transportation commitments by producers or gas purchasers to ship gas on a pipeline are the basis for the financing of a pipeline project. Construction financing will also depend on the ability of a project proponent to finance the equity portion of the project.

Factor: The Project's Economic Viability from the Producers' Perspective, and the Producers' Likelihood to Make Firm Transportation Commitments to the Pipeline

Firm transportation commitments are an important basis for financing pipeline construction and a significant factor in determining a project's economic viability. For a pipeline from the North Slope, the three Major North Slope Producers will be the likely initial gas shippers as they hold the majority of gas reserves on the North Slope. To evaluate if the Producers are likely to make firm commitments to a pipeline, several questions must be answered, including:

- Does the pipeline project offer a significant enough return to the producers to encourage them to commit to ship gas on a pipeline? Answering this question requires an analysis of the likely cash flow and NPV that a project will generate for the Major North Slope Producers. There are a number of factors that can impact the return to the Producers, including the transportation rates offered by the pipeline. Chapter Three provides the result of this NPV calculation for the TC Alaska proposed project; Chapter Four provides the result for the LNG project options.

- Does the pipeline allow the Producers to ship gas to their preferred markets? An overland project generally calls for construction of a pipeline from Alaska's North Slope to the Alberta Hub; from Alberta, a project could use existing pipelines that transport gas to the Lower 48, or build a new one to markets farther south, such as Chicago. An LNG project would construct a pipeline from the North Slope to a processing and shipping facility, most likely in Valdez. From there, the product would be shipped via marine transport to Asian or West Coast markets. Chapter Three addresses the Alberta and North American markets, while Chapter Four addresses the markets in Asia.
- Are the Producers reasonably insulated from pipeline construction cost overruns, which would increase the tariff they pay for shipping gas on the line? Firm transportation commitments will be more attractive to producers if a project proponent offers risk sharing tariff terms that can reasonably insulate shippers from some of the impacts of pipeline construction cost overruns, and if the project proponent has a track record of controlling cost overruns. Chapter Three discusses these factors.
- Are there risks to the Producers if they decide not to make firm transportation commitments to an otherwise economic project? Among other things, these risks could include violations of oil and gas lease terms, or anti-trust and regulatory challenges. In addition, pressure from shareholders, Congress and the public to market the gas resource, particularly as oil and natural gas prices climb, may influence the Producers' decision whether to commit gas for shipping on a pipeline. These issues are addressed in Chapter Three.

Factor: The Technical Viability of the Project

Evaluating the technical viability of a project is an important step in the consideration of a pipeline project. Technical viability rests on, among other things, sound development, engineering/design, and construction plans and sufficient natural gas reserves to justify pipeline construction. The technical evaluations of the projects and options are evaluated in Chapters Three, Four and Five.

Factor: Holding a Binding Open Season

An important benchmark on the path to getting a pipeline built is preparing for and holding an initial binding open season. A binding open season is when gas shippers can commit to pay for space on the pipeline (that is, make firm transportation commitments). These firm commitments are used by the pipeline developer as the basis for obtaining credit support to fund construction activities. These issues are discussed in Chapters Three and Five.

A binding open season is when gas shippers can commit to pay for space on the pipeline (that is, make firm transportation commitments). These firm commitments are used by the pipeline developer as the basis for obtaining credit support to fund the pipeline project.

Factor: Applying for Regulatory Permits and Certifications

Another important benchmark to keep the project moving forward is the application for necessary federal, state, local, and (if applicable) provincial or federal Canadian permits and certifications. Obtaining these permits and certificates is necessary for the construction and operation of the proposed project. These topics are covered in Chapters Three through Five.

Factor: The Financial Strength of the Project Proponent

The project proponents will be required to obtain financing for the project. This includes raising equity and securing debt. Financing issues are analyzed in Chapters Three through Five.

Factor: Legal and Regulatory Challenges and Other Hurdles

Legal and regulatory considerations will be faced by any project proponent. The complexity of these challenges depends on the type of pipeline and the pipeline route. An overland pipeline will face state and federal permitting hurdles in Alaska, as well as regulatory and First Nation hurdles in Canada. An LNG project will face similar state and federal permitting challenges and will encounter additional regulatory hurdles in the form of an export license should a project target Asian markets, and Jones Act limitations should a project target markets in the continental United States or Hawaii. These topics are discussed in Chapters Three through Five.

2. Jobs and Long-term Careers for Alaskans

Alaska's economic history has, to date, been one of boom and bust. Economic spikes centered around the fur trade, gold rushes, and then oil development have shaped the politics, society, and economy of Alaska. A natural gas pipeline construction project will represent the largest boom to Alaska's economy since construction of the Trans-Alaska Pipeline System (TAPS) in the 1970s.

Pipeline construction will generate thousands of jobs for a limited period of time. By working to ensure that an effective open access pipeline is built from the North Slope to market, the AGIA process will: create a more competitive gas basin on the North Slope, which will more quickly lead to the creation of the long-term, high-wage jobs that are important to the state's economy; will sufficiently maximize revenues that when spent will generate additional long-term jobs in other sectors of the Alaska economy; and will ensure that local workers and businesses benefit from the construction and operation of a new natural gas pipeline.

Factor: Create a More Competitive Gas Basin

A competitive gas basin will create an environment where all explorers and developers, from the individual wildcatter to the major international corporation, will be encouraged to explore and invest in the development of the state's natural gas resources. A competitive basin also will more quickly create the long-term jobs and careers that Alaskans want.

> A competitive gas basin on the North Slope will more quickly lead to the creation of the long-term, high-wage jobs that are important to the state's economy.

A pipeline that can be expanded to ship new natural gas as it is found and developed, and that offers reasonable transportation rates for all shippers so that the economics of transporting newly-found gas to market are attractive, will create this more competitive natural gas basin.

Factor: Maximize Revenue to the State and Create Long-term Jobs Throughout the Economy

An open, competitive natural gas basin will generate significant new revenue streams for the state that can lead to the creation of further long-term employment opportunities.

The expenditure of state tax revenues and royalty revenue earned from the production of the state's natural gas resources will generate additional, non-natural gas related long-term jobs in the state. Direct, indirect, and induced jobs will be generated as state revenue from gas sales and gas production is spent to fund government services and capital projects around the state.

Further, by obtaining sufficient revenues from oil and gas development, the state can shield other sectors from a tax burden to further foster economic expansion.

The revenue that the state will receive from natural gas production will be directly influenced by the wellhead price (or net back price) of natural gas and the volume of natural gas produced. The higher the net back price, the higher the state's income, which in turn equates to greater numbers of long-term direct, indirect, and induced jobs created throughout the Alaska economy. These revenues will also bolster Alaska's Permanent Fund, which creates employment throughout the economy as a result of paying dividends to Alaskans.

The revenue that the state will receive from natural gas production will be directly influenced by the wellhead price (or net back price) of natural gas and the volume of natural gas produced.

Factor: Maximizing the Employment Opportunities for Alaskans

A commitment by a pipeline proponent to establish an Alaska headquarters, hire Alaskans, and utilize Alaska businesses to the maximum extent permitted by law, will ensure that Alaskans have the opportunity to obtain local pipeline development and construction jobs. In addition, training Alaskans for pipeline-related jobs should begin as early as possible so that Alaskans have the job skills that will be required during construction.[3]

3. Affordable Energy for Alaskans

Ever-rising fuel prices are increasing hardships for Alaska communities and families, and there is no single solution to ease this energy crunch. However, in-state supply of North Slope natural gas could help reduce energy costs in some regions of the state and allow for the development of value-added petrochemical industries within Alaska.

Natural gas is currently used in only limited locations within the state. The majority of current non-oil field consumption of natural gas occurs in Southcentral Alaska, where natural gas from the Cook Inlet Basin is used for heat and cooking, to generate electricity, and in industrial facilities. Very little

> To meet the energy needs of Alaskans, a pipeline project must be designed to include in-state delivery points and to offer economic distance-sensitive tariffs for delivery of gas within Alaska.

[3] The State of Alaska has already begun efforts to prepare an Alaska workforce for pipeline jobs. The Department of Labor and Workforce Development's AGIA Strategic Training Plan is available at http://www.labor.state.ak.us/AGIA_teams/docs-combined/agiaweb.pdf

natural gas is used elsewhere in Alaska due to a lack of transportation infrastructure and a lack of local supply. A National Energy Technology Laboratory report released in 2006 indicates that natural gas demand from both residential and business consumers will be strong after North Slope gas becomes available (NETL 2006).

In rural areas, the high cost of energy hampers economic development. While the low population density of rural Alaska and the long distances between populated areas make construction of an in-state natural gas distribution system economically infeasible, there are technologically feasible means of supplying rural Alaska with natural gas or gas products. One such concept is the stripping of propane from North Slope natural gas, containerizing it, and then trucking or barging it to communities located off the pipeline route.

A natural gas pipeline from the North Slope will be designed to primarily export natural gas from Alaska. Consequently, in order to implement one of the fundamental tenets of AGIA (providing North Slope gas directly to Alaskans), a pipeline project must be designed to include in-state delivery points and to offer economic distance-sensitive tariffs for delivery of gas within Alaska.

Factor: In-state Delivery Points

In-state delivery points are akin to freeway off-ramps—they are a collection of valves and piping that allow natural gas to be removed from one pipeline and transferred into another pipeline for transport and delivery.

An ideal natural gas pipeline project would provide delivery points in locations that can best serve the energy needs of Alaskans, including rural Alaska. AGIA requires this.

Factor: Economic In-state, Distance-sensitive Tariffs

Providing in-state delivery points and sufficient quantities of natural gas to meet in-state needs are but two components of meeting the in-state energy needs of Alaskans. The other factor to consider is whether a project will transport natural gas to those delivery points at a transportation rate that is reasonable and affordable.

> Alaskans would pay a distance-sensitive tariff, meaning natural gas shipped within Alaska will be cheaper than natural gas shipped to the Lower 48.

Establishing an in-state, distance-sensitive tariff is one means that a pipeline operator may employ to ensure that natural gas is available to Alaskans at affordable and reasonable rates. A distance-sensitive tariff is a transportation rate under which local consumers (Alaskans) would pay only for the cost of shipping natural gas from the North Slope to the in-state delivery point. If a distance-sensitive tariff was not used, local consumers could pay the same amount for shipping as consumers at the end of the pipeline in Alberta. AGIA requires distance-sensitive tariffs.

Factor: Expansion Provisions

Expansion of the pipeline provides additional opportunities for in-state consumers to access affordable North Slope gas. Because effective open access and low tariff provisions promote gas exploration and development, Alaskans will benefit from an environment in which companies compete to meet Alaskans' energy needs.

4. Sufficiently Maximizing Revenues to the State and Its Citizens

Alaska owns its oil and gas natural resources. Through leases, the state gives companies the right to produce, and profit from, the state's oil and gas. As an owner, the state is entitled to a percentage of the oil and gas produced on the leases—its "royalty" share. As a sovereign, the state also taxes the profit on production. Maximizing these revenues over the long term will ensure that future generations of Alaskans benefit from the state's finite natural gas resources.

The proposed project's net present value of the anticipated cash flow to the state is a factor in determining whether a natural gas pipeline project maximizes revenues to the state. Under AGIA, the net present value evaluation considers:

- How quickly the applicant proposes to begin construction of the proposed project and how quickly the project will commence commercial operations.
- The net back value of the gas and estimated transportation costs (tariffs) and treatment costs.
- The applicant's ability to prevent or reduce project cost overruns that would increase the tariff.
- The initial design capacity of the project and the extent to which it can accommodate low-cost expansion.
- The amount of the reimbursement by the state that the applicant has proposed.

- Other factors found by the commissioners to be relevant to the evaluation of the net present value of the anticipated cash flow to the state (AS 43.90.170(b)).

While the state does not control how much revenue it will receive from commercialization of its natural gas resources, it can influence when and how natural gas is produced by ensuring a pipeline is open and expandable, and can influence cost factors such as tariffs.

Factor: Minimizing Tariffs

> A high tariff will lower the state's royalty and tax revenue.

Pipeline tariffs are the amount that a pipeline owner charges shippers to transport gas through a pipeline. Tariffs are deducted from the market price of natural gas before the state's royalty amount and production tax is calculated. Thus, a high tariff will serve to lower the state's royalty and tax revenue. Transportation rates can be reduced through specific measures including using a higher debt/equity ratio for ratemaking purposes, preventing and managing cost overruns, and utilizing specific tariff types to minimize the charges to shippers.

↓ tariffs = ↑ net back value = ↑ state revenues

Factor: Decreasing the Equity in the Debt/Equity Ratio

A capital structure with a higher debt/equity ratio can drastically reduce pipeline tariffs because the lesser the amount of equity in the capital structure, the lower will be the pipeline's transportation rate. This is because equity is a much more expensive means of financing a pipeline than debt. The Federal Energy Regulatory Commission (FERC) allows a return on equity for a new pipeline of approximately 13% to 14%, whereas debt can be financed at current rates of interest at approximately 7% to 8%. Consequently, the higher the amount of debt financing, the lower the tariff. Low tariffs lead to higher net back values for natural gas at the wellhead—the higher the net back, the greater the value of the state's royalty natural gas.

↑ debt/equity ratio = ↓ tariff = ↑ net back value = ↑ state revenues

Factor: Minimizing Cost Overruns

Preventing and managing project cost overruns will maximize the value of a pipeline project to Alaskans. Cost overruns raise the capital cost of the project, which in turn raise the tariff, and lower the net back value of the natural gas shipped through the pipeline system.

$$\downarrow \text{cost overruns} = \downarrow \text{tariff} = \uparrow \text{net back value} = \uparrow \text{state revenues}$$

E. Summary

Alaskans have high and reasonable expectations from a natural gas pipeline. They want long-term jobs and careers; they want access to economic natural gas from the North Slope to alleviate high energy prices; they want to see the state maximize the revenue from the production of its natural gas resources; they want to avoid giving unnecessary concessions to get a pipeline built or to get producers to commit to ship the state's natural gas; and they want to avoid the delays and false starts that have plagued natural gas pipeline projects for more than 30 years.

These expectations guided the commissioners' evaluation; the factors described above in Sections D.1 through D.4 are among those that the commissioners used to develop their Findings and Determination.

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Chapter Two — Technical Background

Table of Contents

A. Natural Gas Primer 2-1
1. Natural Gas Markets 2-1
2. LNG Basics 2-3
3. History of LNG 2-3
4. Asian Gas Quality Demands 2-4

B. Pipeline Primer 2-5
1. Natural Gas Pipeline Project Development 2-5
2. Project Analysis 2-6
3. Pipeline Regulation 2-7
4. The Alaska Natural Gas Pipeline Act and Impacts on the Regulation of an Alaska Natural Gas Pipeline 2-9
5. Alaska's Natural Gas Resources 2-10

C. Analysis Team 2-11

D. References 2-14

Figures

Figure 2-1: Pipeline Flow 2-2
Figure 2-2: Natural Gas Production 2-2
Figure 2-3: Potential LNG Trading Routes from Alaska 2-4

Tables

Table 2-1: Contractor Expertise 2-11

A. Natural Gas Primer

Natural gas is a general term applied to a mixture of combustible hydrocarbon gases that are produced from both natural gas wells and from oil wells. When natural gas flows out of a reservoir, it may contain a combination of methane, butane, propane, ethane, carbon dioxide (CO_2), hydrogen sulfide (H_2S), water vapor (H_2O), and other compounds. Natural gas that contains significant portions of heavier hydrocarbons like butane, propane, and ethane is referred to as "wet gas;" natural gas that is mostly methane is called "dry gas." Much of the natural gas in the Prudhoe Bay reservoir is wet gas, but there are significant accumulations of dry gas on the North Slope as well.

To prepare natural gas for delivery to market in a high pressure pipeline, natural gas must often be processed or treated. In this process, such as would occur in a gas treatment plant (GTP), water is removed from the natural gas stream to prevent pipeline corrosion, and the non-commercial gases, carbon dioxide, and hydrogen sulfide are removed and sometimes reinjected back into the geologic formation to maintain reservoir pressures.

The ethane, propane and butanes in wet gas are known as natural gas liquids (NGLs). These may be removed from the gas stream in a process sometimes known as "stripping" or "extraction" at a Processing or Straddle Plant. Natural gas liquids may be used as a feedstock for petrochemical manufacture, and can also be liquefied and used by consumers. One of the liquefied components—propane—is used in many rural villages for heating. After removing NGLs, the remaining natural gas will now be "dry gas," containing mostly methane. This is the natural gas that is piped into homes and businesses. Figures 2-1 and 2-2 are schematics of the components and processes found in a generic natural gas production system.

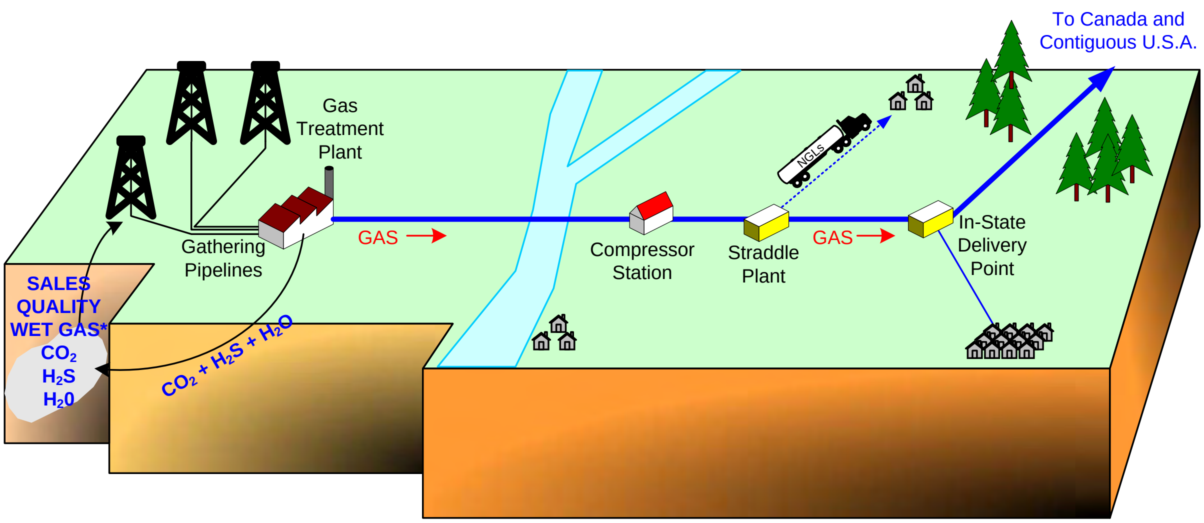
1. Natural Gas Markets

In North America, a common pricing point for natural gas prices is the Henry Hub near Erath, Louisiana. This is also the physical location employed by the New York Mercantile Exchange or NYMEX for settling futures contracts when those transactions result in physical delivery rather than simply clearing on the exchange. In Canada, a common pricing point for natural gas is in Alberta at the AECO Hub. Most of the demand for natural gas in the North American (United

> The Alaska Gasline Inducement Act (AGIA) established an open and competitive process for developing a natural gas pipeline on terms that maximize benefits for the people of Alaska.

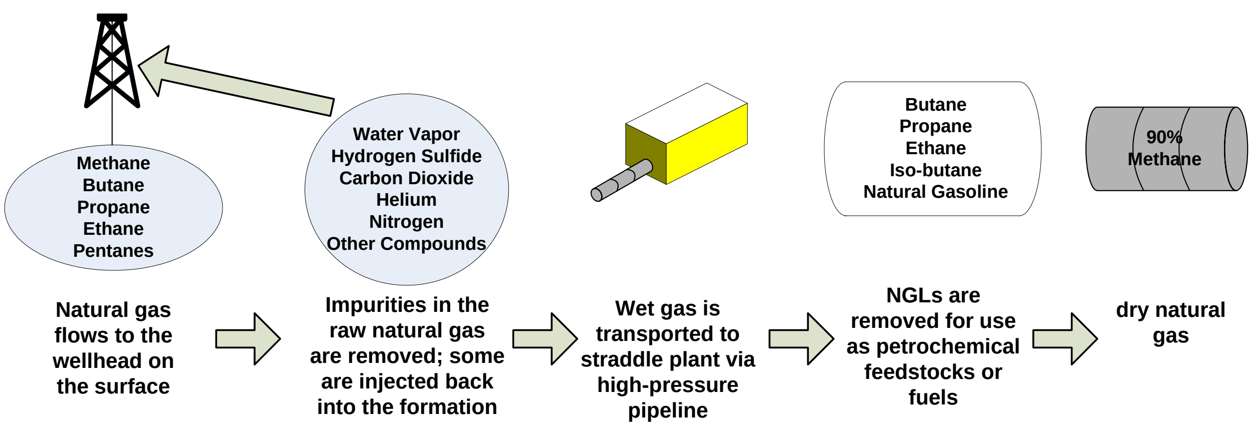
States and Canada) market is met by domestic production. More than 80% of the natural gas imported by the United States has come from Canada (EIA 2008a). Longstanding treaties between the United States and Canada prohibit discriminatory treatment and allow for a transparent trade of gas between the two countries.[1]

Figure 2-1: Pipeline Flow



*Sales Quality Gas = Wet Gas (methane, butane, propane, ethane, pentanes)

Figure 2-2: Natural Gas Production



[1] United States Secretary of State and the Government of Canada. 1977. Agreement on Principles Applicable to a Northern Natural Gas Pipeline (with annexes).

2. LNG Basics

In areas of the world that must import their energy and that cannot be reached by an overland pipeline from oil and gas producing areas, marine transportation supplies their energy. Natural gas moved in this way is shipped via tankers as Liquefied Natural Gas (LNG). For LNG to be transported economically in tankers, compressed gas from the pipeline system must be purified and super-cooled until it condenses into a liquid at roughly -260°F. This energy-intensive process, called liquefaction, takes place in processing equipment called "trains." A LNG train is a complete processing unit that turns natural gas into a liquid. The “train” consists of a collection of sub-units and equipment that cleans, compresses and cools natural gas into a liquid. A LNG plant consists of one or more “trains” plus support facilities such as utilities, storage tanks and jetties. LNG tankers keep the gas in this super-cooled state during transport using built-in refrigeration systems. When the ships arrive at the receiving terminal, a “re-gasification” facility must be available to heat the LNG back to natural gas so that it can be transported via pipeline.

LNG plants are large, complex processing facilities. Because of the demands that constructing such a facility in Alaska would put on the global construction infrastructure, it would be installed in sections, with each section beginning to produce LNG for export after it is installed and commissioned for service. Thus, LNG production would ‘ramp up’ to its full capacity over a period of time depending on the configuration of the facility and the number of “trains.”

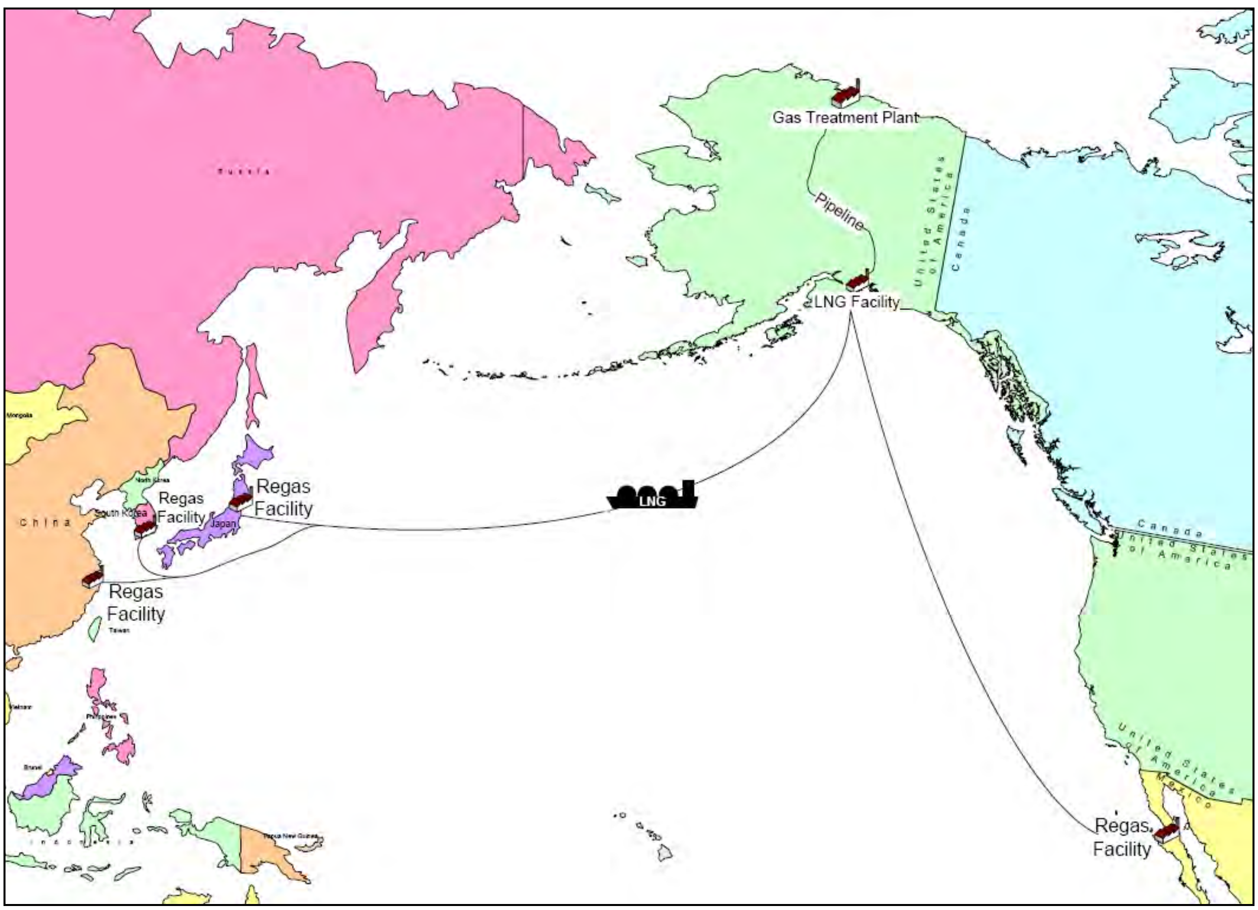
3. History of LNG

The first regular LNG bulk trade started in 1964 between Algeria and the United Kingdom, and the first Pacific trade was started in 1969 between Kenai and Tokyo (Tussing 2005). The LNG trade has grown considerably over recent decades due in large part to demand in Asian energy markets. Because countries like Japan, Taiwan and South Korea produce very little domestic gas, they are heavily dependent on steady supplies of foreign gas imports. These countries are thus often more concerned about security of supply than price. In Asia, prices have traditionally been set using formulas that link the price paid for natural gas to the price paid for crude oil. These price formulas are set at the time of the initial long-term sale in response to market conditions at the time, and are reviewed periodically. As a result, there is no single market price for LNG in Asia. When the market moves quickly from surplus to shortage, as it has done in recent years, large price differentials between different contracts occur (Appendix I, Section 4.5).

4. Asian Gas Quality Demands

The specifications for LNG sold to Asian markets differ from LNG sold to the USA and Europe, primarily because of the Asian market need for richer (higher Btu) gas. The reason for this stems from differences in design between gas-distribution systems. Gas burners—particularly those in home appliances—can only handle a limited range of gas quality safely. Gas burners in one region will be designed for different types of gas than gas burners in another region, depending on the predominant gas type in that region. Asian markets were developed around the use of relatively wet (energy-rich) LNG and cannot easily use the drier gas sold to U.S. and European markets (Appendix I, Section 4.4). Therefore, LNG from Alaska being sold to the Asian market would need to meet their higher gas quality (higher Btu) requirements.

Figure 2-3: Potential LNG Trading Routes from Alaska



B. Pipeline Primer

1. Natural Gas Pipeline Project Development

Any supply-driven gas pipeline project begins with the natural gas resource - how much natural gas is available, where do the producers want to market the natural gas, and what is the best way to get the gas to market?

Any supply-driven project—be it an overland pipeline or an LNG project—will progress through similar groundwork and permitting activities, including:

- Starting preliminary work with regulatory bodies.
- Communicating with potential customers to assess interest.
- Determining project destination and scope.
- Conducting preliminary design, engineering and field work.
- Designing commercial terms and tariff structure(s) in preparation for a binding “open season.”

Early pipeline development efforts focus on generating a detailed and comprehensive plan for the project in preparation for holding an open season. An open season is an event during which a pipeline project sponsor offers terms to potential shippers who seek to reserve capacity in a pipeline. Shippers can include gas producers, utilities, and end users. In North American markets, open seasons help determine the need for new pipeline capacity.

Open seasons can be either binding or non-binding. Non-binding open seasons are held early in a project’s development to gauge potential interest. In contrast, in a binding open season, bids are contractually binding once they are accepted by the project sponsor. A binding bid will generally specify a date by which the parties must enter into a “precedent agreement” and, ultimately, a contract reserving capacity on the pipeline. These contracts are called “Firm Transportation Commitments,” “FTs” or “Ship or Pay Contracts.” The precedent agreement contains the terms and provisions describing the price of the capacity, volume of capacity reserved, and length of the contract.

A “successful” open season is one in which enough potential shippers commit to enter into firm transportation contracts to enable the project to obtain financing. By contrast, an “unsuccessful” open season is one in which the sponsors fail to obtain sufficient commitments for capacity for the project to move forward to detailed design, engineering, and construction. An unsuccessful open season does not necessarily equate to a failed project. Rather it demonstrates the market is unable or unwilling at that time to accept the proposed terms. In this case, negotiations will likely continue in the future to seek a common, mutually beneficial agreement.

There are no restrictions on the number of open seasons that can be conducted for any particular project. In the Lower 48, it is not uncommon for sponsors proposing new pipeline capacity to hold two or more open seasons before the proposed project's design and shipping terms are fully coordinated with the interests of potential shippers.

LNG projects and overland pipeline projects are developed and financed differently. Because the largest markets for LNG cannot meet their natural gas demands with domestic supplies, LNG buyers are often very concerned about the volume and security of supply. Virtually all LNG projects are vertically integrated and contain structured, long-term commercial commitments between the producers (sellers) and consumers (buyers) of LNG (see Appendix I for greater detail on the workings of the LNG market and the structure of LNG projects). In contrast, overland pipelines in North America are typically part of a network that can easily move gas from one market to another, allowing project stakeholders to take additional risks. Financing for overland pipeline projects generally depends on the credit-worthiness of the gas shippers or those making the firm transportation commitments, rather than a review of the complex financial and commercial relationships included in a LNG project.

2. Project Analysis

The analysis of a proposed project leading up to and following an open season is varied and complex. The pipeline project sponsor must establish reasonable confidence in a project's technical, commercial, and financial viability to encourage gas shippers to make long-term binding shipping commitments.

A technical viability analysis determines if the project can be permitted, engineered and constructed, and estimates the capital costs and schedule for completion. The commercial evaluation determines if there is a downstream market into which gas can be sold, and the economics of transporting and selling gas to the market over the life of the pipeline and its contracts. The financial review evaluates the economics of the project to determine if the project proponent has sufficient financial resources and bonding capacity to finance the project.

Because each type of analysis depends on information from the others, they must be advanced in parallel.

The technical development of a pipeline project includes conducting the necessary engineering and environmental studies, obtaining all regulatory permits, and estimating the costs and schedule. There are a multitude of components involved in the evaluation, such as pipe size, pipe specification, compressor stations, availability and price of steel, and labor costs. Each of these factors affect cost estimates for the project, which in turn impact the project's various commercial components. Thorough commercial analysis is complex in that it attempts to quantify a project's total value after considering any potential risk factors. Two common methods of quantifying a project's value are the calculation of Net Present Value (NPV) and Internal Rate of Return (IRR).

Net Present Value is an economic calculation used to appraise and compare the financial value of long-term projects. An NPV calculation figures the present value of an investment that may generate returns for many years. It measures the profits (or losses) that a project will produce over time in today's money. Because NPV is expressed in the common term of today's money, it can be used to compare the relative benefits of several competing projects.

IRR is a capital budgeting metric used by firms to decide whether they should make a given investment. IRR is an indicator of the efficiency of an investment; it is a calculation of the earnings or "cash flow yield" a firm could expect to realize on an investment.

3. Pipeline Regulation

Gas pipelines are regulated by different agencies depending on where they begin and end. Transportation of gas within the State of Alaska (intrastate) is regulated by the Regulatory Commission of Alaska, while transport between states (interstate) is regulated by the Federal Energy Regulatory Commission (FERC). The FERC's counterpart in Canada is the National Energy Board (FERC 2001).

Under both Regulatory Commission of Alaska and FERC jurisdiction, any gas pipeline project sponsor must first obtain a Certificate of Public Convenience and Necessity (CPCN). A CPCN is the primary certification issued by the regulatory agency which verifies that the project sponsor is able to construct and operate a gas pipeline, and that the project is in the best interest of the public.

In filing for a CPCN, the pipeline project sponsor provides the required details of the proposed gas pipeline and sets forth its proposed rates and all of the other terms and conditions of service. The rate and terms of service materials are contained in a document known as the pipeline company's "tariff." (Frequently, though, the term "tariff" refers to the rates to be charged for particular services.)

FERC review of the sponsor's application for a CPCN includes a review of the environmental aspects of the project. This is one of the most time consuming aspects of the regulatory process. To expedite the certification process, FERC has established a "pre-filing" process to allow the environmental work to start even before the certificate application is filed (FERC 2008). During the "pre-filing" process the FERC staff works with the project sponsor and interested parties to establish the scope of the necessary environmental review and may select an independent contractor to perform the environmental review.

FERC also reviews the design of the project, the route, the proposed rates and any other aspects that interested parties identify in their filings with the agency. In a project that involves a new pipeline such as an Alaska natural gas pipeline project, the FERC will review and set the initial tariff for the project during the CPCN proceeding.

Under the Natural Gas Act and FERC regulations, rates have to be "just and reasonable." This generally means that the rates are based on the actual or projected costs of the project and earn a reasonable return on the company's investment. Rates set in this manner are referred to as "recourse rates" and any shipper (or potential shipper) has the right to obtain capacity and service on the pipeline at those recourse rates if there is available capacity on the pipeline.

Because pipelines receive a regulated rate of return, how much of the pipeline construction is financed with debt and how much with equity is significant to potential shippers. A rate of return between 11% and 14% plus an allowance for applicable income taxes is typically allowed on portions of the project that are equity-financed, while the borrowed interest rate (which is typically lower that the rate of return on equity) is allowed on portions of the project that are debt-financed. As a result, the ratio of debt to equity financing for a project has a large impact on the final tariff: more debt lowers the tariff, while more equity raises it.

FERC rules also allow for "negotiated rates." Negotiated rates on new pipeline projects are often lower than the recourse rates for several reasons. First, the recourse rates that are set in the CPCN are based on initial projected costs, not actual costs, so the sponsor will typically estimate costs on the high rather than the low side. Second, negotiated rates frequently involve innovative concepts such as “levelized” rates or “term-differentiated” rates.

Levelized rates are established for long periods of time and are lower in the early years and higher in the later years than would be achieved through conventional rate making. Levelization is accomplished by deferring recovery of depreciation expenses by the pipeline company from the early years to the later years. Term-differentiated rates fluctuate according to the duration of the transportation contract: rates are generally higher for shorter term contracts and lower for longer term contracts. This reflects the fact that the sponsor has more time to recover its initial investment (and associated returns) and has less risk of not being able to sell capacity when it has long term contracts than when it is under short term contracts. This translates into a somewhat lower rate for longer term contracts. Most recent pipeline projects in the Lower 48 are fully or mostly subscribed under negotiated rather than recourse rates. (For more information on rates, see Appendix G1, Section 3.7.)

4. The Alaska Natural Gas Pipeline Act and Impacts on the Regulation of an Alaska Natural Gas Pipeline

Failed construction efforts over the past decades have inspired a number of laws and regulations which will apply to an Alaska natural gas pipeline project.

Congress enacted the Alaska Natural Gas Pipeline Act (ANGPA) in 2004. ANGPA created a clear and expedited process for acting upon a pipeline certificate application, provided FERC with limited authority to require expansions, created a central coordinator for the issuance by other federal agencies of permits necessary for a pipeline, prohibited an “Over-the-Top” route from Prudhoe Bay through the Beaufort Sea to Canada’s Mackenzie River delta, confirmed the jurisdiction of the Regulatory Commission of Alaska over an in-state lateral pipeline, gave the state specific rights with respect to the shipment of royalty gas for in-state needs, and authorized a Federal Loan Guarantee of up to $18 billion (escalating with inflation) for an Alaska gas pipeline project that serves the North American market. To help expedite the review process, ANGPA included a provision requiring the FERC to presume a need for the project and to presume that there will be adequate downstream capacity to move Alaskan gas to markets (ANGPA 2004).

Inclusion of the Federal Loan Guarantee stemmed from widespread concerns over the estimated project cost and difficulties that previous project sponsors had encountered with financing. The additional assurance that the loan guarantees provide to potential lenders should allow the project sponsor to borrow at a lower interest rate, thus improving the project's economics and lowering the transportation rate.

Decisions from the FERC are always subject to review by the Federal courts. However, ANGPA also dictates that any appeal from FERC orders relating to the Alaskan project can only be appealed to the U.S. Court of Appeals for the District of Columbia Circuit and also mandates that the court must expedite its actions on appeals related to the Alaskan gas pipeline (ANGPA 2004).

5. Alaska's Natural Gas Resources

Alaskan natural gas is a largely untapped U.S. energy resource. Until recently, no exploration expressly targeting natural gas had taken place on the North Slope. Existing gas resources have been discovered as a byproduct of the search for oil. Natural gas produced with oil is used either as fuel in oil production facilities or is compressed and injected back into the reservoirs to enhance oil recovery.

Recent studies estimate that there are 224 trillion cubic feet (Tcf) of undiscovered, technically recoverable resources throughout the Alaskan Arctic. These are natural gas resources that may be technically and physically recovered independent of price. Of this amount, 137 Tcf are categorized as undiscovered, "economically recoverable" resources (USGS 2005; NETL 2007). Economically recoverable resources are sensitive to both price and technology; an increase in price or an improvement in technology would be expected to increase these estimates. In addition to these resource estimates are roughly 24.5 Tcf of natural gas reserves known to exist within Prudhoe Bay, plus 9 Tcf of natural gas reserves discovered in other existing fields on the North Slope, including Point Thomson.[2]

[2] To understand the magnitude of these resources, the volumes can be compared to the annual total consumption by commercial and residential users in the United States of 23 Tcf. (EIA 2008b)

C. Analysis Team

A 1,715 mile natural gas pipeline as proposed by TC Alaska from the North Slope to the border between the Canadian Provinces of British Columbia and Alberta, would be one of the largest and costliest projects ever constructed in the world. AGIA Statute AS 43.90.170 requires the commissioners to analyze technical, commercial, and financial and hydrocarbon reserves supporting or related to the Project. The commissioners assembled a team of experts to help analyze the NPV and likelihood of success (LOS) in support of the commissioners' determination of whether the TC Alaska Application sufficiently maximizes benefits for the state and its people and is the right project for Alaska. Key contractors and their expertise are provided in Table 2-1 below; a list of all contractors and their respective resumes are provided in Appendix E.

Table 2-1: Contractor Expertise

FIRM	EXPERTISE
AMEC-Paragon, Inc. (AMEC)	Leading provider of services and engineering solutions to the world's infrastructure, manufacturing and process industries. AMEC assisted in cost estimating for the pipeline portions of the project in both Alaska and Canada, hydraulic flow modeling of the proposed facilities, and historical analysis of capital cost escalation for pipeline projects.
Bennett Jones	Internationally recognized Canadian law firm with long-standing practice in oil and gas industry, mergers and acquisitions, foreign exploration and international investment coupled with evolving regulatory legislation, stakeholder community, commercial matters, and strategic advice on export and commodity tax compliance matters. Bennett Jones has extensive experience negotiating joint ventures and resource development agreements for native reserve and treaty lands, counseling governments and proponents on engineering, procurement and construction contracts, and representing industry participants on surface rights acquisition matters for wells, facilities and pipelines. Bennett Jones provided legal expertise including Canadian regulatory, First Nations and environmental considerations for natural gas pipeline critical path analysis.
Black & Veatch, Lukens Energy Group Enterprise Management Solutions	With more than 80 years of experience in oil and gas engineering design and commercial analysis, Black and Veatch led the commercial analysis that included development of the NPV model and commercial analysis of the likelihood of success.

FIRM	EXPERTISE
Brown, Williams, Moorhead & Quinn, Inc. (BWMQ)	Leading energy consulting firm that provides comprehensive energy related services to hundreds of clients, including natural gas and oil pipeline companies, local distribution companies, energy producers, shippers and federal and state agencies. BWMQ provided advice on how to properly interpret and account for FERC precedents and current policies in the natural gas pipeline industry.
Energy Capital Advisors	Has provided clients with a wide array of financial services throughout the international energy spectrum, with an emphasis on petroleum ventures. Energy Capital Advisors supplied commercial oversight and assisted in coordinating efforts between commercial and technical groups.
Energy Project Consultants LLC	More than 40 years of experience in pipeline design and construction. EPC directed the Technical Team and provided expertise in engineering, costs and scheduling of pipeline systems for the U.S. pipeline segment analysis.
Gaffney, Cline and Associates	International energy consulting firm that has been providing clients with value added, commercially viable results for over 40 years. Provided cost information for the Black and Veatch model of the GTP and other economic aspects of the proposed TC Alaska Project. Provided economic and fiscal system expertise for the analysis.
Gas Strategies	Experts that provide advice and data on strategic energy matters for commercial and governmental clients around the globe. These leaders in the industry analyzed the path of natural gas and LNG from supply source to market and specialize in: evaluation and feasibility, demand and pricing analysis, commercial due diligence, and market regulation, restructuring, liberalization and competition.
Goldman Sachs	Leading global investment management, banking and securities firm that provided the financial analysis of the TransCanada co-applicants, TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd., in terms of their financial capabilities to obtain financing for the Project as well as evaluating the firms' likelihood of financial success.
Greenberg Traurig	One of the largest law firms in the U.S. that has expertise representing electric power generators, natural gas pipeline companies and other industry participants before the FERC, SEC and other federal agencies in a wide range of regulatory matters. Greenberg Traurig's Energy and Natural Resources practice group provided advice on legal aspects of the proposed Project.

FIRM	EXPERTISE
Heenan Blaikie, LLC	Internationally recognized Canadian law firm provides a full range of legal services to some of Canada's largest oil and gas producers and emerging companies. Its regulatory lawyers have acted for both government and industry in numerous applications before the National Energy Board and provincial regulatory bodies and the courts. Heenan Blaikie has extensive experience in major inter-provincial and international pipeline and power line facilities, tolls and tariff applications, and representing power producers, marketers and consumer groups on jurisdictional, commercial, environmental and First Nations issues. Heenan Blaikie provided consultation on Canadian federal, provincial and First-Nation issues.
Merlin Associates	Merlin Associates is a leading technical and engineering consulting organization offering specialized expertise in oil and gas production and development to energy companies worldwide. Merlin Associates' publication "LNG: Cost and Competition" (co-authored with Poten and Partners, Inc.) is the standard reference used by many of the leading LNG project participants, consulting and engineering firms, and financial institutions of the world. Provided cost validation.
Mustang Management, Ltd. (Mustang)	Canadian company that specializes in pipeline construction and installation. Provided cost validation for costs related to pipeline construction in Canada.
PetroTel	PetroTel is a recognized worldwide industry leader in enhanced oil recovery, reservoir characterization and simulation, coalbed methane, production, and exploration technologies. PetroTel provided professional consulting and advisory services.
Pingo International, Inc.	More than 30 years of experience in pipeline design and construction. Pingo provided expertise in engineering, costs and scheduling of pipeline systems for the Canadian pipeline segment analysis.
Westney Consulting Group	Houston-based consulting group with 30 years experience in global gas projects including: pipelines, NGL, GTP, and LNG projects. Westney's contribution included the use of a proprietary model to provide cost analysis and Monte Carlo simulations into the NPV evaluations, world-wide LNG expertise, and risk analysis systems.
Wood Mackenzie	Wood Mackenzie developed proprietary commodity pricing forecasts for the State of Alaska. This confidential and proprietary information was used to support evaluations of other potential oil and gas developments that could also potentially utilize capacity in the proposed Project.

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Chapter Three — Analysis of TC Alaska's Application

Table of Contents

A. Introduction and Summary 3-3
B. Who is TC Alaska?...3-3
1. History and Company Description...3-3
a. TransCanada in Alaska 3-3
C. Summary of Proposed Project 3-3
1. Gas Treatment Plant (GTP) 3-3
a. Potential Equity Partners...3-3
b. Management Challenges 3-3
c. Regulatory Challenges...3-3
d. Transportation Challenges 3-3
D. TC Alaska's Project Would Produce a Significantly Positive Net Present Value for the State of Alaska 3-3
1. Summary of Methodology and Results of NPV Analysis.................................3-3
2. NPV Methodology 3-3
a. General Approach 3-3
b. Natural Gas Prices 3-3
c. EIA Price Forecast 3-3
d. Wood Mackenzie Price Projection...3-3
e. Projection Based on Forward-Looking North American Supply and Demand Model 3-3
f. Estimated Volumes of Natural Gas Sold 3-3
g. Estimated Pipeline and GTP Costs, Schedule, and Tariffs 3-3
h. Pipeline Cost and Schedule Analysis, Including Cost and Schedule Ranges............3-3
i. Nominal Dollar Cost Ranges and Tariffs: Escalation Risk 3-3
j. Upstream Costs..3-3
3. Estimated NPV Produced by the Project—Results of the NPV Analysis 3-3
a. Estimated NPV under the Proposal Base Case 3-3
b. Estimated NPV Under the Conservative Base Case and Low Volume Sensitivity Case Remain Favorable. 3-3
c. The Project Would Produce a Positive NPV Even If No Point Thomson or YTF Gas Is Ever Produced. 3-3
4. Impact of $500 Million Match 3-3
5. Availability of Low Cost Expansion 3-3
E. Analysis of the Likelihood of Success of TC Alaska's Project...3-3
1. Introduction and Summary 3-3
2. Methodology for Analyzing the Project's Likelihood of Success 3-3
3. Analysis of Likelihood of Success Criteria Under AGIA Section 170 3-3

a. TC Alaska Has Submitted a Plan for its Project That is Technically Feasible, Reasonable, and Specific. 3-3
b. TC Alaska Has Demonstrated the Technical and Financial Ability To Construct the Project. 3-3
c. TC Alaska Has Submitted a Reasonable Commercial Plan Which, Coupled With Economic and Political Factors, Should Help To Encourage Firm Shipping Commitments 3-3
d. TC Alaska's Ability To Overcome Barriers To Obtaining Firm Shipping Commitments....3-3
e. Other Factors Which Indicate TC Alaska's Project Has A Reasonable Prospect of Securing Firm Shipping Commitments....3-3
F. Summary....3-3
G. References....3-3

Figures

Figure 3-1. Map of TransCanada Pipeline Operations 3-3
Figure 3-2. Present Value of $100 Cash Flow in Future....3-3
Figure 3-3. Present Value of $100 Cash Flow in Future Years 3-3
Figure 3-4. Sensitivity of State NPV to Discount Rates 3-3
Figure 3-5. NPV Modeling 3-3
Figure 3-6. Annual Henry Hub Price....3-3
Figure 3-7. EIA-Based Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars) 3-3
Figure 3-8. Wood Mackenzie-Based Henry Hub Forecast to 2045 (Nominal dollars) 3-3
Figure 3-9. Wood Mackenzie Basis Forecast 3-3
Figure 3-10. Wood Mackenzie-Based Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars) 3-3
Figure 3-11. Black and Veatch Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars) 3-3
Figure 3-12. U.S. Gas-fired Power Generation Demand Distribution Range....3-3
Figure 3-13. WCSB Finding and Development Cost Curve (Real 2008 $) 3-3
Figure 3-14. U.S. Lower 48 Industrial Demand Distribution Range....3-3
Figure 3-15. Relative Impact of Price Drivers on AECO HUB Price Formation, 2022 (Nominal $)....3-3
Figure 3-16. Distribution Range of AECO Price Forecasts over Time (Nominal $) 3-3
Figure 3-17. AECO Price Forecasts (Nominal $)....3-3
Figure 3-18. Production Profile for Proposal Base Case 3-3
Figure 3-19. Production Profile for Conservative Base Case 3-3
Figure 3-20. Subproject Component Cost Ranges—Derivation Process 3-3

Figure 3-21. Proposal Base Case Cost Distribution—Alaska Pipeline 3-3
Figure 3-22. Proposal Base Case Cost Distribution—Yukon-BC Pipeline..............................3-3
Figure 3-23. Proposal Base Case Cost Distribution - GTP...3-3
Figure 3-24. Proposal Base Case Cost Distribution—Integrated Project 3-3
Figure 3-25. Project Cost Risk: Comparing Project Escalation with Project Scope Risks Showing Cost Uncertainty and Risk Increasing With Escalation Rates 3-3
Figure 3-26. Tariff Distributions by Project Throughput:Smaller Projects Give Higher Tariffs..3-3
Figure 3-27. State NPV5 Tornado Diagram: The Relative Importance of Different Project Risks...3-3
Figure 3-28. State NPV5 Sensitivity to Price 3-3
Figue 3-29. Comparing TC Alaska Pipeline Tariff (Nominal $) with Various AECO Price Forecasts 3-3
Figure 3-30. Producer NPV_{10} Tornado Diagram: The Relative Importance of Different Project Risks...3-3
Figure 3-31. Pipeline Tariffs Under Proposal, Conservative, and Low Volume Cases...........3-3
Figure 3-32. State NPV5 Under Proposal, Conservative, and Low Volume Cases...............3-3
Figure 3-33. Aggregate Producer NPV Under Proposal, Conservative, and Low Volume Cases 3-3
Figure 3-34. Impact of Contract and Depreciation Periods on AECO Tariff 3-3
Figure 3-35. Reserve Risk: Producer NPV Assuming No YTF Gas 3-3
Figure 3-36. Reserve Risk: Yearly Net Back Cash Flow 3-3
Figure 3-37. State of Alaska NPV5 with and without $500m match 3-3
Figure 3-38. AGIA Roll-in-Rate Provision 3-3
Figure 3-39. Schedule Risk of Proposal Base Case..3-3
Figure 3-40. Impact of Commercial Terms of Transportation Contracts to AECO Tariff 3-3
Figure 3-41. Impact of Commercial Terms of Transportation Contracts to Producer NPV_{10} and NPV_{15}..3-3
Figure 3-42. Tariff Consequences of Cost Overruns With and Without 100% Debt Financing 3-3
Figure 3-43. TransCanada NPV8.8 Sensitivity Consequences of Cost Overruns With and Without 100% Debt Financing..3-3
Figure 3-44. TransCanada NPV8.8 For Different Project Configurations..............................3-3
Figure 3-45. U.S. Government NPV_5 For Different Project Configurations............................3-3
Figue 3-46. State NPV_5 For Different Project Configurations 3-3
Figure 3-47. Percentage Price Drop Necessary to Generate NPV of Zero For Producers' Proved Reserves 3-3
Figure 3-48 Aggregate Producers NPV_{10} - 4.5 BCF/d Proposal Base Case With and Without Price Uncertainty...3-3
Figure 3-49. Real AECO Price Forecasts vs. Tariff + Fuel..3-3
Figure 3-50. Aggregate Producers NPV_{10} Uncertainty for the 3.5, 4.0, and 4.5 Bcf/d Cases 3-3
Figure 3-51. Impact of Different Periods of Fiscal Uncertainty for Producer NPV_{10}................3-3

Tables

Table 3-1. NETL's Estimate of Economically Recoverable Natural Gas Reserves 3-3

A. Introduction and Summary

After providing background information about TC Alaska and a brief summary of its application, this chapter of the Findings discusses the analysis of the net present value and likelihood of success of TC Alaska's Application. In summary:

- TC Alaska is a subsidiary of TransCanada Corporation (TransCanada). TransCanada, through its independent pipeline company affiliates, owns and operates one of the largest natural gas pipeline transportation networks in North America. TransCanada has pledged all support necessary, both financial and otherwise, to TC Alaska to achieve completion of the project.
- In its Application, TC Alaska proposes to construct a 4.5 Bcf/day pipeline from the North Slope to interconnect with the AECO Hub. TC Alaska commits to all of the AGIA requirements, which are integral to achieving a number of state benefits. These legally enforceable commitments include:
  - o Commitments to expand the project's capacity when warranted, and to use rolled-in rate treatment for expansions, which will encourage maximum exploration and development of Alaska's natural gas resources, which in turn will lead to more long-term employment opportunities for Alaskans.
  - o The commitment to use a minimum 70/30 debt/equity ratio for ratemaking purposes, which will keep rates low and thereby enhance state revenues, while also encouraging exploration and development of Alaska's natural gas resources, which again will lead to more long-term employment opportunities for Alaskans.
  - o The commitments to hold an open season by September 30, 2009, to initiate the FERC pre-filing process by June 2010 and to file for a FERC certificate by December 2011, which will help get a gasline more quickly.[1]
  - o The commitment to provide firm natural gas transportation service to a minimum of five delivery points in this state using distance-sensitive rates, which helps to ensure natural gas for Alaskans.
  - o The commitments, to the maximum extent permitted by law, to hire Alaska residents and to negotiate a project labor agreement, which help ensure jobs for Alaskans.

[1] In its Application, TC Alaska premised these dates on receiving the AGIA License by April 1, 2008. According to TC Alaska, if the License is issued later this year, these dates may need to be adjusted. However, for ease of reference in these Findings we will continue to refer to the original dates used by TC Alaska in its Application.

- TC Alaska's Project is likely to produce a very significant cash flow and positive NPV for the State of Alaska and for the other major stakeholders in the Project, including the Major North Slope Producers. Specifically:
  - The State of Alaska would realize an estimated cash flow of $261.5 billion, and an estimated NPV of approximately $66.1 billion at a discount rate of 5%.
  - The Major North Slope Producers would realize an estimated cash flow of $147.4 billion, and an estimated NPV of approximately $13.5 billion at a discount rate of 10%.[2]

TC Alaska's Project is likely to produce a very significant cash flow and positive NPV for the State of Alaska and for the other major stakeholders in the Project, including the Major North Slope Producers.

- TC Alaska's Project also has a significant likelihood of success, for several reasons including the following:
  - First, TransCanada is a highly experienced, independent natural gas pipeline company, with the necessary experience (operating within U.S., Mexico, Canada, arctic and near-arctic conditions) and financial resources to complete its Project. It has also proposed commercial terms that contain several attractive features, including the offer to share the risk of cost overruns, which are likely to improve significantly after TC Alaska negotiates commercial terms with the Major North Slope Producers.
  - Second, there is a reasonable likelihood that TC Alaska will be able to successfully overcome the key barriers to the Project, including the need for firm shipping agreements with the Major North Slope Producers. For the reasons explained later in this chapter, the commissioners conclude TC Alaska has a significant prospect of obtaining firm shipping commitments even in light of the Producer Project recently proposed by BP and ConocoPhillips. The potential benefits to be gained from the TC Alaska Project, and the risks to all of the parties of not taking reasonable actions to make the Project a success, are simply too large for the parties to allow the Project to fail.

[2] As explained more fully herein, the Producer NPV would be significantly higher at the same 5% discount rate used for the state.

B. Who is TC Alaska?

1. History and Company Description

TransCanada is one of North America's largest energy infrastructure companies. TransCanada's operations include natural gas pipelines, power (electric) generation, LNG and natural gas storage. First and foremost, TransCanada is an independent natural gas pipeline company that owns one of the largest natural gas pipeline systems in North America.[3] In 2007, TransCanada reported assets of $30.3 billion resulting in a net income of $1.22 billion.[4] The natural gas pipeline portion of TransCanada's operating portfolio is principally comprised of the company's pipelines in Canada, the United States and Mexico. TransCanada operates over 36,000 miles of wholly-owned natural gas pipelines. The majority of TransCanada's pipelines transport natural gas from Alberta to major markets in the United States and Canada (Application 2007, Section 2.1.1). Beyond its experience owning and operating pipeline systems, TransCanada also has extensive experience in constructing and operating natural gas pipelines in harsh, cold weather conditions (Application 2007, Executive Summary, page 3).

A map of TransCanada's network is provided in Figure 3-1 below.

a. TransCanada in Alaska

In 2005 TransCanada discussed the Alaskan portion of a proposed Alaska natural gas pipeline project with Alaska North Slope producers and the State of Alaska. The prior Administration eventually decided not to pursue a contract with TransCanada, and instead negotiated a contract under the SGDA process with the Major North Slope Producers. That contract ultimately failed to secure legislative approval.

Continuing to pursue its interest in developing a natural gas pipeline in Alaska, on November 30, 2007, TransCanada, through TC Alaska submitted an application in response to the AGIA Request for Applications (RFA). On January 4, 2008, the commissioners determined that TC Alaska's Application satisfied all of the mandatory requirements set forth in AS 43.90.130 and complied with the requirements set forth in the RFA. Accordingly, TC Alaska's Application is reviewed and analyzed in the subsequent sections of these Findings.

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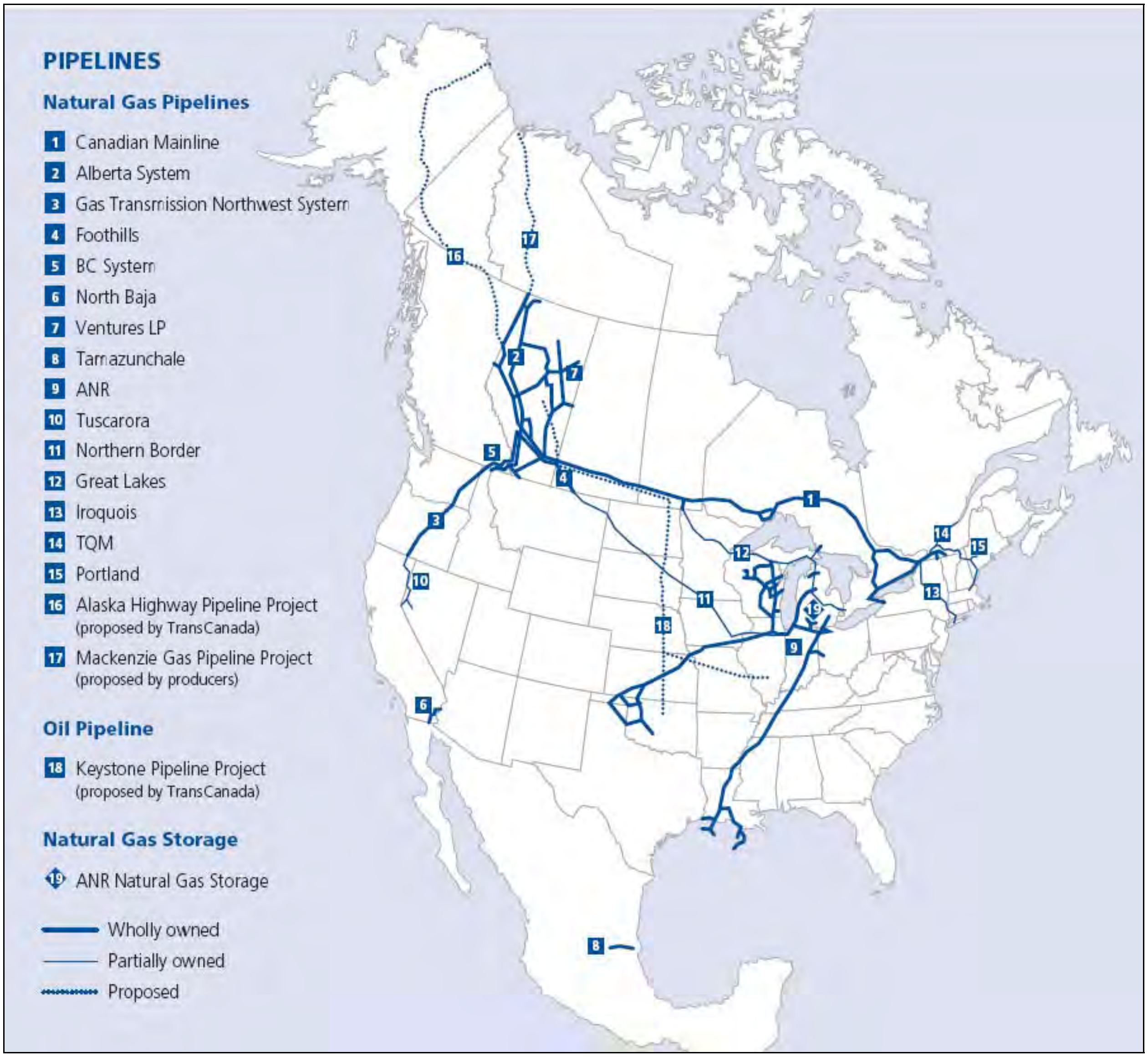
[3] See: http://www.transcanada.com/gas_transmission/index.html

[4] http://www.transcanada.com/investor/annual_reports/2007/2007_TCC_AR_Financial_Highlights.pdf

Figure 3-1. Map of TransCanada Pipeline Operations



Source: TransCanada 2007

C. Summary of Proposed Project

TransCanada Alaska and Foothills Pipe Lines Ltd. (TC Alaska) jointly responded to the RFA on November 30, 2007. TransCanada and Foothills Pipe Lines Ltd. are wholly-owned subsidiaries of TransCanada Corporation. The TC Alaska Application proposes to construct a 4.5 Bcf/day natural gas pipeline from Prudhoe Bay to existing pipeline infrastructure near Boundary Lake in Alberta, Canada. A summary of the information and data provided in the November 30, 2007 Application is provided in the following sections.[5]

TC Alaska proposes to build a natural gas pipeline from a gas treatment plant (GTP) on the North Slope, across the Canadian border and interconnecting with existing facilities near Boundary Lake near the Alberta-British Columbia border.[6] From there, TC Alaska proposes to add new pipeline infrastructure to existing infrastructure from Boundary Lake, Alberta to connect with the AECO Hub (Application 2007, Section 2.1.1). At Boundary Lake the pipeline will connect with the existing Canadian pipeline grid system that has 15,000 miles of pipe, 1,000 receipt points and 200 delivery points (Application 2007, Executive Summary, page 4). This existing pipeline network feeds all major gas consuming markets in North America. The gas from the North Slope will flow through and be traded at the AECO Hub, which is one of the largest natural gas trading hubs in North America (Application 2007, Executive Summary. p. 4).

TC Alaska proposes to construct the Alaska section of the pipeline using 48-inch diameter Grade X80 steel pipe with a wall thickness of slightly over one inch in diameter. The Alaska portion of the pipeline will be approximately 750 miles in length (Application 2007, Section 2.1.1). The pipeline will generally follow the Trans Alaska Pipeline System (TAPS) route from Prudhoe Bay to Delta Junction. From Delta Junction the pipeline will follow the Alaska Highway to the border of Alaska and Canada (Yukon Territory) (Application 2007, Section 2.1.1). TC Alaska proposes to bury the pipeline except at metering stations, compressor stations, certain major river crossings and selected seismic fault lines. Initially a total of six compressor stations will be located in Alaska to operate the pipeline at a capacity of 4.5 Bcf/d. TC Alaska proposes to retain these basic design parameters so long as it receives firm shipping commitments of at

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[5] The complete TC Alaska Application is online at http://www.dog.dnr.state.ak.us/agia/PublicApplications/trans%20canada/ application/ transcanada%20application%20(non-confidential).pdf.

[6] The Application contains numerous commitments and TC Alaska's project plan. Those commitments and project plan can only be changed in accordance with AGIA, notwithstanding how they may be described in these Findings.

least 3.5 Bcf/d.[7] According to the Application, through the addition of seven compression stations in Alaska, the capacity of the proposed system could be expanded to 5.9 Bcf/d.[8] Pursuant to AGIA, TC Alaska's Application commits to providing a minimum of five delivery points within Alaska. These in-state delivery points will include connections at Fairbanks and Delta Junction (Application 2007, Section 2.2).

The Canadian section of the pipeline will also be constructed of 48-inch diameter Grade X80 steel pipe. The pipeline in Canada will be approximately 965 miles long with 517 miles in the Yukon Territory and 448 miles in British Columbia (Application 2007, Section 2.1.1). The Canadian section of the pipeline would originate near Beaver Creek, Yukon. Generally, the pipeline would parallel the Alaska Highway through the Yukon Territory and then cross into British Columbia. The Yukon section will follow an established easement right held in Foothills' name (Application 2007, Section 2.2.4.2). The pipeline will be buried except at compressor stations, metering stations and certain major river crossings. Ten compressor stations will be constructed at the same time as the pipeline to operate at a capacity of 4.5 Bcf/d (Application 2007, Section 2.1.1.3). According to the Application, ultimately there could be up to nineteen stations built allowing the pipeline to operate at a capacity of 5.9 Bcf/d (Application 2007, Section 2.2.1.4).

After the Alaska natural gas reaches the AECO Hub, TC Alaska's Application assumes that the gas will be processed through existing third-party natural gas liquids (NGL) facilities ("straddle plants") in Alberta (Application 2007, Section 2.1.4). The NGL processing facilities remove gas components such as propane, butane and ethane. There are a number of large existing NGL processing facilities in Alberta that TC Alaska expects will have the sufficient capacity to accommodate the Alaska gas. TC Alaska's Application also accommodates the development of new NGL processing facilities in Alaska (Application 2007, Executive Summary, p. 4).

1. Gas Treatment Plant (GTP)

The GTP is necessary for treating natural gas that is to be shipped via pipeline from the Alaska North Slope. The GTP will process approximately 5 Bcf/d of residue gas from the existing Central Gas Treatment Facility located at Prudhoe Bay. This residue gas would be treated by

[7] The state has confirmed that, technically, TransCanada's project is indeed technically feasible at this reduced throughput. *See* Appendix F, Exhibit J, at page 8.

[8] *Id*.

removing the carbon dioxide and other objectionable components. The 4.5 Bcf/d of sales gas would then be chilled to 28°F and compressed to 2,500 pounds per square inch gauge prior to shipping. The carbon dioxide would be returned to the residue gas stream and re-injected into the Prudhoe Bay reservoir (Application 2007, Section 2.1.2).

TC Alaska states in its Application that it does not intend to develop, own, or operate the GTP. However, in the event no third-party expresses a willingness to undertake the GTP, TC Alaska would include the GTP as part of its open season and stands prepared to develop, own, and operate the facility (Application 2007, Section 2.1.2).

TC Alaska, however, has stated in its Application that it is open to offering equity stakes in the project and would welcome project partners.

a. Potential Equity Partners

TC Alaska's Application is not dependent on partnerships with non-affiliated pipeline companies nor is it subject to any ownership interests by current or potential natural gas producers in Alaska. TC Alaska, however, has stated in its Application that it is open to offering equity stakes in the project and would welcome project partners (Application 2007, Section 2.2.3.7). TC Alaska has proposed ownership interests to potential anchor shippers on the pipeline.

b. Management Challenges

TC Alaska's project has three main phases: the project development phase; the project execution phase; and the project operations phase (Application 2007, Executive Summary, p. 5).

The project development phase would begin with the issuance of the AGIA license in 2008 and go through August 2013. This phase begins by performing the Front End Engineering Design (FEED) that refines the project scope and attendant cost estimates, project schedules, engineering and environmental work that support the open season. After open season, the FEED work includes the routing, engineering and design work. The project development phase concludes with the "Decision to Proceed" milestone. TC Alaska estimates that 3,750,000 labor hours, at a cost of $625 million, will be required to complete the development phase of the project in Alaska and Canada (Application 2007, Executive Summary, page 7).

The project execution phase would commence immediately after a favorable Decision to Proceed, which, under TC Alaska's current estimated timetable, is expected in September 2013

(Application 2007, Section 2.6). The execution phase includes the construction of the pipeline and all associated facilities. This phase continues until the actual construction of the pipeline and associated facilities is completed, the pipeline is commissioned, and all major components are functioning and commercial operations begin. TC Alaska estimates that this phase will be completed by November 2017 (Application 2007, Section 2.6).

The pipeline operations phase would begin with the commencement of commercial operations. This phase continues for the life of the pipeline, until the pipeline is removed from service. TC Alaska proposes in its Application to be the operator of the pipeline and would be responsible for all operations and maintenance activities. TC Alaska commits in its Application to assess market demand for additional pipeline capacity at least every two years after the initial open season. TC Alaska would also be responsible for the development, management and execution of future expansion projects (Application 2007, Executive Summary, page 6).

c. Regulatory Challenges

The AGIA licensee will be required to obtain a variety of permits and approvals from both United States and Canadian regulatory agencies. The ability to successfully manage the regulatory process is critical to meeting project schedules and the ultimate success of the project.

In seeking FERC certification of the proposed project, TC Alaska has made enforceable commitments in its Application to:

- Conclude an initial binding Open Season within 18 months after issuance of the AGIA license (estimated by TC Alaska in its Application to be September 30, 2009);
- Apply for FERC approval to use NEPA pre-filing procedures by June 2010 (*see* 18 CFR § 157.21); and
- Apply for a FERC certificate of public convenience and necessity authorizing the construction and operation of the Alaska section by December 2011 (Application 2007, Executive Summary, page 7).

In addition to these commitments, and other enforceable commitments made in its Application, in the December 14, 2007 response to Request for Clarification from the commissioners, TransCanada Corporation emphasized its commitment to providing all support necessary, both financial and otherwise, to the Applicants to achieve completion of the project.

With regard to Canadian regulatory issues, the Northern Pipeline Act (NPA) is the Canadian legislation that provides an expedited regulatory approval process for the development of the Alaska Pipeline Project through Canada. TC Alaska asserts that Co-Applicant Foothills holds certificates of public convenience and necessity pursuant to the NPA for the Canadian portion of the project. Foothills currently own and operate a portion of the Canada Section known as the Foothills Pre-Build. These pipelines were constructed in the early 1980s and serve to move western Canadian gas to market (Application 2007, Executive Summary,. page 11). The Pre-Build accounts for 30% of the Canadian section (Application 2007, Section 2.8).

In addition to the NPA approvals, TC Alaska states it will need to obtain the following permits for the construction of the Alaska Pipeline Project through Canada:

- Leave to Proceed order from the Designated Officer (DO) for the Alaska Pipeline Project.
- DO approval and certification of various plans, profiles and book of reference.
- NEB Approval of the tolling methodology and tariffs.
- NEB Leave to Open.
- Authorizations under the Fisheries Act and the Species at Risk Act.
- Provincial and Territorial approvals.

TC Alaska has identified up-front planning, proper coordination, early identification of relevant issues and executing an effective stakeholders plan as some key issues to address in order to avoid unnecessary regulatory delays.

d. Transportation Challenges

In its Application, TC Alaska recognizes that the agreement of natural gas producers to commit gas to ship through the pipeline is an essential component in the success of the Alaska Pipeline Project. An open season is the process by which the producers or other potential shippers can commit to ship natural gas, and the pipeline owner can commit to provide transportation serviced to the producers or other potential shippers. To attract shippers to participate in the initial open season, TC Alaska is willing to offer anchor shippers a potential ownership option in the pipeline in exchange for committing a threshold amount of gas during the initial open season (Application 2007, Executive Summary, page 14).

D. TC Alaska's Project Would Produce a Significantly Positive Net Present Value for the State of Alaska

AGIA requires the commissioners to use a two-part analysis in evaluating applications for the AGIA license. First, the commissioners must "rank each application according to the NPV of the anticipated cash flow to the state from the applicant's project proposal." As discussed in Chapters 1 and 6 of these Findings, the NPV to the state is important for all Alaskans because it represents money the state could receive from royalties and taxes as a result of the Project. That money can be used for essential state services such as roads and schools, and to continue Alaska's economic security.

Second, the commissioners must weigh the NPV of the project's anticipated cash flow to the state "by the project's likelihood of success" (AS 43.90.170(a)). The likelihood a project will succeed is important to the state because, even if a project would produce a high NPV in theory, if the project is not successfully completed it may not provide any benefits to the state.

After completing this process and considering the public comments, AGIA directs the commissioners to determine whether an application proposes a project that will sufficiently maximize the benefits to the people of Alaska and merits issuance of an AGIA license (AS 43.90.180).

Five parties responded to the AGIA RFA by submitting applications. Of these, only one application met the threshold "completeness" requirements of the statute. Accordingly, the AGIA statute's instructions for "ranking" are not fully applicable: there is only one AGIA-compliant applicant, so it clearly ranks first. An assessment of the TC Alaska Project's NPV and likelihood of success was nevertheless undertaken to determine whether awarding TC Alaska a license would sufficiently maximize the benefits to the state. This subsection of the Findings will discuss the analysis undertaken to evaluate the NPV of the Project, including the methodology used, and the results of the analysis.

When evaluating the NPV of anticipated cash flow to the state from an applicant's project proposal, AGIA directs the commissioners to consider a number of criteria that affect the NPV. They must use an undiscounted value and, at a minimum, discount rates of two, five, six, and eight percent. They must also consider how quickly the

> The net back value of the gas is the destination value (price sold at market) minus the cost of transportation from the inlet of the GTP to the destination market.

applicant proposes to begin construction of the proposed project and how quickly the project will commence commercial operation; the net back value of the gas and estimated transportation (tariff) and treatment costs; the applicant's ability to prevent or reduce project cost overruns that would increase the tariff; the initial design capacity of the project and the extent to which it can accommodate low-cost expansion; the amount of the reimbursement by the state that the applicant has proposed; the economic value resulting from payments required to be made to the state under the proposal;[9] and other factors found by the commissioners to be relevant to the evaluation of the NPV of the anticipated cash flow to the state (AS 43.90.170).

1. Summary of Methodology and Results of NPV Analysis

Having considered numerous factors, potential uncertainties, and various scenarios, the commissioners' general conclusion is clear: based on the many variables considered—including gas prices, project costs, cost escalation rates, capacity subscription (project throughput), available gas reserves including the timing of when Point Thomson gas will be available, the extent of future gas discoveries, project schedule (including the risk of delay), tariff terms, discount rates, and other factors—*the economics of the TC Alaska Project are robust and generate significant cash flows and NPVs to all the major stakeholders, including the state*.

> The economics of the TC Alaska Project are robust and generate significant cash flows and NPVs to all the major stakeholders, including the state.

The eventual gasline project that emerges will almost certainly differ in some respects from the project proposed in an AGIA application. The applicant, as a pipeline company, cannot control the amount of capacity that is eventually subscribed for in an open season. Future gas prices are notoriously difficult to predict. Meanwhile, because actual orders for long-lead items for pipeline construction are unlikely to occur for many years, the eventual cost of the project cannot be known with certainty. And finally, future commercial negotiations between the pipeline company and potential shippers, along with the regulatory process at FERC and the NEB, will likely modify (and, from the shippers' perspective, generally improve) the applicants' proposed tariff rates and terms of service. Each of these factors can significantly affect the NPV that flows to the state from a proposed project.

[9] This provision of the statute directs the commissioners to consider extra payments if any, made by the project sponsors to the State (*e.g*. payments in lieu of tax, dividends from the state's AGIA-inducement contribution should

To assess the Project's economics and to organize its investigation of factors that create uncertainty which could impact the estimated NPV, the state adopted two "base" cases. These base cases were defined by fixed assumptions concerning project size (throughput), the gas volumes coming from different fields, and tariff terms.

The "Proposal Base Case" largely mirrors TC Alaska's Project size and tariff terms. It contemplates a pipeline that transports 4.5 Bcf/d, initially made up of 3.0 Bcf/d from Prudhoe Bay, 0.9 Bcf/d from Point Thomson, and 0.6 Bcf/day from other existing proved reserves. It assumes TC Alaska's negotiated rate offer of a 75/25 debt to equity capital structure, a 14% return on equity, levelized transportation rates, and 25-year shipping contracts that fully amortize the initial pipeline investment (Application 2007, Section 2.2.3.7).

The "Conservative Base Case" was developed to analyze the scenario in which, at the time of pipeline financing, Point Thomson gas is not available to be committed to the project. It contemplates a pipeline that transports 4.0 Bcf/d, initially made up of 3.5 Bcf/d from Prudhoe Bay, and 0.5 Bcf/day from other existing proved reserves. It assumes TC Alaska's negotiated rate offer of a 75/25 debt to equity capital structure, a 14% return on equity[10], levelized transportation rates, but assumes 20-year shipping contracts that fully amortize the initial pipeline investment. Although the 20-year depreciation schedule was not explicitly offered in its Application, TC Alaska made clear that it is amenable to term-differentiated rates of 30 and 35 years, the only requirement being that the shipping contracts fully amortize the investment. (Application 2007, Section 2.2). The commissioners see no logical nor commercial reason why TC Alaska would not find a similar 20-year arrangement perfectly acceptable so long as it fully amortizes TC Alaska's investment.

The "Conservative Base Case" was generated because the availability of Point Thomson gas is uncertain. The Point Thomson reservoir is classified, for regulatory purposes, as an oil field that must be managed to prevent "waste" of the oil resource.[11] Therefore, it is possible that Alaska

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the project be completed). TC Alaska proposed no such extra payments and the issue is not further considered.

[10] TC Alaska proposed that return on equity be set using a 965 basis point premium above the 10-year US Treasury bond rate. See Application at 2.2-67. For purposes of the analysis we assume that return on equity is a constant 14%, which is the figure TC Alaska used in its application for tariff calculations (Application at 2.2-68). Although this rate of return could change depending upon changes in underlying interest rates, we have not attempted to model this. We think it quite unlikely that this term would survive commercial negotiations with shippers (see Appendix J; Appendix G2). Finally, potential shippers and the State would have the ability to oppose the proposed 965 basis point premium at FERC

[11] See statement of AOGCC November 3, 2006, in the matter of an Appeal from the October 27, 2005 Amended

Oil and Gas Conservation Commission (AOGCC) will require that the oil must be produced before natural gas is produced (the gas is needed to maintain pressure in the field so the oil can be produced). The timing and quantity of Point Thomson gas availability will only be known after significant geologic uncertainties are resolved (Appendix O). Because Point Thomson development has not yet occurred, the production method and date of Point Thomson gas development would not be known by the time of TC Alaska's initial open season.[12]

It is unclear at this time whether the initial development method will primarily target liquids (oil and gas condensates[13]) or gas. An immediate gas production project ("blow-down") may not be consistent with the requirements of the AOGCC. Instead, a project that targets liquid production, a process known as cycling, where gas is removed and reinjected to enhance oil recovery, may first occur.

The Point Thomson unit has been terminated by the Commissioner of Natural Resources, and his decision is the subject of a legal challenge. However, even if the unit's status were clear, the geologic uncertainty makes it questionable whether Point Thomson gas could be committed to the project during the development phase of the Project.

Although analyzed through complex economic and statistical procedures, the basic framework for considering the economics of TC Alaska's proposed Project is straight-forward. For an Alaska natural gas pipeline project to be economic, the price of natural gas must be high enough to cover the project's costs. On a per unit basis the project's costs consist of the cost of gas transportation, or tariff, and the costs of gas production. The net cash flow from gas, or "Upstream Divisible Income," is thus: (1) the final destination price of the gas, times (2) the volume of gas transported, minus (3) total tariff payments and (4) out of pocket production costs. (Each of these major components is discussed in subsections, below). Upstream Divisible Income is shared between the producers, the State of Alaska[14] and the Federal

Decision on Proposed Plan of Development for the Point Thomson unit.

[12] The existing geological uncertainty at Point Thomson, which limits its availability for underpinning the project's financing, most likely would have been sufficiently resolved had the former Unit operator fulfilled its obligations under the Plans of Development over the past thirty years.

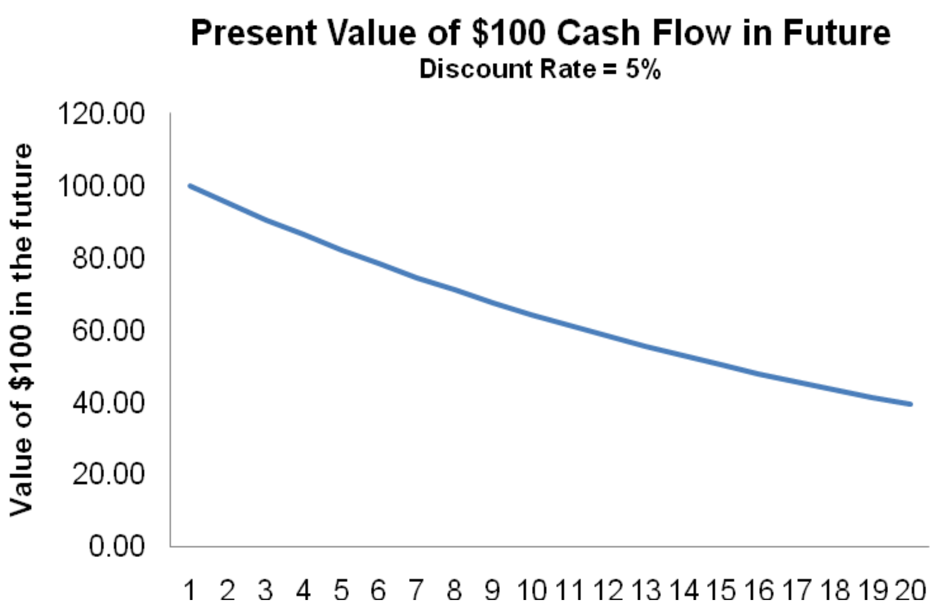
[13] Condensates are liquid hydrocarbons that are produced from high pressured gas reservoirs. Condensates in the reservoir remain in the gaseous phase and, as long as sufficient pressure is maintained through gas cycling, will remain gaseous and can be brought to the surface. Once at the surface, pressure can be reduced and the condensates collected for transportation to market as a liquid product.

[14] For purposes of this finding, property tax payments to municipalities are considered payments to the State of Alaska.

Government. The government share is composed of royalty, state production taxes (AS 42.55), state corporate income taxes (AS 43.20), Federal income taxes, and state and local property taxes (AS 43.56). Royalty and production taxes make up the bulk of the state's income. The pipeline tariff also generates a "Midstream Divisible Income," consisting of profits for the pipeline owner as well as property and corporate income taxes for the state, and corporate income taxes for the Federal government.

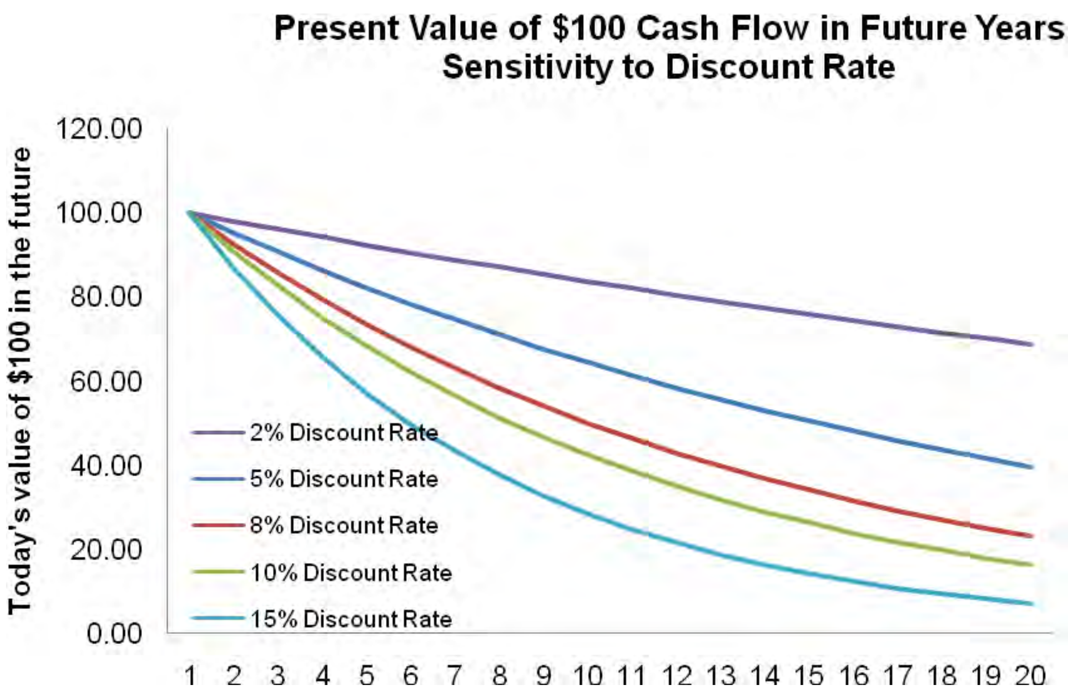
By itself, the concept of Divisible Income, or the net cash flow from the project, does not recognize that a dollar received 20 years from now has less value than a dollar received today. In recognition that there is a time value of money, and in accordance with the statutory requirement (AS 43.90.170(b)), the calculated *present value* of the entire future stream of the state's share of project net cash flows, or the state's NPV. The farther into the future that a given net cash flow occurs the smaller its size will be in today's dollars and the smaller its contribution to total NPV. Accordingly, all things being equal, project delays reduce the NPV. Figure 3-2, below, provides an illustrative example of this concept.

Figure 3-2. Present Value of $100 Cash Flow in Future



In addition, the contribution of a given future net cash flow to total NPV shrinks as the discount rate increases. At a 5% discount rate $100 is worth $39.57 in twenty years' time; at a 10% discount rate $100 is worth less than half this ($16.35) and at a 15% discount rate it is worth only $7.03 (Figure 3-3). The Producers' greater discount rate, compared with the state, helps explain why in the results that follow discounted state benefits from a project exceed producer benefits (Newell 2004).

Figure 3-3. Present Value of $100 Cash Flow in Future Years



As will be seen, this principle would make an equivalent cash flow to the Major North Slope Producers at a 15% rate look less than it would look at the 5% discount rate used for the state.[15]

If it could be built today an Alaska natural gas project as proposed by TC Alaska would be economic. Natural gas prices at the AECO Hub, the planned end point of the Project, are currently in the $9.30-9.67/MMBtu range,[16] well above the total estimated costs and tariff rate for the pipeline and gas treatment facilities, which in current 2008 dollars are estimated to be $3.19/MMBtu for the Proposal Base Case, and $3.59 for the Conservative Base Case

[15] Using a lower discount rate for the State than the Producers is appropriate because it is generally assumed that government has a different role than a private company. A private company is focused on shorter-term revenues for its shareholders. By contrast, a government is more concerned about future generations and (unlike a private company) does not pay federal income tax and thus has a lower cost of capital. For these reasons, it is generally accepted that a government's discount rate is lower than that of a private company.

[16] According to the May 19, 2008 issue of *Gas* Daily, prices for the AECO Hub are in the $C9.30-9.67/MMBtu range. Platts, *Gas Daily Price Guide.* Midpoint Average at the AECO-C Hub, April 2008.

(Appendix G1, Section 5.7.2). For the "base case" in-service date of 2020,[17] Wood Mackenzie foresees natural gas prices at about $9.65/MMBtu, with the tariff at $4.73 MMBtu for the Proposal Base Case and $5.33 for the Conservative Base Case (Appendix G1; Section 6.4).

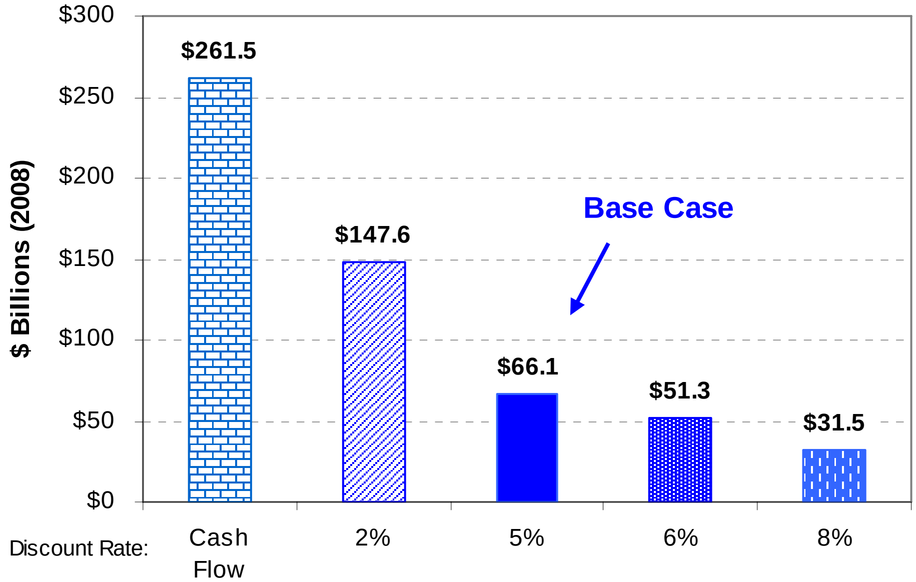
After deducting the cost of producing natural gas the Project produces significant positive cash flow and NPV. As discussed below, the analysis shows that TC Alaska's Project, as modeled under its proposed commercial terms, would generate very significant profits for all parties under both Base Cases. Net cash flow to the state under the Proposal Base Case would exceed $260 billion over a 25 year period which, at a 5% discount rate, is worth over $66 billion in today's dollars (Appendix G1; Section 5.7.9). For the Conservative Base Case, the state's NPV_5 is $60.7 billion (Appendix G1; Section 6.4). The Project would also produce a positive NPV to the state under any of the discount rates of two, five, six, and eight percent specified in AGIA. In addition, under both base cases the Project would produce a significant NPV for the Major North Slope Producers, the U.S. Government, and TC Alaska (Appendix G1; Sections 5 and 6). Moreover, the analysis shows that if TC Alaska were to construct the Project, the Major North Slope Producers would stand to achieve an internal rate of return of over 50% under both Base Cases (Appendix G1, Sections 5 and 6).

The Project would also produce a positive NPV to the State under any of the discount rates of two, five, six, and eight percent specified in AGIA.

The state NPV for the Proposal Base Case is shown under discount rates of two, five, six, and eight percent on an undiscounted basis. As one would expect, the state's NPV declines regularly and substantially as the discount rate rises.

[17] See discussion in Chapter 3 (D)(a) of the analysis of schedule risk, which explains why 2020 is the "base case" for the project's in-service date.

Figure 3-4. Sensitivity of State NPV to Discount Rates



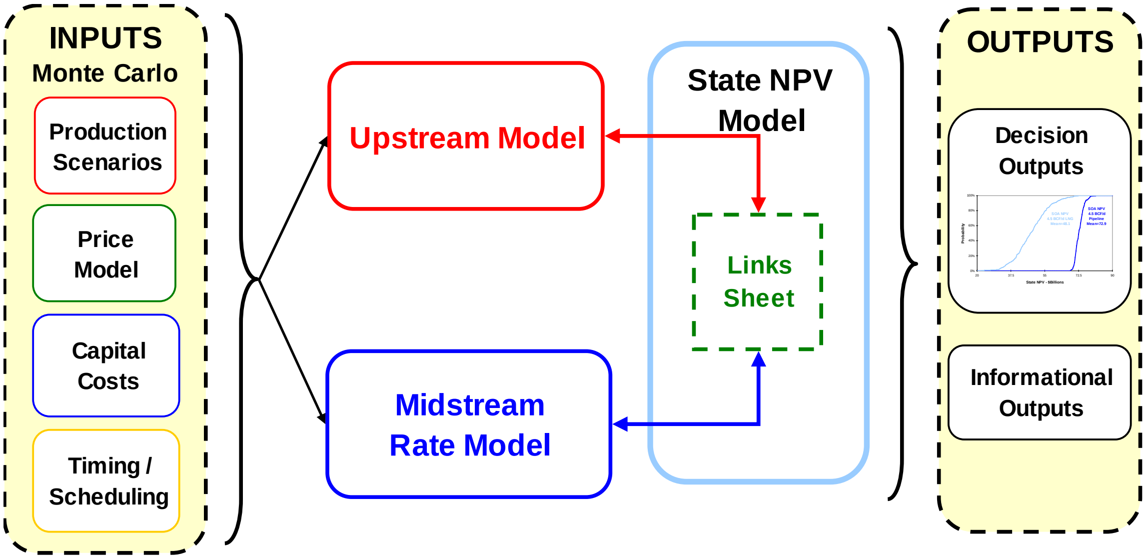
Source: Black and Veatch, Appendix G.1, Section 5.7.9

2. NPV Methodology

a. General Approach

The commissioners employed a large team, from multiple disciplines, to collaboratively develop a model to calculate the state's NPV, as well as the returns to various stakeholders. The overall model itself—the state NPV Model—was built and operated by Black and Veatch with the state's active collaboration and direction. The NPV model in it simplest expression contains outputs, algorithms, and inputs, as summarized in Figure 3-5.

Figure 3-5. NPV Modeling



Source: Black and Veatch, Appendix G1, Section 3.1

The NPV Model generates informational outputs on each stakeholder's share of project Divisible Income, including the state's NPV. It links two key submodels (algorithms), the Midstream and Upstream models, which themselves are composed of further submodels. The Midstream Model calculates tariffs for the pipeline and GTP, which include property and corporate income tax payments. The Upstream Model calculates Upstream Divisible Income, and addresses gas and oil production volumes, sales values, production costs, and taxes and royalty. Upstream Model calculations, including calculations of production taxes and royalty, receive as input the Midstream Model's tariff outputs.

The easily categorized inputs are shown in the diagram and were supplied as follows:

- Gas and Oil Production Volume Scenarios

  Gas volumes both directly (through sales volumes) and indirectly (through tariff impacts) affect project revenues. Oil volumes, and the impact of gas sales on oil production, affect the calculation of project revenue because project revenue is measured as the difference between revenue with and without a major gas sale. Production scenarios were provided by the State of Alaska, which relied significantly on work by PetroTel for Point Thomson[18] and Prudhoe Bay, and the National Energy Technology Laboratory (NETL)[19] for undiscovered resources.

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[18] Appendix O, by the Division of Oil and Gas, summarizes in public form PetroTel's report on Point Thomson which, because it contains confidential data, cannot be made public.

[19] See http://www.netl.doe.gov/publications/press/2008/08002-DOE_Releases_Alaska_Report.html for the NETL

- Prices

  Prices directly affect revenue from the sale of gas. Separate price forecasts were obtained from the US DOE's Energy Information Administration, Wood Mackenzie,[20] Gas Strategies Consulting,[21] and Black and Veatch.[22]

- Midstream Capital Costs

  The capital costs of the pipeline, GTP, and (as applicable) LNG liquefaction facilities are a key input into the Midstream Model, and significantly affect Midstream tariffs. Cost ranges were developed and reviewed by a large engineering team (the state's "Technical Team"), including Westney Consulting, Energy Project Consultants, Pingo International, AMEC Paragon, Colt Engineering, Mustang Management, Energy Operations Consulting, Black and Veatch, and Merlin Associates (See Appendix F).

- Project Schedules and Timing

  Project schedules affect the timing of when gas sales begin, and because of discounting and both gas price and project cost escalation, can significantly affect project NPV. Project schedule ranges were developed and reviewed by the state's Technical Team (See Appendix F).

- Interest Rates

  The project is highly capital intensive. Much of the funds to finance construction will be borrowed. The interest rates attached to such borrowings will significantly affect the Midstream tariffs. Goldman Sachs used its own models to generate interest rate inputs assumptions (see Appendix H).

- Operation and Maintenance (O&M) Costs

  O&M costs affect the tariff rate. For the Midstream Model input, O&M costs were reviewed and developed by the state's Technical Team (Appendix F). O&M costs also affect the cost of production (Appendix G1).

- Escalation Rates

  Escalation rates refer to the rate at which future costs and prices change. Escalation rates for midstream costs have a particularly large impact on tariffs. The Technical Team provided guidance as to appropriate cost escalation rate assumptions (Appendix F, Section 2.1.5).

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report. See Appendix L by the Division of Oil and Gas, for a summary of the NETL study and an explanation for how that study was extended for use in the Upstream Model.

[20] See Appendix N which provides a summary of the key parameters and expectations that underlie Wood Mackenzie's views of future gas prices in North America (both at Henry Hub and AECO Hub), as well as world oil prices. Wood Mackenzie's full report is available for subscription and, accordingly, cannot be provided here in full.

[21] Appendix I contains Gas Strategies' full report, including a discussion of LNG pricing and a forecast of Asian LNG prices based on Wood Mackenzie's views of future oil prices.

[22] The Black and Veatch approach to North American gas price forecasting is detailed in Appendix G1. As explained there, Black and Veatch created an entire price model that was integrated into the NPV model to facilitate systematic exploration of price uncertainty.

The NPV Model enabled the state to assess the Project's net cash flow and NPV under a range of different assumptions. These included the Proposal Base Case set of assumptions, and alternative assumptions and scenarios. This allowed the commissioners to evaluate and answer a number of key questions, including: What are the key factors that affect the Project's overall economics, and what are their relative magnitudes? How are the Project's risks and rewards distributed? What is the value of various aspects of TC Alaska's commercial offer? The following discussion summarizes the major assumptions and sensitivities used by the commissioners in their NPV analysis, including additional aspects of the methodology used to derive those assumptions.

Finally, with respect to the basic model structure, there are important interdependencies of oil and gas development—both in physical production and production tax treatment thereof. The NPV model measures and tracks these. Accordingly, the NPV consequences of a major natural gas sale are measured as the *difference* between a scenario in which there is no gas project and a scenario in which a project is developed.

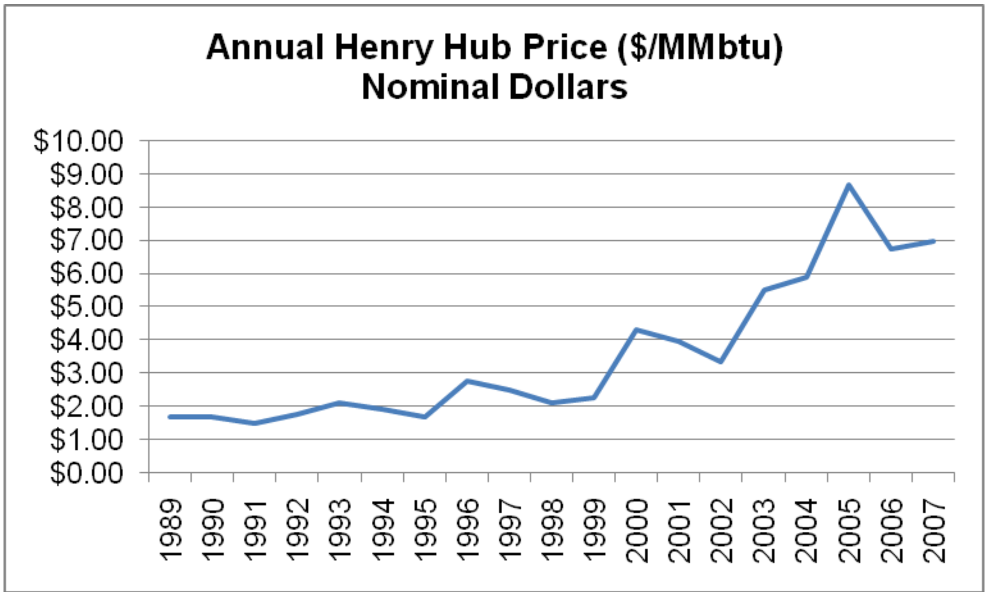
b. Natural Gas Prices

The starting point for the estimate of the Project's cash flow and NPV was the projected price of natural gas during the life of the Project. As noted above, for the Project to be economic, the price of natural gas must be high enough to cover the Project's costs, including a sufficient profit for the pipeline and for the producers of natural gas after the deduction of state revenues, including royalty and tax payments.

In the late 1970s and 1980s, the price of natural gas, one of the key variables (along with costs and other factors) in determining whether a project would be economic, was generally not considered by some to be high enough to cover the cost of constructing an Alaska gas pipeline project and provide a reasonable profit to the pipeline and the producers. In the mid-1980s, for example, gas prices ranged generally between from \$1.73 and \$2.71.[23] Since 2000 the price of natural gas has steadily increased.

[23]Price published by the U.S. Department of Energy, Energy Information Administration; http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3M.htm.

Figure 3-6. Annual Henry Hub Price



Source: US DOE, Energy Information Administration

Natural gas prices at the AECO Hub, the planned end point of the Project, are currently in the $9.30-9.67/MMBtu range.[24] If the pipeline could be built today, such prices would be sufficient to easily cover the tariff rate and provide substantially positive net backs, profits to the Major North Slope Producers and significant cash flow to the state.[25]

Of course, the Project cannot be built "today." Under TC Alaska's proposed timeline it will not commence for at least ten years. Thus, estimating the cash flow and NPV of the Project requires projecting the price of natural gas well into the future, beginning on the projected in-service date of the Project (*i.e.,* an estimate of the date on which the Project would initially transport natural gas for its shippers), and continuing throughout the projected life of the Project.

Projecting the future price of natural gas is challenging. However, as discussed in later sections, the price of natural gas has the single largest effect on the Project's economics. To cope with the difficulties of projecting future gas prices, given their particular importance, the state used several different approaches: (1) the forecast contained in the Annual Energy Outlook published by the U.S. Energy Information Administration (EIA); (2) a forecast provided by the Wood

[24] According to the May 19, 2008 issue of *Gas* Daily, prices for the AECO Hub are in the $C9.30-9.67/MMBtu range. Platts, *Gas Daily Price Guide.* Midpoint Average at the AECO-C Hub, April 2008.

[25] Recall that, if built today, the tariff would be $3.19 for the Proposal Base Case and $3.59 for the Conservative Base Case.

MacKenzie consulting group; (3) a probability distribution of forecast prices produced by Black and Veatch; and (4) an entirely agnostic approach that simply considers project economics assuming that prices, in real terms, were to remain unchanged at a number of different levels.

EIA's forecast has several strong features. The AEO is a free, public, and common reference point in the energy industry. It reflects a fundamental supply and demand model, which is integrated into a broad overall assessment of demand, supply and prices for oil, natural gas and electric power. For these reasons the AGIA RFA directed applicants to base their analyses on EIA's projections.[26] However, the AEO only provides a forecast of natural gas prices at Henry Hub, a major trading point in Louisiana. Accordingly, AECO Hub prices—which determine the Project's economics, because this is where the TC Alaska project would deliver the gas—have to be inferred. Some have also questioned whether EIA's projections are overly conservative, as during the last ten years they have tended to systematically underestimate natural gas prices (Appendix G1, Section 4.3).

Although it is available only a subscription basis, Wood Mackenzie's price forecast is also widely used in the natural gas industry. Wood Mackenzie's clients include each of the Major North Slope Producers and a large number of other major energy companies.[27] Like EIA, Wood Mackenzie's price forecast reflects an integrated view of the energy sector. Unlike EIA, Wood Mackenzie offers a direct price projection for the AECO Hub itself, in addition to projections for Henry Hub.

The Wood Mackenzie forecast was the reference forecast used to generate "base case" results, for several reasons. First, it offers a widely respected, public (if proprietary) natural gas price forecast. Second, Wood Mackenzie directly forecasts prices into the AECO Hub—the relevant market. Finally, this price forecast is modeled on a consistent basis with Wood Mackenzie's forecast of world oil prices, upon which LNG prices are based. This permits an "apples to apples" modeling comparison of Asian LNG prices and AECO Hub prices (which will be discussed later in the analysis of LNG options in Chapter 4).

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[26] To facilitate an "apples to apples" comparison between competing applications, Section 3 of the RFA directed all Applicants to benchmark their estimate of natural gas prices off the U.S. EIA's most recent Annual Energy Outlook forecast of Henry Hub spot market prices. The RFA also permitted the use of other gas price forecasts in addition to the EIA forecast. RFA at Section 3.2.1.

[27]http://www.woodmacresearch.com/cgi-bin/corp/portal/corp/overview.jsp?overview_title=corpCredentials. According to Wood Mackenzie, 24 out of the 25 largest energy companies are clients.

At the state's direction Black and Veatch used the North American Gas Model to develop projections of AECO Hub prices. It did so in recognition that the main drivers of gas supply (e.g. production costs) and demand (e.g. electricity demand, industrial demand, LNG imports) and thus gas price, are themselves highly uncertain. Both the EIA and Wood Mackenzie price forecasts each embody only a single view of these main drivers of supply and demand. Accordingly, they do not recognize these uncertainties. They do not permit an explicit and quantitative consideration of price uncertainty as driven by supply and demand uncertainty. There is no way using the EIA and Wood Mackenzie forecasts to address questions like: "what would happen to prices if LNG imports were 40% higher than EIA is assuming?," or "how would a decrease of 60% in electricity demand for gas affect prices?" The Black and Veatch approach permits just this kind of direct consideration of price uncertainty. It culminates in the development of probability distributions of the AECO Hub price over time. The Black and Veatch model structure and its assumptions are discussed in detail in Appendix G1, Section 4.

Each of the foregoing gas price forecasts derive from different fundamental models of supply and demand, and use different sets of assumptions regarding the determinants of supply and demand. They each provide different insights into what prices may be. However, precisely because they are sophisticated—embodying numerous inputs and assumptions—they can be difficult to understand. Accordingly, project economics and state NPV were also modeled on the basis of a series flat real prices. Although natural gas prices are highly volatile and are anything but flat, the advantage to looking at project economics "as if" prices were flat is that the assumption is directly and easily understood.

As discussed below, the conclusion that the Project would produce significant NPVs to the state and other key stakeholders is robust across the different price projections. Further, under relatively unlikely low price scenarios, the project's economics appear favorable even if the Project experiences significant cost increases.

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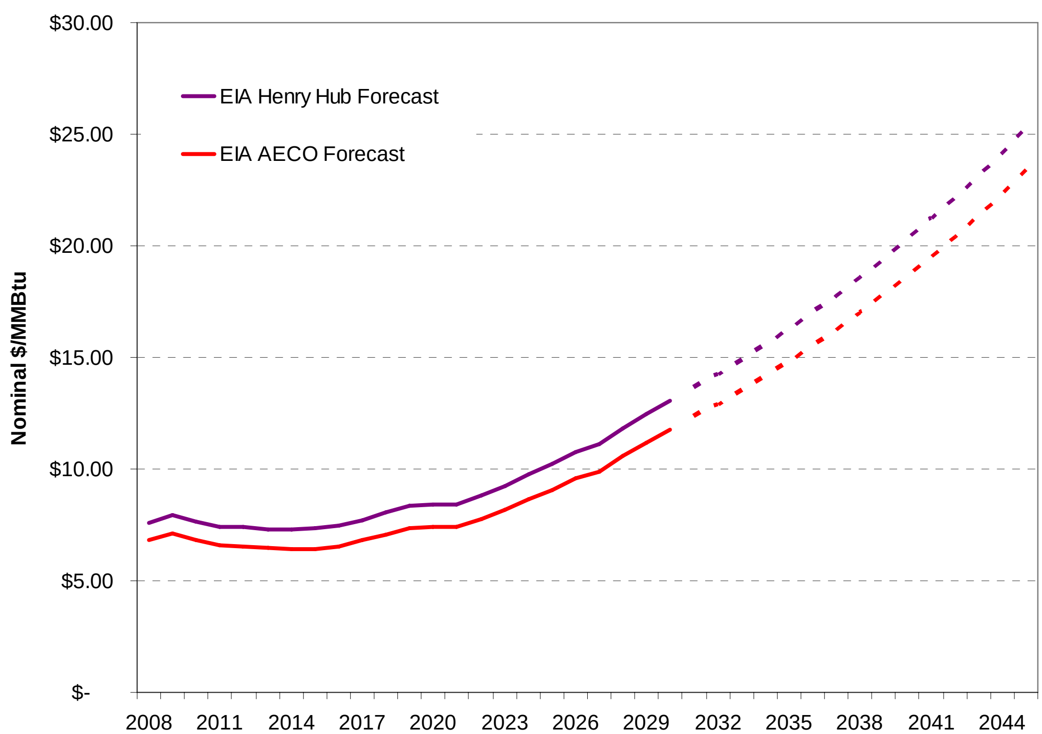
c. EIA Price Forecast

In its 2008 annual energy outlook, EIA projected the price of natural gas at Henry Hub to be approximately \$8.40/MMBtu in 2020 (in nominal dollars), increasing to approximately \$13.06/MMBtu in 2030 (again, in nominal dollars).

EIA does not project a price at the AECO Hub, the projected destination point for the Project. To help account for this fact, TC Alaska reduced the EIA projection for Henry Hub by 75 cents per MMBtu based on a measure of the historical difference between the price of gas at Henry Hub and the AECO Hub.[28] In effect, it subtracted 75 cents from each of the prices in the previous graph. When we use EIA price forecasts we follow TC Alaska's suggested approach. (Appendix G1, Section 4.3.5.4, reproduced in Figure 3-7). However, using a historically-based price differential is not consistent with the fundamental supply-demand model EIA used to forecast prices. Further, at least in Wood Mackenzie's view, the assumption of a constant 75 cent price differential between Henry Hub and the AECO Hub is conservative and in the future AECO Hub prices may be closer to Henry Hub.

Figure 3-7. EIA-Based Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars)



Source: Black and Veatch, Appendix G1, Section 4.3.5.4.

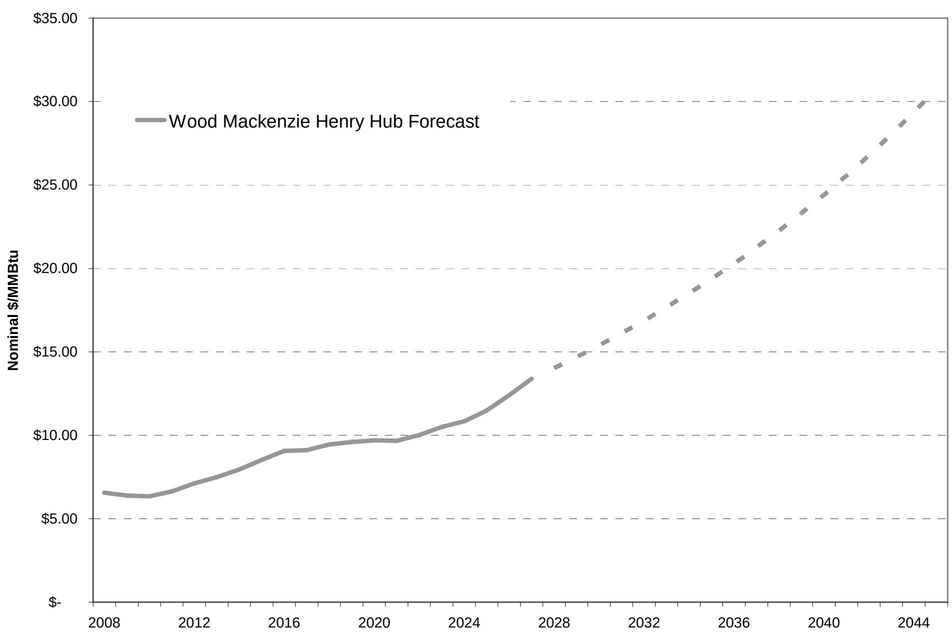
[28] Application at 2.10-5; *see* Appendix G.1 at Section 4.3.5.3 (establishing that $0.75) generally reflects the historical differential between Henry Hub spot prices and Alberta Hub spot prices.

As Figure 3-7 demonstrates, the 2008 EIA forecast projects that in the year 2020 the price of natural gas at AECO will be approximately $7.40/MMBtu, and approximately $11.77/MMBtu by 2030.[29] There are reasons to think that EIA's pricing outlook is conservative. Over roughly the last eight years the EIA has consistently underestimated prices (Appendix G1, Section 4.3.4.5).

d. Wood Mackenzie Price Projection

In addition to the EIA projection, a projection of natural gas prices supplied by the Wood Mackenzie consulting group was considered. The details underlying Wood Mackenzie's "view of the world"—its projections of fundamental supply and demand drivers—are reviewed in Appendix N. The Wood Mackenzie forecast extends only to 2027. Because the NPV model requires price inputs for the first twenty-five years of gas flow, Black and Veatch extrapolated the Wood Mackenzie forecast using the real price growth rate exhibited during 2020-2027. (Appendix G1, Section 4.3.6.3) This is reflected in Figure 3-8.

Figure 3-8. Wood Mackenzie-Based Henry Hub Forecast to 2045 (Nominal dollars)

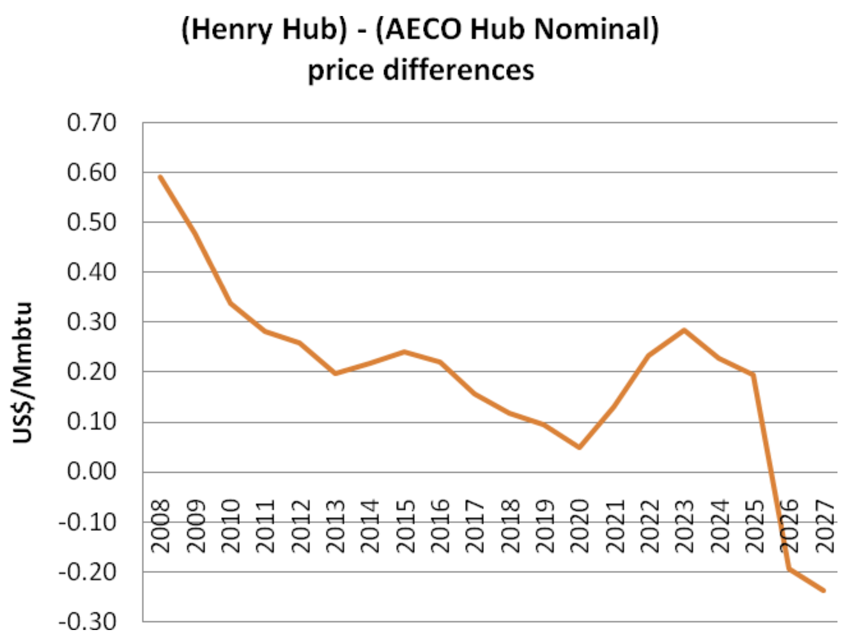


Sources: Wood Mackenzie's Long Term View—January 2008 Update: Gas and Power Service; Black and Veatch; Appendix G1, Section 4.3.6.3

[29] The EIA publishes its price forecast in "real" dollars. These have been converted to "nominal" dollars by assuming a 2.5% rate of inflation. EIA's real-dollar estimates are $5.60/MMBtu and $6.85/MMBtu for 2020 and 2030, respectively.

As noted earlier, the EIA forecast is used to derive an AECO Hub price assuming AECO Hub prices continue to reflect the historical average reduction of approximately 75 cents per MMBtu from Henry Hub prices. (Appendix G1, Section 4.3.6.3). However, this method of deriving AECO Hub prices does not fully account for future supply and demand conditions that will determine actual prices at the AECO Hub. By contrast, Wood Mackenzie projects that the price of natural gas at AECO Hub will actually *increase* relative to the Henry Hub price. Figure 3-9 reflects this expected convergence of AECO and Henry Hub prices.

Figure 3-9. Wood Mackenzie Basis Forecast



Source: Wood Mackenzie's Long Term View—January 2008 Update: Gas and Power Service; Black and Veatch; Appendix G1, Section 4.3.6.3

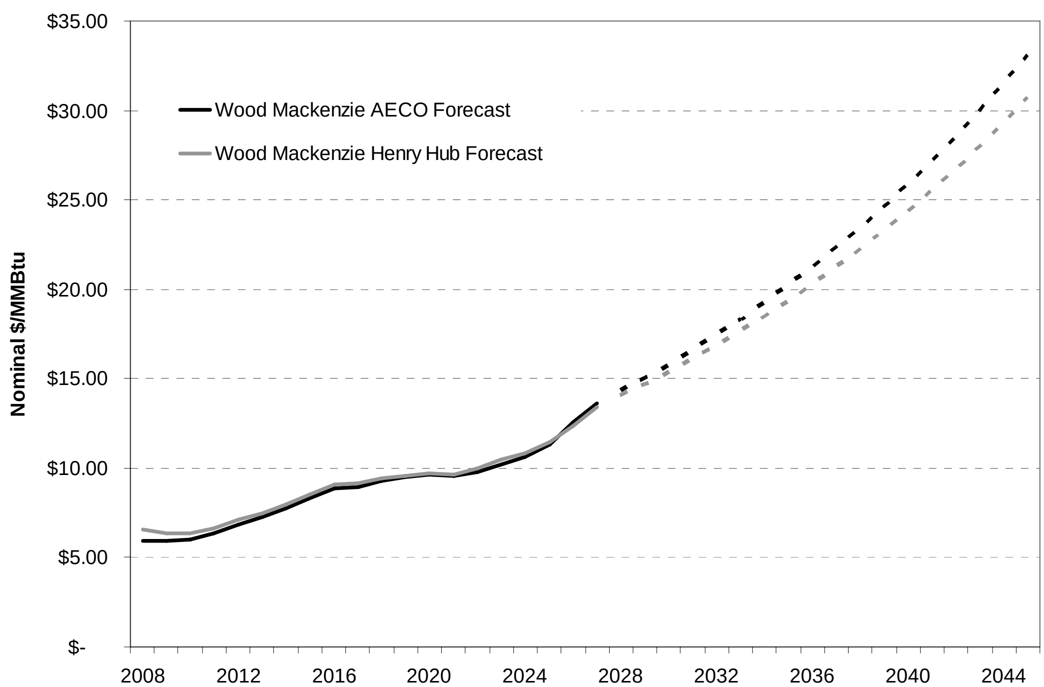
Wood Mackenzie forecasts future changes in Canadian natural gas supply and demand that differ from the historical data supplied in the Application using EIA-adjusted data. Specifically, Wood Mackenzie projects demand for natural gas in Canada to continue to increase. At the same time, Wood Mackenzie projects that the available supply of natural gas in Canada, which is already flat and in some cases declining, will decrease. According to Wood Mackenzie, both of these factors—increasing Canadian demand and decreasing Canadian supply—will tend to increase the price of gas at AECO Hub relative to the Henry Hub price.[30] Wood Mackenzie thus

[30] As will be discussed in Section E, the decrease in Canadian supply will also result in lower throughput and more unutilized capacity on TransCanada's pipelines located in Canada, absent the construction of the Project. This

projects a price of natural gas at AECO Hub of approximately $9.65/MMBtu in 2020, with gradual increases thereafter.

Beginning in about the year 2016 and continuing through at least the year 2030, the Wood Mackenzie natural gas price forecast exceeds EIA's 2008 forecast by a full $2/ MMBtu. The Wood Mackenzie forecast for AECO is shown in Figure 3-10.

Figure 3-10. Wood Mackenzie-Based Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars)



Source: Wood Mackenzie's Long Term View—January 2008 Update: Gas and Power Service; Black and Veatch; Appendix G1, Section 4.14

Because the Wood Mackenzie price forecast generally exceeds the EIA forecast, it results in a higher cash flow and NPV to the state.

e. Projection Based on Forward-Looking North American Supply and Demand Model

The NPV model also used price forecasts generated by Black and Veatch that use the North America Regional Gas model (NARG) as a platform. The state commissioned Black and

provides TransCanada with an increased incentive take the necessary steps to make the Project become a reality.

Veatch to generate these forecasts so that gas price uncertainty, as caused by uncertainty in the fundamental drivers of supply and demand, could be systematically addressed.

The NARG model analyzes the entire North American market, including all demand centers at the state and provincial level (including major demand centers like New York City, Chicago and Los Angeles) all North American natural gas producing basins, and the entire North American natural gas pipeline grid (Appendix G1, Section 4.3.7). The NARG model generates price forecasts for all demand centers and major supply hubs (including the AECO Hub), and corresponding pipeline flows across the entire grid. The model balances supply and demand by matching natural gas production from each basin with pipeline flows and natural gas consumption across the entire North American market.

The NARG modeling effort began with establishing a "base case" price forecast—a direct analogue of the forecasts provided by EIA and Wood Mackenzie. Major assumptions that underlie this base case are discussed in Appendix G1, Section 4.3.7.2. In general, base case assumptions that Black and Veatch adopted for various drivers can be considered "conservative." That is, they tend to err on the side of driving gas prices down.[31] They assume, for example, that:

- U.S. natural gas demand, in aggregate, will remain virtually flat for the next 35 years, despite a reasonable expectation of significant economic growth in North America, and despite the possibly increased need to use natural gas (rather than coal) given efforts to reduce greenhouse gas emissions.
- Even though gas exploration and development costs have increased approximately 100% since 2003,[32] costs are assumed to remain essentially flat for the discovery of approximately the next 190 Tcf in the Western Canada Sedimentary Basin, the Rockies, and the Gulf of Mexico (offshore). The assumption of relative stability of E&D costs in these areas tends to result in lower projected gas prices inasmuch as higher finding costs put upward pressure on the price of marginal supplies and thus on gas prices generally.

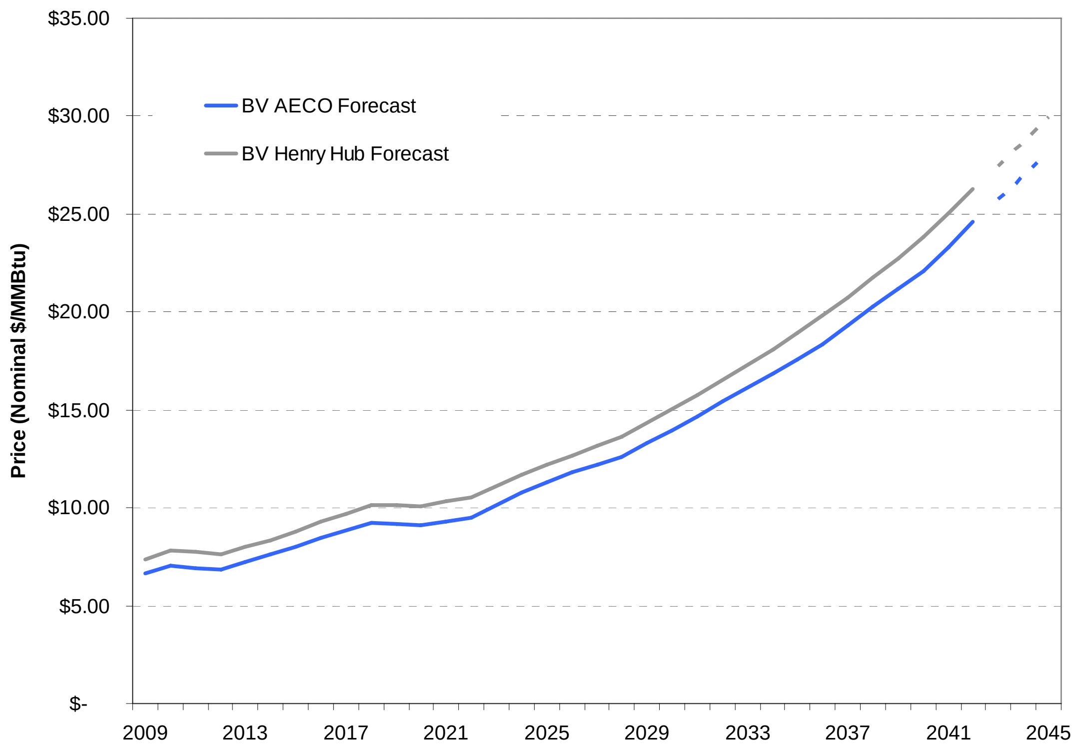
[31] The state has twice previously hired Black and Veatch to create long-term price projections. There, too, an effort was made to err on the side of caution, and assume price-driver values that depress gas prices. As discussed in Appendix G1, Section 4.3.7.3.4, a review of past Black and Veatch forecasts suggests that assumptions have indeed been conservative; realized gas prices have exceeded forecasted prices.

[32] IHS/CERA upstream capital cost index, "Costs...have doubled since 2005," CERA May 14, 2008

- A large increase in LNG imports into the U.S. from approximately 2.5 Bcf/day in 2008 to almost 11 Bcf/day in 2020, and over 15 Bcf/day in 2040. This assumption can be considered to provide a conservative projection of AECO Hub prices in two respects: the import volumes are higher compared with industry estimates and the import price is expected to be at levels below market-clearing price (LNG is an inframarginal source of supply) (Appendix G1, Section 4.3.6.2.3). Lower LNG import volumes or higher import costs will result in upward pressure on North American natural gas prices where the import volumes arrive regardless of the LNG premium that may be enjoyed in other markets during the period (See Appendix I).

Based on these assumptions, Black and Veatch's NARG Model generates an AECO Hub base case price forecast of approximately $9.10/MMBtu in 2020, as shown in Figure 3-11:

Figure 3-11. Black and Veatch Henry Hub and AECO Price Forecasts to 2045 (Nominal dollars)



Source: Black and Veatch; Appendix G1, Section 4.3.7.3.2.

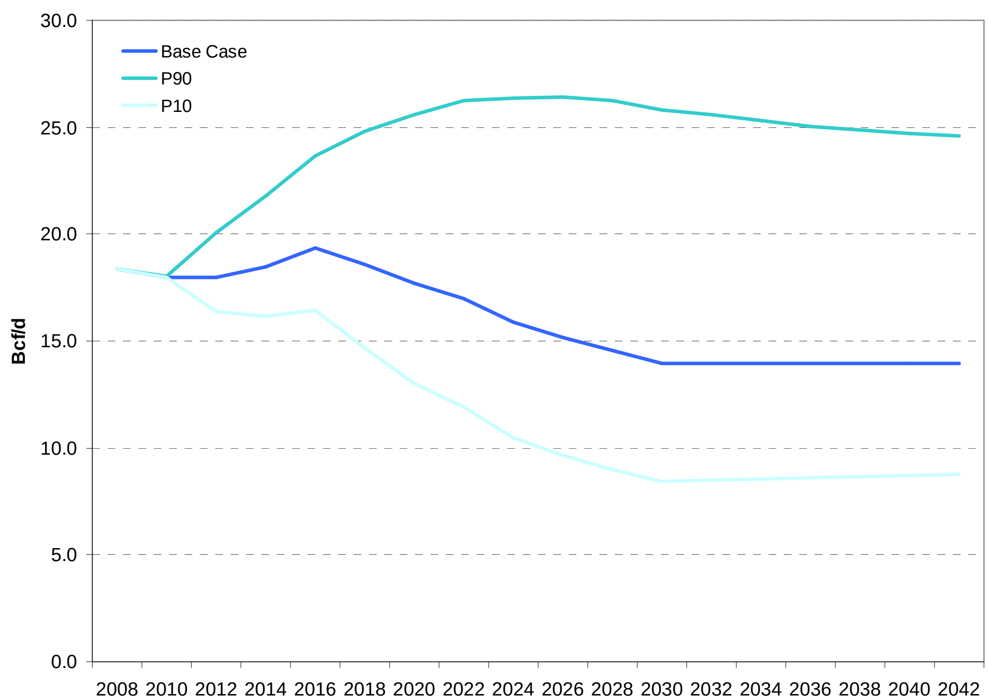
In general, the Black and Veatch base case forecast initially closely tracks Wood Mackenzie's before occupying a mid-point between EIA's and Wood Mackenzie's.

Black and Veatch's approach to long-term price forecasting not only focuses on providing baseline projections under specific assumptions, but also emphasizes the range of uncertainties around the forecasts. This permits a much fuller assessment of price risks and highlights the market factors that could influence natural gas prices.

Wide ranges of important supply and demand drivers of natural gas prices were modeled. For each given variable, both a "high" case and a "low" case were considered. In the "high" case there is a 90% chance that the variable will have a value at or below; in the "low" case there is only a 10% chance that the variable will take a value at or below the case. For example, the P90 case for LNG imports assumes that LNG will supply fully one-third of U.S. demand (LNG currently makes up about 3%)[33] (Appendix I, Section 4.2).

Some sample drivers, and the range of their considered values, are shown in Figure 3-12 (see Appendix G1, Section 4.3.8 for more assumptions and discussion):

Figure 3-12. U.S. Gas-fired Power Generation Demand Distribution Range

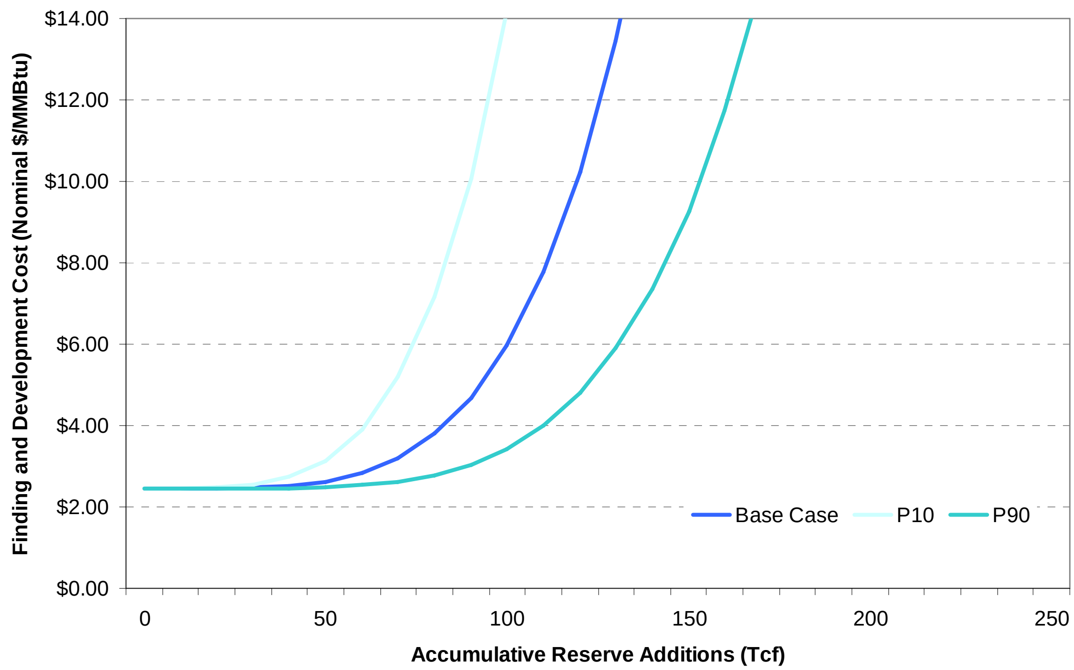


Source: Black and Veatch; Appendix G1, Section. 4.3.8.2.4

[33] *See* EIA, 2008: "Natural Gas Consumption by End Use"; http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm, and EIA, 2008: "U.S. Natural Gas Imports by Country" http://tonto.eia.doe.gov/dnav/ng/ng_move_impc_s1_a.htm

The foregoing imagines the need for gas generation being both much larger and significantly smaller than under the "base case."

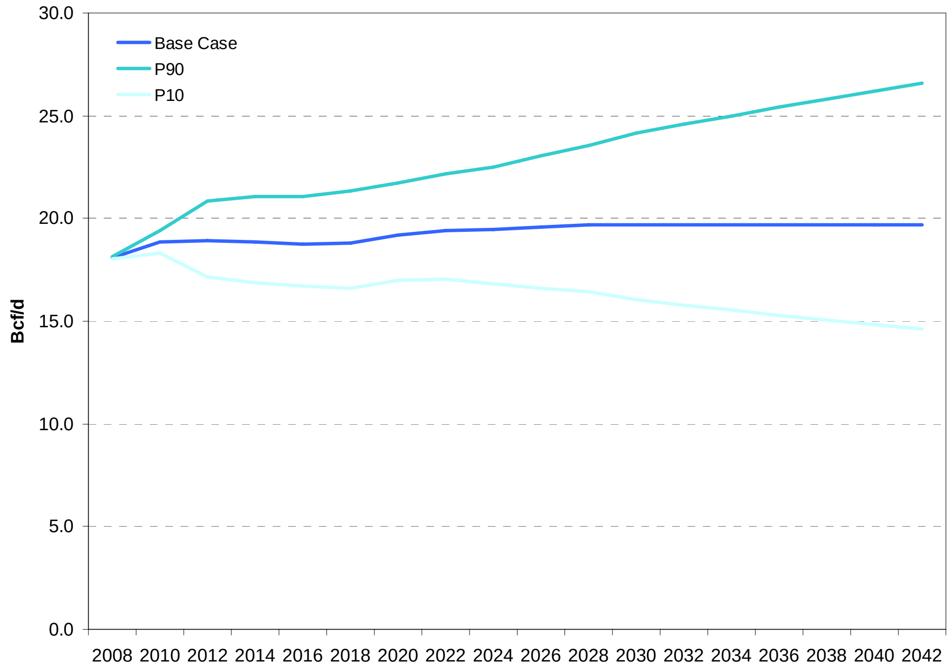
Figure 3-13. WCSB Finding and Development Cost Curve (Real 2008 $)



Source: Black and Veatch; Appendix G1, Section 4.3.8.2.1

The cost of finding and developing new gas resources in a given supply basin has a significant effect on future prices. Here we assume a high-to-low multiple of about two.

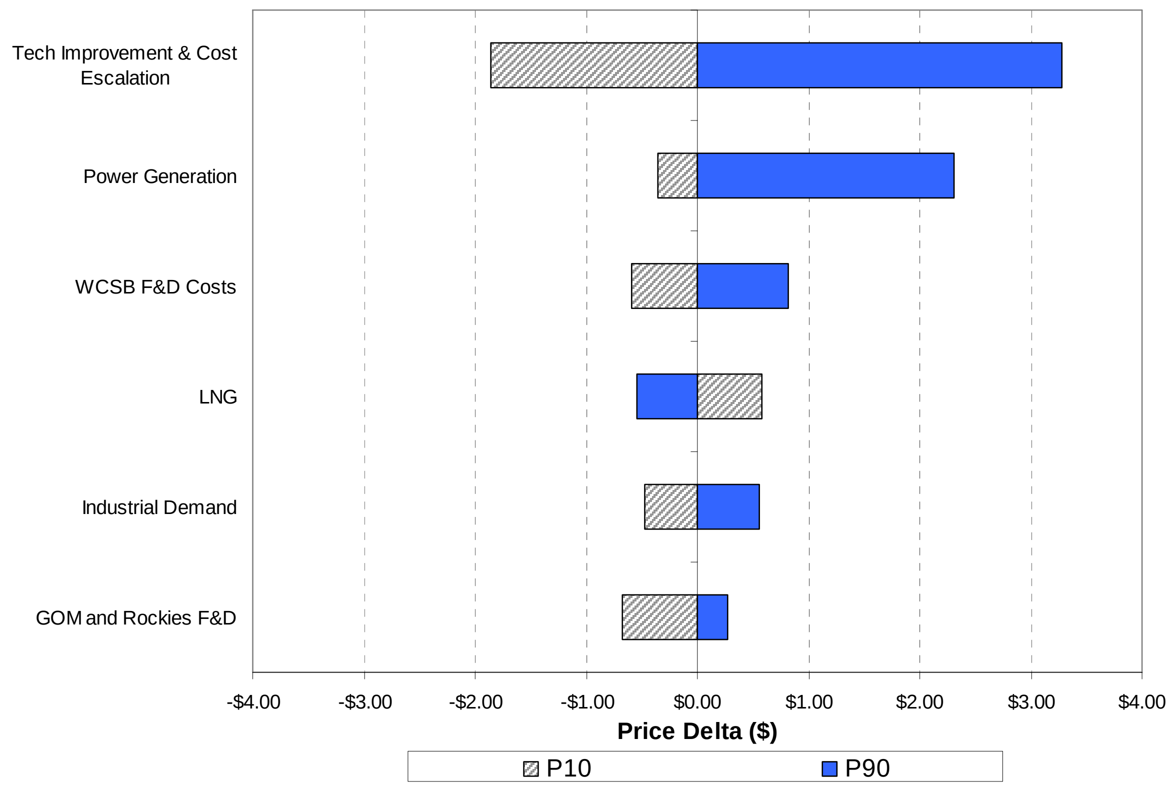
Figure 3-14. U.S. Lower 48 Industrial Demand Distribution Range



Source: Black and Veatch; Appendix G1, Section 4.3.8.2.5

The relative impact of each fundamental driver on the AECO Hub price is shown, below (Figure 3-15).

Figure 3-15. Relative Impact of Price Drivers on AECO HUB Price Formation, 2022 (Nominal $)



Source: Black and Veatch; Appendix G1, Section 4.3.8.3

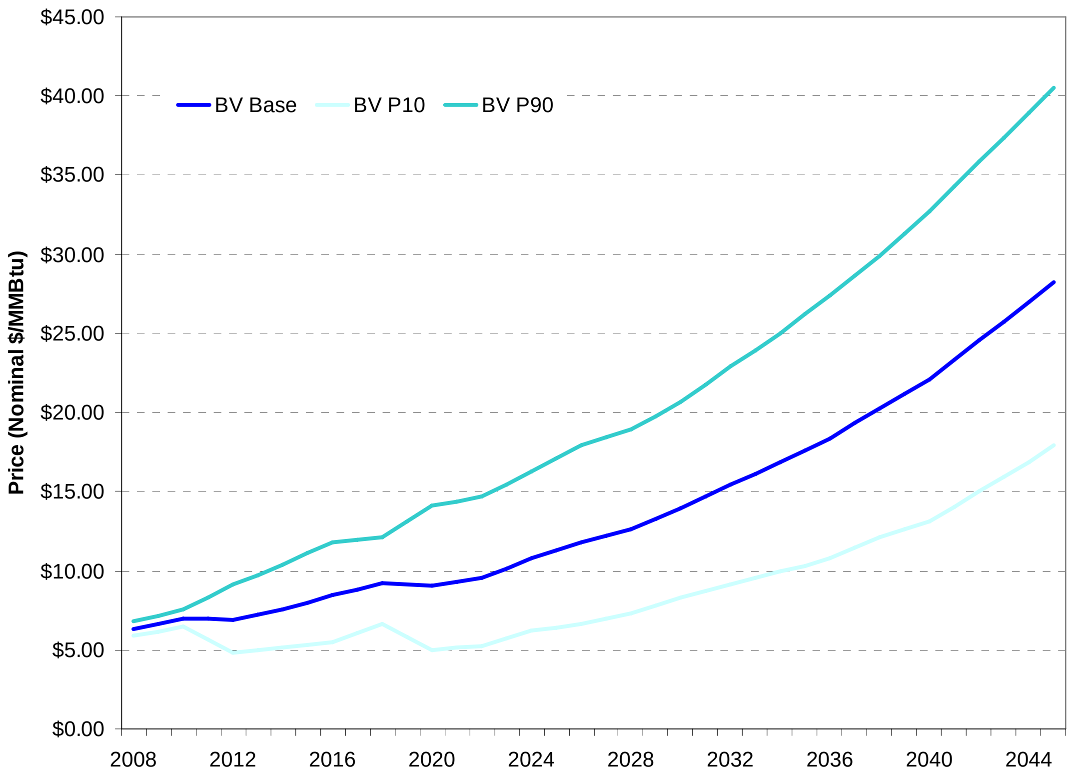
The impact of each driver is shown by assuming all other drivers are held constant at their "base case" levels, and then varying the driver in question. By a significant margin, the largest effect on AECO Hub prices in 2022 is the cost of finding and developing new gas resources, which is itself most affected by the rate of technological innovation and cost escalation. The level of gas demand from power generation also particularly matters in this time frame.

Although the previous chart considers them separately, the uncertainties in each of these drivers can be jointly considered. That is, one might want to know, for example, both what the price would be if LNG imports are high, and electricity demand is low, but also the likelihood of both events simultaneously occurring. Using statistical techniques, Black and Veatch integrated the NARG analysis into a Monte Carlo framework[34] (Appendix G1, Section 4.3.8.1). This result is not a *single* price forecast, but many thousands of price forecasts. The collection of these

[34] Although the details differ somewhat, the general Monte Carlo simulation approach taken for price is similar to that used in the cost modeling work, which is discussed ,below.

forecasts forms a probability distribution of future prices. The results are shown, below (Figure 3-16).

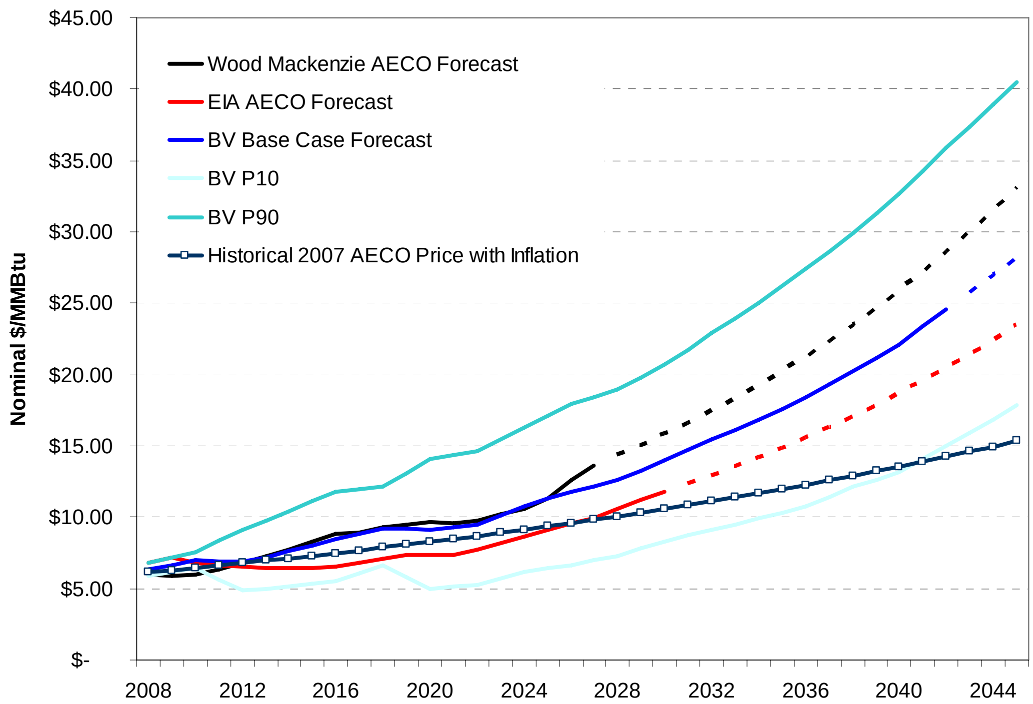
Figure 3-16. Distribution Range of AECO Price Forecasts over Time (Nominal $)



Source: Black and Veatch; Appendix G1, Section 4.3.8.4

The relevant question, when considering future gas prices, remains simple: will they generally be greater than the costs of gas transportation, treatment, and production, so that the project generates positive net backs and can provide a positive NPV? The answer cannot be known with certainty. However, on balance it appears highly likely that they will be. The following chart (Figure 3-17) shows the EIA, Wood Mackenzie, and Black and Veatch forecast.

Figure 3-17. AECO Price Forecasts (Nominal $)



Source: Black and Veatch; Appendix G1, Section 4.3.8,

f. Estimated Volumes of Natural Gas Sold

The second component of the net cash flow formula (price multiplied by volume minus cost equals net cash flow) is the volume of natural gas. In its application TC Alaska contemplates an initial annual average daily project capacity of 4.5 Bcf/day (Application 2007, Section 2.1.1). The pipeline base design—pipeline diameter, yield strength, compressor size—will accommodate volumes as small as 3.5 Bcf/d and provide for expansion through infill compression up to at least 5.9 Bcf/d (Application 2007, Section 2.2.3.2(1); 2.2.1). Because TC Alaska does not control gas reserves it cannot determine how much gas the pipeline will transport. Accordingly, throughput must be modeled according to various plausible scenarios. There are two issues of importance that must be considered in constructing any plausible throughput scenario: a) how much gas, in total, will flow; b) the relative proportions from various gas fields of this total flow. Total flow is an important determinant of total project revenue. The relative proportions matter because the costs of production differ considerably across fields and, because of the net profit tax structure of the state's production tax, production costs have a significant effect on state NPV.

The NPV model tracks four major "pools" of gas. Prudhoe Bay will be the project's main anchor. It contains over 24 Tcf of gas (ADNR 2007).[35] Point Thomson also contains very significant gas reserves; based on work by PetroTel, it may contain up to 10.4 Tcf of gas (Appendix O). Total recoverable reserves from Point Thomson could range from 5 to 7 Tcf.[36] Other "State Existing" proved reserves, scattered between the Colville River, Duck Island, Kuparuk, and Northstar Units, and the Greater Point McIntyre Area of Prudhoe Bay, together total roughly 3.7 Tcf of known gas reserves. These are modeled as a single "pool." Finally, gas for the project may come from significant yet to be found (YTF) resources.

Prudhoe Bay

Prudhoe Bay currently produces over 7.4 Bcf/d,[37] most of which is currently reinjected into the reservoir to maintain reservoir energy and enhance oil production. The unit is clearly capable of producing natural gas at a very considerable rate. The issue for this analysis is simply what rate might be approved by the Alaska Oil and Gas Conservation Commission (AOGCC), and what the consequences of different off-take rates for oil production might be.

We have modeled gas off-take rates for Prudhoe Bay and into the Project at 3.0 Bcf/d (for the "Proposal Base Case") and 3.5 Bcf/d (for the "Conservative Base Case"). These off-take rates, although in excess of those currently approved by AOGCC, are nevertheless reasonable because they are highly likely to pass regulatory muster. The remainder of this subsection explains why.

The AOGCC is responsible for implementing the Alaska Oil and Gas Conservation Act (AS 31). It is charged with regulating oil and gas practices in order to prevent "waste" of oil and gas and promote greater ultimate recovery of oil and gas. "Waste," in addition to its ordinary meaning, includes:

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[35] Alaska Department of Natural Resources (ADNR). *Alaska Oil and Gas Report*. July 2007. Available at http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm

[36] The low end of this range reflects low-end results generated by PetroTel in its Point Thomson reservoir simulation work for a gas cycling development, while the upper end reflects possible recovery under gas blow-down development; *see* Appendix O for discussion.

[37] See BP's submitted "2008 Plan of Development and Annual Progress Report for the Initial Participating Areas of the Prudhoe Bay Unit," March 31, 2008; p. 4.

> "the inefficient, excessive, or improper use of, or unnecessary dissipation of, reservoir energy; and the locating, spacing, drilling, equipping, operating or producing, of any oil or gas well in a manner which results or tends to result in reducing the quantity of oil or gas to be recovered from a pool in this state under operations conducted in accordance with good oil field engineering practices." (AS 31.05.170(15)(A))

In most cases "the specified wastes represent physical losses of oil and gas that tend to occur under competitive exploitation of petroleum deposits by individual operators using primary means of recovery." (McDonald 1971). McDonald goes on to explain that the "prevention of operations tending to cause loss of ultimate recovery does not in practice extend to a positive requirement that all feasible means be employed to maximize recovery" (McDonald, p. 122) and goes on to define waste as *"a preventable loss the value of which exceeds the cost of avoidance" (*McDonald, p. 129, emphasis added)

AOGCC carries out its responsibility by regulating the quantity and rate of the production of oil and gas. (AS 31.05.030(e)(1)(F)). The AOGCC does not determine and direct the rate or method of production. Rather it responds to operators specific requests for approval of off-take rates and volumes. Operators file requests with the AOGCC for allowable off-take rates and volumes with technical justification for their requests.

In 1977, the Prudhoe Bay Unit (PBU) owners requested and received approval from the AOGCC of a maximum allowable PBU annual gas off-take rate of 2.7 billion standard cubic feet per day (BSCF/D), which contemplated an annual average gas pipeline delivery sales rate of 2.0 BSCF/D.

Between 2002 and 2007, there was much public discussion by the Major North Slope Producers and others about a 4.3 BSCF/D gas pipeline with capacity to expand to 5.6 BSCF/D.[38] The AOGCC expressed concern that delay in their decision-making could disrupt a timetable for a potential gas line project. The AOGCC adopted a proactive approach to ensure there would be an adequate factual basis for its eventual decision on allowable gas off-take. The PBU working interest owners (WIOs) provided the AOGCC access to their reservoir simulation and other relevant engineering studies for the purpose of analyzing gas off-take rates and gas sales startup timing for the PBU.

The AOGCC conducted a confidential study and recommended that a change to the current off-

[38] These prior discussions provide indirect support for the feasibility of TC Alaska's proposed 4.5 Bcf/day Project.

take rule was not necessary at that time because the producers had not yet requested a different gas off-take rate and did not have a sales startup date.[39] The AOGCC determined that the ultimate impact of gas sales on hydrocarbon recovery could not be appraised in the absence of a proposed development plan that identifies the start date, sales rate and liquid loss mitigation efforts. The AOGCC noted that the longer gas sales are delayed, the greater the risk that well and facilities failures will result in premature field shutdown. While the results of its study are confidential, the AOGCC has signaled that it is not concerned about a greater off-take rate to accommodate a major gas sale as long as the PBU continues to increase the capture of oil prior to gas sales and ensures that facility and well downtime is minimized. For example, in testimony before the Senate Resources Committee of the Alaska Legislature, Commissioner Cathy Foerster stated that "whenever we get a gas line and whatever gas sales volume, within reason, is called upon from Prudhoe Bay, it will be the right answer . . . the 'right answer' is that we will want to sell whatever volume is needed from Prudhoe Bay and we'll want to sell it whenever it is needed to ensure that the gas line is a go (Foerster, 2008)."

The Division of Oil and Gas (DOG) professionally evaluated all reservoir information provided by the PBU operator as part of its responsibility to evaluate and approve annual Plans of Development for the PBU. Based on all the information available, DOG believes that there is little risk that the AOGCC will not approve a change to the off-take rate for a major gas sale (assuming that PBU oil continues to be aggressively produced and mitigation alternatives are adopted). The PBU owners have an ongoing responsibility to provide the DOG with an annual reservoir surveillance report, an annual field overview presentation and annual plan of development that must be approved by the DOG.

As recently as March 2008, the PBU owners have shared with the DOG information about their gas sales evaluation framework. Potential major gas sales are at least ten years away. During the pre-commitment stage PBU working interest owners (WIOs) will look at gas off-take studies and will use a new full-field model for major gas sales forecasting. The PBU WIOs also plan to engage in depletion strategies to optimize total economic hydrocarbon recovery with gas sales. They continue to evaluate enhanced oil recovery options including potential use of carbon dioxide concurrent with major gas sales.

Oil recovery from the PBU has far exceeded initial expectations. In 1977 the PBU owners

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[39] *See* Prudhoe Gas Sales Reservoir Study, Feb. 28, 2007, Public Report Summary and Slides.

projected they would recover approximately 9 billion barrels of oil, begin major gas sales in the 1980s and reach end of field life by 2003. Gas sales didn't materialize in the 1980s and more than 11 billion barrels of oil have been recovered to date. PBU oil recovery is currently projected to reach 13 billion barrels, providing another almost 2 billion barrels of oil. PBU's 24 TCF of gas in the gas cap is equivalent to 4 billion barrels of oil. Gas is currently reinjected to produce oil. As time goes on, there is ever increasing water and gas in every barrel of oil that is produced. The increasing costs to produce a marginal barrel of oil will tip towards producing the gas for sale rather than consuming it to produce marginal barrels of oil. The success in recovering oil will make it easier for the AOGCC to approve whatever amount of gas the producers eventually seek permission to take. PBU oil production will continue even after major gas sales begin.

In sum, for the reasons discussed above, we believe that at the appropriate time in the future AOGCC will take the actions necessary to facilitate sales of natural gas needed to fill the Project capacity consistent with the volume forecast relied on in our NPV analysis.

Point Thomson

As discussed earlier, the nature and pace of development at Point Thomson is subject to considerable uncertainty. The primary driver of this is actually geological uncertainty. Different geological interpretations of the available data suggest:

- The volumes of original gas in place (OGIP) range from 8.5-10.4 trillion cubic feet (TCF).
- The volumes of associated condensate range from 490-600 million barrels (MMB) of condensate in place.
- A range of volumes of original oil in place (OOIP) in the oil-rim from 580-950 MMB (Appendix O).

Resolution of what is actually in place and what can be recovered, and how, will not occur until more wells are drilled and production begins. It is exceedingly unlikely, even absent the extant litigation over Point Thomson development that the necessary actions—development, commercial, and regulatory—could be taken in time. With financing decisions needing to be made within roughly 6 years, it is highly unlikely that geological uncertainty could be resolved sufficiently, and in a timely manner, for Point Thomson gas to be available to help underpin the initial financing of any gas pipeline project.

Nevertheless, for NPV modeling purposes we consider two cases. In the first, the "Proposal Base Case," Point Thomson is indeed available to help underpin project financing. It gets developed using a primary depletion strategy ("gas blowdown") and initially produces at 1 Bcf/d. In the second case, the "Conservative Base Case," Point Thomson is developed as a cycling project and is not available until much later.

State Existing

Other proved gas reserves are brought into the project, in aggregate, in both Base Cases at an initial rate of 0.5 Bcf/d. Additional details concerning the assumptions made regarding other proved gas reserves are included in Appendix G1, Section 4.

Yet To Find Gas

Studies estimate that there are 224 trillion cubic feet of undiscovered, technically recoverable natural gas resources throughout the Alaskan Arctic (USGS, 2005. NETL, 2007. Appendix O). Of this amount, 137 trillion cubic feet are categorized as undiscovered, economically recoverable resources. (NETL 2007). In terms of overall hydrocarbon potential there would appear to be an abundant supply of natural gas for the project. Although gas exploration and development is an inherently uncertain business, it appears that future gas discoveries will be more than sufficient to fill the pipeline's capacity during the life of the Project. The conclusion is reinforced by a comparison with the reserve base supporting other greenfield projects. (Appendix J; Section III) In both Proposal and Conservative Base Cases, the NPV model assumes that sufficient gas will be found to keep the Project operating at full capacity.

Although gas exploration and development is an inherently uncertain business, it appears that future gas discoveries will be more than sufficient to fill the pipeline's capacity during the life of the Project.

The modeling assumptions around "yet to find" (YTF) gas volumes, timing, and cost of development are based squarely on a recent study by the U.S. Department of Energy's National Energy Technology Laboratory (NETL; Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?; hereafter "Alaska Gas Study").[40] NETL concludes there are approximately

[40] Appendix L provides a detailed discussion of the NETL study, and explains the minor extensions of the study upon which the timing, volume, and cost assumptions concerning YTF gas were based. The assumptions about costs for developing YTF resources were then used in the Upstream Model. For details see Appendix G1, Section 3.8.

137 Tcf of economically recoverable natural gas reserves on the North Slope, about four times greater than estimates of known reserves. Table 3-1 summarizes NETL's conclusions, showing NETL's estimates within various individual North Slope producing areas.

Table 3-1. NETL's Estimate of Economically Recoverable Natural Gas Reserves

Exploration Province	Near Term 2005 to 2015	Long Term 2015 to 2050	Total 2005 to 2050
Colville-Canning and State Beaufort Sea	10.0 TCF	23.3 TCF	33.3 TCF
Beaufort Sea OCS	1.0 TCF	20.0 TCF	21.0 TCF
Chukchi Sea OCS	0 TCF	50.0 TCF	50.0 TCF
NPRA	1.0 TCF	30.0 TCF	31.0 TCF
ANWR 1002 Area	0 TCF	2.0 TCF	2.0 TCF
TOTAL ARCTIC ALASKA	**12.0 TCF**	**125.3 TCF**	**137.3 TCF**

Source: National Energy Technology Laboratory 2007

Under NETL's estimate there should be more than enough natural gas to fill the Project's capacity for the entire 25-year Project life, and for a significant time beyond. At a capacity of 4.5 Bcf/day, it would take 41 Tcf of gas to keep the Project at capacity for 25 years—roughly 6 Tcf beyond the existing proved reserve base, or only about 5% of the total economically recoverable reserves that NETL estimates exist. On the other hand, if NETL's estimates are correct, then reserves should be sufficient to keep the pipeline full for more than 100 years. Even under a conservative assumption, it appears that there is more than enough economically recoverable natural gas reserves exist to fill the Project's capacity during the Project's proposed 25-year life and beyond.

In general the NPV model assumes that YTF gas is available to fill the pipeline capacity when it is needed. This involves making simplifying assumptions that depart from the "real world": rather than gas developments being "lumpy" and potentially requiring expansions, for the Base Cases the model assumes that YTF gas flows into the Project as needed. The alternative approach—trying to make "realistic" assumptions about the timing and degree of "lumpiness" of discoveries, with possible attendant expansion—would have been worse. For modeling details for YTF gas see Appendix G1, Section 3.8. It is worth stressing that the economic returns provided by YTF gas, discussed subsequently in this Chapter, appear sufficiently attractive to attract the necessary investment. The profile of gas production from different "pools" for the Proposal Base Case and Conservative Base Cases are shown below (Figure 3-18 and Figure 3-19, respectively).[41]

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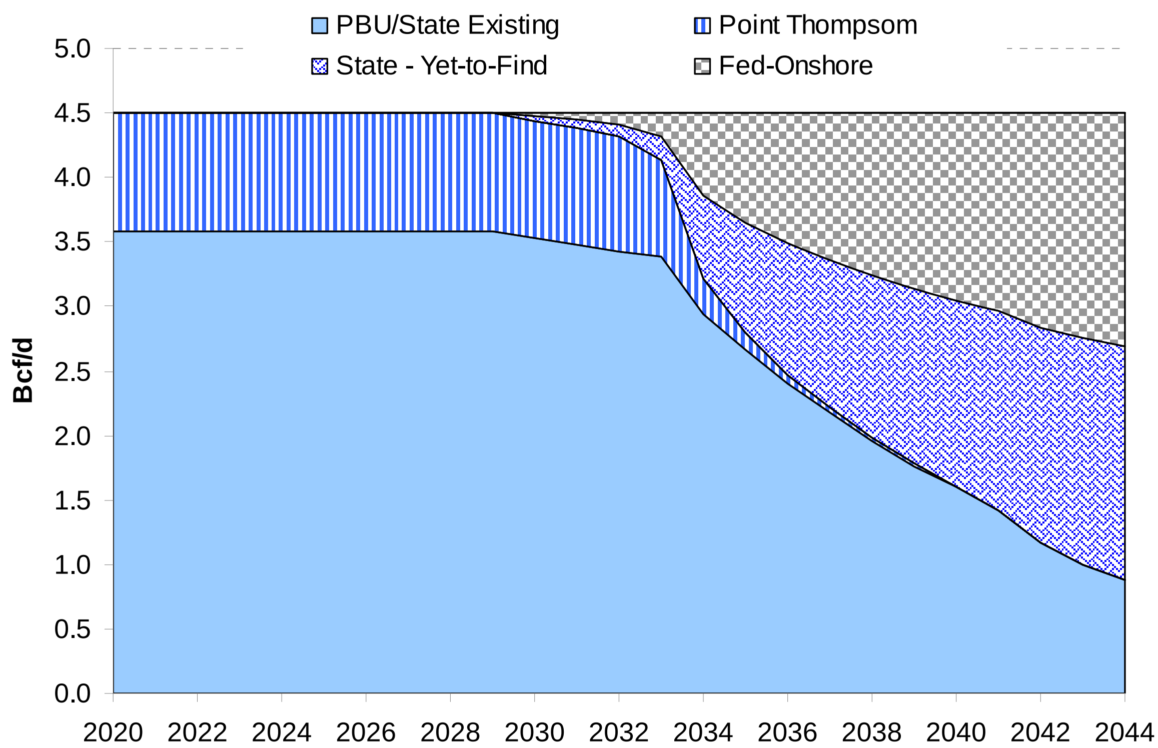
[41] Note that, to maintain the data confidentiality, Prudhoe Bay and State Existing gas are shown as an aggregate

Figure 3-18. Production Profile for Proposal Base Case



Source: Black and Veatch; Appendix G1, Section 4.2.2.1

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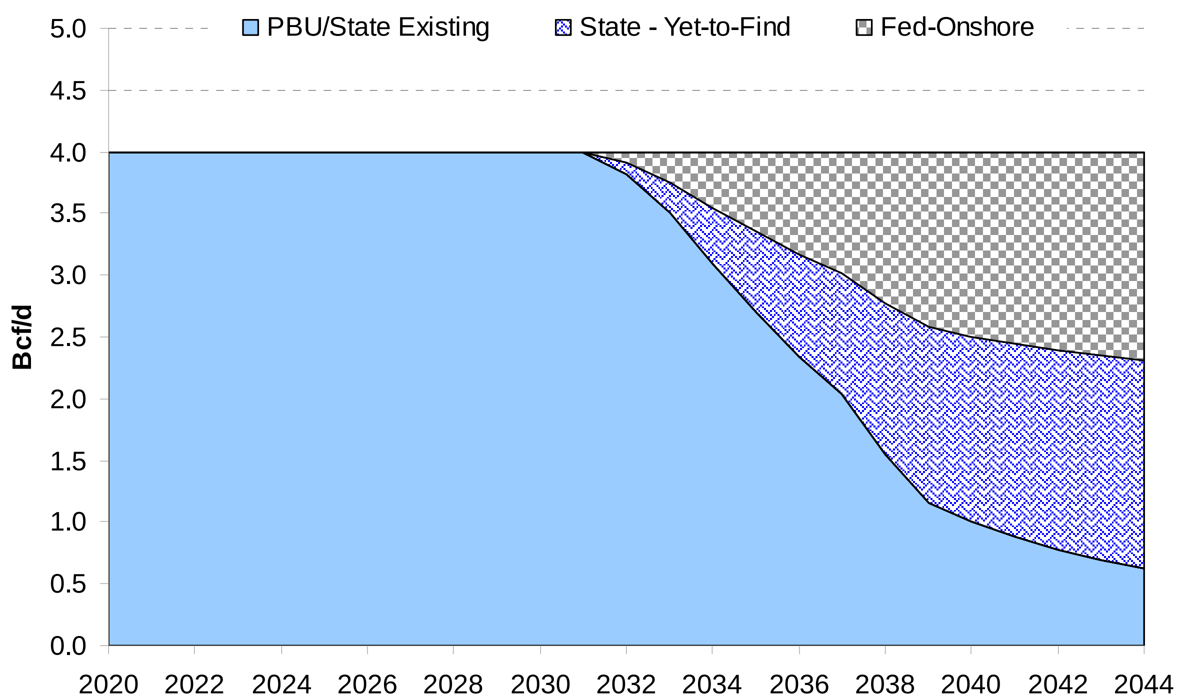
pool, even though the model tracks each separately.

Figure 3-19. Production Profile for Conservative Base Case



Source: Black and Veatch; Appendix G1, Section 4.2.3.1

Production scenario sensitivities were run off the Base Cases. For both cases, project economics were considered for the extreme case where no YTF resources were developed. The Proposal Base Case was also run under the assumption that PTU was not available, but that PBU production was increased to make up the difference. Details and results are available in Appendix G1 Sections 5 and 6, and are treated later in this Chapter.

Market factors, including competition among producers and the production economics of particular fields, are likely to determine exactly which scenario becomes reality. Producers will incur only minimal incremental costs to produce natural gas from Prudhoe Bay, due to the fact that natural gas can be produced using the extensive infrastructure already in place which is used to produce oil (Appendix G1, Section 3.8). The production costs for Point Thomson, and YTF gas will be materially greater, because those areas do not have extensive production infrastructure already in place (Appendix G1, Section 3.8).

From an NPV perspective, the lower production costs at Prudhoe Bay mean that the NPV to the state and the Major North Slope Producers is significantly higher under the scenarios that assume no Point Thomson production, and more rapid production of Prudhoe Bay. The low incremental cost of natural gas from Prudhoe Bay should mean that production and sale of these volumes would be very profitable to the Major North Slope Producers and would justify construction of a pipeline to deliver North Slope gas to market even in the absence of the other volumes expected to be available. This is detailed fully in later sections summarizing the NPV to each of the major stakeholders (Appendix G1, Section 5.6).

The low incremental cost of natural gas from Prudhoe Bay should mean that production and sale of these volumes would be very profitable to the Major North Slope Producers and would justify construction of a pipeline to deliver North Slope gas to market even in the absence of the other volumes expected to be available.

g. Estimated Pipeline and GTP Costs, Schedule, and Tariffs

Overview

Pipeline and GTP tariffs are a key determinant of the state's overall NPV from the project. As the tariff or transportation rate rises (which is based on the cost of the Project), the value upon which royalty and production taxes are based falls. Accordingly, the state focused extensively on developing an independent understanding of the future costs of the pipeline and GTP.

The state did not rely on TC Alaska's assessment, as presented in its Application, of the Project's cost and schedule (Application 2007, Section 2.5). Doing so would have failed to address the risk that TC Alaska's assessment might be incorrect. Just as with future prices, future costs cannot be known with certainty. Accordingly, the state particularly focused on developing a detailed understanding of the probable range and relatively likelihood of future cost outcomes.

There are two key types of uncertainty that affect future costs of the Project. The first is Project "scope uncertainty." That is, there is currently an imperfect understanding of all of the details of exactly what will be constructed and how it will be constructed. Until those details are resolved it is impossible to develop a fully refined understanding of what the project may cost. In general, as more field work, detailed engineering, and procurement planning are performed, scope uncertainty diminishes.

The second type of uncertainty is cost "escalation uncertainty." That is, even if project scope could be perfectly understood today, there remains considerable uncertainty as to what it will cost to build the project being contemplated. Actual procurement—whereupon actual costs of various portions of the project get established—will not begin for at least five and a half years and is more likely to start six and a half years from now. (Application 2007, Section 2.6) Predicting the cost of steel, labor, and other critical inputs into the cost of Project construction that far into the future is exceedingly difficult.

To separate the effects and importance of "scope" from "escalation" uncertainty, the AGIA RFA asked applicants to submit costs in 2007 dollars. In essence, TC Alaska's Project cost estimate reflects its current understanding of project scope. By stripping out uncertainty as to future costs of steel, labor, and the like, TC Alaska's cost estimate could be critically reviewed and assessed for scope uncertainty. As discussed in detail in the next section, TC Alaska's cost estimate was subject to a thorough due diligence review by the state. Recognizing that all cost estimates used for planning purposes should be both realistic and aggressive—if they are not aggressive, then there is no hope of achieving a favorable outcome in practice—the state endeavored to develop a detailed understanding of the risks of costs differing from those used in planning. Accordingly, the state directed its Technical Team to develop probability distributions of project costs, as expressed in current dollars.

The eventual GTP and pipeline cost estimates, which determine eventual GTP and pipeline tariff estimates, were established by escalating the current dollar (scope) cost estimates by an escalation rate. In NPV model runs the base case escalation rate is 4% per year. Additional sensitivities of 2% and 6% were also considered.[42] Although cost increases in the industry have climbed much faster than 4% for the last few years, on balance we believe that this trend is unlikely to continue. Over the last twenty five years, the pipeline escalation rate has averaged about 3.6% per year (Appendix F, Section 2.1.5). Pipeline capital costs are currently above the historical trend line, which suggests that a continuing acceleration of costs is unlikely to be sustained. (Appendix F, Section 2.1.5).

In current dollars, reflecting the base-case escalation rate of 4% per year, the mid-range cost estimate for the Proposal Base Case is a little more than $31 billion; the mid-range cost estimate for the Conservative Base Case is about $29 billion (Appendix F, Exhibit D). If the project could be built today the tariffs would be $3.19 and $3.59 for the two respective Base Cases. After accounting for annual cost escalation of 4%, the final project costs for money as

[42] Appendix F (Tech Team), Section 2.1.5, provides support for why these escalation rates are reasonable.

spent will be $45 billion for the Proposal Base Case, and $42 billion for the Conservative Base Case. As noted earlier, these figures translate to tariffs if $4.73 and $5.33 for the Proposal Base and Conservative Base Cases, respectively (Appendix G1, Section 6.4.1). Under each of the price projections discussed earlier, including conservative Black and Veatch pricing scenarios, the Project provides significantly positive net backs.

The following discussion summarizes our assessment—both the method of investigation and the study results—of Project cost and schedule risk, as expressed in probability distributions.[43]

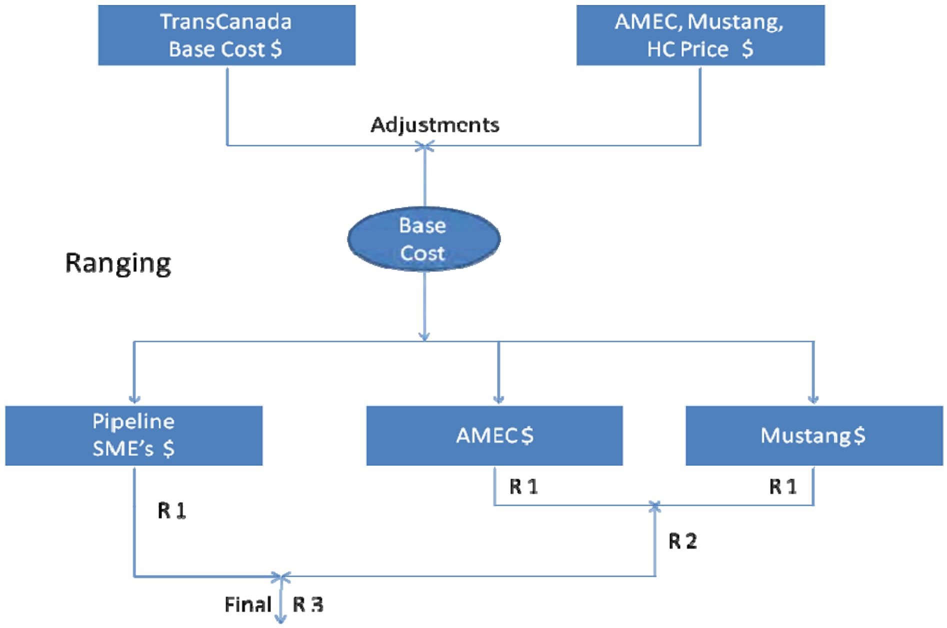
h. Pipeline Cost and Schedule Analysis, Including Cost and Schedule Ranges

Current-dollar Cost Ranges: Scope Risk. To assess Project Cost risk the state did not rely on TC Alaska's cost estimate, but rather developed an independent assessment of Project Scope risk. TC Alaska's cost estimate can be located as one possible outcome along the range of possible project cost outcomes.[44] Separate probability distributions for each major subproject—GTP, Alaska pipeline segment, Canadian pipeline segment—were developed for both the development phase and the execution phase. A complex, multi-step process was used to develop the probability distributions. This process is depicted on the following chart (Figure 3-20):

[43] More detailed treatment of the topic is provided in Appendix F.

[44] TransCanada's total estimated cost for the Project is approximately $25.8 billion, including $20 billion for the pipeline facilities and $5.8 billion for the GTP. *See* Application at 2.5-2. TransCanada also included total cost estimates for its proposed project at the "sub-project" level (*i.e.,* Gas Treatment Plant, Alaska Pipeline Segment and Canadian Pipeline Segment). In response to information requests, TransCanada provided a more detailed breakout of pipeline development phase costs and pipeline execution phase costs by subproject, and more detail to distinguish between pipeline and compression costs during the Development Phase and the Execution Phase of the Project. (See TransCanada's responses to data requests dated December 11, 2007, January 15 and January 24, 2008). The more detailed cost estimates became the starting point for the cost analysis.

Figure 3-20. Subproject Component Cost Ranges—Derivation Process



Source: Westney 2008, Appendix F, Section 3.2.2

The Technical Team first divided each subproject into a number of major cost components. Major components of the Alaska pipeline subproject, for example, include Major Equipment and Materials, Installation, and Owners Costs (Appendix F, Table 1). For each subproject component a "base case" cost estimate was developed. The "base case" was determined with reference both to TC Alaska's estimate for the subproject component cost and to an independent cost estimate developed by the state's Technical Team (Appendix F, Section 2.1).[45] In some cases, the TC Alaska estimates were used to set the "base case" for the simple reason that TC Alaska's estimates, if generally validated by the independent estimate, reflected TransCanada's years of experience studying this project and dealing with large diameter, high-pressure gas pipelines in near-arctic conditions (Appendix F, Section 2.1).

The "base cases" became anchors for estimating "best" and "worst" case outcomes for each subproject cost component. (Appendix F, Section 2.1). The "best" case is the lowest value that

[45] In its application TC Alaska stated it preferred not to develop, own, or operate the GTP (an option permitted under RFA Section 2.1.2), but that it would do so if necessary. Application at 3.2.1-12. The Application nonetheless contained a conceptual design and description of the GTP plant and an overall cost estimate of $5 billion. Application at 2.1-12. Because TC Alaska provided relatively limited cost and schedule details concerning the GTP the "base" cases for GTP costs were primarily developed by Westney Consulting and Black and Veatch Engineering; (Appendix F, Section 2.1.1 and Appendix F, Exhibits B and J). The cost estimates were not based on a complete simulated GTP design, but were sufficient to provide a basis to make informed judgments as to cost and timing. Appendix F, Section 3.2.1 contains a detailed discussion surrounding the basis for GTP design adopted here.

each subproject component could reasonably be expected to attain. In essence, the "best" case reflects the lowest cost assuming "everything generally would go right"; there is about a 5% probability that the actual cost would be even lower than the "best" case. The "worst" case is similarly defined in terms of virtually nothing "going right"; there is about a 5% probability that the actual cost would be even higher than the "worst" case. Each subproject component "base," "best," and "worst" case determination was made by subject matter experts (SMEs) using a facilitated consensus process (Appendix F, Section 2.1.4). The determinations, along with the rationales underlying these determinations, are discussed in Appendix F, Exhibit B.

These *cost ranges* represent the reasonable bounds of outcomes associated with each subproject cost component. Once the foregoing *cost ranges* were established, appropriate probability distributions to characterize the relative likelihood of different outcomes within each range were selected.[46] Each of these probability distributions over each cost range for each subproject component was then used in a Monte Carlo simulation to develop a probability distribution for cost outcomes for the full subproject.[47] Monte Carlo simulation is a well-established method for probabilistic analysis, and a widely-used technique for predicting the likely range of outcomes for the cost and schedule of a construction project. Westney has developed and used variations of this technique for the past 30 years. A number of federal agencies and offices rely on the Monte Carlo simulation method as an analytical tool in a variety of circumstances, and view it as a valid methodological tool.[48] The results of the Monte Carlo

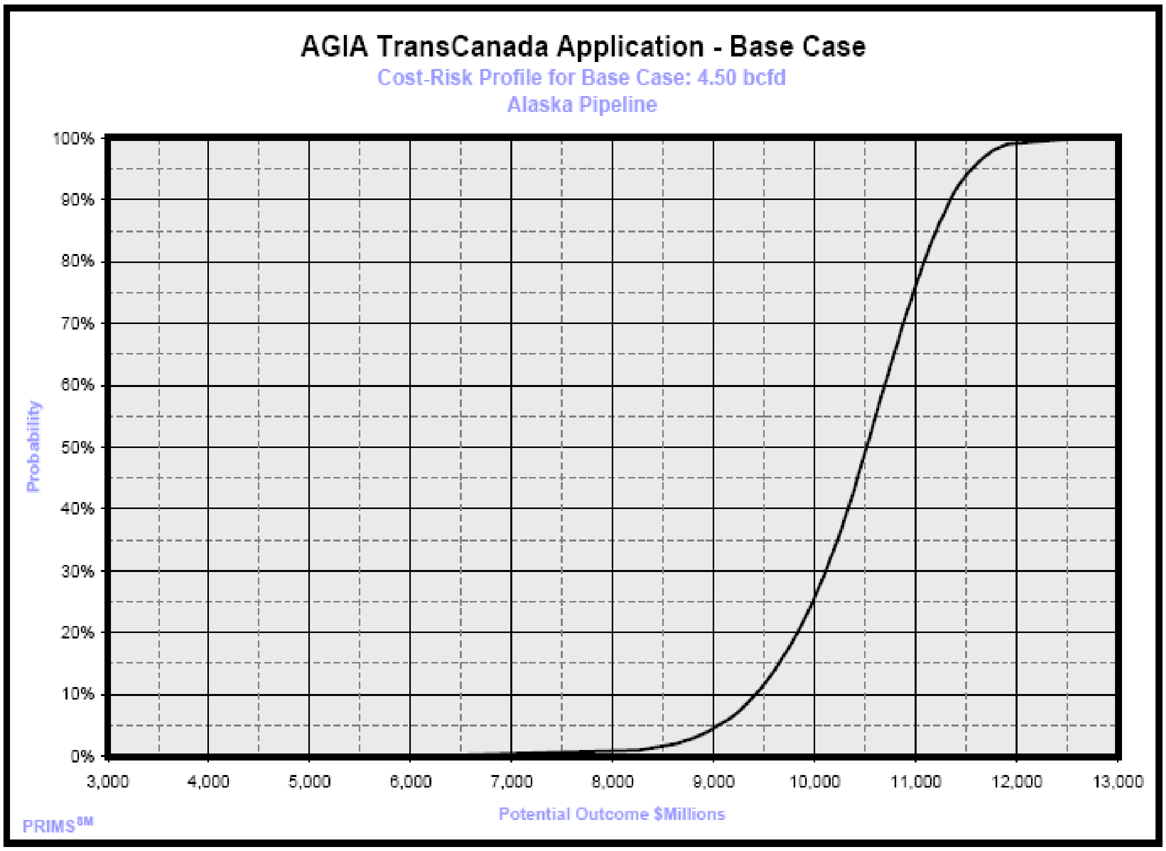
[46] A Minimum Extreme Distribution (right skewed) was used for the GTP because the GTP will be the largest gas treatment plant ever built and there are larger than normal risks associated with installation on the North Slope. A Maximum Extreme Distribution (left skewed) was used for the pipelines because it better matches historical estimates when a project is well defined by significant study and years of preliminary design. The normal "bell shaped" curve was used for the LNG Plant study because the costs used in the LNG study were based on historic projects with very wide cost ranges that were built over the past several years and were geographically spread around the world. (Appendix F, Section 2.1.4)

[47] In Monte Carlo simulation a computer selects at random one of the cost estimates contained in *each* of the subproject component ranges. The software then calculates the total cost that would result from that particular combination of subproject component costs. The process is then repeated thousands of times (10,000 iterations being standard practice) to produce an entire probability distribution, composed of the thousands of run results, for the total subproject cost.

[48] For example, the federal government's Government Accountability Office (the audit arm of Congress) and the executive branch Office of Management and Budget each view the Monte Carlo method as a valid methodology and employ it as an analytical tool in a broad array of circumstances. *See* GAO-06-823 (Washington, D.C., July 27, 2006) and OMB Circular Q-4. Other agencies which rely on the Monte Carlo method include: (1) the National Aeronautics and Space Administration (NASA), which has a Cost Estimating Handbook that calls for Monte Carlo simulation in cost estimating; and (2) the Federal Aviation Administration, which has a "Standard Benefits Analysis Methodology Final Guideline" (approved November 22, 2002) that recommends Monte Carlo simulation as an analytical tool as part of a complete cost estimate analysis—specifically to develop a statistical distribution of costs for various project elements and to compute the statistically-derived risk-adjusted constant dollars based on randomized parameters according to a range specified by an analyst as is done in the Westney model. In addition, the Department of

simulations, reflecting project scope pipeline cost risk, are presented in Figure 3-21. In current dollars, the Alaska pipeline subproject cost estimates ranged from roughly $8 billion to $12 billion for a 4.5 Bcf/day project, with a midpoint probability of $10.5 billion (Appendix F, Exhibit D; note that this and subsequent cost distributions, shown below, are Execution Phase costs only and do not include costs from the Development Phase). This compares with TC Alaska's estimate of $9.8 billion for the Alaska pipeline segment (Application 2007, Section 2.5.2).

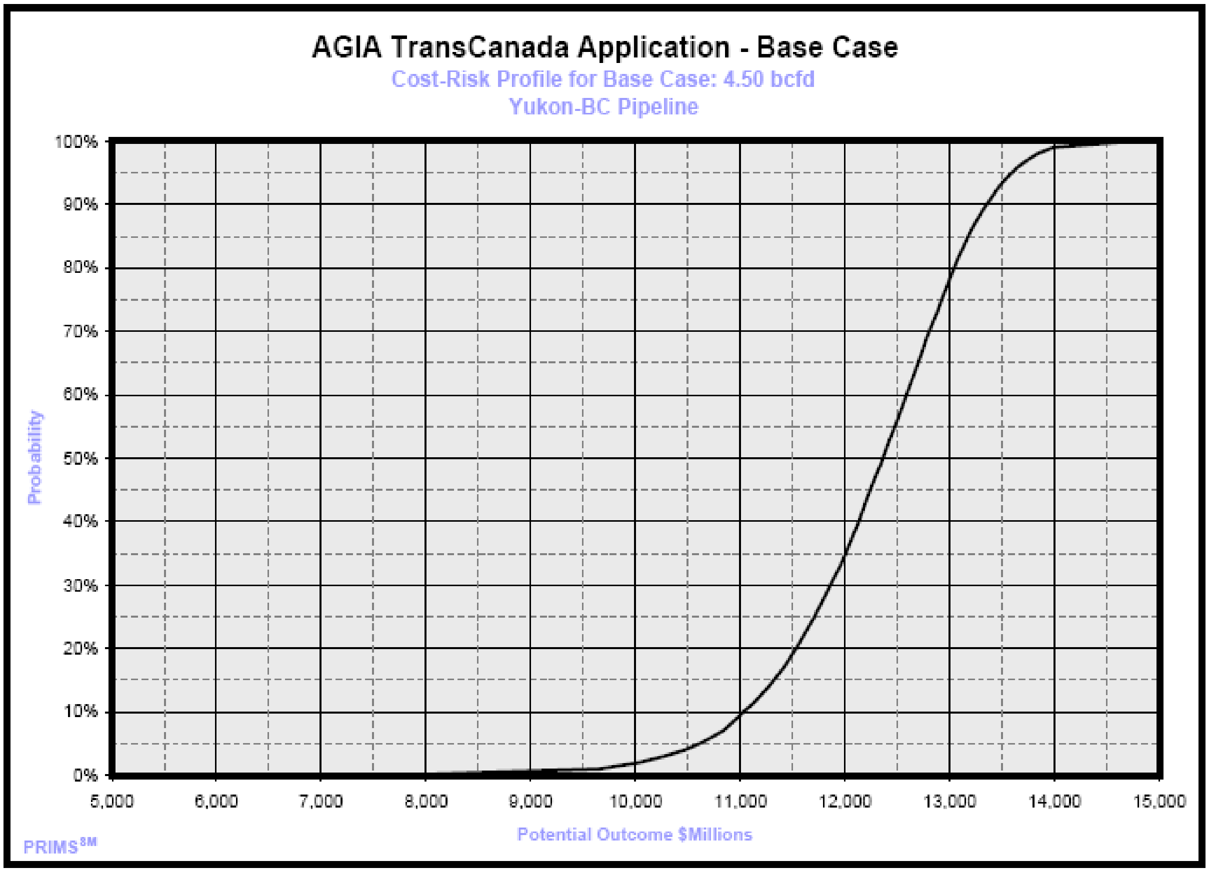
Figure 3-21. Proposal Base Case Cost Distribution—Alaska Pipeline



Source: Westney 2008; Appendix F, Exhibit D

Energy's Los Alamos National Laboratory cites applications of Monte Carlo methods to: cancer therapy; traffic flow; Dow-Jones forecasting; oil well exploration; stellar evolution reactor design; quantum chromo-dynamics; modeling of materials and chemicals; grain growth modeling in metallic alloys; behavior of nanostructures and polymers; and protein structure predictions. *See* Kindinger, "*Use of Probabilistic Cost and Schedule Analysis Results for Project Budgeting and Contingency Analysis at Los Alamos National Laboratory"* Los Alamos National Laboratory, 1999. In addition to the examples listed above, numerous Federal Register notices cite to the Monte Carlo method used by many Federal agencies, including the Environmental Protection Agency, the Department of Homeland Security, and the Board of Governors of the Federal Reserve. *See, e.g.* ,65 FR 7550 (Environmental Protection Agency), 73 FR 18384 (Department of Homeland Security), and 71 FR 55,958 (Board of Governors of the Federal Reserve). .

Figure 3-22. Proposal Base Case Cost Distribution—Yukon-BC Pipeline

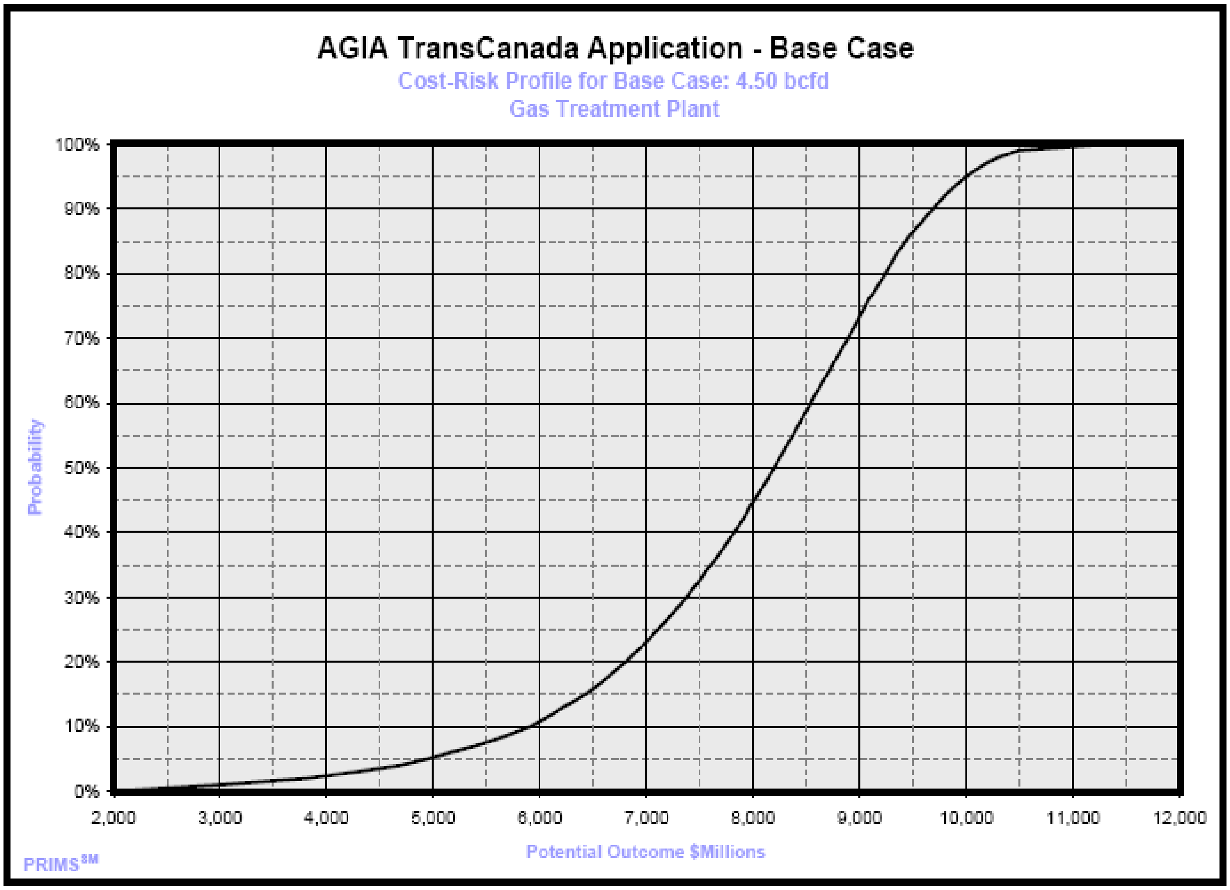


Source: Westney 2008; Appendix F, Exhibit D

The Yukon-BC pipeline subproject cost estimate ranges from roughly $9.5 to $14 billion, with a midpoint probability of $12.4 billion (Appendix F, Exhibit D). This compares with TC Alaska's estimate of $9.1 billion for the Yukon-BC pipeline segment (Application 2007, Section 2.5.2).

The GTP subproject cost estimate ranges from roughly $3 to $10.5 billion, with a midpoint probability of $8.2 billion. This compares with TC Alaska's estimate of $5.7 billion for the GTP (Application 2007, Section 2.5.2). While the cost range for the GTP is broad, estimating the cost of the GTP is particularly difficult in light of the numerous factors involved in designing, fabricating, transporting and installing the plant on the North Slope (Appendix F). Accordingly, the Technical Team's cost range prudently recognizes the possibility that costs for the GTP could increase significantly.

Figure 3-23. Proposal Base Case Cost Distribution - GTP



Source: Westney 2008; Appendix F, Exhibit D

Although the cost ranging for the GTP substantially relied on the state's own assessment of costs, the range appears reasonably supported by two recent, independent estimates. First, ConocoPhillips has recently indicated that it has done significant work on the design of the GTP, and has indicated a cost range of $4 to $6 billion (2007 dollars) for an outlet capacity of 4 Bcf/day and an inlet capacity of 4.5 Bcf/day.[49] Second, in a 2006 study done for the Alaska Department of Revenue, Petroleum Finance Corporation (PFC Energy) analyzed work done by Bechtel Corporation concerning the 3.8 Bcf/day outlet (4.3 Bcf/day inlet) plant proposed by the Port Authority to supply an LNG project. Bechtel estimated the cost of the GTP to be $5.1 billion (PFC Energy 2006). Converting these values into 2007 dollars for the present analysis and

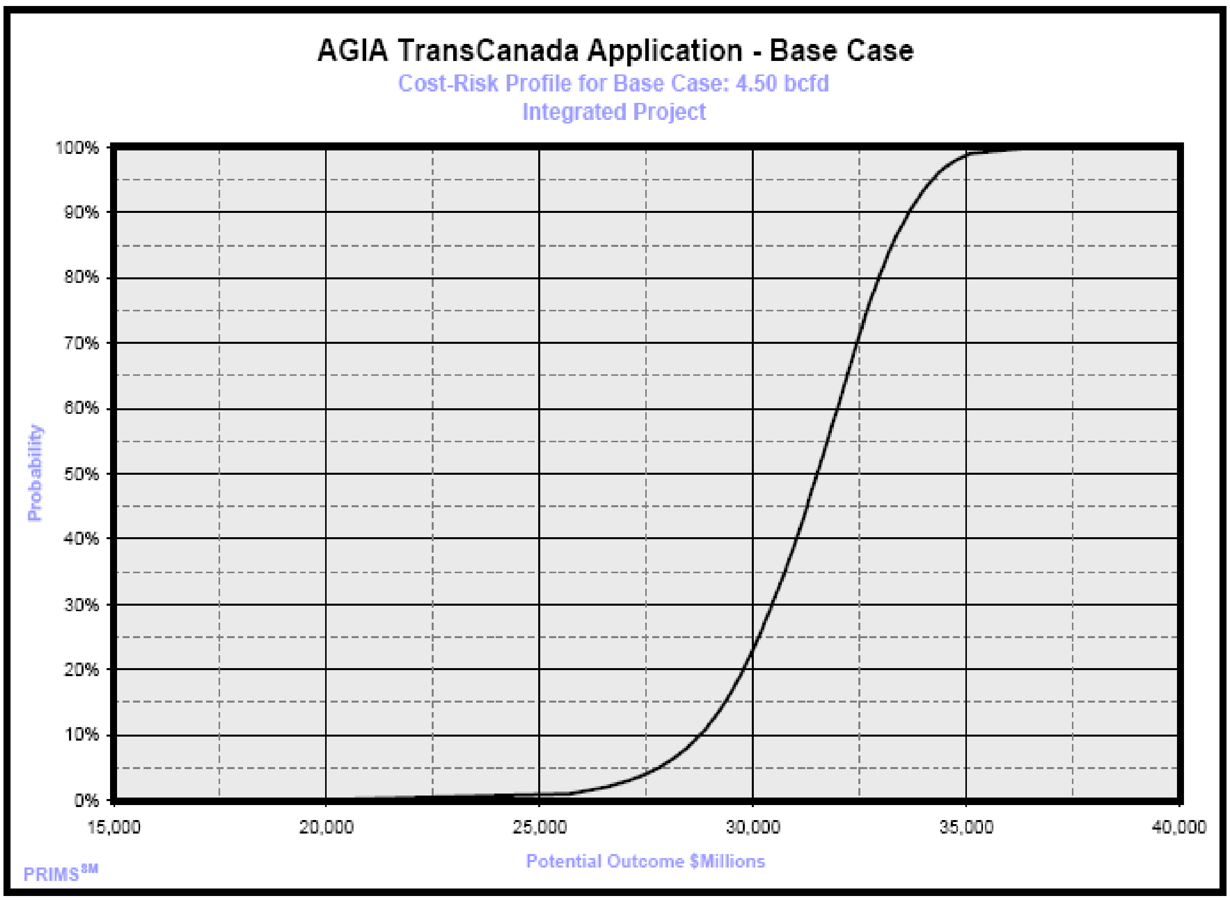
[49] ConocoPhillips Company, *Proposal to the State of Alaska*, at Section III, pages 1-4 (November 30, 2007)

adjusting them for published upstream capital cost escalation factors results in a $6.5 billion cost, which is less than the midpoint assumed by the Technical Team.

Overall, for the reasons summarized above and detailed in the Technical Team report (Appendix F), the GTP cost range provides a reasonable estimate for purposes of analyzing the TC Alaska proposal and assessing the NPV, and its uncertainty, to the state.

When considering the sum of all project subcomponents, and including the uncertainty associated with the development stage of the project, in current-day collars the project scope risk for the project's execution phase is summarized by the Figure 3-24, below.

Figure 3-24. Proposal Base Case Cost Distribution—Integrated Project



Source: Westney 2008, Appendix F, Exhibit D

The integrated project cost ranges from roughly $23 to $35 billion, with a midpoint probability of roughly $31.5 billion (Appendix F, Exhibit D). This is roughly 25% greater than TC Alaska's integrated project cost estimate of $25.1 billion (Application 2007, Section 2.5.1). This reflects the fact that the Technical Team, rather than accepting TC Alaska's cost estimates, independently analyzed those cost estimates and increased them where appropriate based on the Technical Team's experience and the objective evidence available to the Team.[50]

Given the foregoing, the likelihood seems small that TC Alaska will achieve its Application project cost estimate. However, this conclusion should be tempered in that these probability distributions were developed assuming a pipeline operator of *neutral competence*. To the extent that the operator does a good job anticipating, planning for, and working to mitigate project risks, the probability distributions will tend to skew to the left (there will be more likelihood of achieving lower-cost outcomes than illustrated here). As discussed below, TransCanada is an excellent pipeline operator. Accordingly, we expect that, on balance, the probability distributions that best describe likely outcomes are somewhat more favorable than what is presented here. However, no attempt was made in any of the NPV analysis to quantitatively adjust the probability distributions to reflect this.

As well, it should be stressed that we believe that TC Alaska's cost estimate is an appropriate one for this stage of project planning, if unlikely to be realized. Cost estimates used for planning purposes should be both realistic and aggressive. If they are not aggressive, then there is no hope of achieving a favorable outcome in practice. As described in the Technical Team's report, we believe that TC Alaska's estimate is realistically aggressive (Appendix F, Section 3.5).

Cost estimates used for planning purposes should be both realistic and aggressive. If they are not aggressive, then there is no hope of achieving a favorable outcome in practice. The commissioners believe that TC Alaska's estimate is realistically aggressive.

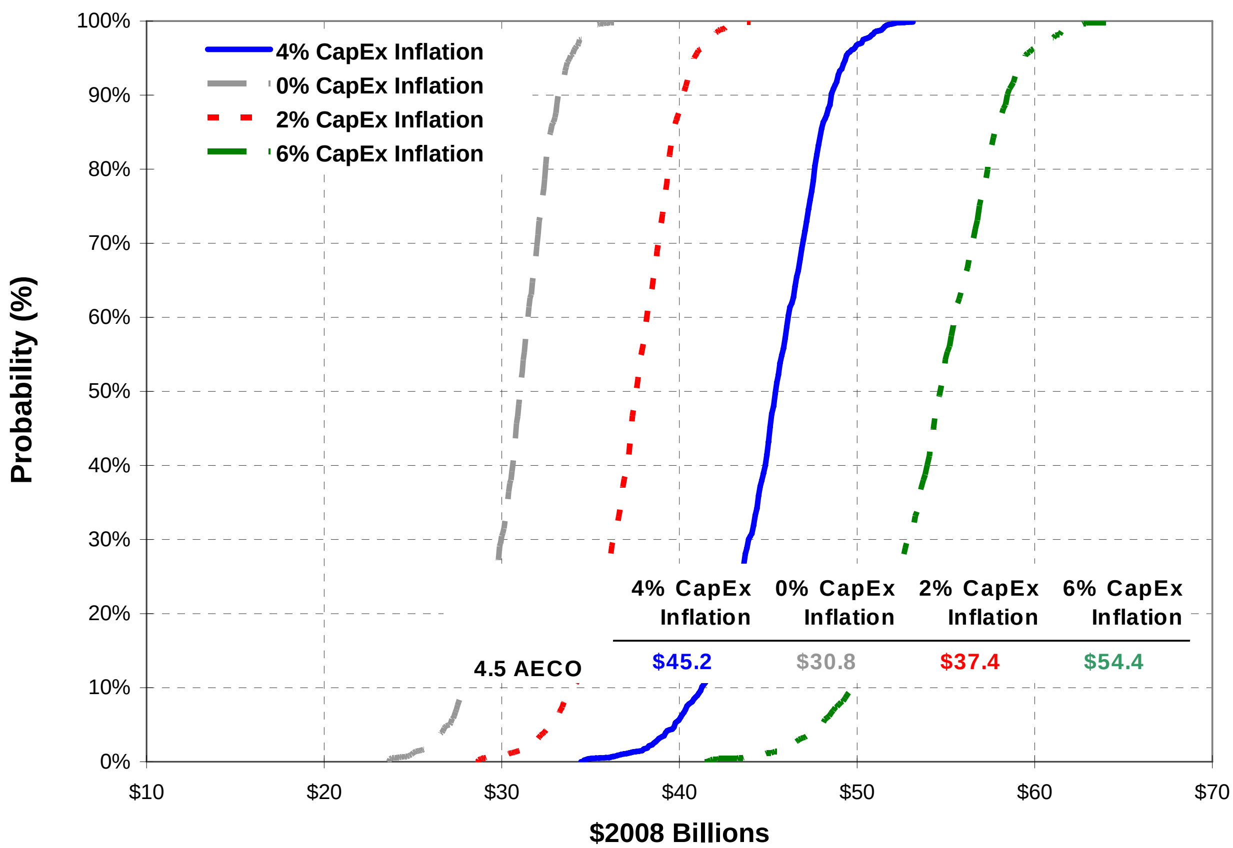
[50] The P95 cost estimate is approximately 40% more than TC Alaska's estimated Project cost, similar to the cost overrun scenario outlined in Exxon's comments. Compare Appendix F, Exhibit D with Exxon's Comments at 3.11.

i. Nominal Dollar Cost Ranges and Tariffs: Escalation Risk

The cost probability distributions discussed in the previous section indicate the risks associated with project scope. There is also cost risk associated with cost escalation. Assuming a 4% annual escalation rate, the integrated project cost ranges from roughly $35 to $55 billion, with a midpoint probability of roughly $45 billion (Appendix F). Put differently, this cost range reflects the actual money that may be spent on the project by the time it goes into service, over ten years from now.

If the escalation rate is 6%, such that pipeline construction costs in the next ten years exceed the annual rate of the last ten years (Appendix F, Section 2.1.5), then the project costs will be greater and the cost range will be wider. The integrated project cost ranges from roughly $45 to $65 billion, with a midpoint probability of roughly $54 billion (Figure 3-25).

Figure 3-25. Project Cost Risk: Comparing Project Escalation with Project Scope Risks Showing Cost Uncertainty and Risk Increasing With Escalation Rates



Source: Black and Veatch, Appendix G1, Appendix C

Schedule Risk

In addition to the cost ranges, the Technical Team also established an estimate of ranges for when the Project would be built, because the time at which the Project is completed is a significant factor in determining the NPV for the project. In an NPV analysis, a dollar in hand now is worth more than a dollar ten years from now. Thus, to determine the Project's NPV, it is important to determine not only how much the Project will cost, but *when* the Project will commence service and begin to generate revenues.[51] In order to estimate schedule ranges the Technical Team reviewed TC Alaska's proposed timeline and, as in the case of the cost ranges discussed above, worked with AMEC and Mustang to develop an estimate of probable ranges for completion of various aspects of the Project.

As with the development of the cost estimate, the Technical Team independently estimated the schedule range for the "Best Duration" and "Worst Duration" (P95 best case and P5 worst case) that each activity might involve. These activities included construction, procurement, permitting, engineering and design activities. A duration range for each activity was developed (Appendix F, Exhibit C) and used in Monte Carlo simulations. The process used to derive these schedule ranges, and the results of that process, are discussed in detail in the Technical Team's Report (Appendix F, Sections 2.1.2 and Section 3.3).

As it turns out, the GTP schedule plays a key role in the overall project timing. GTP construction is a function of the time from order placement to North Slope delivery of the large gas treating modules. As discussed in the Technical Team report (Appendix F), fabrication, delivery to the North Slope and assembly of the GTP on the North Slope is a complex process that will require at least two summer seasons to accommodate two sea-lifts.

TC Alaska has stated in its application that it would not make final procurement commitments for materials until the FERC permit and a Decision to Proceed was final (Application 2007, Section 2.1.2). This would set the ordering of the vessels no earlier than the end of November 2013 with the first sealift for North Slope delivery occurring no earlier than September 2016

[51] The NPV of a project is the difference between the sum of the discounted cash flows which are expected from the investment and the amount which is initially invested. If the NPV results in a positive amount, the company should pursue the project. Net Present Value is an economic calculation used to appraise the financial value of long-term projects. An NPV calculation figures the present value of an investment that may generate returns for many years; in short, the AGIA NPV calculation allows us to understand, in terms of today's money, the profits (or losses) that an AGIA Application offers the state.

(Appendix F, Exhibit C). The second sealift would be landed in September the following year, or 2017 (Appendix F, Exhibit C). This would allow for earliest delivery of first gas, at one-half capacity (2.25 Bcf/d), to the pipeline inlet in November 2017 and the earliest final full volume (4.5 Bcf/d) to the pipeline inlet in June 2018 (Appendix F, Exhibit C).

The Technical Team estimates TC Alaska's project will likely commence service between the middle of 2018 and the beginning of 2022, with 2020 as the midpoint estimate (Appendix F, Exhibit D).

Spend Curve Estimates for Project Costs

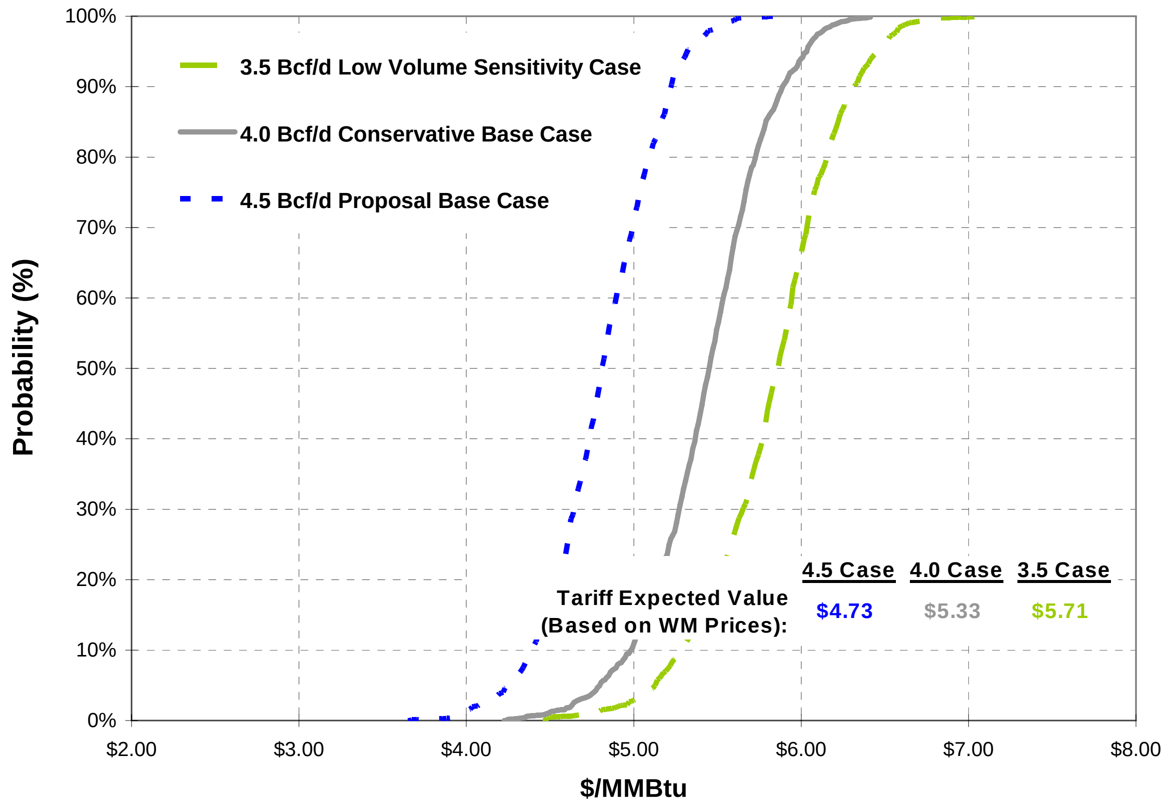
The Project's pipeline and GTP tariffs will reflect the returns to capital that investors require. Accordingly, to develop pipeline and GTP tariffs, it is necessary to know when in the process the dollars will be spent to develop and construct each subproject so that these returns can be appropriately calculated. The Technical Team used TC Alaska's estimate of the likely timing of its expenditures on a year-to-year basis as a basis for developing reasonable schedules for yearly capital expenditures. (Appendix F, Section 3.2.3). These schedules were then converted from a "dollar per year" basis to a "percentage of cost per duration" basis, so that spend schedules could be developed for the joint ranges of cost and duration schedules discussed previously (Appendix F, Section 3.2.3).

Tariff Rates, Based on Estimated Project Costs and Schedules

Estimating a net back price is a prerequisite to estimating the royalties and production taxes the state would receive as a result of the Project; that is, the price of the gas at the AECO Hub less the transportation cost or tariff. The net back price serves as the basis for calculating the state's royalties and production taxes. In broad terms, a distribution of net back prices was determined by translating the full range of project cost estimates into a similar range of unit rate "costs of service," or tariffs. These were then subtracted from the projected AECO Hub natural gas price. Combined with the distribution of prices, then, the distribution of tariffs is key.

Under the Proposal Base Case, which has significantly greater throughput for a relatively minor increase in corresponding costs, the distribution of project tariffs is presented below. Under the Conservative Base Case project costs are slightly lower but this is overcome by the significantly smaller throughput, leading to a generally greater per unit cost (or tariff).

Figure 3-26. Tariff Distributions by Project Throughput: Smaller Projects Give Higher Tariffs



Source: Black and Veatch, Appendix F, Appendix C

The conversion of these project cost estimates into a tariff rate is discussed in detail at Appendix G1. To summarize briefly, however, a pipeline's tariff rate is the sum of four basic components: (1) operating expenses; (2) return on rate base (*i.e.,* a return on the pipeline's capital expenses as approved by FERC); (3) income and other taxes; and (4) depreciation expense.[52] Components (2), (3), and (4), above, are directly affected by the project's capital costs, discussed above (Appendix G1, Section 3.7).

The NPV model incorporated the Technical Team's estimate of Project operating expenses. The Technical Team's estimate was derived from TC Alaska's estimated operating expenses, independent estimates of those expenses, and by reference to actual operating expenses on several major interstate natural gas pipelines (Appendix F, Section 2.1.5 and Appendix J).

[52] *See, e.g.*, Schneider, Steven, *Natural Gas Pipeline Regulation and its Impact on Value* (1997) at: http://law.honigman.com/db30/cgi-bin/pubs/Schneidera67602.pdf.

The second component, return on rate base, reflects a return on capital expenses (both equity and debt). The NPV analysis took the previously-discussed ranges of capital costs and calculated the return on rate base by applying a 14% return on equity to the 25% equity portion of the Project rate base, and a 7.06% debt cost to the 75% debt portion of the Project rate base, to determine the total return on rate base (Appendix G1, Section 5.7.2).

The NPV model applied appropriate federal and state tax rates for income and other taxes to derive an estimate of the taxes FERC (and the NEB) would allow to be recovered by the Project in tariff rates. Because income taxes are affected by pipeline income (or return, see above), the Project's capital cost indirectly affects income tax costs (Appendix G1, Section 3.7).

Finally, the NPV model calculates the annual depreciation expense, or an allowance for the return of capital to investors, by multiplying the rate base by the depreciation rate derived from the proposed 25-year Project life. The Commercial Team thus used a 4% depreciation rate, which would be necessary to fully depreciate the Project rate base over 25 years under the Proposal Base Case. For the calculation of state and federal income taxes the NPV model uses tax depreciation rates based on a tax life of 7 years for the Alaska pipeline sections and a tax life of 15 years for the GTP plant or a rate of 14.3% and 6.6% respectively (Appendix G1, Section 3.7.2).[53]

In simplified terms, the sum of these four rate components was then divided by the projected billing determinants of 4.5 Bcf/day to determine the projected tariff rate, which was calculated on a levelized basis (*i.e.,* the rate does not change over the 25 years of the project). For the Proposal Base Case, in 2008 dollars, the projected tariff rate (assuming a 25-year project life and firm contracts with a term of 25 years) is approximately $3.19. After accounting for escalation in construction costs, the midpoint likely tariff in 2020 would be approximately $4.73 (Appendix G1, Section 5). This estimated rate is well below each of the natural gas price projections used in the analysis. The Project appears likely to produce positive net backs for the Major North Slope Producers and other producers, as well as significant cash flow and a positive NPV for the state.

In addition, it should be recognized that while FERC requires all pipelines to have a tariff rate (also known as the recourse rate), most major new projects enter into negotiated rate contracts

[53] Although the BandV report states that Federal Tax Life was set at 7 years, the NPV model does use a 15 year Tax Life for the GTP.

with their major shippers.[54] These negotiated rate contracts typically are lower than the recourse rate (Appendix J, Section 1). Thus, it is to be expected that TC Alaska and the Major North Slope Producers would enter into negotiated rate contracts. Due to the bargaining power of the Major North Slope Producers, the negotiated rates would probably be lower than the FERC-approved tariff rate. To the extent TC Alaska and the Major North Slope Producers negotiate rates which are less than the tariff rates modeled here, the net back, cash flow and NPV produced by the Project would be even *higher* than if Major North Slope Producers were to pay the recourse tariff rate. That is because, in conjunction with the earlier explanation of net back pricing, lower tariff rates produce a higher net back, which means higher state tax and royalty revenues.

In addition, the estimated rates may be conservative because two elements of the tariff rate may be overstated. First, TC Alaska's return on equity may be reduced below 14% once the Project has been constructed and in the event TC Alaska files a rate case with FERC.[55] FERC policy generally allows a new pipeline a higher return on equity than an existing pipeline, in view of the higher risks faced by a new pipeline.[56] For purposes of this analysis, the Commercial Team conservatively assumed TC Alaska will receive a 14% return on equity throughout the 25-year Project life. A reduction in this return on equity would reduce the tariff rate and increase the net back, cash flow and NPV produced by the Project (assuming shippers pay the tariff rate instead of negotiated rates).[57]

The second rate component which may be overstated, also resulting in an understatement of the net backs, cash flow and NPV that the Project would likely produce to the state, is depreciation expense. A key factor in determining a pipeline's rates is the depreciable life of the project. If a longer depreciable life is used to calculate rates, then the costs of the project can be recovered and spread over a longer time period, resulting in lower rates than if a shorter time

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[54] *See, e.g., Rockies Express Pipeline, LLC* Application at 26; Appendix A of sample precedent agreement between Rockies Express Pipeline, LLC and shipper at: http://www.kindermorgan.com/business/gas_pipelines/rockies_express/rex_docs.cfm (December 17, 2005).

[55] In this regard, TransCanada proposed (but did not require as a condition of its Application) to charge a return on equity of 965 basis points above the U.S. 10-year Treasury Note, to be reset annually. As discussed in Appendix G1, this proposal may not be accepted by FERC. *See* Application at Section 2.2.3.7(1).

[56] *Alliance Pipeline, L.P.*, Preliminary Determination of Non-Environmental Issues, 80 FERC ¶ 61,149 (1997).

[57] In addition, a 14% equity return is significantly higher than the equity returns typically approved by the NEB, according to the state's Canadian legal counsel. Thus, this assumption may understate the NPV of the Project to the state (because it reduces the net back price used to determine state royalty and production tax revenues).

period is used, all other factors being equal. Conversely, the use of a shorter depreciable life for ratemaking purposes results in higher rates, but reduces the pipeline's risk of cost recovery somewhat because the pipeline will not bear the risk of finding firm shippers for its capacity over a longer time period.

TC Alaska has proposed to use a 25-year depreciable life for ratemaking purposes. Application at 13, 2.2-65. While TC Alaska's proposed 25-year Project life can be questioned, it is not unreasonable by industry and FERC standards. For example, when Kern River Gas Transmission Company constructed a major new pipeline from the Rockies to California in the early 1990s, Kern River proposed and FERC approved the use of a 25-year depreciable life for use in calculating Kern River's initial rates.[58] Other pipelines have also proposed, and received FERC approval of, 25-year depreciable lives for ratemaking purposes.[59]

A number of other pipelines, however, have proposed longer depreciable lives, which also have been approved by FERC. For example, FERC recently approved the 35-year depreciable life proposed by Rockies Express. Numerous other similar examples also exist.[60] Moreover, in pipeline rate proceedings at FERC (which traditionally have not occurred until several years after the pipeline's in-service date), FERC typically requires pipelines to use a depreciable life of longer than 25 years, based on an assessment of the natural gas reserves available to be transported by the pipeline and other factors[61]. For example, in Kern River's recent rate case, FERC required Kern River to use a 35-year depreciable life, instead of the 25-year depreciable life on which Kern River based its initial project rates.[62]

Recent estimates have indicated that the recoverable natural gas reserves on Alaska's North Slope significantly exceed prior estimates. Indeed, the Alaska Gas Study discussed above indicates that there are economically recoverable reserves available to fill the capacity of the Project for decades. (NETL 2007, pp. vii-ix, 22-23) Accordingly, in a future rate proceeding

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[58] *See Kern River Gas Transmission Co.,* 50 FERC ¶ 61,069 (1990).

[59] *See, e.g., AES Ocean Express,* LLC, 103 FERC ¶ 61,030 (2003); *Mojave Pipeline Co.*, 58 FERC ¶ 61,074 (1992); *Wyoming-California Pipeline Co.*, 50 FERC ¶ 61,070 (1990).

[60] *See, e.g., Colorado Interstate Gas Co.*, 122 FERC ¶ 61,256 (2008); *Entrega Gas Pipeline, Inc.*, 112 FERC ¶ 61,177 (2005); *Kinder Morgan North Texas Pipeline, L.P.*, 111 FERC ¶ 61,439 (2005).

[61] *See, e.g., Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036 (2003), *order on reh'g*, 107 FERC ¶ 61,164, at PP 21-52 (2004); *Iroquois Gas Transmission System, L.P.*, 86 FERC ¶ 61,261 (1999).

[62] *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077 (2006).

FERC may require TC Alaska to use a depreciable life of more than 25 years for ratemaking purposes. If that occurs, then (all other factors being equal) TC Alaska's tariff rates would decrease, the net back price would increase, and the royalty and tax revenue which the state will derive as a result of the Project would increase, thus increasing the NPV to the state.[63] Accordingly, from an NPV perspective, because FERC may require the use of a longer depreciable life in the future, the use of TC Alaska's proposed 25-year depreciable life to calculate the Project's rates results in a conservative assessment of the likely NPV the Project would produce for the state.

j. Upstream Costs

The costs of production have three effects on state NPV. First, capital expenditures end up being subject to state and local property tax. Second, capital expenditures affect producer property balances, which in turn affect state corporate income tax. Finally, upstream capital and operating costs are deductible from production taxes, and capital costs can be eligible for investment tax credits. A detailed explanation of how upstream costs are modeled can be found at Appendix G1, Section 3.8.

3. Estimated NPV Produced by the Project—Results of the NPV Analysis

In the prior sections of this Chapter, we have explained the fundamental elements of our NPV analysis, including projected natural gas prices, Project costs and tariffs, and volumes to be produced and transported through the Project. This section summarizes the results of the NPV analysis for the 4.5 Bcf/d-capacity Proposal and 4.0 Bcf/d-capacity Conservative Base Cases, as well as results of various sensitivities (e.g. prices, volumes, tariff terms) off those cases.

The evidence, as discussed in more detail in the Commercial Team report, demonstrates that the state, the Major North Slope Producers, and TC Alaska would each realize a very significant NPV from the Project under both the Proposal and Conservative Base Cases. Indeed, the Project presents an economically attractive opportunity for the state, for the Major North Slope Producers, and for TC Alaska under a range of volume scenarios, and under a variety of different, sometimes very conservative assumptions regarding natural gas prices, costs and other factors.

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[63] An increase in the depreciable life from 25 years to 35 years would reduce the tariff rate by approximately

a. Estimated NPV under the Proposal Base Case

Under the Proposal Base Case set of assumptions (which will be summarized shortly), the Project would produce the following results:

- The State of Alaska would realize an estimated NPV of approximately $66 billion at a discount rate of 5%.
- The Major North Slope Producers would realize an estimated NPV of $13.5 billion at a discount rate of 10%, and an NPV of approximately $5.2 billion at a discount rate of 15%. Like TC Alaska, Producer NPV would be significantly higher if the same 5% discount rate were used to calculate their NPV. Higher discount rates are appropriate for the Producers, however, to reflect the higher rate of return they generally demand before proceeding with a project. The Producers would also realize extremely high internal rates of return from the production and sale of gas from Prudhoe Bay and other state existing fields,[64] and economic returns from the production and sale of Point Thomson and Yet-to-find (YTF) gas.[65]
- TC Alaska would realize an NPV of $4.5 billion at a discount rate of 8.8%. TC Alaska's discount rate was set at its assumed weighted average cost of capital for the Project. For a given equivalent net cash flow TC Alaska's NPV will be lower than the state's, because its discount rate is greater. For discussion see Section C.1 of this Chapter.

These results are derived from the Proposal Base Case set of assumptions, which include the following:

$0.20/MMBtu and increase the net back price by a corresponding amount.

[64] Not too much should be made of exceedingly high rates internal rates of return (IRR) for gas produced from these fields. IRRs much above 30% cease to be very meaningful. The math embedded in the IRR calculation implicitly assumes that revenue from an investment can be reinvested at that rate; however, there simply are not many opportunities to earn returns at this level. Moreover, once a project's internal rate of return meets a company's hurdle rate it is unlikely to be used as an important determinant of investment choices. (Finizza, 2006).

Note that IRRs drop dramatically if one were to treat firm transportation commitments as a capitalized investment. We do not believe that this is the proper way to consider or calculate IRRs. However, we acknowledge that there is controversy on the subject. Accordingly, we do not focus particularly, nor base our findings, upon the IRR results. The controversy surrounding how IRR "should" be calculated with regard to shipping commitments is largely a sideshow. The main emphasis properly belongs on project NPV, which is the primary measure for whether the project will add value to the company (Finizza, 2006). As it happens, Producer NPV is fairly insensitive to whether shipping commitments are capitalized. (See Appendix F.1, Section 6.8 for discussion and results; capitalizing the shipping commitment yields investment measures similar to those that are obtained when the Producers are assumed to own the pipeline.)

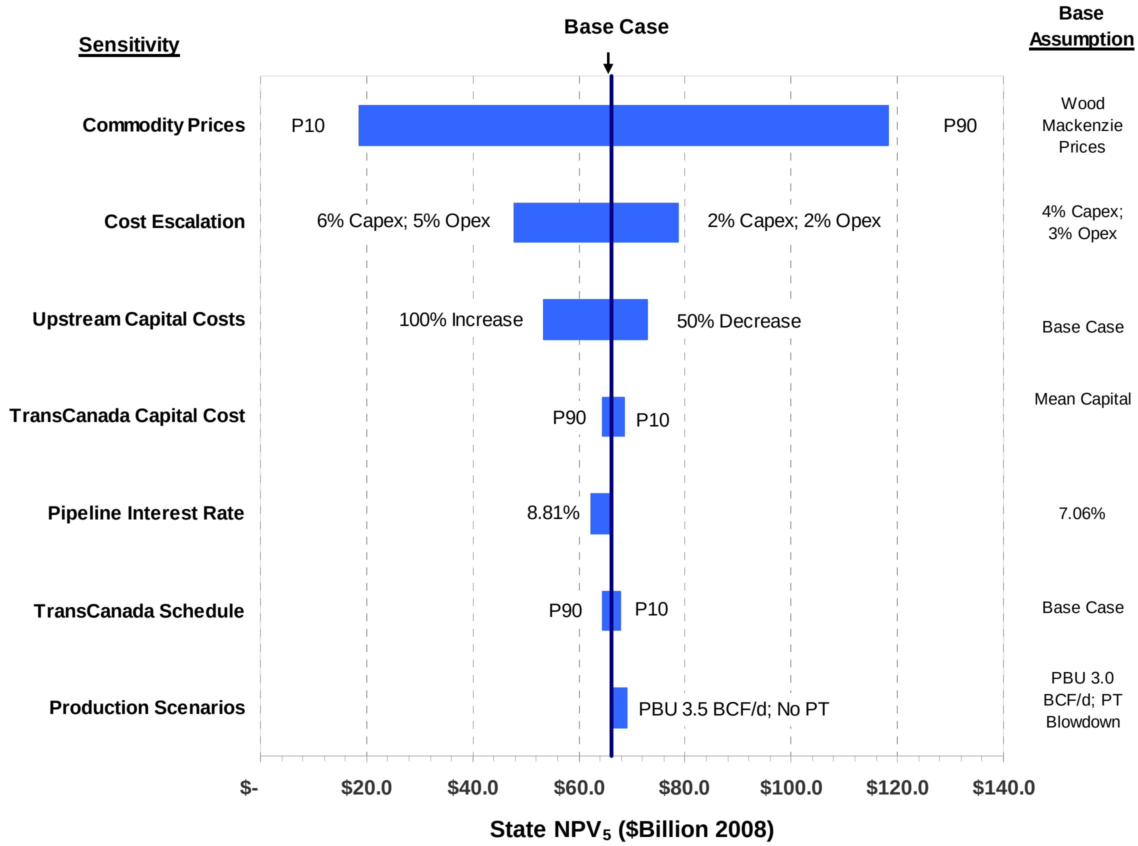
[65] See Appendix K for discussion of the relative acceptability of project economics of YTF gas.

- Natural gas prices: We relied on a gas price forecast supplied by the well-respected Wood Mackenzie consulting firm, a firm that has done work for numerous companies in the natural gas industry, including the Major North Slope Producers. We also considered price forecasts prepared by the EIA and Black and Veatch.
- Production scenarios: As a variation to the Proposal Base Case, we assessed Project returns assuming that initial volumes from Prudhoe Bay were 3.5 Bcf/day, state existing reserves came in initially at about 0.7 Bcf/day, and the remainder of the volumes is made up of YTF gas. Point Thomson gas does not enter the project in this sensitivity. Assessment of the extreme case in which Point Thomson gas does not enter the project at all is evaluated more fully under the Conservative Base Case.
- Schedule: The midpoint probability schedule estimate, in which the Project would begin transporting gas in the year 2020.
- Capital Cost: The midpoint probability cost estimate for the Project of approximately $31.3 billion in current or "real" dollars.
- Cost escalation: Capital costs for the Project escalate at an annual rate of 4%, and operating costs escalate at an annual rate of 3%.
- Pipeline Interest Rate: The Project would rely on the Federal Loan Guarantee provided by the Alaska Natural Gas Pipeline Act, which results in a lower interest rate than would otherwise be the case.
- Contract length and depreciation period: the Project would be depreciated over a 25-year period, shippers would sign 25-year firm shipping commitments, and pipeline tariffs would be levelized.

In evaluating the NPV of the Project, sensitivity analysis was performed to analyze the effect of different factors on Project economics for the stakeholders, including the state, the Major North Slope Producers and TC Alaska. In a sensitivity analysis the relative importance of risk factors that can affect the NPV results for each stakeholder are assessed. A "Tornado Diagram" provides a tool to visually compare the results of different sensitivity cases at the same time. A tornado diagram essentially shows which factors have the largest estimated impact on NPV. A tornado diagram reflecting the main factors that can affect the NPV to the state is shown below (Figure 3-27).[66]

[66] The assumption that is being varied in each bar of the tornado diagram chart is listed on the left-hand side under the 'Sensitivity' heading, while the list to the right of the chart describes what the base case assumption is for each sensitivity case. The x-axis gives the State of Alaska NPV value (in billions of dollars). The vertical line shown near the center of the chart is the base case NPV and is labeled 'Base Case' at the top of the chart. The bars to the right

Figure 3-27. State NPV5 Tornado Diagram: The Relative Importance of Different Project Risks



The left-hand side of each bar on the chart plots the low NPV result while the right-hand side of each bar plots the high NPV result. The factor shown at the top of the chart (natural gas prices) has the greatest impact on the Proposal Base Case results, while the factor at the bottom of the chart (pipeline interest rate) has the smallest impact. The results show the range of uncertainty evaluated for the State of Alaska NPV for a TC Alaska 4.5 Bcf/d pipeline to AECO Hub.

The main points reflected in this Proposal Base Case tornado diagram are as follows:

Overall: The results show that for all sensitivity cases, the State of Alaska's NPV remains substantial. In other words, even if a worst case scenario occurs for a single factor (such as gas prices), the Project would still generate a positive NPV assuming the other Proposal Base Case assumptions are correct. It would take a "perfect storm" of worst case scenarios from multiple

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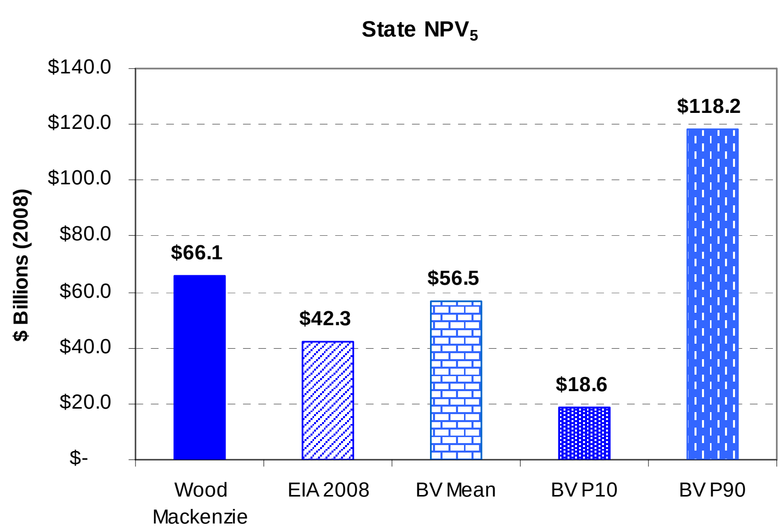
and left of this base case NPV line show how much the base case NPV changes depending on the assumptions used. The labels found at the end of each bar describe what assumption is used to generate the results shown on the far left and right side of the bar chart.

factors for the Project to be uneconomic. Indeed, as discussed below, a "perfect storm" of low gas prices and high construction costs, together, are not enough to generate negative state NPV.

It would take a "perfect storm" of worst case scenarios for multiple factors for the Project to be uneconomic. Indeed, as discussed below, a "perfect storm" of low gas prices and high construction costs, together, are not enough to generate negative state NPV.

Natural gas prices: The factor with by far the biggest potential impact on the state's NPV (and the Producers' NPV) is the price of natural gas. However, as reflected in the diagram above, even in an extreme low price scenario (depicted above as the "P10" scenario, in which there is only 10% likelihood that prices will be at, or below, the very low price), the state NPV would still be approximately $20 billion over the life of the Project.[67] Conversely, in an extreme high price scenario (P90), in which there is a 90% likelihood that prices will be at or below a very high level), the state NPV would swell to approximately $100 billion. As discussed earlier, the commissioners and the Commercial Team assessed Project economics under several different price scenarios. Under each pricing scenario, the Project has a positive estimated NPV in the aggregate over its 25-year life (Appendix G1, Figure 5-8).

Figure 3-28. State NPV5 Sensitivity to Price

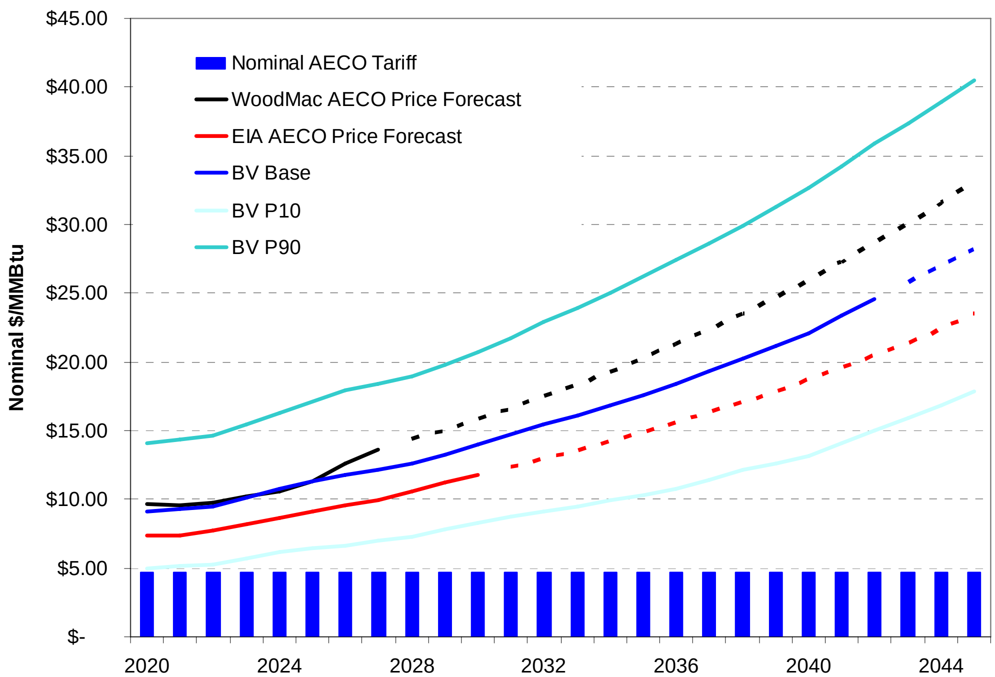


Source: Black and Veatch, Appendix G1, Section 6.6.1

[67] Note that while the Wood Mackenzie pricing projection is used to generate the Base Case result (represented by the blue line in the chart above), the P10 and P90 cases reflect the Black and Veatch assessment of price probabilities. The Wood Mackenzie and Black and Veatch approaches to price are explained in more detail earlier this Chapter, and in Appendix BandV, Section 4.

In addition, while in the aggregate the state NPV is significant, even for very low prices, Project net backs appear to be quite robust even under low gas price scenarios that are quite unlikely. The following chart (Figure 3-29) shows the full range of Project forecast prices discussed above, including the average 2007 AECO Hub gas price, as compared with Proposal Base Case tariffs.

Figue 3-29. Comparing TC Alaska Pipeline Tariff (Nominal $) with Various AECO Price Forecasts



Source: Black and Veatch; Appendix G1, Section 5.7.1.. Chart assumes Proposal Base Case tariffs

As shown in this chart, net backs are positive for the EIA forecast, the Wood Mackenzie forecast, the Black and Veatch base forecast, and if the average AECO Hub price during 2007 were achieved. Indeed, under the Black and Veatch probability distribution of prices there is a 90% chance[68] that prices will be sufficient, in every single year of the project, to generate positive net backs. Thus, under Proposal Base Case assumptions net back risks appear modest.

[68] The "PV P10" line shows that there is at most a 10% chance, for each and every year, that prices will be at or below that level. Put differently, the chance is 90% that prices will exceed that level.

Escalation in project costs: After natural gas prices, the factor with the next largest impact on the State's NPV is the rate of Project cost escalation. As reflected in Figure 3-29, even if the costs of the inputs required to construct the Project (steel, labor, major construction equipment) were to increase at an annual rate of 6%—a rate that would in nominal dollars more than double project costs from today's level by the in-service date—the state would still realize a very positive NPV.

Interest Rate Risk: The Project is extremely capital intensive and will require several tens of billions of dollars in debt financing. The interest rate that must be paid on such debt has a large effect on the Project tariff. Indeed, the risk of rising interest rates may have a bigger effect on overall project returns than project scope or schedule risk (discussed below). Interest rates affect the Project much the same way as does capital cost escalation risk

Capital Cost (or Project Scope) Risk: What the diagram refers to as "capital cost" risk has earlier been referred to as "Project scope risk." Earlier sections of this Chapter explain that the Monte Carlo range of project costs, expressed in current-day dollars, reflects the cost uncertainty that is caused by less than complete project definition. The Tornado Diagram (Figure 3-25) shows that the NPV risk caused by Project scope uncertainty is relatively small. Indeed, the NPV risks associated with Project cost escalation dwarf the risks associated with Project scope.[69] Project scope risk also takes a back seat to interest rate risk.

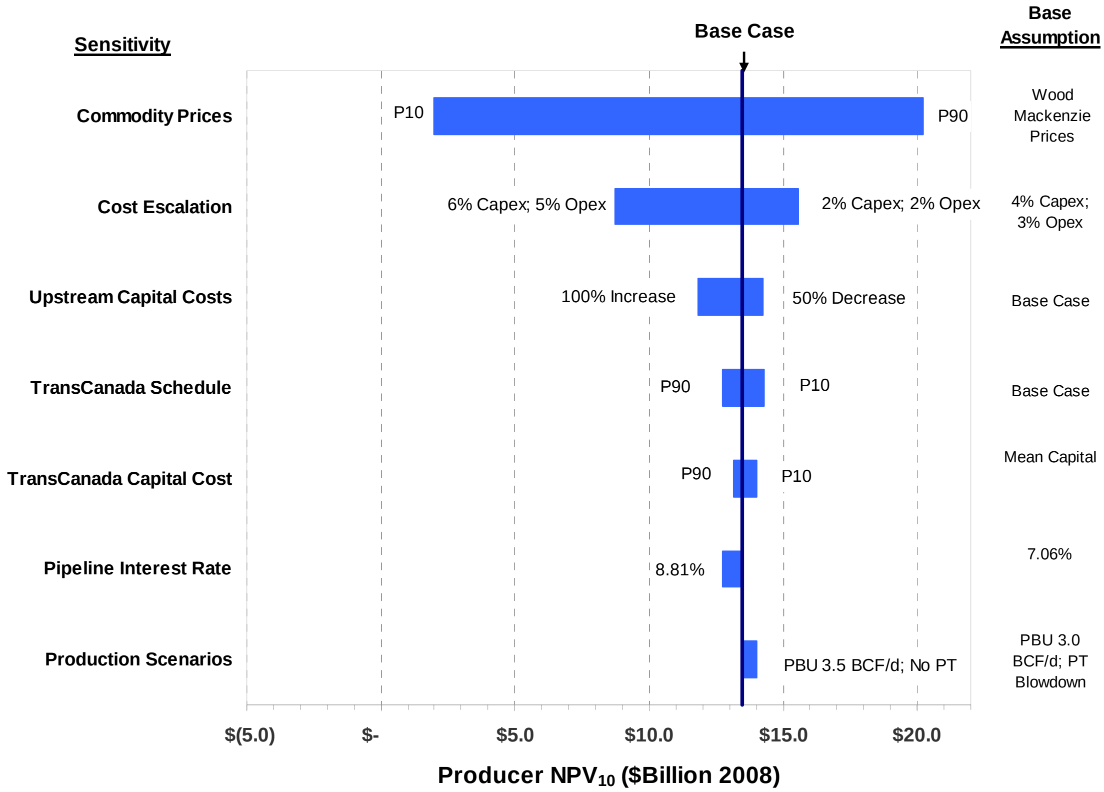
Production Scenarios: State NPV climbs if Point Thomson gas is displaced by Prudhoe Bay, other state existing, and YTF gas. Because Prudhoe Bay gas is especially profitable, flowing more of it, earlier, increases state NPV_5.

Schedule: Although they are large (potentially billions of dollars) in absolute terms, the risks associated with Project delay are comparatively small compared with the risks associated with price, cost escalation, and the level of upstream capital costs associated with YTF gas.

The same risk factors that affect the NPV to the state also affect Producer NPV. The following tornado diagram shows the sensitivity of Producer NPV, as measured against the Proposal Base Case, to various risk factors.

[69] Recall that Project Scope risk – or "Capital Cost" risk in the diagram – is calculated assuming a 4% annual rate of cost escalation; the Project Escalation risk assumes the P50 cost estimate.

Figure 3-30. Producer NPV_{10} Tornado Diagram: The Relative Importance of Different Project Risks



Source: Black and Veatch, Appendix G1, Section 5.6.2

In general, the various risk factors affect Producer NPV in a manner very similar to the state NPV. This is because the state derives the bulk of its revenues from royalty and production taxes, which are directly dependent on the degree to which Producers realize profits as a result of shipping their gas through the pipeline and selling that gas at the AECO Hub. Two issues deserve particular attention.

First, the majority of these risk factors involve things over which a producer or pipeline can exercise relatively limited control. The most significant exception is probably the ability of a pipeline company to control project costs through careful management of project scope risk. Still, the impact of this factor is relatively small compared with others.

Second, capital cost (scope) risk appears to have a relatively modest impact on Producer NPV. Given the substantial rewards that the Project offers anchor shippers, it is not apparent that capital cost risk would prohibit them from participating as shippers in TC Alaska's project.

We have reviewed the Project economics from numerous perspectives and have run numerous scenarios to assess the impact of many variables. We acknowledge the inherent difficulty in projecting future events. However, over a wide range of future events the Project's economics are robust.

b. Estimated NPV Under the Conservative Base Case and Low Volume Sensitivity Case Remain Favorable.

A Point Thomson resource study performed for the commissioners by Petrotel, a summary of which is attached at Appendix O, discusses the uncertainties associated with the development of natural gas reserves at Point Thomson. Given the potential condensate and black oil resource at Point Thomson, and the need for maintaining reservoir energy to maximize recovery of these hydrocarbons, gas may not be available from Point Thomson for the Project for many years. Accordingly, Project economics were assessed assuming, in the extreme, that Point Thomson gas might not be available during the first 25 years of Project operations. Under this Conservative Base Case, the capacity of the Project was reduced from 4.5 Bcf/day to 4.0 Bcf/day, and the initial term of firm shipping contracts was reduced from 25 to 20 years. The P50 current-dollar cost estimate for the Conservative Base Case is $29.4 billion,[70] about $2 billion less than the P50 estimate for the Proposal Base Case.[71]

In addition, to assess whether the Project economics remain attractive with an even smaller pipeline project, the commissioners and the Commercial Team also considered a pipeline configuration of 3.5 Bcf/day, which is referred to as the Low Volume Sensitivity case.

The Conservative Base Case offers several lessons, including:

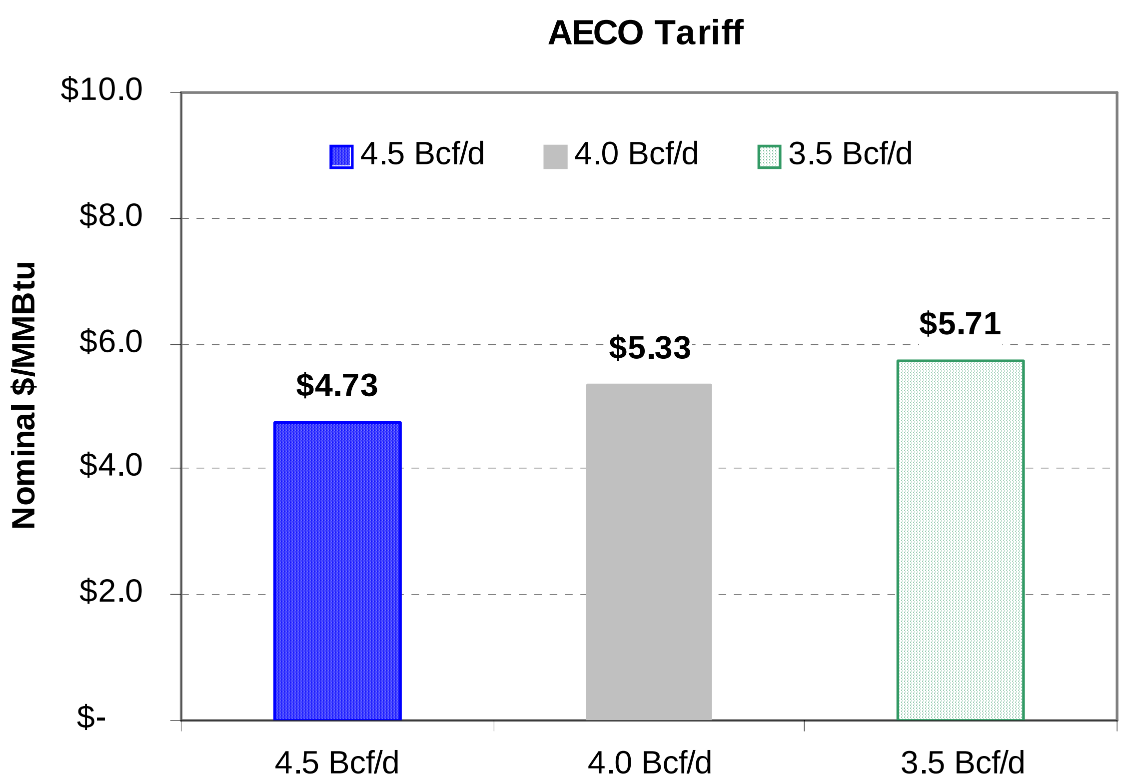
- <u>Tariff rates increase by about 13%</u>. This increase results from the smaller pipeline capacity and shorter contract/depreciation period. Essentially, even though the Conservative Base Case costs about $2 billion less than the Proposal Base Case, the tariff rate of the Conservative Base Case increases due to the need to recover that $29.4 million over a shorter period of time (20 years instead of 25 years) and over a smaller

[70] Recall that a "P50" cost estimate represents the level of costs that generate an equal likelihood of greater or smaller costs.

[71] In current-day dollars, the midpoint probability estimate Conservative Base Case project cost is $29.4 billion. The reduction, compared with the Proposal Base Case, is due primarily to reduced needs for pipeline compressor stations, as well as reduced GTP costs. (*See* Appendix F, Exhibit D, for details.).

volume of firm shipping contracts (4.0 Bcf/day instead of 4.5 Bcf/day). Similarly, the 3.5 Bcf/day case indicates an increase in the tariff rate of approximately 21% above the Proposal Base Case (Figure 3-31).

Figure 3-31. Pipeline Tariffs Under Proposal, Conservative, and Low Volume Cases



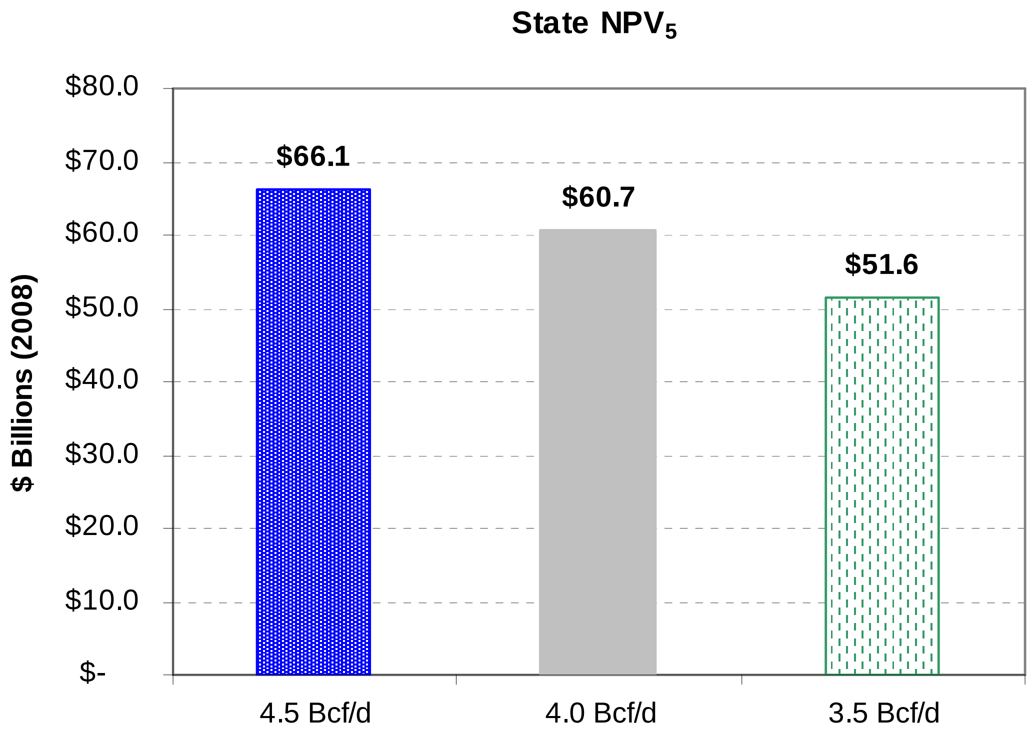
Source: Black and Veatch; Appendix G1, Section 6.4.1

- The Conservative Base Case Creates Less Reserve Risk. Initial shippers on the pipeline face *reserve risk*. In the later years of their firm transportation contracts, the lessees at Prudhoe Bay and the other fields with known gas reserves will face production declines such that they will have more capacity than throughput. To fully use such capacity, YTF gas will be needed. Accordingly, a commitment to ship on the pipeline places the initial shippers at risk for not finding sufficient reserves to fill their capacity in later years. The Conservative Base Case, which contemplates 20-year shipping contracts, reduces the reserve risk for the initial shippers compared with the 25-year contract period assumed in the Proposal Base Case. In the 4.0 Bcf/day Conservative Base Case, with a 20-year contract period, producers must find enough

YTF gas to fill only 15% of the contracted volumes during the life of the contract (the majority of which is required in the last few years). In contrast, the Proposal Base Case, even with Point Thomson gas, requires producers to find enough YTF gas to fill 26% of their initially contracted capacity. The smaller 3.5 Bcf/day configuration under the Low Volume Sensitivity Case has the lowest reserve risk, requiring the production of only 10% YTF volumes (assuming 20-year shipping contracts). In essence, by reducing the pipeline capacity from 4.5 to 4.0 (or 3.5) Bcf/day and reducing the contract period from 25 to 20 years, the shippers have to find significantly less YTF volumes to fill the pipeline and fully utilize their firm capacity.

- Mitigating *Reserve Risk* Involves Tradeoffs with *Net back Risk*. As discussed earlier, tariffs rise as initial throughput and contract lengths decline. This increases exposure to price risk—at least during earlier years of pipeline operation. But, as initial throughput and contract lengths decline, the need to find new gas to fill existing capacity falls. Conversely, one can increase early-year net backs by increasing the transportation contract length and pipeline size, but this *may* reduce cash flow in future years (such that, in the limit, gas revenues from diminished production fail to cover the costs of the total transportation commitment).
- Despite Increased Tariffs, Estimated NPVs Remain Positive. As discussed earlier, the 4.0 Bcf/day Conservative Base Case offers substantial net revenues to the state, the Producers and TransCanada. State NPV would *decrease* by only 8% under the Conservative Base Case due to greater gas production at Prudhoe Bay. The NPV to the state under the 3.5 Bcf/day Low Volume Sensitivity Case is about 15% less than under the Conservative Base Case, but is still approximately $51.6 billion.

Figure 3-32. State NPV5 Under Proposal, Conservative, and Low Volume Cases

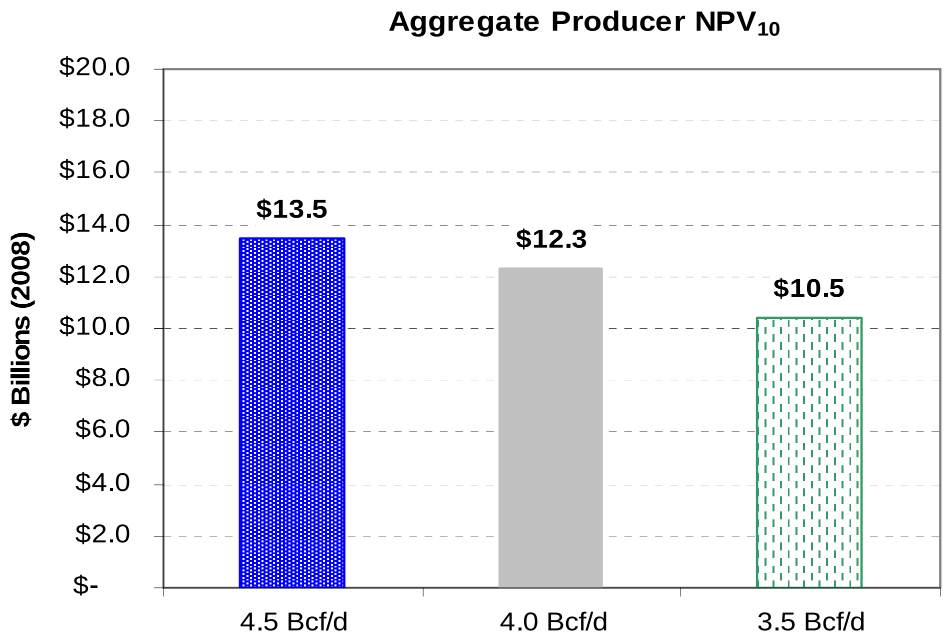


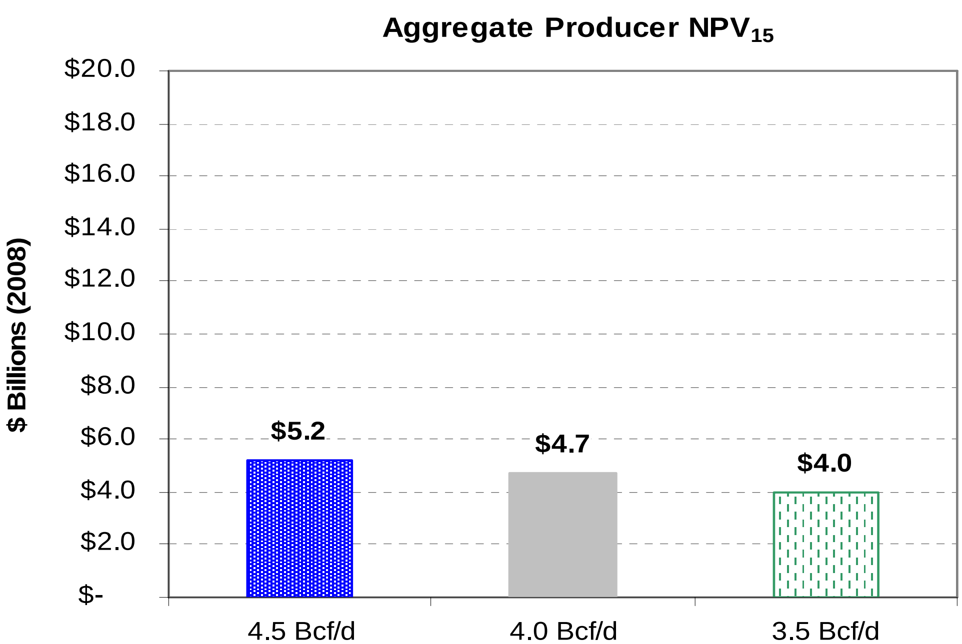
Source: Black and Veatch; Appendix G.1, Section 6.4.2

The NPV results for the Major North Slope Producers are directionally similar to the state results under the Conservative Base Case and the Low Volume Sensitivity Case. The Producer NPV_{10} under the Conservative Base Case is 9% less than the Proposal Base Case (approximately $12.3 billion), and is about 23% less under the Low Volume Sensitivity Case (approximately $10.5 billion) than under the Proposal Base Case. Fundamentally, the smaller 4.0 Bcf/day and 3.5 Bcf/day cases are profitable projects for the state and the Major North Slope Producers, despite their smaller size.[72]

[72] For more details on these results, *see* Appendix G1, Section 6.

Figure 3-33. Aggregate Producer NPV Under Proposal, Conservative, and Low Volume Cases



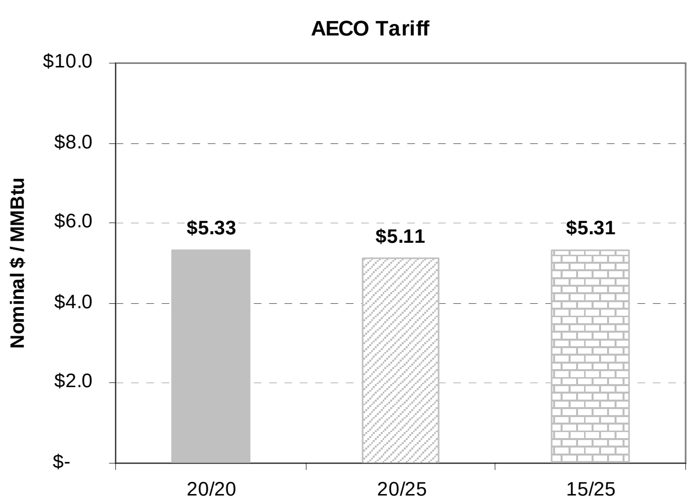


Source: Black and Veatch, Appendix G1, Section 6.4.2

- The NPV May Improve After TransCanada Negotiates with the Producers. Under the Conservative Base Case, we assumed a 20-year firm contract term, which matches the assumed 20-year depreciation life of the pipeline. The firm transportation commitment contract term has been assumed to match the 20-year assumed depreciation life of the 4.0 Bcf/day project, consistent with the spirit of the Application. Thus, TC Alaska has initially proposed for shippers (the Major North Slope Producers) to sign 25-year, 30-year, or 35-year contracts using corresponding 25-year, 30-year, or 35-year depreciation periods. However, it is possible that, after negotiations between TC Alaska and the Producers, TC Alaska will offer a contract period that is shorter than the depreciation period. For example, it could offer contracts for 20, or even 15 years but depreciate the pipeline over 25 years. Such an offering would fit squarely within the mainstream of commercial transactions on Lower 48 projects, and appears feasible from a financing perspective.[73]

  Initial shippers could substantially benefit from this approach. In the first instance they would be able to "shed" the majority of their reserve risk. Secondarily, tariffs determined on a levelized basis would drop. Figure 3-34 shows tariffs for the Conservative Base Case, and variations of that case where the Project is depreciated over 25 years but initial shipping contracts are 20 and 15 years in duration.

Figure 3-34. Impact of Contract and Depreciation Periods on AECO Tariff



Source: Black and Veatch, Appendix G1, Section 6.7.1

[73] See Appendix H, Section VI.B (for results) and Section VI.D (for discussion).

Given shorter contracts and a longer depreciation period Producer net backs would improve, as would the NPVs for the Producers and the state.

In such a scenario, TC Alaska would essentially be offering to take some of the reserve risk by agreeing to bear the risk of finding shippers to contract for capacity on the pipeline over the remaining depreciable life of the Project. If TC Alaska takes that risk, and continues to use a 25-year depreciation period, NPVs to the state and the Producers would improve, all other things being equal (Appendix G1, Sections 6.5 and 6.7 for discussion).

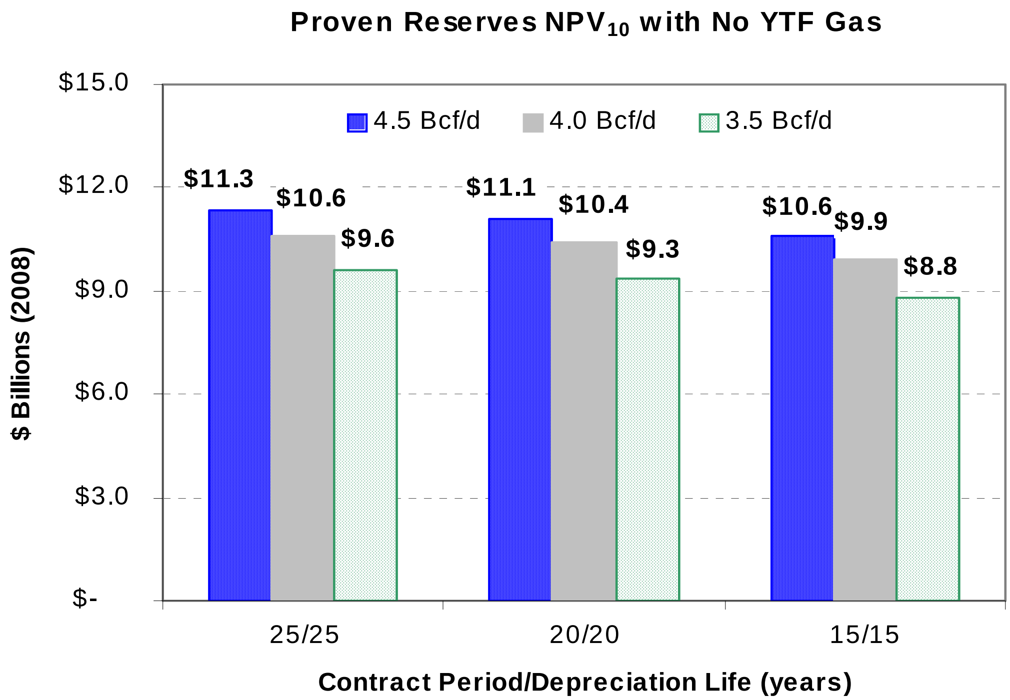
c. The Project Would Produce a Positive NPV Even If No Point Thomson or YTF Gas Is Ever Produced.

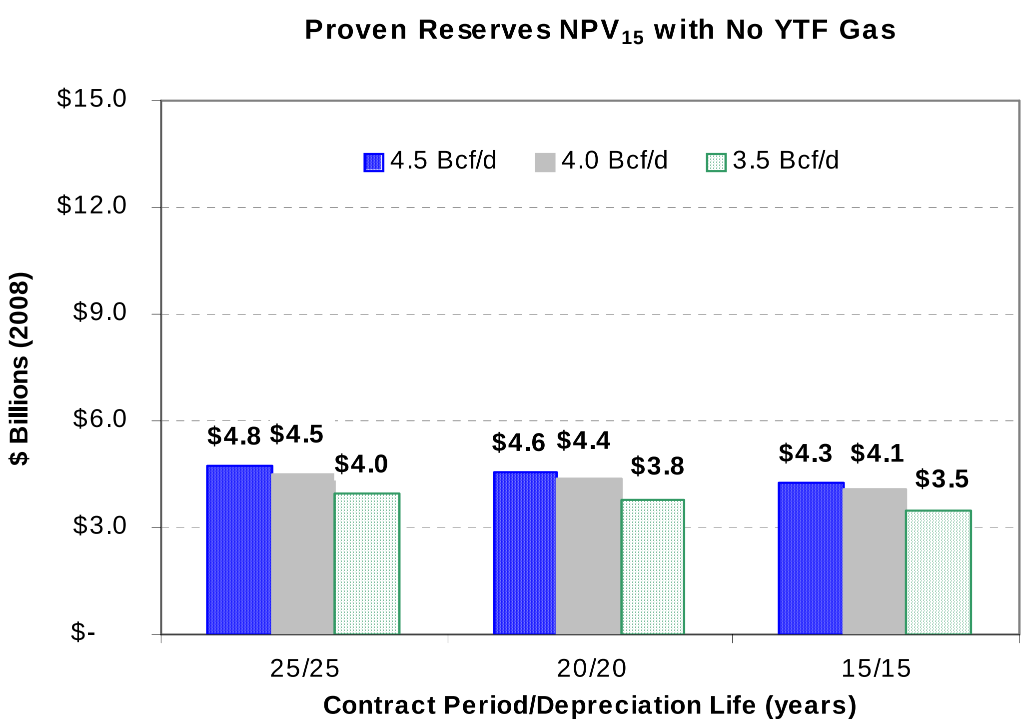
When considering the potential impact of Point Thomson and YTF gas on Project NPVs, it is critical to understand that the Project would very likely produce profitable NPVs *even if no Point Thomson or YTF gas is ever produced.* This is true for the Proposal Base Case, the Conservative Base Case, and the Low Volume Sensitivity Case, as demonstrated in the chart below (Figure 3-32):

When considering the potential impact of Point Thomson and YTF gas on Project NPVs, it is critical to understand that the Project would produce profitable NPVs *even if no Point Thomson or YTF gas is ever produced.*

As the previous chart demonstrates, even if the only gas that is ever shipped through the Project is the Prudhoe Bay and state existing gas, the Project would very likely produce a significant NPV to the state and significant profits to the Major North Slope Producers.

Figure 3-35. Reserve Risk: Producer NPV Assuming No YTF Gas

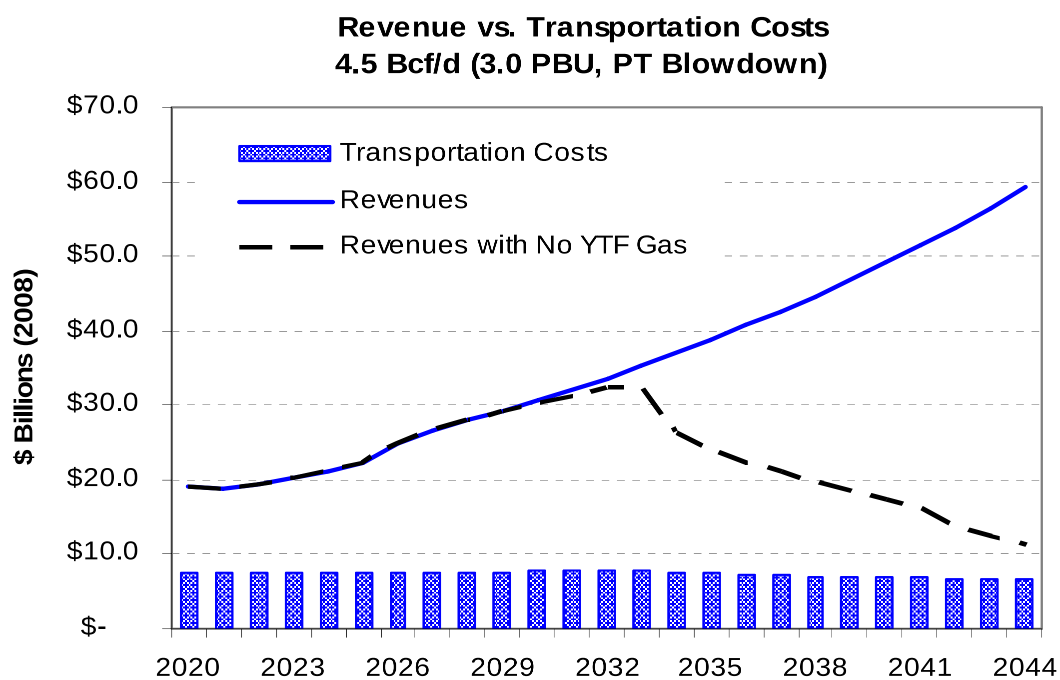


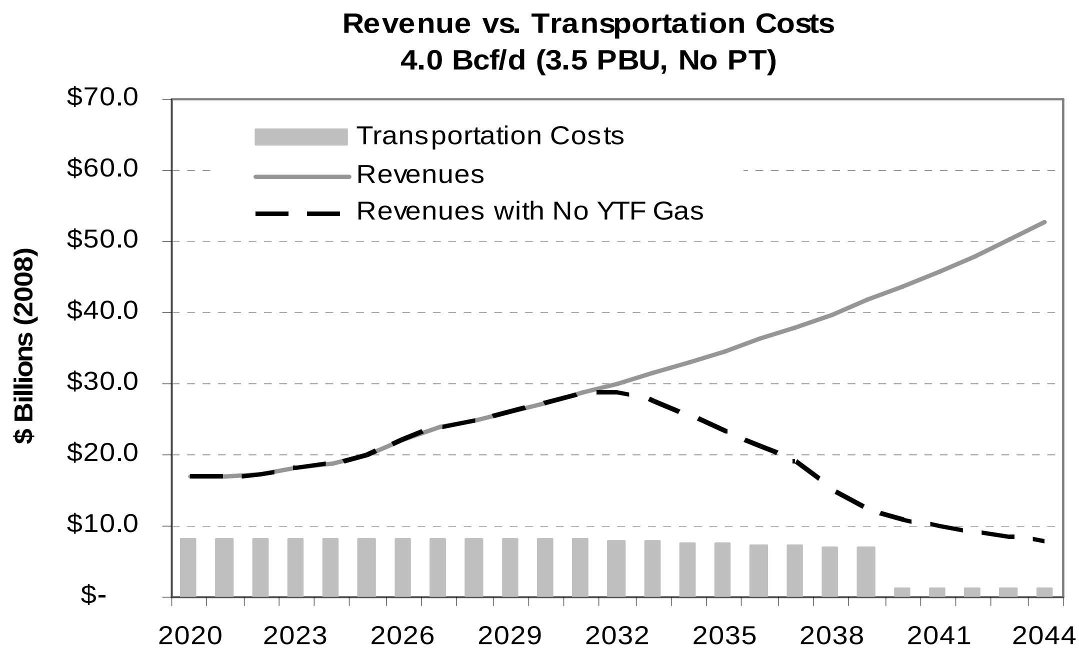


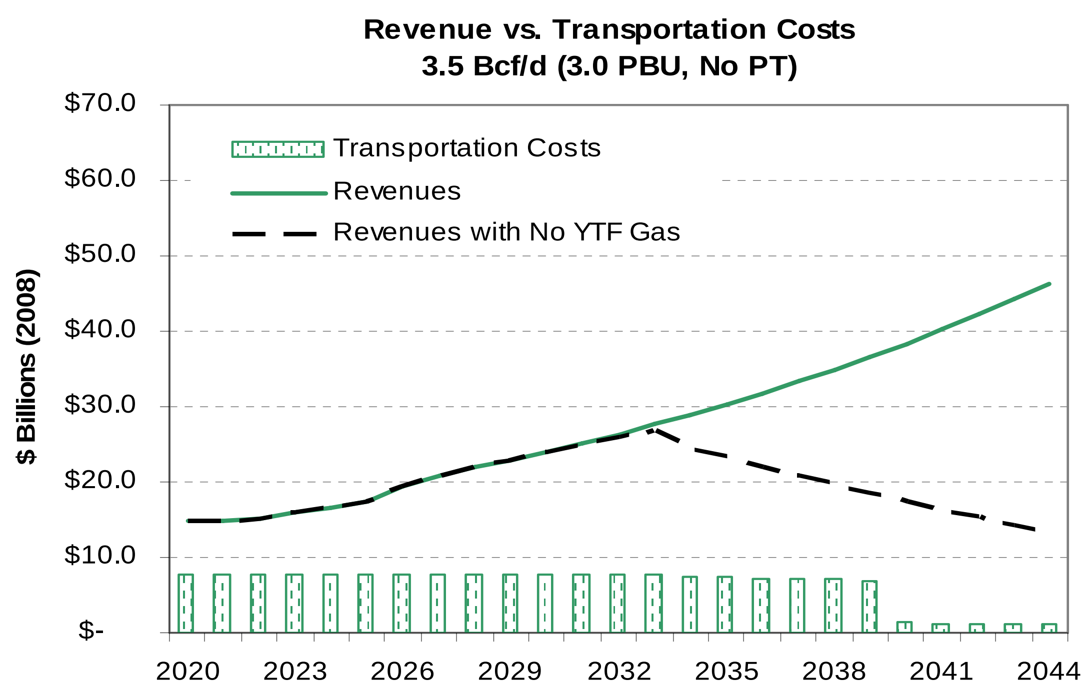
Source: Black and Veatch, Appendix G1, Section 6.5.2

Of course, producers may care about more than NPV in the aggregate. If they cannot keep their capacity full, then the risk increases that they will have periods of negative cash flow. To assess this risk we compare annual revenues and costs for the Major North Slope Producers, assuming that no additional gas was discovered and developed over the next 30 years. The results are shown in the following three charts (Figure 3-36). Even with declining production and pipeline throughput, revenues under the Wood Mackenzie price forecast are more than sufficient in every year to fully cover all transportation and upstream production costs. Cash flow for the Producers remains positive for the Proposal Base Case, Conservative Base Case, and 3.5 Bcf/d throughput case.

Figure 3-36. Reserve Risk: Yearly Net Back Cash Flow







Source: Black and Veatch, Appendix G1, Section 6.5.2

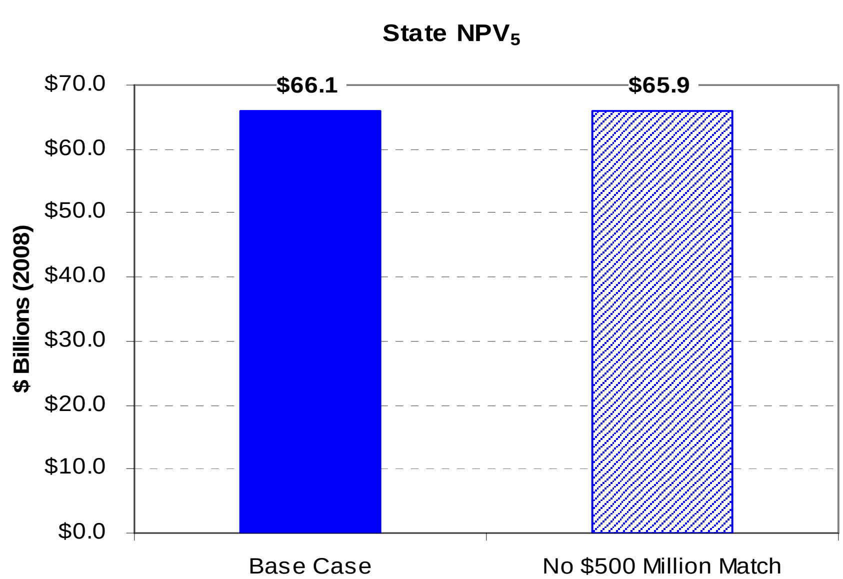
Of course, this seems an extremely conservative set of cases. It assumes that no additional gas will be found and developed, despite the NETL study conclusions that there is at least a 50% chance that over 137 Tcf of gas on the North Slope can be economically developed. It also assumes that Point Thomson gas never comes into the project. This confirms again that the Project presents an attractive economic opportunity to the state and the Major North Slope Producers.

4. Impact of $500 Million Match

AS 43.90.170(b)(5) requires the commissioners to consider, in analyzing the estimated NPV of the Project, the impact of the $500 million in state matching funds that would be available to TC Alaska. Assuming the project goes forward, the state would actually receive a higher NPV as a result of paying the $500 million (Appendix G1, Section 5.7). This is because the matching funds will not be included in the rates TC Alaska would charge for the Project (Application 2007, Section 2.2.3.7). This in turn reduces the tariff by about 6 cents/MMBtu. The state receives the value of tariff reduction through increased royalty and production taxes. Accordingly, the state is more than paid back for its $500 million investment in getting the project going, and keeping it going.

The state is paid back for its $500 million investment in getting the project going, and keeping it going.

Figure 3-37. State of Alaska NPV5 with and without $500m match



Source: Black and Veatch, Appendix G1, Section 5.7.8.2

The Producer Project by BP and ConocoPhillips would not require any state matching funds. Some have suggested that the state would be better off abandoning AGIA and thus avoiding what they consider the unnecessary expenditure of $500 million of state funds on the TC Alaska Project. This analysis, however, demonstrates that the state would actually receive a net benefit if the Project is constructed, even without consideration of the numerous other benefits provided by TC Alaska's Application (including enforceable commitments to expansion, rolled-in rates treatment for those expansions, rates based on no more than a 70/30 debt to equity ratio, progressing the project by making regulatory filings on a fixed timeline, hiring state workers to the extent permitted by law, providing in-state deliveries of natural gas at economic rates, etc.).

In any event, even if the $500 million would not result in lower transportation rates and would therefore represent a real cost to the state, that cost would be much less than the *billion*s in tax concessions which the Major North Slope Producers demanded,[74] and that the previous administration was willing to provide, under the SGDA contract negotiations as a precondition to even considering a pipeline project. According to the comments they filed in the AGIA public comment process (discussed more fully later in this Chapter), BP and ConocoPhillips have not abandoned their demands for fiscal concessions by the state. Thus, it is reasonable to conclude that the $500 million of state matching funds required by AGIA would be less than the amount the state would be required to spend or forego to induce construction of a gasline in the absence of AGIA.

5. Availability of Low Cost Expansion

AGIA requires the commissioners to consider the applicant's initial design capacity and the extent to which the design can accommodate low-cost expansion. AS 43.90.170(b)(4) Under the direction of the commissioners, the Technical and Commercial Teams analyzed this issue. The NPV of the Project under the proposed initial design capacity of 4.5 Bcf/day has been discussed above. This section will briefly discuss the extent to which that design can accommodate low-cost expansion.

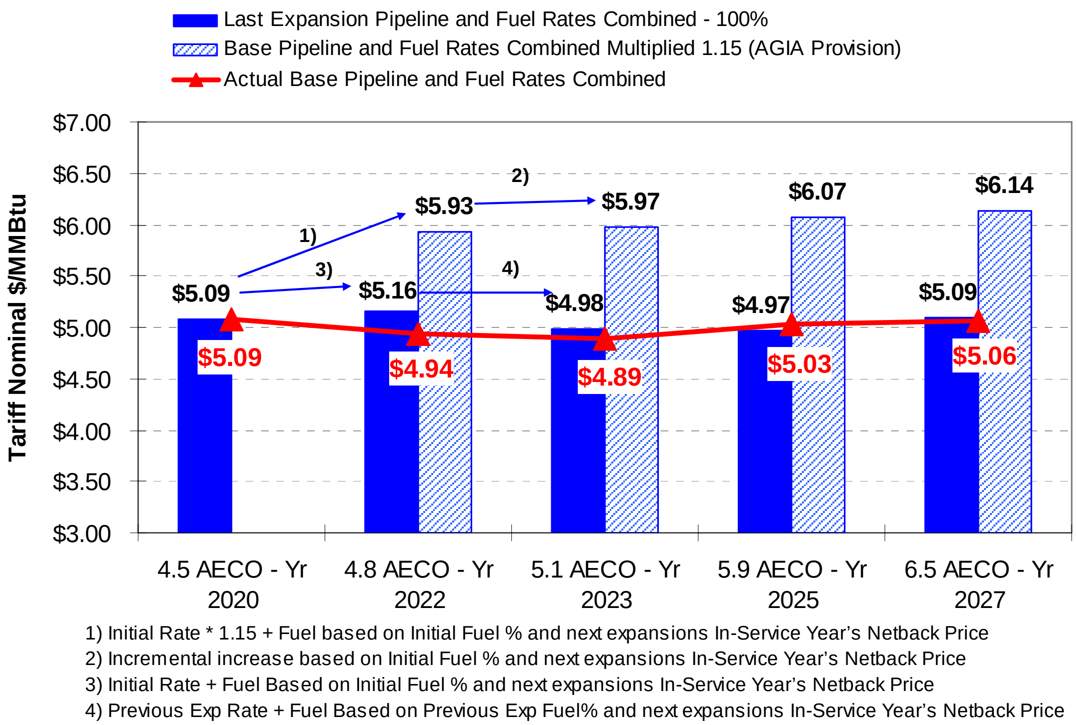
[74] The $10 billion figure is measured in 2005 dollars, based on analysis by the Legislature's consultants EconOne, assuming a $4 gas price. The figure climbs to over $20 billion assuming an $8 gas price. For details, see slides 15-18 of: Pulliam, Barry. 2006. Comments to Legislature on Gas Contract and Fiscal Interest Findings: Returns to the state and Producers. June 14, 2006. Available at http://lba.legis.state.ak.us/sga/doc_log/2006-06-14_pulliam1.pdf.

The state has confirmed that, on an engineering basis, TC Alaska's initial design capacity of 4.5 Bcf/day can be expanded with infill compression—which is cheaper than pipeline looping—to 5.9 Bcf/day.[75] Such expansions can be accommodated using TC Alaska's design parameters for compressor stations. Accordingly, up to 1.4 Bcf/d of additional capacity can be accommodated in "engineering increments," as AGIA defines that term. In other words, potential shippers can be assured that TC Alaska's design accommodates an additional 1.4 Bcf/d of capacity under AGIA-mandated expansions. TC Alaska's system can be expanded even further, to 6.5 Bcf/d, through added compression at existing compressor stations. However, this would require adding compressor units of a different size than that proposed by TC Alaska. (Appendix F, Exhibit J)

To assess the degree to which the Project can be expanded on a low-cost basis, a series of compression-only expansions were analyzed. Rolling the cost of those expansions into the Project rates would cause relatively small rate increases in, and in some cases would actually decrease, the Project rates (including the cost of fuel) (Appendix G1, Section 5.7.8.6). The projected rate for the compression expansions analyzed by the Commercial Team is shown in Figure 3-38 (Appendix G.1, Section 5.7.8.6). In this example, the AGIA rolled-in rate provisions provide shippers who would use expansion capacity above 5.1 Bcf/d assurance that they can get their gas into the project on reasonable terms. Rather than facing incremental rates, they enjoy rolled-in rates. Meanwhile, the "burden" associated with rolled-in rates on initial shippers is small. The expansions beyond 5.1 Bcf/d do not increase rates above the level that they initially paid.

[75] *See* Appendix F, Exhibit J at p. 8.

Figure 3-38. AGIA Roll-in-Rate Provision



Source: Black and Veatch, Appendix G1, Section 5.7.8.6

As can be seen (Figure 3-35), the Project can be expanded up to 6.5 Bcf/day on a low-cost basis, actually resulting in reduced rates (compared with initial rates) in 2027 for the full 6.5 Bcf/day of capacity. Even though AGIA requires the roll-in of expansion costs up to 115% of the original Project rate (as reflected in the striped bars in the chart), the AGIA rolled-in rate provisions would only be implicated when the pipeline expanded from 5.1 to 5.9 Bcf/day. Thus, the 4.5 Bcf/day capacity of the Project appears to provide at least 2.0 Bcf/day of low cost expansion capacity.

E. Analysis of the Likelihood of Success of TC Alaska's Project

1. Introduction and Summary

Because the commissioners have found that the TC Alaska Project would produce a positive estimated NPV for the state and the other stakeholders in the Project, the analysis now turns to the Project's likelihood of success (AS 43.90.170(c)). After reviewing the evidence, we believe TC Alaska's Project has a significant prospect of succeeding, for three principal reasons.

First, TC Alaska has submitted a plan for its Project that is technically feasible, reasonable, and specific. Under the supervision of the commissioners, the Technical Team rigorously analyzed TC Alaska's proposed plan. TC Alaska's Application describes a detailed plan for its Project that provides more specificity than AGIA and the RFA required. TC Alaska's plan for a pipeline through Alaska to interconnect with the AECO Hub in Alberta is also technically sound and reasonably addresses the challenges of constructing a large diameter natural pipeline in arctic conditions.

Second, TC Alaska has the technical expertise and financial ability to construct the Project. TC Alaska has demonstrated, both through the specifics of its application and its track record, that it is willing and financially and technically capable (Appendix F, Section 3.5) of implementing the proposed project work plan. TC Alaska is one of the largest natural gas pipeline companies in North America and is an experienced, independent natural gas pipeline builder and operator (Application 2007, Attachment 1-1). Its experience in constructing and operating pipelines throughout the United States and Canada includes experience constructing and operating pipelines in harsh near-arctic conditions similar to Alaska's. TC Alaska has also submitted a reasonable plan to manage and minimize cost overruns, although to a large degree increases in the price of steel and other inputs are out of its control. In addition, TC Alaska has demonstrated it has the financial resources to construct the Project, assuming it receives firm shipping commitments that would enable it to obtain financing.[76]

TC Alaska has the technical expertise and financial ability to construct the Project. TC Alaska has demonstrated, both through the specifics of its application and its track record, that it is willing and financially and technically capable.

[76] For detailed analysis, see Appendix H, Section II.D.

Third, TC Alaska has submitted a reasonable commercial plan which, coupled with the economic, political and legal environment, appears to generate the favorable conditions needed to encourage shippers to sign the firm shipping commitments necessary for the Project to succeed (Appendix G2, Section 4). TC Alaska has proposed reasonable commercial terms for potential shippers that will allow them to participate by committing in an open season to ship their gas on the future pipeline. In addition, TC Alaska's proposed commercial terms are likely to be further improved and refined during negotiations between TC Alaska and the Major North Slope Producers and the regulatory processes at FERC and the NEB.[77]

Finally, the likelihood that TC Alaska's proposed Project will succeed is enhanced by the Project's strong potential profitability as shown in the results of the NPV analysis discussed in the preceding section of these Findings. Indeed, the Project's robust economics are reasonably likely to help generate the necessary commercial, political and regulatory environment that will encourage potential shippers to sign firm shipping agreements, thus enabling the Project to obtain financing and move forward. Accordingly, the commissioners conclude that the Project is likely to succeed.

The following discussion of the Project's likelihood of success first summarizes the methodology that was used, followed by discussion of the three sets of issues discussed above.

2. Methodology for Analyzing the Project's Likelihood of Success

AS 43.90.170 directs the commissioners to consider several specific criteria that affect the likelihood that the proposed Project will succeed:

(1) the reasonableness, specificity, and feasibility of the applicant's work plan, timeline, and budget required to be submitted under AS 43.90.130, including the applicant's plan to manage cost overruns, insulate shippers from the effect of cost overruns, and encourage shippers to participate in the first binding open season;

(2) the financial resources of the applicant;

[77] *Appendix J,* Section 1; Appendix G2, Section 4. These Findings do not constitute an endorsement of any of the proposed terms. The state retains its right to oppose any commercial or other terms proposed by TransCanada or TC Alaska at FERC and the NEB.

(3) the ability of the applicant to comply with the proposed performance schedule;

(4) the applicant's organization, experience, accounting and operational controls, technical skills or the ability to obtain them, and necessary equipment or the ability to obtain the necessary equipment;

(5) the applicant's record of

(A) performance on projects not licensed under this chapter;

(B) integrity and good business ethics; and

(6) other evidence and factors found by the commissioners to be relevant to the evaluation of the project's likelihood of success. (AS 43.90.170(c)).

A project's likelihood of success under these factors cannot be as easily quantified numerically as the NPV analysis. It is possible, however, to assess whether a particular factor has a positive, negative or neutral impact on the Project's likelihood of success. The method for evaluating TC Alaska's proposal used a three-tiered approach to assess the impact of various factors relevant to the Project's likelihood of success. A finding of "Positive Impact" indicates that the Project would have an increased likelihood of success based on the particular factor under analysis. A finding of "Negative Impact" indicates that the Project would have a decreased likelihood of success as a result of the factor. A finding of "No Impact" indicates that the factor under review would have no impact on the Project's likelihood of success.

These LOS impacts simply indicate that the area that the project will probably land on cost and duration probability curves. A negative impact will tend to move the outcome up the curves, to the right, a positive impact down the curves to the left, and a neutral impact will tend to stay around the midpoint of the curves.

3. Analysis of Likelihood of Success Criteria Under AGIA Section 170

a. TC Alaska Has Submitted a Plan for its Project That is Technically Feasible, Reasonable, and Specific.

i. Specificity

AS 43.90.170(c)(1) requires the commissioners to consider "[t]he reasonableness, specificity, and feasibility of the applicant's work plan, timeline, and budget required to be submitted under

AS 43.90.130." A certain degree of specificity was required in an AGIA application to assess whether a project plan is reasonable and feasible. The RFA issued in July 2007 required applicants to provide a substantial amount of specific information about their proposed project. In addition to the required information, the RFA also requested, but did not require, applicants to provide additional information that would aid the commissioners in evaluating the applications. RFA Section 3.1 - 3.1.4.

Overall, TC Alaska's Application provides an excellent level of detail and specificity, which greatly facilitated the commissioners' ability to evaluate the reasonableness and feasibility of the proposed Project. TC Alaska provided all the information required by the RFA, (TransCanada Completeness Determination Letter (January 4, 2008)), plus a significant amount of additional information.

The overall Project contains a pipeline component and a GTP component. TC Alaska provided an excellent level of specificity in its Application about the pipeline component of the Project.[78] For example, TC Alaska's Application contains a detailed project description, front-end engineering design plan, project cost and schedule estimates, and numerous appendices specifying additional technical details about its proposal (Application 2007, Sections 2.1, 2.2, 2.5, 2.6 and Application Appendices A, B3, B4, B6, N, O, and R). As the Technical Team's report makes clear, the details provided by TC Alaska aided the Technical Team in its analysis of the Project. According to the Technical Team report (Appendix F), TC Alaska provided a complete project design with well-defined key components and assumptions, which positively affects the subproject's likelihood of success (Appendix F, Exhibit A.)

TC Alaska provided a lesser but sufficient level of specificity about the proposed GTP component of its Project. A gas treatment plant, which removes carbon dioxide and other impurities from the gas stream to render the natural gas fit for transportation in an interstate natural gas pipeline, is an essential part of the facilities needed on the North Slope for any Alaska pipeline to transport North Slope natural gas to market. As permitted by AGIA and the RFA, TC Alaska does not propose to own the GTP. [79] (Application 2007, Section 2.1-12)

[78] The state's Technical Team determined that the applicant had done a favorable job of defining the pipeline subproject scope and capabilities in sufficient detail to allow analysis, and that the pipeline's key components and assumptions were well defined. See Appendix F, Exhibit F.

[79] The RFA does not require an applicant to submit a GTP design if they do not intend to build the GTP. (RFA Section 2.1.2). Since TransCanada does not intend (at least initially) to design, build or operate the GTP, it is not required to

Rather, TC Alaska suggests that the current owners of the Central Gas Facility at Prudhoe Bay (the Major North Slope Producers) should own and operate the GTP.[80] (Application 2007, Section 2.2.3.12) TC Alaska's proposal does state, however, that it would "be prepared to build, own and operate" the new GTP facility if the Major North Slope Producers do not agree to own and operate the GTP (Application 2007, Section 2.2). The Major North Slope Producers may ultimately own the GTP as an adjunct to their production operations. It is reasonable that TC Alaska provides less detail about the GTP than about the pipeline component of the Project because TC Alaska does not propose to own the GTP. In addition, the Major North Slope Producers have much of the specific information about gas quality that will dictate the specifications of the GTP that will need to be constructed. They also control and have the final say on how much of the existing North Slope infrastructure can be utilized by the GTP. The Technical Team studied the significant current uncertainties surrounding the GTP element of the Project. They concluded that with sufficient engineering and design work the Major North Slope Producers, TC Alaska, or a third-party should be able to construct a GTP with sufficient capacity on a schedule consistent with the pipeline element of TC Alaska's Project.[81] This could allow gas to flow on a schedule and within the cost range reflected in the Technical Team's report (Appendix F). Thus, notwithstanding the complexities of designing, building and transporting such a facility to the North Slope, the commissioners believe the GTP should not negatively impact the overall likelihood of the success of the Project.

ii. Technical Feasibility and Reasonableness of the Project Plan, Including the Project Cost and Schedule

From a technical standpoint, TC Alaska's project plan is highly reasonable and feasible for two reasons. First, TC Alaska is generally relying upon proven technology and methods. Although it says that it will consider using pipe with yield strengths greater than X80, (Application 2007, Section 2.21), TC Alaska bases their application on existing, proven technology. (Appendix F,

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provide design information. Nevertheless, TransCanada presented a "conceptual design" for the GTP (Application 2007, Section 2.1).

[80] The Central Gas Facility is a gas treatment facility on the North Slope that removes water and some liquid hydrocarbons that are then shipped down the TAPS line. The remaining gas stream is then re-injected into the reservoir for pressure maintenance in the reservoir.

[81] Without specific design plans, in order to review the likelihood of success aspects of the GTP, Black and Veatch (with Amec-Paragon Engineering) performed a limited engineering study to determine the requirements for the GTP and to estimate a feasible construction schedule and cost range. (Appendix G1 at Exhibit J.) While the study shows that designing and constructing a North Slope GTP is a major and complex undertaking, it appears to be feasible if the project is properly managed.

Exhibit A) For both GTP and pipeline subprojects, TC Alaska's technical design is based on existing technology that has been used on major United States and Canadian natural gas pipelines (Appendix F, Exhibit A). Such technology includes the proposed 48-inch diameter pipeline, which is adequate to transport 4.5 Bcf/day at a pressure of 2500 pounds per square inch gauge (psig), expandable to approximately 6.5 Bcf/day using compression without pipeline looping. (Appendix F, Exhibit J)

Second, to the extent TC Alaska proposes to use an aggressive approach or newer, less tested technology, it is aware of the risks and has appropriate mechanisms in place to monitor the technology (Appendix F, Exhibit F), or will likely be able to address any issues that arise due to its experience and expertise as a pipeline operator (see next section for discussion).

Of all the details contained in TC Alaska's Application, none were determined to have a negative impact on the project's likelihood of success (Appendix F, Section 3.5). Further, only a few issues concerning the realism and feasibility of TC Alaska's design resulted in a "no impact" rating with regard to the likelihood of the pipeline subproject's success as specified in their Application.

- Strain-based design. TC Alaska proposes to use strain-based design to address stresses on the project associated with frost heave and thaw settlement. (Application 2007, Sections 2.2.1, 2.4.8, 2.9.5)[82] Although strain-based designs have been approved

[82] Frost-heave can occur when a pipeline is transporting gas that has a temperature below freezing and the pipeline crosses unfrozen, wet terrain. The cold pipe will tend to freeze the unfrozen saturated soil that surrounds the pipe resulting in the formation of an ice ball (frost bulb) around the pipe. This frost bulb can grow to the extent that it forces the pipe upwards (frost heave). Appendix F, Exhibit A.

Thaw settlement occurs when the pipeline is transporting gas that has a temperature above the melting point of ice and the pipeline crosses terrain that is frozen at pipeline depth in soils with high ice content. The warm gas inside the pipe will tend to melt the ice in the soil, and the pipe could settle as it loses support from the underlying frozen soil. Appendix F, Exhibit A.

Both of these unique arctic events, discussed in TransCanada's Application (Section 2.2, pages 17-30), can induce stresses and strains on the pipe that must be accommodated in the pipeline design and during operation. Among other things, frost heave and thaw settlement require limits on the flaw size in the pipe and welding requirements that ensure welds are actually stronger than the surrounding pipe.

Pipelines can be subjected to a variety of forces (loads). These forces cause stresses and strains in the pipeline. Stress is a measure of the amount of pulling or pushing the pipe steel is being subjected to. If you pull too much the steel will break apart. Strain is a measure of how much the steel is stretching as a result of this force. If you stretch the steel too much it will break apart.

The two basic types of pipeline loads are Primary loads (example is force on the pipeline steel due to the pressure of the gas in the pipeline) and Secondary loads (example the force on the pipeline steel due to it being bent because of the movement of the soil around the pipeline due to frost heave). The Conventional Design approach for pipelines is for the stress in the pipeline steel caused by both Primary and Secondary loads to be limited to a fraction of the capability of the pipeline steel.

for onshore applications in Canada, and offshore applications in the U.S., and although the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration is working with the Canada's National Energy Board on a trans-border study of pipeline safety (PHMSA 2008), the Technical Team noted that it is not currently permitted under US regulations.(Appendix F, Exhibit F). The Technical Team believes there is a high probability that this design approach will be approved by U.S regulators. If it is not permitted to use strain based design, TransCanada's expertise as an operator and its track record of completing projects on time lead us to agree with the Technical Team that this is not a factor that is likely to cause a negative impact to the project's likelihood of success.

- Pipeline Gas Temperature. In Alaska and into the first initial compressor station in Yukon, TC Alaska is planning to limit discharge temperature of the gas coming out of the compressor stations to just below freezing; further "downstream" than this the gas temperature would be allowed to rise (see Application at 2.10). Gas temperature matters in the presence of high ice-content soils: if soils melt then this could cause strain on the pipeline (Appendix F, Exhibit F). The extent to which this design plan is appropriate, therefore, depends upon actual soil conditions. TC Alaska plans to review these design assumptions for the Yukon-BC section to ensure the appropriateness of their design assumptions. It is expected that this issue will be resolved by TC Alaska as more site-specific soil data becomes available (Appendix F, Exhibit F).

In addition to the foregoing, the project's massive size will create labor and equipment availability challenges. These challenges are not unique to TC Alaska's plan, but rather are inherent to the scale of the project. (Appendix F, Exhibit F) However, the Technical Team concluded that TC Alaska would be able to overcome the design, construction, and operating challenges inherent to the project (Appendix F, Exhibit F).

Except for these issues, the pipeline subproject project plan specified in the Application earned positive impact ratings on the vast majority of technical issues. For example, TC

An alternative design approach is to use Strain Based design. The stress in the pipeline steel due to the Primary loads is still limited to a fraction of the capability of the pipeline steel, same as the Conventional Design approach. The unique element of the Strain Based Design is the Secondary loads are limited by the strain (not the stress) in the pipeline steel (example is the amount of bending caused by frost heave would be limited by the amount of strain in the pipeline steel) The amount of strain allowed in the pipeline steel is a fraction of the strain capability of the pipeline steels.

Alaska earned positive impact ratings regarding the following factors for the pipeline subproject.

- Whether the subproject development plan reflects a complete and realistic FEED (two-stage Front End Engineering and Design) plan with a scope of work, resource plan, governance model, and schedule necessary to support project execution, (Appendix F, Exhibit F).[83]
- Whether the stakeholder management plan addresses the key stakeholders, key issues to be addressed and a viable plan to address their needs within the context of the subproject, (Appendix F, Exhibit F).[84]
- Whether TC Alaska's project execution plan is realistic and achievable in light of the subproject challenges, (Appendix F, Exhibit F).
- Whether the construction management plan address the challenges associated with the project location as well as the potential project resources environment (Appendix F, Exhibit F).

TC Alaska's cost estimate methodology is appropriate for each subproject such that the estimated cost is realistic and achievable; for the pipeline subproject it positively contributes to the project's likelihood of success. (Appendix F, Exhibit F). Because of this, it was possible to carefully and rigorously assess TC Alaska's actual cost estimates. As noted earlier, it is somewhat unlikely that TC Alaska's cost, expressed in 2007 dollars, will be achieved. (See Section D.2, above, for an assessment of the likely distribution of Project costs), That, however, does not impugn the appropriateness of TC Alaska's estimate, or reduce the Project's likelihood of success, given the current state of Project planning. TC Alaska's cost estimate was determined to be "aggressive but realistic." That is, if things were to go well it would be achieved as it is realistic, but it is on the optimistic end of the achievable range—it is aggressive. Such an estimate is appropriate for planning purposes: if one does not "aim high" at this stage, there is little hope of achieving a favorable cost outcome. TC Alaska's scheduling methodology is

[83] The FEED plan that TransCanada proposes has one phase designed to define the pipeline plan in sufficient detail for the open season and another phase involving work necessary to support the regulatory process and to implement the execution plan for the project (Application 2007, Section 2.1). The Technical Team report concluded that this is reasonable and should support the project's ultimate execution (Appendix F, Exhibit A).

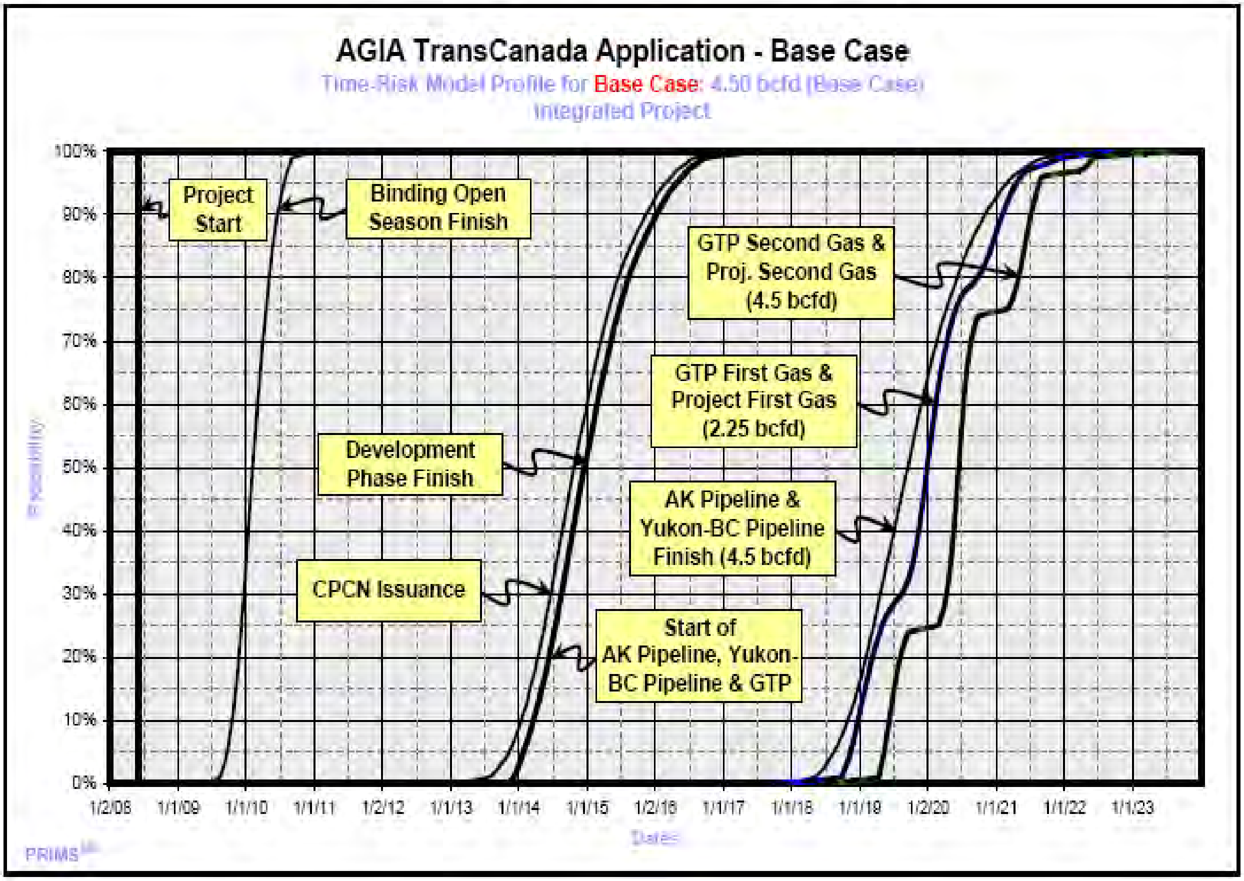
[84] We note that TC Alaska has provided a 13-page list of the stakeholders it has identified for this project (Appendix G to the Application).

appropriate for the subproject such that the estimated schedule is realistic and achievable, and its methodology for the pipeline subproject contributes positively to the Application's likelihood of success (Appendix F, Exhibit F). As with TC Alaska's proposed cost estimate, the proposed schedule itself was carefully scrutinized by the commissioners and their Technical Team. *See* Appendix F, Sections 2.1.2, 3.2, and Exhibit D.

Overall TC Alaska adopted a relatively conservative scheduling approach (Appendix F, Exhibit F). It does not currently plan to unconditionally award contracts to material suppliers or construction contractors until after a Certificate of Public Convenience and Necessity has been awarded by the FERC and NEB (Appendix F, Exhibit F) and the Decision of Notice to Proceed has been made. By staging their activities in this way they reduce their risk exposure; if additional risk were taken on—such as awarding these and other contracts earlier in the development phase—the overall schedule could potentially be accelerated (Appendix F, Exhibit F).

The commissioners scrutinized the development phase of proposed schedule, especially in regards to obtaining necessary regulatory permits. TC Alaska's proposal to complete the project's development phase and obtain the necessary permits within five and a half years is aggressive but not unreasonable. The commissioners believe TC Alaska's proposed schedule is technically feasible and reasonable under the circumstances. As discussed in the Technical Team report (Appendix F), the Technical Team's most likely outcome (the "P50" estimate) is that TC Alaska will not be able to begin the execution phase for approximately six and a half years after license award (Appendix F, Exhibit D).

Figure 3-39. Schedule Risk of Proposal Base Case



Source: Westney 2008, Appendix F, Exhibit D

TC Alaska's estimate of the conclusion of the development phase, which comes in a full year earlier than the Technical Team's midpoint probability estimate, is assessed as having a likelihood of about 5%. However, that does not mean that TC Alaska has proposed an unreasonable schedule. Given the adage that "a project expands to fill the time made available to it," a reasonable but aggressive schedule is necessary; there is little hope of making a shorter development schedule if a longer one is planned. Meanwhile, TC Alaska has a good understanding of the critical activities that must be scheduled (Appendix F). The Technical Team Report (Appendix F) concludes that TC Alaska may be able to achieve its aggressive schedule if many things "go right" for TC Alaska—especially with regard to the Canadian regulatory and First Nations issues. The fact that TC Alaska is pushing to construct the pipeline as soon as possible positively contributes to the Project's likelihood of success, given the state's interest in getting a gasline as soon as possible.

One particular issue that could impact the Project schedule which the commissioners analyzed carefully is the question of how long it will take TC Alaska to obtain Canadian regulatory authorizations.[85] AGIA requires that any applicant proposing a pipeline through Canada must provide, “a thorough description of the applicant’s plan to obtain necessary rights-of-way and authorizations in Canada…” (AS 43.90.130(2)(D)(i)). TC Alaska has indicated that it already holds certain rights-of-way through Canada (Application 2007, Section 2.2.4.2) and also holds certificates of public convenience and necessity to construct and operate the first gas pipeline from Alaska into Canada pursuant to the Northern Pipeline Act (NPA) (Application 2007, Section 2.2.3.13).[86]

However, in public comments (Appendix A, Alliance Comments, March 6 2008) and in earlier testimony before the Legislature, parties have asserted that TC Alaska's (through Foothills) Northern Pipeline Act certificates are dated, fail to reflect current environmental standards and are no longer valid. To better understand these Canadian issues, the commissioners retained the Canadian law firm of Bennett Jones LLP (“Bennett Jones”), which has significant experience in Canadian energy regulatory issues, to review TC Alaska’s application with respect to its authorizations and plans to obtain regulatory authorization and access (*i.e.,* rights-of-way) through Canada and the probable time line for obtaining such necessary approvals. The Bennett Jones report is attached as Appendix S1.

According to Bennett Jones, the five and one-half years that TC Alaska’s schedule includes for obtaining Canadian regulatory authorizations is probably optimistic. Bennett Jones suggests that a seven-year time frame is more likely due to the likelihood that at least certain of the risks identified with associated delays, will actually be encountered by the project, regardless of who builds it. This is similar to (although somewhat shorter than) the time the Mackenzie Valley Gas pipeline project has taken to obtain the necessary authorizations to build its pipeline in Canada. However, it is reasonable to expect that TC Alaska, as an experienced Canadian pipeline

[85] Pursuant to the Energy Policy Act of 2005, Congress required FERC to provide the U.S. regulatory authorizations within specified time periods which generally are significantly shorter than the estimated time it will take to obtain regulatory authorizations for the Canadian portion of the Project. Further, ANGPA requires that the FERC complete its review of an application for an Alaskan pipeline within 20 months of receiving a complete application. Accordingly, the focus of the discussion here is on the Canadian issues.

[86] Because of TransCanada’s unique position in Canada with regard to regulatory certificate and right of way matters, it is impossible to separate TC Alaska’s project plan from TC Alaska’s capabilities for implementing the plan. The following discussion reflects this fact.

operator, will pursue an approach to obtaining Canadian regulatory authorizations that does not repeat some of the mistakes made by Mackenzie (Appendix S1).

With respect to timing we note that recently Canadian officials have announced a new policy designed to expedite energy projects.[87] While it remains unclear what effect this might have on TC Alaska's proposal (or whether it would apply inasmuch as TC Alaska will be advancing its project under the authority of the NPA), it suggests a step in the right direction. Further, we note the public comments of Mr. Gary Lunn, Minister of Natural Resources of the Canadian government. He notes that the Canadian authorities are preparing for an Alaska project, "and are cognizant of the need for an efficient and effective review process that can match the time lines of a parallel process by the [FERC]…" This again, suggests that Canadian authorizations can be obtained in a timely manner.

In analyzing the feasibility and reasonableness of TC Alaska's proposed schedule for obtaining regulatory permits and its likelihood of success, the commissioners considered a variety of factors, including the seven-year estimate provided by Bennett Jones and the six-and-one-half year estimate by the technical team. The commissioners have confidence in the reliability of the schedule for obtaining Canadian regulatory permits because Bennett Jones and the Technical Team reached their schedule estimates independently of one another, and yet were only six months apart in their estimate of the most likely outcome.

Several of the conclusions in the Bennett Jones report are significant. Bennett Jones (Appendix S1, Section A) notes that the NPA created a "single window" agency (the Northern Pipeline Agency (NPAgency)) for obtaining all Canadian authorizations required to build the ANGTS project.[88] It notes also that the NPA was enacted to ensure the "prompt issuance of all necessary permits, licenses, certificates, rights-of-way, leases and other authorizations required for the expeditious construction and commencement of operation of the Pipeline" as had been

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[87] Petroleum News, *Canada to Fast Track Alaska*, Vol. 13, No. 19, at 1 (May 11, 2008).

[88] As required by the RFA, TC Alaska provided details of its plans to secure regulatory authorizations and rights-of-way in Alaska and Canada. Application 2007, Sections 2.2.4.1 and 2.2.4.2. TC Alaska asserts that it presently holds certificate authority to build the first gas pipeline from Alaska pursuant to the Northern Pipeline Act (NPA"). Application 2007, Section 2.2.3.13. The State received public comments asserting that TC Alaska's reliance on the thirty-year old NPA is misplaced (BP Comments at 2) These comments claim that the NPA is outdated and does not reflect modern environmental and other standards. However, TC Alaska claims that the NPA is still in effect and has no sunset or expiry date. TC Alaska also claims that it already holds easements for such a pipeline through the Yukon and has certain other rights to access lands over which its proposed pipeline will run. Application 2007, Section 2.2.4.2. TC Alaska also explains that it has identified approximate forty First Nations with whom it has either contacted to consult on its project or with whom it anticipates such consultation. Application 2007, Section 2.9.5(1).

agreed to by the U.S. and Canada in the September 20, 1977 *Agreement between Canada and the United States of American on Principles Applicable to a Northern Natural Gas Pipeline*. After analyzing the argument that the NPA is not applicable to the APP, Bennett Jones concludes that the NPA is still valid and the certificates issued there under continue to be effective. Bennett Jones concludes that "the legislation by its terms continues to apply;" stating that the Certificates do not have an expiration date (Appendix S1, Section D.2). They note that the NPA was utilized as recently as 1998 when certain of the Foothills Pre-Build[89] facilities were expanded. (Appendix S1, Section D.2).

According to Bennett Jones, however, the NPA is silent on process. While the idea underlying the NPA was to create a "single window" for all required regulatory approvals related to the project, the Act is silent on exactly how this is to be accomplished. The NPAgency is empowered to develop procedures and processes to implement the Act. The NPAgency can have critical regulatory functions carried out under the NPAgency's authority and to transfer issues to the NPAgency staff from other Federal agencies to evaluate and analyze the project. The NPAgency may adopt review standards used by other agencies. For example, the NPAgency could require that the *standards and requirements* of Canadian Environmental Assessment Agency (CEAA) be applied to environmental review under the NPA. If the NPAgency applies other agencies' review standards Bennett Jones suggests that objections to TC Alaska's reliance on the NPA can be minimized and the risks of litigation about this issue reduced.

Bennett Jones also notes that TC Alaska has the opportunity to propose to the NPAgency the use of a joint Yukon/Federal panel to review the impacts of the project in Yukon just as would likely occur if the Yukon Environmental and Socio-Economic Assessment Act (YESAA) were directly triggered by the project. Bennett Jones believes that YESAA would apply. Here again, by adopting the substance if not the actual form of YESAA review, TC Alaska and the NPAgency could reduce the risk of litigation that could delay the project.

Public comments questioned whether the current TC Alaska application describes the project that was approved and certificated in the 1970s. The early project plan was for a 2.4 Bcf/day

[89] The "Pre-Build" refers to the existing natural gas pipeline system built under certificates issued pursuant to Canada's Northern Pipeline Act that starts at Caroline, Alberta and branches into two legs, 1) south-east to Monchy, SK and 2) southwest to Kingsgate, BC, which is owned by Foothills Pipe Lines, LTD. A wholly-owned subsidiary of TransCanada Corporation (TC Alaska Glossary).

line. Now, however, a much higher pressure, larger diameter and more expensive line is contemplated. Commenters argue that this difference triggers the requirement in the NPA for National Energy Board (NEB) approval of an "expansion." Bennett Jones concludes that an expansion approval process would in turn trigger CEAA's public hearing process and major environmental review.

Bennett Jones suggests that there may be merit to the expansion claim (Appendix S) but advises that it could be resolved within the seven year time frame that they have identified. However, this issue, like other Canadian legal and regulatory issues discussed in the Bennett Jones report, should not adversely impact the Project's likelihood of success because the time line developed by the Technical Team presumes that the final regulatory approval of the project in Canada will extend beyond the five and one-half years suggested by TC Alaska. The longer time line was also used in the NPV analysis.[90]

Another Canadian regulatory issue arises from TC Alaska's proposal to make use of only the Alberta pipeline system owned by Foothills once the pipeline reaches Alberta. Potential shippers (i.e., ExxonMobil) and competitors of TC Alaska (i.e., Alliance) have commented on this matter, calling it a "tying" arrangement. The State of Alaska cannot resolve this issue. It will be resolved by Canadian regulators when TC Alaska puts forth its open season or re-engages the NPA permitting process. Bennett Jones commented on this issue in their report, however, noting that it could result in litigation and thereby delay the project. However, they also note that if TC Alaska adopts a flexible and expansive approach to the issue of moving Alaskan gas on the most economic and efficient route to markets, making use of all available infrastructure, it will be able to mitigate the risks on this issue. Nonetheless, the risk of delay associated with resolution of this matter is incorporated in the time line used in the NPV analysis of the project.

Another issue the project faces in Canada is the duty to consult with First Nations. The consultations that occurred in the 1970s may not be adequate today given Constitutional changes that occurred during the intervening years. Bennett Jones notes that the current duty to consult is quite rigorous and likely to be quite time consuming (Appendix S1, Section D.5). While TC Alaska does appear to hold easements through the Yukon as detailed in the application (Application 2007, Section 2.2.4.2), the right-of-way through British Columbia is unresolved. Furthermore, given the vagueness of the project's configuration in Alberta, that right-of-way may also be unresolved.

TC Alaska acknowledges that it has a duty to consult with First Nations (Application 2007, Section 2.2.3.13) and indicates it has a long-standing relationship with affected First Nations. While the nature of these long-standing relationships may be questioned (Government of Liard First Nation Comments, at 2-5) it is clear that TC Alaska acknowledges the necessity for such consultations (Appendix F, Exhibit F) and has a long history of working with First Nations on this project and others. (Application 2007, Section 2.9.5.) Accordingly, the current duty to consult with First Nations may cause some delay, but does not appear to negatively affect the overall likelihood of project success.

We note that the duty to consult will apply to any project crossing lands claimed by First Nations' or lands traditionally used by First Nations. Given TransCanada's years of presence in these communities as detailed in the application, TC Alaska appears to have a significantly higher likelihood of success than a newcomer or newcomers to the project who may have no prior experience in such consultations.

> Given TransCanada's years of presence in First Nation as detailed in the application, TC Alaska appears to have a significantly higher likelihood of success than a newcomer or newcomers to the project who may have no prior experience in such consultations.

Before concluding, we focus again on TC Alaska's plan for the GTP subproject. AGIA requires an applicant to explain how they propose to deal with the GTP, regardless of whether that plant is part of the applicant's proposal. (AS 43.90.130(8). As noted earlier, TC Alaska does not propose to construct or own the GTP. Rather, they suggest that the Major North Slope Producers should build, own and operate the GTP. However, in the event that the Major North Slope Producers do not wish to, TC Alaska stands prepared to do so. Accordingly, TC Alaska provided a basic work plan, timeline, and budget for a GTP to address this contingency. That they did so contributes to the overall Project's likelihood of success, as it demonstrates a willingness to taking relatively unusual actions to see the project through. However, because their work plan concerning the GTP subproject was conducted at a relatively high level, the Technical Team generally concluded that the plan neutrally affected the Project's

[90] We note that the Technical Team utilized a 6 ½ year time line whereas Bennett Jones suggests that a 7-year time line is the most probable. The minor six-month difference is not material to the NPV analysis on a project of this

overall likelihood of success.[91] (See, generally, Appendix F, Exhibit F). We concur with their assessment.

In sum, from a technical standpoint, TC Alaska's plan and schedule for constructing the Project are challenging yet technically reasonable and feasible, are appropriate for planning purposes, and contribute positively to the likelihood of success of the Project.

b. TC Alaska Has Demonstrated the Technical and Financial Ability To Construct the Project.

Having concluded that TC Alaska's plan has the requisite specificity, and is reasonable and feasible, we next analyze several of the specific factors set forth AS 43.90.170(c) to determine whether TC Alaska has demonstrated the technical and financial ability to successfully complete its plan. For the reasons discussed below, we conclude that TC Alaska has demonstrated that ability.

i. TC Alaska's experience, skills and capabilities

To determine the likelihood that an applicant can successfully execute its plan, AGIA requires the commissioners to consider the "applicant's organization, experience, accounting and operational controls, technical skills or the ability to obtain them, and necessary equipment or the ability to obtain the necessary equipment." AS 43.90.170(c)(4) Similarly, AGIA requires the commissioners to assess the "ability of the applicant to comply with the proposed performance schedule" (AS 43.90.170(c)(3)). To analyze how TC Alaska does in regard to these criteria, the Technical Team employed its Positive Impact/No Impact/Negative Impact analysis framework. They awarded a Positive Impact rating on TC Alaska's overall likelihood of success. The commissioners concur with and adopt the Technical Team's assessment.

In response to a state data request, TransCanada clarified that, as the parent company of TC Alaska, it was committing to:

> *Make available the necessary human resources, technical know-how and expertise, management information systems, and procedures and policies to ensure that the Co-Applicants can meet their AGIA undertakings. (Palmer, 12/14/2007; Letter to Marty*

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scale.

[91] TC Alaska's conceptual design for the GTP is based on existing and well proven technology. (Appendix F, Exhibit F). This contributes favorably to the project's likelihood of success, as problems that can occur with using cutting edge approaches are unlikely to materialize.

> *Rutherford, Deputy Commissioner, Alaska Department of Natural Resources, December 14, 2007).*

Accordingly, when analyzing TC Alaska's experience, skills, equipment and capabilities we look through them to their parent, TransCanada.

TC Alaska appears to have the work processes and project governance standards in place to effectively manage the project (Appendix F, Exhibit F). The Technical Team assessed that TC Alaska demonstrated the appropriate work processes, governance, and staff competencies with ability to manage major pipeline projects on cost and on schedule (Appendix F, Exhibit A). TC Alaska's demonstrated ability to manage major pipeline projects on cost and on schedule (Appendix F, Exhibit F) is an important factor which contributes positively to the Project's overall likelihood of success. Although it appears that no company has experience dealing with the unique attributes of this Project, the commissioners concur with the Technical Team's assessment that:

> "the areas where TransCanada lacks experience are generally areas where TransCanada's technical and management capabilities can be adapted to these challenges and the TransCanada staff can be supplemented with contract staff with the necessary experience" (Appendix F, Exhibit F).

TransCanada's solid track record as a pipeline operator also indicates it will be able to successfully mitigate the risks associated with its technical plan (Appendix D*,* Palmer Letter February 8, 2008). It has a good understanding of the critical activities that must be scheduled for a large international Arctic pipeline (Appendix F, Exhibit F).

Meanwhile, TransCanada presents a documented record of constructing projects at or near the projected costs *(*Application 2007, Section 2.9.3). This suggests that TC Alaska's likelihood of completing the Alaska project at or near the estimated cost—at least with respect to controllable costs—is good (Appendix F, Exhibit F). The Technical Team expressed some concern that TC Alaska's role in the Keystone project and a possible lead role in the Mackenzie Gas project could reduce the involvement of key management personnel and could result in a lack of experienced staff to meet all the staffing requirements that the company will face. (Appendix F, Exhibit F). On the other hand, as TC Alaska notes, TC Alaska's ability to manage the Project may actually benefit from the increased staffing on those two projects, provided TC Alaska can rely on those staffing resources for the Alaskan pipeline project as the Keystone and Mackenzie projects are completed (Appendix D, Palmer Letter February 8, 2008). Due to the uncertainty with this issue, the Technical Team gave it a neutral impact rating.

The Technical Team noted that TC Alaska has significant experience in dealing with multitudes of stakeholders based on its experience in other major projects, including the Keystone project, Gas Pacifico (Argentina and Chile) and Tamazunchale (in Mexico) (Appendix F Exhibit F). Further TC Alaska has extensive experience in dealing with the Aboriginal communities in Canada (Appendix F).

A positive contributing factor to the Project's likelihood of success is TransCanada's experience in operating and managing large complex projects (Appendix F, Exhibit A). TransCanada is one of the leading pipeline operating companies in North America, if not the world (Appendix F, Exhibit F). Moreover, TransCanada has experience in large natural gas pipelines through its other natural gas and oil pipeline projects—including the Keystone oil pipeline project involving over 1600 miles of 30" and 36" pipe running from Canada to the U.S. (Appendix F, Exhibit F). TC Alaska has constructed hundreds of miles of high pressure, large diameter gas pipelines in near arctic operating conditions (Appendix D, Palmer, 2/8/2008; letter to Rutz; Additional Clarifying information). Based on TC Alaska's experience, and for the other reasons discussed in the Appendix F, the commissioners conclude TC Alaska has the ability to comply with the schedule it proposed for the Project, and with the more conservative schedule estimated by the Technical Team and used by the commissioners to estimate the NPV of the Project. In addition, as the Technical Team concludes, TC Alaska's organization, experience, skills, and equipment, and the ability to obtain each of these, favorably contributes the pipeline subproject's likelihood of success. The fact that TC Alaska is an experienced natural gas pipeline operator contributes to the likelihood of success of the Project.

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ii. TransCanada's Record of Performance on Other Projects

Another factor the commissioners must consider in assessing the likelihood that an applicant can successfully execute its plan is an applicant's record of performance on other projects. Section 170(c)(5)(A). This provides evidence of the applicant's capabilities (which are considered in the preceding subsection). As summarized below, TC Alaska's record of performance on projects not licensed under AGIA should contribute positively to the Project's likelihood of success.

Given that it is one of the largest natural gas pipeline companies in North America, it is not surprising that TransCanada has built or participated in other large pipeline projects in the past. These include a series of mainline expansions to its natural gas pipeline facilities in North America (Appendix G2, Section 5.2). Other examples of pipelines TransCanada helped build are the Energia Mayakan Natural Gas Pipeline Project in Ciudada Pemex, Tabasco and the Tamazunchale Pipeline Project in Naranjos, Veracruz (Appendix G2, Figure 20).

TC Alaska also appears to be an active participant in environmental management within the industry (Application 2007, Section 2.9.1). TC Alaska's application indicates that it annually compares its safety performance to the average of peer companies in various industry groups and organizations, including the Canadian Energy Pipeline Association, the American Gas Association's transmission group, the Canadian Gas Association and the U.S. Occupational Safety and Health Administration (Application 2007, Section 2.9). From 1996-2006, TC Alaska has equaled or exceeded the safety performance of each of those organizations (Appendix F).

Another indicator of TC Alaska's expertise in planning and executing projects is its record in completing projects on schedule and within the cost estimates (Application 2007, Section 2.9.3).[92] During the period from 1990 to 2000, TC Alaska asserts it added 6,683 miles of pipe and over 3 million more compression horsepower to its existing natural gas pipeline network (Application 2007, Section 2.9.3). According to TC Alaska, it completed these additions within 0.6% of the budgeted amounts Application 2007, Section 2.9.3). TC Alaska also reported that it generally completed these additions on or before the originally scheduled dates and it never experienced substantial schedule setbacks Application 2007, Section 2.9.3). These pipeline projects included pipelines of the same diameter (48") and compression units of the same horsepower that TC Alaska has proposed to install on the Project (Application 2007, Section 2.9.5). TC Alaska also states that it installed several of the pipelines within this group of facilities in the winter in areas with sporadic permafrost (Application 2007, Section 2.9.3)**.**

[92] *See* TC Alaska's 2007 Annual Report at 8; *see also* TC Alaska's website, *available at*: http://www.transcanada.com/ gas transmission/index.html, for a listing of the pipelines it owns and operates; also see Figure 3-1.

Notably, none of the public comments regarding TC Alaska's application disputed these assertions by TC Alaska. Accordingly, TC Alaska's assertions stand and they provide evidence supporting its ability to construct and operate long-distance, natural gas transportation facilities similar to those included in the Project. In sum, TransCanada's history demonstrates a positive likelihood of success with respect to its ability to plan and execute large natural gas pipeline projects in near-arctic as well as other conditions likely to exist in developing the Project.

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iii. TransCanada's Record of Integrity and Business Ethics

To determine the likelihood that an applicant can successfully execute its plan, AGIA also requires the commissioners to consider the applicant's "record of integrity and good business ethics." (AS 43.90.170(c)(5)(B)). As summarized below, TransCanada's record of integrity and good business ethics should contribute positively to the Project's likelihood of success.

First, TransCanada operates over 36,000 miles of wholly-owned natural gas pipelines and maintains a sound record of pipeline safety with agencies responsible for pipeline safety in the U.S. and Canada (Appendix R5 and Appendix S2).

Second, a review of FERC and NEB proceedings indicates no issues of concern at the FERC or the NEB which implicate integrity or business ethics (Appendix S2). As a regulated pipeline company TransCanada has a variety of ongoing regulatory proceedings at FERC, NEB and other agencies. On balance, those proceedings appear to involve routine regulatory matters such as rates, services, and new projects, not issues that might, depending on the nature of the proceeding, raise issues of concern regarding integrity and business ethics. Although Congress gave FERC new civil penalty authority in 2005, which FERC has exercised repeatedly against other companies, a review of FERC orders shows TransCanada and its affiliates do not appear to have been the subject of any civil penalty. (See, e.g. www.ferc.gov media releases on FERC investigations and penalties (which do not include TransCanada or its affiliates.)) Similarly, an assessment of TransCanada's SEC filings revealed no major litigation which implicates integrity or business ethics.

Third, TransCanada has been commended for its record on the environment and corporate governance. For example, TransCanada was named to the Global 100 sustainable corporations during the World Economic Forum in 2007 and 2008 (Appendix R5).. It also was named as a member of the Dow Jones Sustainability Index in 2006 in recognition of its practices in the areas of climate change, corporate governance, and labor practices, among others. *See* Id. Similarly, TransCanada has been recognized by the Canadian Coalition for Good Governance (Appendix R5).

Fourth, TransCanada receives solid customer satisfaction ratings in surveys of customers of natural gas pipelines in North America (Appendix S2). Perhaps more significantly, TransCanada also received high marks from a major potential shipper, ConocoPhillips, in public comments filed by ConocoPhillips. According to ConocoPhillips, "we think highly of TransCanada and they are a valued associate in other large projects in North America."[93] ConocoPhillips's comments appear representative of how the natural gas industry as a whole perceives TransCanada, based on the publicly available information reviewed (Appendix S2). No public comments were received that expressed any concern about TransCanada's record of integrity and business ethics.

In Canada the NEB's Pipelines Services Survey provides an assessment of shippers' satisfaction with the quality of services of major NEB-regulated pipeline companies. In the latest survey (conducted in the first quarter of 2007) TransCanada Pipe Line Company outperformed the industry average for Canadian transmission pipelines (Appendix S2). Further, TransCanada Pipe Lines Ltd. received a Pollution Prevention Award from the Canadian Council of Ministers of the Environment for its "disciplined and cost effective approach to reducing fugitive emissions releases of methane gas from pipeline systems by finding a means of measuring and understanding the scope of the problem, followed by developing the Fugitive Emissions Management Program." In 2005, implementation of this program avoided the release of roughly the equivalent of 201,000 tons of CO_2 into the environment (Appendix S2).

Accordingly, based on the information reviewed above, the commissioners conclude that TransCanada's record of integrity and business ethics is a factor which should positively impact the likelihood of success of the Project, including the likelihood of successfully attracting firm shippers to the Project, successfully constructing the Project, and successfully operating the Project after it commences service.

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[93] See Public Comments filed by ConocoPhillips, Jan. 24, 2008 letter at page 5.

iv. TransCanada's Financial Resources

Another factor the commissioners must consider in assessing the likelihood that an applicant can successfully execute its plan is "the financial resources of the applicant." (AS 43.90.170(c)(2)). The commissioners engaged Goldman, Sachs and Co. (Goldman Sachs) to review TransCanada's financial resources, assess TransCanada's ability to obtain project financing[94], and to prepare a report summarizing its conclusions (Appendix H).

Just as we did when assessing its technical capabilities, we look to TC Alaska's parent company when assessing financial resources. We do so because of TransCanada's clarification of the application.

> "TransCanada Corporation will provide irrevocable commitments to the Co-Applicants and Project lenders with respect to the total equity commitment, consistent with the Negotiated Rate capitalization structure, for the Project to secure financing"[95]

Goldman Sachs analyzed TransCanada's funding needs for the project under both the Base Cases and across a broad range of potential outcomes. They addressed not only the P50, or midpoint cost estimate, but also the P95 cost estimate. They considered the higher interest rate scenarios. And they also considered combinations of the two (Appendix H, Sections V and VI).

In its report, Goldman Sachs explains that TransCanada is a large, diversified energy company with substantial physical and financial resources, as well as a number of growth initiatives (Appendix H, Section II.E). Importantly, TransCanada has strategic and financial incentive to fulfill its obligations under its AGIA proposal (Appendix H, Section IX) and Goldman Sachs concludes that "TransCanada, through its AGIA bidding entities, Foothills Pipe Lines Ltd. and TransCanada Alaska

> TransCanada, through its AGIA bidding entities, Foothills Pipe Lines Ltd. and TransCanada Alaska Company, LLC, has the financial wherewithal to meet the financial obligations implied in the Proposal.

[94] TransCanada's ability to obtain financing for the Project is addressed in later in this chapter.
[95] Letter from Tony Palmer to Marty Rutherford, Deputy Commissioner, Alaska Department of Natural Resources, December 14, 2007

Company, LLC, has the financial wherewithal to meet the financial obligations implied in the Proposal."[96] It also states as follows:

> TransCanada has the ability to fund all of the predevelopment costs and early construction costs from company equity. As construction and procurement spending increases during the execution phase (2014-2019), we believe TransCanada would be able to raise 100% of the substantial equity funded portion of the project through internally generated cash and/or corporate debt. However, funding 100% of the project equity requirements with no equity partners or by raising additional primary equity at the TransCanada level could put financial strain and downward credit ratings pressure on TransCanada during construction. Nevertheless, we expect that TransCanada's credit ratings would remain investment-grade and the company will be able to attract external capital to fund its commitment to the project because the strain is a temporary effect of the major financial requirements during development and project execution and the potential strategic and financial benefits of the Project to the Company are compelling.

TransCanada has previously demonstrated the ability and willingness to take actions to fortify its financial profile materially if it needs to do so to maintain its credit rating. For example, in conjunction with acquiring ANR Pipeline Company in 2007, TransCanada issued additional equity. (TransCanada, 2006). Given the long lead time on the project, TransCanada could take similar, or other, actions to reinforce its credit ratings during the project development phase of the Project (Appendix H Section IV). If this occurs, or if the credit rating agencies view the Project as having a high probability of success, Goldman Sachs believes TransCanada may be able to maintain its currently strong credit ratings, even though the Project will obviously constitute a very large financial undertaking (Appendix H, Section IV).

[96] The Goldman Sachs analysis is based on a wide range of assumptions, including but not limited to the following:

- The Project is a 4.5 Bcf/day system to transport natural gas from Prudhoe Bay to the Alberta market hub;
- 25-year firm shipping contracts with market standard shipper credit requirements;
- Debt is non-recourse to TransCanada (i.e., the debt is 'project debt');
- Capitalization of 70% debt and 30% equity during construction;
- Capital cost overruns to be financed through federally guaranteed cost overrun loans;
- Federally guaranteed capital cost overrun loans to be repaid through shipper surcharge; and
- No project completion guarantee or pre-completion debt guarantee from equity sponsors is assumed.

A number of major factors support financial viability. Some of these are driven by project fundamentals that are independent of TransCanada

- The Project is strategically important for the key principals: TransCanada, the Federal Government, the State of Alaska and prospective shippers;
- TransCanada and the principal Alaska North Slope shippers are financially strong;
- The project shows strong financial results. (Appendix H, Section II.E).

In short, Goldman Sachs believes the Project has strong fundamentals, including the fact that TransCanada is financially strong and possesses the necessary financial wherewithal. It finds that the pro forma financial results are robust, even in the face of stress tests (Appendix H, Section V. D). The commissioners concur with and adopt these conclusions. Accordingly, and as more fully explained in the Goldman Sachs report, the commissioners conclude that TransCanada has the financial resources to fund the equity requirements of the Project and obtain necessary debt financing (Appendix H).

c. TC Alaska Has Submitted a Reasonable Commercial Plan Which, Coupled With Economic and Political Factors, Should Help To Encourage Firm Shipping Commitments

Having concluded that TC Alaska has submitted a plan that is reasonable from a technical standpoint, and that TC Alaska is technically and financially capable of executing that plan, we now turn to the commercial aspects of TC Alaska's plan. As discussed below, we find that TC Alaska has submitted a reasonable commercial plan which, coupled with the economic, political and legal environment, appears to generate the favorable conditions needed to encourage shippers to sign firm shipping commitments.

i. TC Alaska's Commercial Plan

During an open season a pipeline invites potential customers to commit to sign contracts to ship gas on the pipeline. As discussed earlier, and treated further below, the Project's economics are robust. Moreover, as discussed below, there are a number of aspects of TC Alaska's proposal that should be attractive to potential shippers. Accordingly, by themselves these are good reasons to believe that the Major North Slope producers will seek to monetize their gas reserves and participate in an open season.

> It is highly likely that TC Alaska will engage in commercial negotiations with potential shippers to enhance the prospects for success.

Nevertheless, TC Alaska recognizes that it may be a challenge to convince the Major North Slope Producers to participate in the Project’s open season (Application 2007, Section 2.2.3). It is highly likely that TC Alaska will engage in commercial negotiations with potential shippers to enhance the prospects for success (Application 2007, Section 2.2.3), after all, this is typical industry practice.

During or before the open season process, a pipeline and its shippers often negotiate rates based on market factors and the pipeline’s estimate of project costs (Appendix G2, Section 4.1). Sometimes the pipeline and its shippers agree to negotiated rates that are lower than the rate initially offered by the pipeline (Appendix J, Section 1). Negotiations address rates, factors such as the term (length) of any firm service contract, the volume to be contracted, and various other mechanisms for sharing risk (Appendix J, Section 1; Appendix G2, Section 4).

This aspect of the negotiation process for natural gas transportation service is similar in a way to the process of selling and buying a house. The seller makes an initial offer to sell its home at, say, $225,000. After a series of counteroffers by the buyer and seller, they agree on a sales price of $200,000. The fact that the parties ultimately agreed to a price of $200,000 does not mean the initial offer of $225,000 was unreasonable. In fact, in this example, the initial offer established a reasonable framework for an ultimately successful negotiation between the seller and the buyer.

Similar to the initial offer to sell the house discussed in this example, the commercial terms, principally the rates, that TC Alaska has proposed to offer shippers in its Application also establish a reasonable framework for a successful negotiation, and should increase the likelihood of success of the Project by encouraging shippers to participate in the first binding open season (Appendix G2, Section 4). Exxon’s comments (see Appendix A) correctly recognize that TC Alaska’s proposed commercial terms constitute an ”opening offer,” similar to the opening offer in the home sale example. The commissioners analyzed TC Alaska’s proposal from that same perspective. Thus, while it is important to understand TC Alaska’s current commercial terms, it is also important to recognize that those terms are likely to change and improve during the regulatory process, the open season process, and the process of negotiation with the Major North Slope Producers, and will likely end up at a point that is even more favorable from a shipper perspective than the reasonable terms which TC Alaska is proposing today (Appendix G2, Section 4; Appendix J, Section 1).Therefore, from an economic standpoint, the NPV that the Project would produce for the state and the Major North Slope Producers will likely only improve beyond the results discussed earlier in this Chapter.

Even under TC Alaska's current proposal to its shippers, the Project would produce significant cash flow and a positive NPV for Major North Slope Producers and the state. As discussed in the prior Section regarding the Project's estimated NPV, the Proposal Base Case would provide the Major North Slope Producers an NPV_{10} of than $13.5 billion. If, as is currently typical for a major gas pipeline project, TC Alaska and the Major North Slope Producers ultimately negotiate rates in the open season process that are lower than those initially proposed by TC Alaska in its Application (what Exxon correctly terms TC Alaska's "opening offer" to potential shippers),[97] the NPV for the Major North Slope Producers and the state will be even higher.

We also note that while some of TC Alaska's initial transportation offerings favor TC Alaska as opposed to shippers, many of the proposed terms have been accepted by regulators and shippers on other large pipelines. This can be seen in Figure 18 of the Commercial Team report (Appendix G2, Section 4.2). As shown there, the key components of TC Alaska's proposal, including the credit requirements, equity return,[98] overall rate of return, capital structure, depreciable life, and rate structure, are within the range of what has been proposed and accepted for other large pipeline projects (Appendix G1). That is not to say that the commissioners endorse each of TC Alaska's proposed commercial terms. In fact, the state retains the right to oppose any of TC Alaska's proposed terms at FERC or the NEB. However, and without endorsing any specific term, the commissioners believe TC Alaska's package as a whole sets forth a reasonable starting point, which is only likely to improve as TC Alaska negotiates with shippers and seeks regulatory approvals and the reviewing agencies are asked

[97] As noted in Appendix G2, Section 4, it is not uncommon for potential shippers to submit binding offers in pipeline open seasons that do not fully conform to the terms offered by the pipeline or contain contingencies on the occurrence of specific events It is not unreasonable to expect that potential bidders in the open season on the Alaskan project will do the same. As further discussed in the Commercial Team report, there is little risk that a Major North Slope Producer would be unable to obtain capacity on the pipeline if it submitted a non-conforming "low bid" in the open season, because it is unlikely that a third-party lacking in North Slope gas reserves will bid for capacity Even if a low bid is rejected by TC Alaska, it is not likely that capacity will not be available if the shipper were later to offer to acquire capacity at a higher rate given that one of the challenges of the project is fully contracting the system at the beginning

[98] The fact that TC Alaska is asking to have its return on equity set based on a 965 basis point premium to 10-year U.S. Treasuries is discussed in some detail in Appendix J where it is noted that this formula currently produces an equity return of slightly above 13.3%. That report also notes that the current TC Alaska proposal is probably less generous to TC Alaska than the "Incentive Rate of Return" approach adopted for the ANGTS project thirty years ago. The report concludes that while TC Alaska's proposal is not consistent with the FERC's preferred discounted cash flow (DCF") method for setting equity returns, there is reason to believe that it will be accepted by FERC. We note, however, that the equity return that flows from that formula is still above equity returns that the NEB normally allows under a more formulaic approach than the FERC uses (Appendix S2)..

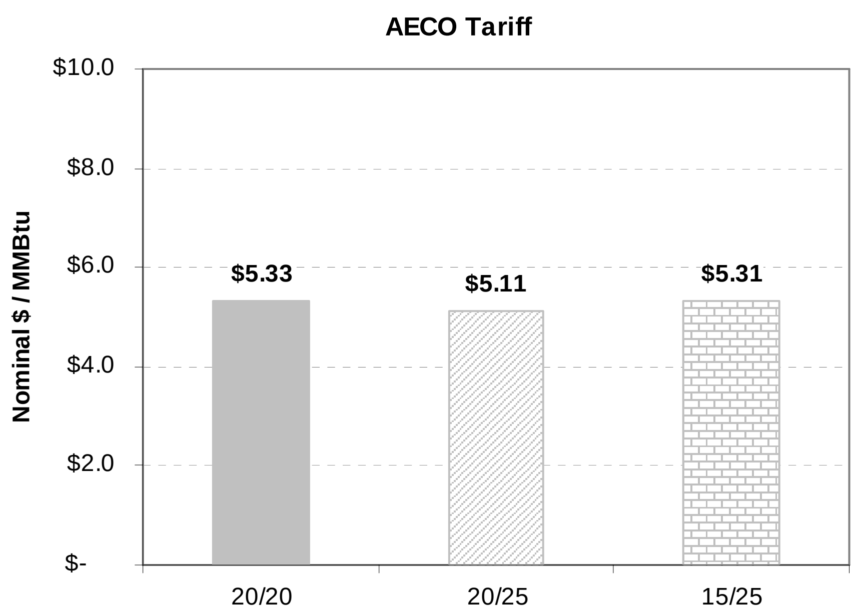
to require more favorable terms.

Some examples of commercial negotiation outcomes, that would enhance the risk reward balance for shippers, might include:

Shorter Contract Lengths. After negotiations between TC Alaska and the Producers, TC Alaska may offer a contract period that is shorter than the depreciation period. For example, they could offer contracts for 20, or even 15 years but depreciate the pipeline over 25 years. Such an offering would fit squarely within the mainstream of commercial transactions on Lower 48 projects (Appendix J, Section 1) and appear feasible from a financing perspective (Appendix H, Section VI.B (for results) and Section VI.D (for discussion)).

Initial shippers could substantially benefit. In the first instance they would be able to “shed” the majority of their reserve risk. Secondarily, tariffs determined on a levelized basis would drop. Figure 3-40 shows tariffs for the Conservative Base Case, and variations of that case where the Project is depreciated over 25 years but initial shipping contracts are 20 and 15 years in duration.

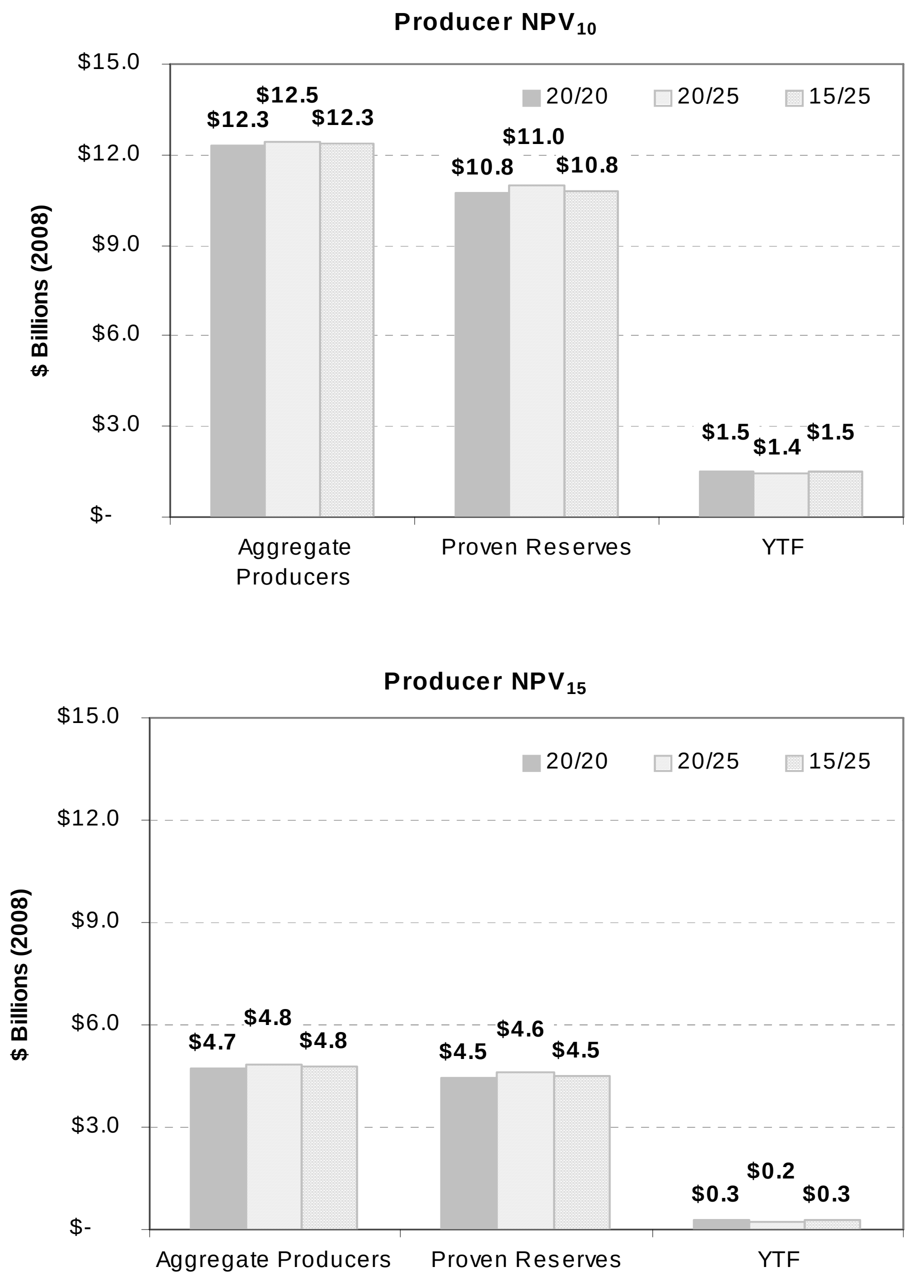
Figure 3-40. Impact of Commercial Terms of Transportation Contracts to AECO Tariff



Source: Black and Veatch, Appendix, G1, Section 6.7.1

Given shorter contracts and a longer depreciation period Producer net backs would improve, as would their NPVs, as shown in Figure 3-41.

Figure 3-41. Impact of Commercial Terms of Transportation Contracts to Producer NPV_{10} and NPV_{15}



Source: Black and Veatch, Appendix, G1, Section 6.7.1

In such a scenario, TC Alaska would essentially be offering to take some of the reserve risk, by agreeing to bear the risk of finding shippers to contract for capacity on the pipeline over the remaining depreciable life. If TC Alaska takes that risk, and continues to use a 25-year depreciation period, NPVs to the state and the Producers would improve, all other things being equal (Appendix G1, Section 6.7.1).

Reduced ROE. The Proposal and Conservative Base Cases are modeled assuming that rates are based on a 14% return on equity (ROE). It is possible that, after negotiations, the return on equity that TC Alaska receives would be reduced from its initial offer. (Appendix J, Section 1; Appendix G2, Section 4). If the ROE were reduced from 14 to 12%, under the Proposal Base Case the "all in" tariff to the AECO Hub would decrease by \$0.28/MMBtu, and the Producers' aggregate NPV_{10} would increase by about \$400 million (Appendix G1, Section 5.7).

Increased Cost Overrun Risk Sharing. TC Alaska proposes to share some of the risk of cost overruns by taking, for five years, a reduction in its return on equity should an overrun occur. Application at 2.2-66. Given a 20% cost overrun (measured against the cost estimate at the time the FERC certificate is issued), the ROE reduction mechanism would decrease tariffs by \$0.04/MMBtu from where they would otherwise be; a 40% cost overrun would decrease tariffs by about \$0.09/MMBtu. The respective Producer NPV_{10} benefits would be between \$70 and \$200 million, and TC Alaska $NPV_{8.8}$ losses would be between \$200 and \$300 million (Appendix G1, Section 5.7). In light of common practice on other pipelines, increased cost overrun risk sharing on TC Alaska's part would seem a reasonable possible outcome of negotiations (Appendix G2, Section 4.4).

In addition to offering to negotiate rates, TC Alaska has also offered potential shippers several other commercial terms that should further increase the potential that shippers will sign firm transportation commitments. For example, a favorable aspect of TC Alaska's proposal is its statement that it will be receptive to term-differentiated rates (Application 2007, Section 2.2). Term-differentiated rates are rates that vary by the length of the contract term. Thus, shippers that sign up for a longer-term contract can obtain lower rates than shippers that sign shorter-term contracts. This recognizes the increased risk that a pipeline with shorter-term contracts will, in the future after shipper contracts expire, lack sufficient shippers to allow the pipeline to recover its costs. Term-differentiated rates allow the pipeline to recover its capital costs from shippers over a longer-term period, thus lowering the rates paid by shippers that sign

In addition to offering to negotiate rates, TC Alaska has also offered potential shippers several other commercial terms that should further increase the potential that shippers will sign firm transportation commitments.

longer-term contracts. TC Alaska's willingness to consider term-differentiated rates would allow shippers to lower their rates and transportation costs by extending the duration of their contracts. A similar approach has been successfully employed on other major natural gas pipeline systems, including the Kern River system.[99]

In addition, the precedent agreements TC Alaska will negotiate with shippers in the context of the open season provide another vehicle for shippers to negotiate favorable terms. A precedent agreement is a contractual agreement by the shipper to sign a firm transportation contract with the pipeline at the rates, volumes, contract duration and other terms set forth in the precedent agreement. As explained in the Commercial Team report, a precedent agreement typically will give shippers (and the pipeline) the option of terminating the agreement if certain conditions do not occur (Appendix G2, Section 4.1).

Currently, TC Alaska has proposed to require shippers that terminate their precedent agreement to pay a pro rata share of all of TC Alaska's unreimbursed development costs (Application 2007, Section 2.2). However, this term may be substantially modified during the process of negotiation that will occur between TC Alaska and potential shippers. As an example, in the Rockies Express project the precedent agreements provided shippers with the right to back out of the commitment to sign a firm shipping contract if certain milestone dates were not met (such as obtaining certificate authorization by specified dates, and putting segments into service by specified dates).[100] Based on the experience of Rockies Express and other pipelines in the natural gas industry, it can reasonably be expected that shippers will be able to negotiate similar protections with TC Alaska (Appendix G1, Section 4.1).

> TC Alaska is providing prospective shippers with an important negotiated term by offering anchor shippers an equity ownership interest in the project.

Further, TC Alaska is providing prospective shippers with an important negotiated term by offering anchor shippers an equity ownership interest in the project (Application 2007, Section 2.2.3.8). An anchor shipper is a shipper that makes a firm commitment to contract for a large volume of a new pipeline's capacity, typically in exchange for a more favorable (lower) rate than the pipeline offers to non-anchor shippers. Here, TC Alaska has

[99] See, *Kern River Gas Transmission Company*, 94 FERC ¶ 61,115 at p 61,439 (2001).

[100] Rockies Express Generic Precedent Agreement at 3, located at:
http://www.kindermorgan.com/business/gas_pipelines/rockies_express/PA_Rockies_Express_12-17-05.pdf

extended the anchor shipper concept beyond the concept of lower rates by offering anchor shippers the ability to own a portion of the Project. As a part-owner of the Project, shippers will be able to influence the terms and conditions that are offered by TC Alaska and also reduce their overall costs of shipping gas by sharing in the profits of the project as part owners. Partial ownership may also give an anchor shipper the ability to control cost overruns through the owner/shipper's influence over project development (Appendix G2, Section 4.3).

A notable example of this anchor shipper concept is the Rockies Express pipeline. There, ConocoPhillips agreed to become an anchor shipper in exchange for a partial ownership interest in the pipeline, which is majority-owned by an independent pipeline company (Kinder Morgan). TC Alaska's willingness to offer the Major North Slope Producers a similar equity ownership interest will enhance its ability to attract them to the Project as anchor shippers, either during or after the first open season process.

In sum, these elements of TC Alaska's initial proposal to potential shippers, including the ability of shippers to enter into even more favorable negotiated rates than the rates currently proposed by TC Alaska, enhance the Project's likelihood of success.

ii. TC Alaska's Plan To Manage and Insulate Shippers From Cost Overruns

AGIA directs the commissioners to consider how TC Alaska's proposes to manage cost overruns and to insulate shippers from the effect of cost overruns. (AS 43.90.170(c)(1)). There are two aspects to this evaluation.

The first can be broadly viewed as "technical." "Managing cost overruns" is done, in part, through an engineering and management plan for doing so. An overall technical work plan that is specific, reasonable, and feasible stands a better chance of producing good outcomes, with regard to cost overrun risk, than one that is not. Specific aspects of the work plan that directly go to the question of managing cost overruns were also addressed in the commissioners' assessment of TC Alaska's proposal. These include:

- Is the cost estimate methodology appropriate?
- Does the cost estimating process have means to establish the risk of cost overruns?
- Are reasonable contingency levels applied to the overall cost estimate?
- Does the risk management plan list major risks and an assessment of their impact on the subproject, as well as an appropriate mitigation plan?

The commissioners' assessment of these factors has been discussed previously in this chapter.

The Technical Team addressed these and other questions that are directly relevant to the Applicant's plan for managing cost overruns. They determined that TC Alaska's plan contributed positively to the project's likelihood of success, meaning that the plan was a good one (Appendix F, Exhibit F). The commissioners agree with their analysis and find that TC Alaska has a good technical plan for managing cost overruns.

The second aspect of addressing cost overrun risk is commercial. In the end, shippers should be encouraged to participate in an open season. Given the fact that shippers have incentive to reduce their exposure to cost overrun risk, they are more likely to participate in an open season if this risk is smaller. Accordingly, the statute directs the commissioners to assess the extent to which TC Alaska will take actions that insulate shippers from this risk.

For reasons discussed below, the commissioners find that TC Alaska's proposals for addressing cost overrun risks help encourage shippers to participate in an open season. First, TC Alaska's proposals remove any incentive that TC Alaska might have to permit cost overruns. Second, TC Alaska's proposals create incentives for TC Alaska to avoid cost overruns. And third, in indicating a willingness to negotiate commercial terms with shippers (Appendix G2, Section 4), we expect that TC Alaska may take further actions in this regard. to insulate shippers from cost overruns. In addition, the allocation of responsibility for cost overruns, and the risks associated with cost overruns, are likely to be the subject of intense negotiations between TC Alaska and its potential shippers. Thus, like the negotiated rates issue just discussed, it seems likely that TC Alaska ultimately will agree to address cost overruns in a way that is even more favorable to shippers as compared with its initial proposal and offer to shippers (Appendix G2, Section 4.4).

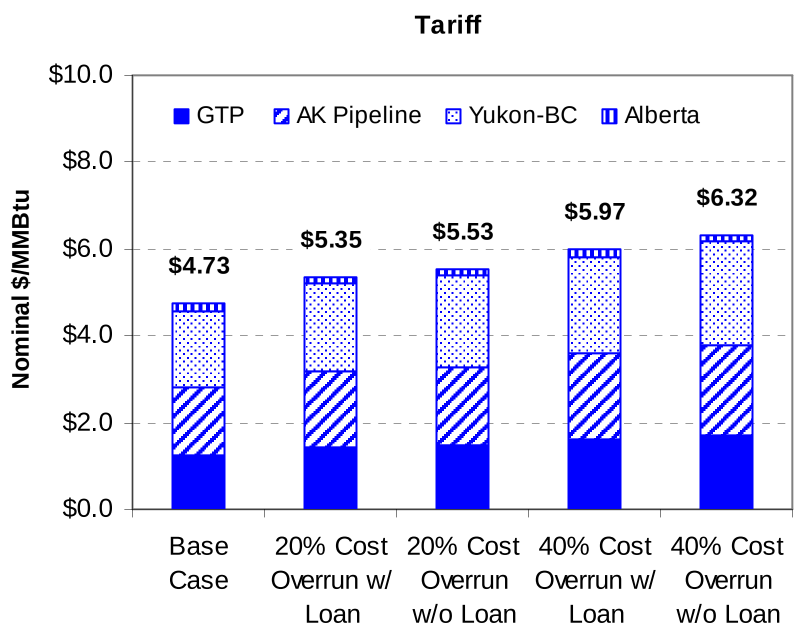
> The commissioners find that TC Alaska's proposals for addressing cost overrun risks help encourage shippers to participate in an open season.

TC Alaska has proposed several measures which help to insulate shippers from the risk of cost overruns. First, TC Alaska has proposed to use Federal Loan Guarantee funds in a way that would help hold down tariff rate increases due to the costs of financing cost overruns and encourages TC Alaska to control cost overruns. Specifically, TC Alaska proposes to use Federal Loan Guarantee

> TC Alaska has proposed several measures which help to insulate shippers from the risk of cost overruns.

funds to finance cost overruns using 100% debt (Application 2007, Section 2.2.3.1). This has the effect of making the financing cost for such facilities as low as possible since the cost of debt guaranteed by the U.S. government is anticipated to be the lowest cost source of capital available to TC Alaska. And, in particular, it is considerably less costly than equity. The lower financing rate would be reflected in proportionately lower increases in the tariff rates from cost overruns than would otherwise occur. As shown in Figure 3-42, compared with maintaining the 75/25 debt-equity ratio of the base project, TC Alaska's cost overrun financing proposal would reduce tariffs by nearly $.18/MMBtu for a 20% cost overrun, and $.35/MMBtu for a 40% cost overrun.

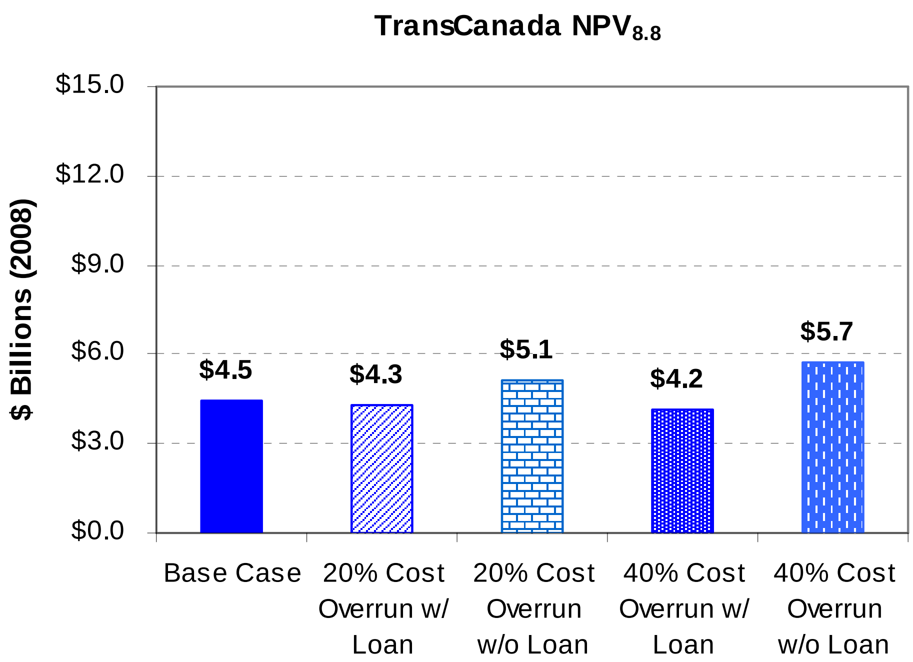
Figure 3-42. Tariff Consequences of Cost Overruns With and Without 100% Debt Financing



Source: Black and Veatch, Appendix G1, Section 5.7.8.1

In addition, TC Alaska's proposal to fund cost overruns with 100% debt would help to align the interests of TC Alaska and its shippers in controlling cost overruns, because TC Alaska would not earn any additional return should an overrun occur. Having no additional equity in the project means that TC Alaska could earn no additional profits. In other words, TC Alaska will not profit from cost overruns, and thus would have no incentive to permit Project costs to increase.[101] This is shown in Figure 3-43 (EconOne 2008).

Figure 3-43. TransCanada NPV8.8 Sensitivity Consequences of Cost Overruns102 With and Without 100% Debt Financing



Source: Black and Veatch, Appendix G1, Section 5.7.8.1

Second, TC Alaska has proposed to insulate shippers from at least some of the effects of cost overruns by offering to absorb, to the extent cost overruns occur, up to a 200 basis point reduction in its equity return (*i.e.,* a reduction from a return on equity of 14 to 12%) for up to five years (Application 2007, Section 2.2.3.6).

This proposal does not have a large impact on the rates paid by shippers due in substantial part to the fact that TC Alaska has proposed a shipper-friendly capital structure with an equity ratio of only 25% upon FERC approval of the Project's capital costs. Nevertheless, TC Alaska's agreement to reduce its return on equity by up to 200 basis points is more than just a symbolic

[101] Appendix A, Exxon Comments.

[102] A discount rate of 8.8% is equal to the TransCanada weighted average cost of capital for the Proposal Base Case.

gesture on its part. Rather, it represents a material portion of its potential benefits from the project. Accordingly, the ROE penalty that TC Alaska offers should give it an additional incentive to control costs and prevent cost overruns. This is especially the case because, as discussed above, TC Alaska's proposal would remove any incentive to allow a cost overrun.

In addition, it should be noted that FERC and NEB also will review costs to determine whether they were prudently incurred. Thus, there are regulatory protections available to shippers if TC Alaska attempts to include imprudently incurred costs, including cost overruns, in its tariff recourse rates. In addition, the state would have the right to join shippers in opposing the recovery of imprudently incurred costs at FERC or the NEB.

Third, TC Alaska is proposing to allow negotiated rate shippers an option to defer payment of costs associated with cost overruns whenever market conditions do not allow such costs to be recovered (Application 2007, Section 2.2). This would help to ensure that shippers are not put into a negative cash flow condition to pay for cost overruns. At the same time, TC Alaska would only recover costs associated with cost overruns when that can be accomplished while still providing a positive net back to the upstream producers. This element of TC Alaska's proposal would help reduce the potential impact of cost overruns on its shippers. This proposal—if accepted by the US DOE as part of an acceptable loan guarantee package under ANGPA—would have involve the Federal Government share in the risk of poor net backs If approved it would provide shipper something of a price floor. Such a mechanism would appear to have been contemplated in the loan guarantee's authorizing legislation:

> *LOAN TERMS AND FEES: The Secretary may issue Federal guarantee instruments under this section that take into account repayment profiles and grace periods justified by project cash flows and project-specific considerations. [Sec. 116 (d)(1)]*

Fourth, and as discussed earlier, TC Alaska has proposed that shippers who participate in the first binding open season will have the opportunity to obtain an equity ownership interest in the Project (Application 2007, Section 2.2). At this early stage of the process, TC Alaska has not fully defined how an interested party can obtain an equity ownership interest. However, that process will likely be fully fleshed out in the notice of the open season. Through equity participation shippers can have a "seat at the table" regarding activities that might give rise to cost increases, giving them an enhanced ability to prevent cost

> Another means of helping to insulate shippers from cost overruns is the negotiated rate concept that TC Alaska has indicated a willingness to offer its shippers.

overruns. The concept of shipper ownership of an equity interest in a pipeline project is familiar to the Major North Slope Producers; ConocoPhillips has a minority ownership interest in the Rockies Express project as well as a substantial shipping commitment

Finally and as also discussed above, another means of helping to insulate shippers from cost overruns is the negotiated rate concept that TC Alaska has indicated a willingness to offer its shippers (Application 2007, Section 2.2). Negotiated rates are common on new pipelines in the Lower 48 (Appendix J, Attachment 1A). Through negotiated rates shippers and TC Alaska can agree to risk sharing arrangements that satisfy both parties. As an example, the Rockies Express pipeline (commonly referred to as "REX"), which is presently under construction, allowed potential shippers that elected negotiated rates to base their rates on the actual cost of steel—upward or downward from a stated dollar amount per ton.[103] Given the substantial bargaining power of the Major North Slope Producers, it is reasonable to expect that TC Alaska and its shippers may agree to negotiated rates with similar provisions that insulate shippers from a major portion of any cost overruns (Appendix G1).

In fact, in some cases parties agree to negotiated fixed rates for the life of the contract—regardless of the level of cost (Appendix J).[104] The use of negotiated fixed rates provides shippers with the ability to protect themselves against some or all cost overruns. In this regard, it is notable that negotiated rates are often lower than the FERC's cost-based recourse rates (Appendix J). By negotiating rates that are less than the recourse rates, shippers can mitigate or eliminate their exposure to cost overruns that would increase recourse rates above the rate the shippers negotiated (Appendix J).

Notably, the Major North Slope Producers have numerous firm shipping contracts on other pipelines where they have negotiated a fixed rate and eliminated their exposure to cost overruns (Appendix R and Appendix J) Similar negotiated rates, which at a minimum shift a significant part of the risk of cost overruns to the pipeline, are also likely on this Project. While TC Alaska has indicated a willingness to offer negotiated rates to its shippers, and has proposed an initial

[103] The Precedent Agreement can be found at the following webpage: http://www.kindermorgan.com/business/gas_pipelines/rockies_express/PA_Rockies_Express_12-17-05.pdf.

[104] Although this is important to recognize for illustrative purposes, it is an outcome that is highly unlikely on this project. TransCanada's total $NPV_{8.8}$ is about \$4.5 billion under the Proposal Base Case – a third of the Producers' NPV_{10} benefits (*see* Appendix F.1, Section 5.5. A significant cost overrun could essentially wipe out TransCanada's return under a fixed-tariff arrangement. Accordingly, it is more likely that this project will be marked by some middle ground risk sharing.

set of negotiated rate terms, the bargaining power of the Major North Slope Producers would likely dictate that result in any event.

In sum, because TC Alaska has proposed several means of controlling and mitigating the impact of cost overruns, shippers will have options to help insulate themselves from or substantially mitigate the potential impact of cost overruns. Overall, these proposals contribute positively to the Project's likelihood of success.

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d. TC Alaska's Ability To Overcome Barriers To Obtaining Firm Shipping Commitments

As discussed earlier, TC Alaska's proposed commercial terms provide a framework that should encourage shippers to sign firm shipping commitments. Despite that fact, however, significant barriers still exist which TC Alaska will need to overcome to obtain firm shipping commitments. This Section of the Findings concludes that TC Alaska has a reasonable opportunity to overcome those barriers, assuming it receives the AGIA License. As discussed below, due to the Project's strong economics, it is reasonable to conclude that the Major North Slope Producers, TC Alaska, the U.S. government, and the state will take actions that are necessary and appropriate to make the Project a success. The risks to the parties of not progressing the Project , including the loss of profits, are too great.

Whether TC Alaska can obtain long-term firm shipping commitments from the Major North Slope Producers (and potential other shippers) for the initial capacity of the Project will have a critical impact on whether the Project succeeds or fails.[105] Natural gas pipeline companies rarely if ever construct a major project "on spec," *i.e.,* on the speculative hope that shippers will sign firm contracts and a market will materialize after the construction of the project. Before ordering pipe and commencing construction, a company typically must secure long-term firm contracts. Long-

[105] In its Application, TC Alaska raises the possibility of seeking additional Federal government assistance for the project (Application 2.2.3.2). Conceptually, even absent firm shipping contracts. the US Government could act as a "bridge shipper" while the project continued to be developed, If this were to occur long-term firm shipping contracts might not be required to advance the project to completion. The "bridge shipper" concept, while innovative, was not a condition of the Application (Appendix D, Palmer Letter March 12, 2008). "Additional Clarifying Information"] It has not been assumed in any of the analysis of this finding.

term firm contracts, which enable the project to secure financing and, if necessary or desirable, additional equity investors, constitute the economic foundation of a major natural gas pipeline construction project.

In ordinary circumstances, the prospects that the Project could secure firm shipping commitments would be excellent, even after recognizing the unique size and scope of an Alaskan gasline project (Appendix G2, Section 4.1). As explained previously in this Finding, even using a conservative price projection for natural gas, the Project would likely result in significant cash flows, a positive NPV, and a large internal rate of return for the Major North Slope Producers. There are reasonable prospects for some further improvement in shipper economics after negotiations with TC Alaska over contract terms (Appendix G2, Section 4). In addition, the economics of the Project for the Major North Slope Producers (and the state) are likely to improve even further because TC Alaska has offered to enter into firm shipping commitments on commercial terms that are likely to become more attractive after TC Alaska negotiates those terms with the Producers, who possess considerable bargaining power. In addition to the strong economics which the Project would provide, TC Alaska is an experienced pipeline company, with a proven track record as a dependable pipeline owner and operator. According to ConocoPhillips, TC Alaska is a "fine company," and a "valued business associate throughout North America."[106]

> Even using a conservative price projection for natural gas, the Project would likely result in significant cash flows, a positive NPV, and a large internal rate of return for the Major North Slope Producers.

In a normal, competitive situation, in which the production basin has numerous producers seeking to commercialize their reserves, these factors—a project with strong economics and a strong pipeline operator that has made reasonable initial transportation offers to potential shippers to enter

> In a normal, competitive situation in which the production basin has numerous producers seeking to commercialize their reserves, these factors—a project with strong economics and a strong pipeline operator that has made reasonable initial transportation offers to potential shippers to enter into firm shipping agreements—would make it likely that a pipeline project to bring Alaska's gas to market would obtain the necessary firm shipping commitments.

[106] See Jan. 24, 2008 Letter from Mr. J. L. (Jim) Bowles, President of ConocoPhillips Alaska, Inc. to The Honorable Sarah Palin, at page 5. We also noted that ConocoPhillips is a joint venture partner with TransCanada in the Keystone oil pipeline project.

into firm shipping agreements—would make it likely that a pipeline project to bring Alaska's gas to market would obtain the necessary firm shipping commitments. Actual experience in the United States in the past 15 years shows that natural gas producers have supported the construction of new, independent pipelines to ship gas from emerging production basins to various markets when similar conditions have existed. For example, the Kern River Gas Transmission pipeline—an independent gas pipeline not affiliated with major natural gas producers—was constructed in the early 1990s to transport gas from the Rockies to southern California, with the key support of a number of natural gas producers that committed to sign firm shipping contracts with the pipeline.[107]

More recently, the Rockies Express pipeline has been developed to transport gas from the Rockies to markets in the eastern and central U.S. Like Kern River, Rockies Express obtained the support of natural gas producers, including ConocoPhillips and BP that supported the pipeline by signing firm transportation contracts.[108] Although Rockies Express has been developed by a majority owner which is an independent pipeline (Kinder Morgan), the original impetus for the project came from a major producer of natural gas (Encana) seeking to find a market for supplies which previously had lacked sufficient pipeline access to consuming markets.[109]

As these examples demonstrate, when a production basin has less pipeline capacity than the amount of gas production, and when prices support construction of new pipeline capacity, a significant number of natural gas producers typically will facilitate new pipeline construction out of a production basin by signing firm shipping commitments after a process of negotiation with the pipeline sponsor over key commercial and tariff terms. For producers like these, signing firm contracts makes economic sense because the new pipeline capacity enables them to sell more gas, obtain higher prices for their gas, and make more profits.

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[107] Kern River Gas Transmission Co., 50 FERC ¶ 61,069 (1990).

[108] Rockies Express Certificate Application at 32 (Docket No. CP06-354-000, filed May 31, 2006), as amended by the reivsed "shipper table" in the supplement to application filing at Appendix A (filed July 28, 2006). ConocoPhillips is also a minority owner of Rockies Express, while BP is a shipper only. ConocoPhillips Press Release, ConocoPhillips Completes Acquisition of Interest in Rockies Express Pipeline, located at: http://www.conocophillips.com/newsroom/news_releases/2006news/06-30-2006.htm

[109] Rockies Express Pipeline, 116 FERC ¶ 62.151. at p. 64,447. ConocoPhillips is also a minority owner of Rockies Express. *See Id*. at n. 107.

In contrast with these examples of producer-supported, basin-opening pipelines, the Project has not yet received non-binding indications of support from the Major North Slope Producers, although at least one explorer has filed comments in support of the project (Appendix A).[110] Instead, the Major North Slope Producers have filed comments stating they do not support the Project, at least in its current form. More recently, BP and ConocoPhillips have proposed their own project. This Section will examine the Major North Slope Producers' opposition to the TC Alaska Project in detail, which constitutes the biggest potential barrier to the Project's success. As discussed below, despite the current refusal or reluctance of the Major North Slope Producers to support the Project, TC Alaska nonetheless has a reasonable likelihood of succeeding if it receives the AGIA License.

All of the major stakeholders—including TC Alaska, the State of Alaska, the U.S. government, and the Major North Slope Producers—have a significant interest in ensuring that the Project succeeds. Each stakeholder has a great deal at stake. Thus, it is reasonable to assume that each of those stakeholders will take the actions necessary to ensure that, at the end of the day, the project eventually receives the firm shipping contracts that it needs to proceed without undue delay.

i. The Stakeholders in the Project Have a Strong Interest in Seeing the Project Succeed.

All of the major stakeholders—including TC Alaska, the State of Alaska, the U.S. government, and the Major North Slope Producers—have a significant interest in ensuring that the Project succeeds. Each stakeholder has a great deal at stake. Thus, it is reasonable to assume that each of those stakeholders will take the actions necessary to ensure that, at the end of the day, the Project eventually receives the firm shipping contracts that it needs to proceed without undue delay. Indeed, as recognized by Goldman Sachs, "the Project is strategically important for all key principals: TC Alaska, the Federal Government, the State of Alaska and prospective shippers" (Appendix H, Section II.E).

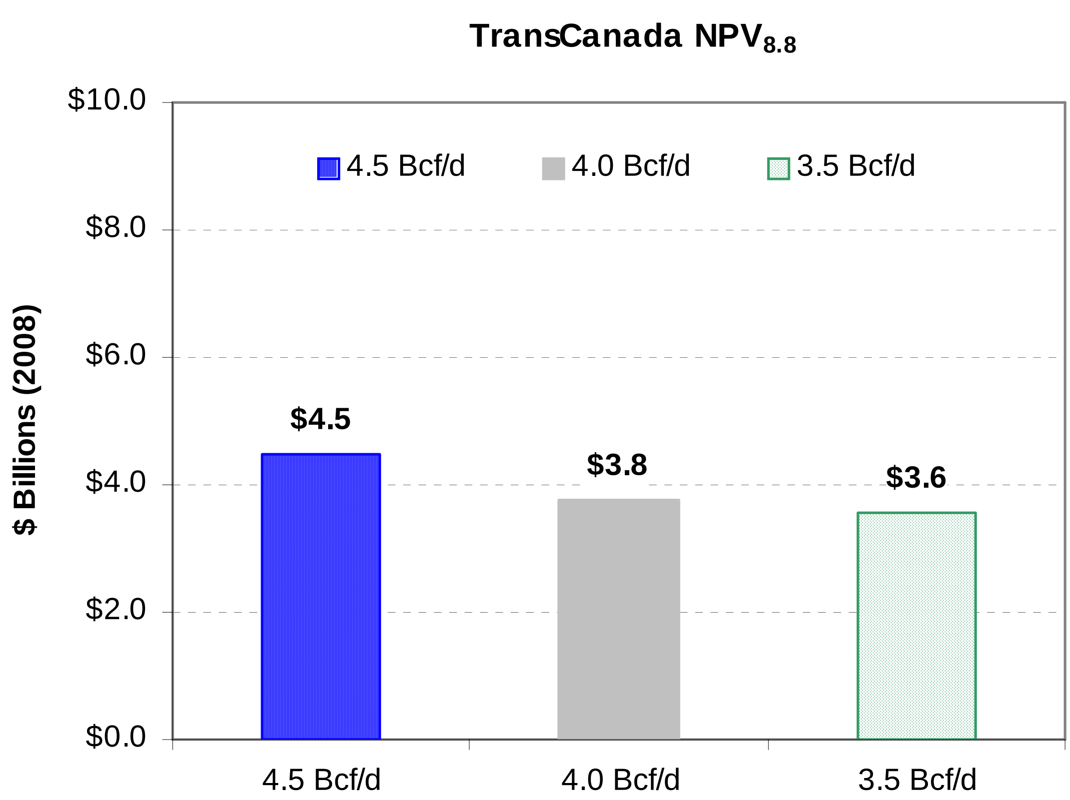
A brief review of these stakeholders' interests follows:

<u>TC Alaska as Stakeholder</u>. TC Alaska has strong incentives to make its proposed Alaska natural gas line to Alberta become a reality. TC Alaska stands to realize a significant amount of

[110] See Comments filed by Anadarko on March 6, 2007.

direct revenue from the Project under the Proposal Base Case, the Conservative Base Case, and the Low Volume Sensitivity Case. (Appendix G1, Section 6.4.2)

Figure 3-44. TransCanada NPV8.8 For Different Project Configurations[111]



Source: Black and Veatch, Appendix G1, Section 6

However, TC Alaska's motivation to see this Project succeed goes far beyond the direct revenue from the Project. It is important to TransCanada to maintain its profile in the financial community as a company with strong growth potential. The TC Alaska Project would enhance this profile, and is therefore important to TransCanada. According to Goldman Sachs:

> TransCanada's growth beyond 2010 at a level consistent what it has achieved to date is less certain, and TransCanada has emphasized the Alaska gas and Mackenzie pipelines as sources of long-term growth. Further, TransCanada currently has the largest natural gas transportation footprint in Canada, with the Foothills Pipeline forming the pre-build for the Alaska natural gas pipeline project.

[111] A discount rate of 8.8% is equal to the TransCanada weighted average cost of capital for the Proposal Base Case.

> TransCanada is clearly heavily incentivized to utilize, and should benefit from its ability to leverage, its existing asset footprint in Western Canada to bring Northern gas to market (Appendix H, Section IX).

In addition, TransCanada will use Alaskan gas to offset a substantial decline in Canadian production which threatens to result in significant underutilization of its existing pipeline system in Canada. TransCanada is the largest natural gas pipeline company in Canada, with approximately 29.5 Bcf/day of capacity on various pipelines that deliver gas to markets across Canada and to U.S. pipelines for further transportation to U.S. markets.[112] It is widely projected that natural gas production in Canada has leveled off and will decline in the near future, causing a reduction in throughput on TransCanada's pipelines (Appendix H; G1; F and J). Thus, in its public comments Anadarko observes that "due to the expected decline in indigenous gas production in the Western Canadian Sedimentary Basin and the growth of Albertan natural gas demand, this project is of critical strategic importance to TC Alaska in terms of offsetting declining throughput on its existing transcontinental pipeline system" (Appendix A, Anadarko Comments).

TC Alaska also needs Alaskan gas because increased Canadian consumption is projected to decrease the gas available to flow through TC Alaska's pipelines to U.S. markets. According to TC Alaska itself, growth in natural gas consumption in Alberta will reduce the amount of natural gas available for transportation on pipelines to the U.S. by approximately 1.9 Bcf/day. This will create further underutilization of TC Alaska's existing pipeline system.[113] Even assuming that construction of the MacKenzie Valley Pipeline occurs, TC Alaska's existing natural gas pipeline system in Canada would have significant excess capacity (Appendix G2, Section 3.3).

Based on these market developments, TC Alaska will face the daunting prospect of a severely underutilized pipeline system unless it can connect its system to new sources of supply. By constructing the Project, TC Alaska stands to increase the competitive position of its existing downstream pipelines, which would receive gas from the Project and transport it to markets and pipelines located beyond the AECO Hub.[114] TC Alaska thus has an incentive to offer a set of commercial terms and take other necessary and appropriate actions that will induce the Major

[112] TransCanada Corporation web-site, available at http://www.transcanada.com/gas_transmission/index.html.

[113] *See* Appendix H, Section IX., Appendix G2, Section 3.3, and Appendix J, Section IV; and Appendix A, Anadarko Comments.

[114] As throughput on these downstream pipelines rises their tariffs will fall, thus making more economic continued gas exports from Canada into the U.S. market.

North Slope Producers to sign firm transportation agreements. TC Alaska should be highly motivated to have the Project succeed, whether or not the first binding open season attracts firm commitments. TC Alaska' strong interest in moving the Project forward represents a positive contributing factor to the Project's likelihood of success.

United States as Stakeholder. A sometimes overlooked fact, which also contributes positively to the Project's likelihood of success, is that the United States government also has a strong incentive to see the Project succeed, for at least four reasons. First, and as confirmed by a recent EIA study, Energy Information Administration, *Analysis of Restricted Natural Gas Supply Cases*, at 8 (2004), the Project would reduce the price of natural gas in the U.S. below the price it would otherwise be if the Project were not built. Natural gas prices in the U.S. are at high historical levels. Higher natural gas prices have a significant impact on U.S. consumers, which rely on natural gas as a source of heat for their homes and schools, to generate electricity which provides air conditioning during the summer, and as a source of fuel or a feedstock for factories and other businesses. Higher energy prices, including prices for natural gas and oil, have a dramatic negative impact on the U.S. economy and U.S. consumers. While no one would contend the Project will solve the Nation's energy problems by itself, it is an important step in the right direction. The Project would supply 6-7% of the total U.S. natural gas demand projected for the year (see EIA AEO), providing an important source of supply to help moderate or reduce the price of natural gas and electricity.

Second, the Project will help enhance the Nation's energy security. Production of natural gas from many domestic production areas is flat or declining[115] (Appendix G1, Section 3). The U.S. must find new sources of supply. LNG is widely expected to play an increasing role (EIA AEO, Wood Mackenzie study). Even assuming Alaskan gas is brought to market in 2020, EIA projects that LNG imports from other countries are projected to increase by 1.4 Bcf/day in 2008 to 7.7 Bcf/day in 2030. (EIA 2008) Without Alaskan gas U.S. dependence on LNG imports from the Middle East and elsewhere will grow. Alaska's natural gas offers an important part of the solution to this problem.

A third reason which should provide the U.S. government with a strong incentive to support the Project is the significant environmental benefit associated with the Project. Natural gas constitutes the cleanest burning fossil fuel, with significantly fewer emissions of carbon and

[115] The Rockies are a notable exception.

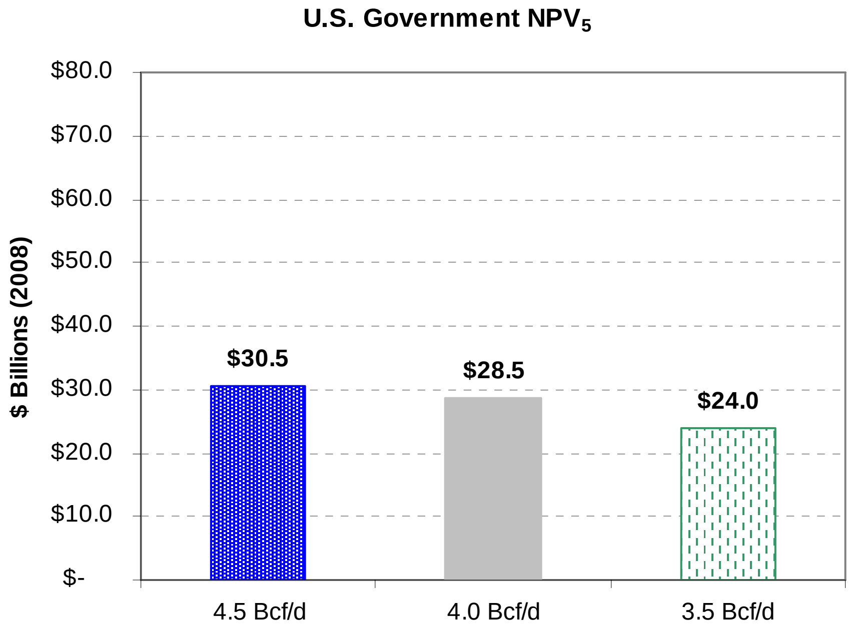
other pollutants than oil and coal. For example, if fifty percent of the natural gas from the Project were used to displace coal-fired electric generation, the Project would provide enough energy to displace between 120-190 coal-fired electric generation plants.[116] With climate change initiatives gaining momentum at the state and federal levels, Alaska's natural gas can play a significant role in efforts to reduce greenhouse gas emissions in the U.S.

Finally, the U.S. Government will gain billions of dollars in revenue once the Project is completed. The U.S. government would receive over $24 billion in royalty and corporate income taxes regardless of the Project's configuration (Figure 3-45). With pipeline expansions, facilitated by AGIA's rolled-in rate provisions, this figure could go considerably higher. Based on the NETL study, it is reasonable to assume that roughly half of YTF gas, including project expansions, will originate from Federal lands (Appendix L). Accordingly, the royalty percentage of U.S. Government income could be expected to significantly climb. This fact alone should provide the U.S. government with a major economic incentive to take action if necessary to facilitate the construction of an Alaskan natural gas pipeline.

If fifty percent of the natural gas from the Project were used to displace coal-fired electric generation, the Project would provide enough energy to displace between 120-190 coal-fired electric generation plants. With climate change initiatives gaining momentum at the state and federal levels, Alaska's natural gas can play a significant role in efforts to reduce greenhouse gas emissions in the U.S.

[116] The displacement number depends on the size and efficiency of the plants in question. For the illustrative purposes here, we assume here that the plants have a capacity of 66.74 megawatts – the average sized plant that EIA described as being planned for 2007-2011; *see* http://www.eia.doe.gov/cneaf/electricity/epa/epat2p5.html. The amount of electricity generated from natural gas depends on the conversion efficiency (or heat rate) of the plant. The average heat rate for natural gas power varies from 7,502 Btu/kWh to 11,664 Btu/kWh; *see* http://www.eia.doe.gov/cneaf/electricity/epa/epata6.html

Figure 3-45. U.S. Government NPV_5 For Different Project Configurations



Source: Black and Veatch, Appendix G1, Section 6.4.2

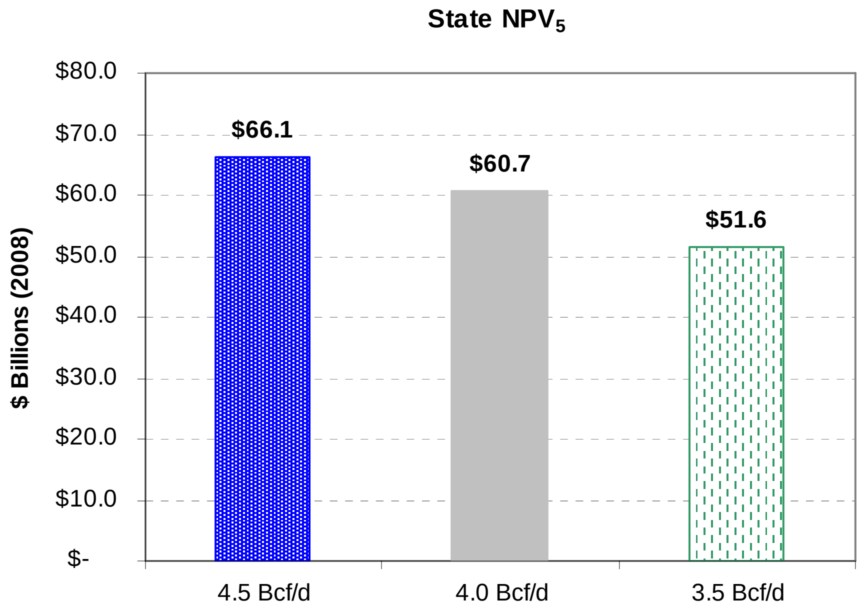
The additional revenues to be realized by the U.S. treasury and the Project's ability to reduce energy prices for U.S. consumers, enhance energy security, and provide environmental benefits, all provide strong incentive for the U.S. government to help an Alaskan gas pipeline succeed. Additional Federal support, such as the "bridge shipper" concept suggested by TC Alaska in its Application (Application 2007, Section 2.2.3.1(4)), may make sense given the benefits that the U.S. Government and its citizens would receive.[117]

<u>The State of Alaska as Stakeholder</u>. The State of Alaska has clear incentives to facilitate the construction of a natural gas pipeline which commercializes North Slope natural gas reserves. The state would receive substantial revenue from royalty and taxes. State NPV_5 ranges from over $51.6 billion to $66.1 billion depending upon the project's throughput (from 3.5 Bcf/day to 4.5 Bcf/day).

[117]ANGPA contemplates that the U.S. Government could play an augmented role if private sector progress is not sufficient (ANGPA 15 USC 720g(b)(1)) if the parties do not act to advance a project soon. Indeed, the Federal Gas Pipeline Coordinator Drue Pierce has suggested that an Alaska gasline is so important that it could merit a federal takeover of the project if the parties do not act to advance a project soon. Associated Press, *Congress Questions Gas Line progress,* located at:

http://www.adn.com/money/indistries/oil/pipeline/story/297218.html (January 29, 2008).

Figue 3-46. State NPV_5 For Different Project Configurations



Source: Black and Veatch, Appendix G1, Section 6.4.2

This would help offset the declining revenues associated with declining North Slope oil production increased revenues would also help augment the continued health of the Permanent Fund.

In addition to the revenue that the Project would generate, the state has a strong incentive to see that the Project proposed by TC Alaska succeeds because of the unique benefits the Project would provide. As discussed in detail in Chapter 5 of these Findings, TC Alaska's Project has committed unequivocally to AGIA's true open access and tariff requirements that are essential to meeting the state's needs. These benefits would not have been secured by the proposed SGDA contract, nor were commitments to them offered by ConocoPhillips' proposal from the fall of 2007 or by the most recent Producers Proposal. TC Alaska's unconditional commitments, including enforceable commitments to move the Project forward by holding an open season and filing for a FERC certificate by specific dates (Application 2007, Section 2.2.4.3), provide the best opportunity to achieve critical state goals,

TC Alaska's unconditional commitments, including enforceable commitments to move the Project forward by holding an open season and filing for a FERC certificate by specific dates, provide the best opportunity to achieve critical state goals, including long-term jobs for Alaskans and natural gas supplies for in-state use.

including long-term jobs for Alaskans and natural gas supplies for in-state use. In short, because the Project makes real commitments, it stands to provide Alaskans with real benefits too.

To ensure that Alaskans finally achieve these and other benefits that an Alaska natural gas pipeline would bring, the state has a strong incentive to use its sovereign authority to ensure that the Project succeeds. The state has already exercised that authority by providing the incentives set forth in AGIA. Given the extraordinarily profitable economics that the Project would produce, there is no demonstrated need for further state incentives at this time.

Nevertheless, should a need be demonstrated in the future, the state has several options to encourage construction of the Project. As discussed below, these include: (1) providing additional upstream incentives to encourage the Major North Slope Producers to sign firm contracts on the Project; and (2) enacting a reserves tax that would apply to any producer which fails to sign a firm contract, (3) investigating whether the Major North Slope Producers have violated their leases or other applicable laws (such as antitrust laws) by failing to produce Alaska's gas, (4) initiating litigation over any such violations, either at the state or federal level (as applicable).

The Major North Slope Producers as Stakeholders.

As discussed earlier, the Major North Slope Producers stand to make huge profits from the sale of Alaskan gas if the Project is built (Appendix G1, Section 5.2). They have a duty to their shareholders to seek profits and should be expected to behave as rational commercial players.

> The fact that BP and ConocoPhillips have proposed the Producer Project strongly suggests that those two producers agree that the economics of a major gas pipeline project to the AECO Hub are favorable.[118] It tends to support the commissioners' conclusion that TC Alaska's Project, which would follow the same general route as the Producer Project, would provide a significantly positive NPV for the Major North Slope Producers. Despite this, they have refused thus far to support the TC Alaska Project. In the discussion that follows, we will analyze their objections to the Project, and the impact of those objections and the Denali proposal on the Project's likelihood of success.

[118] Adams, Mikaila, *BP, ConocoPhillips Put Up $600M for First Leg of Alaska Gas Pipeline*, Oil and Gas Financial Journal, at 12, 14 (May 2008), *available at*: http://www.qmags.com/download/default.aspx?pub=OGFJandupid=13189andfl=others/OGFJ/OGF_20080501_May_2008.pdf

ii. Risks to the Project Economics

Although it would be somewhat inconsistent with the recent launch of the Producer Project, the Major North Slope Producers may contend that risks to the Project economics prevent them from supporting the Project (or moving forward with their own project). Despite huge profits that the Major North Slope Producers stand to earn by supporting the Project, the commissioners recognize that the Project economics are not free from risk. Accordingly, a detailed analysis of project risks—e.g. including gas prices, project costs, cost escalation rates, capacity subscription (project throughput), the timing of when Point Thomson gas will be available, the extent of future gas discoveries, project schedule (including the risk of delay), tariff terms, discount rates, and other factors—was undertaken (Appendix G1). However, despite those risks, on balance the Project appears to present the Major North Slope Producers with a robust profit opportunity.

Net Back Risks

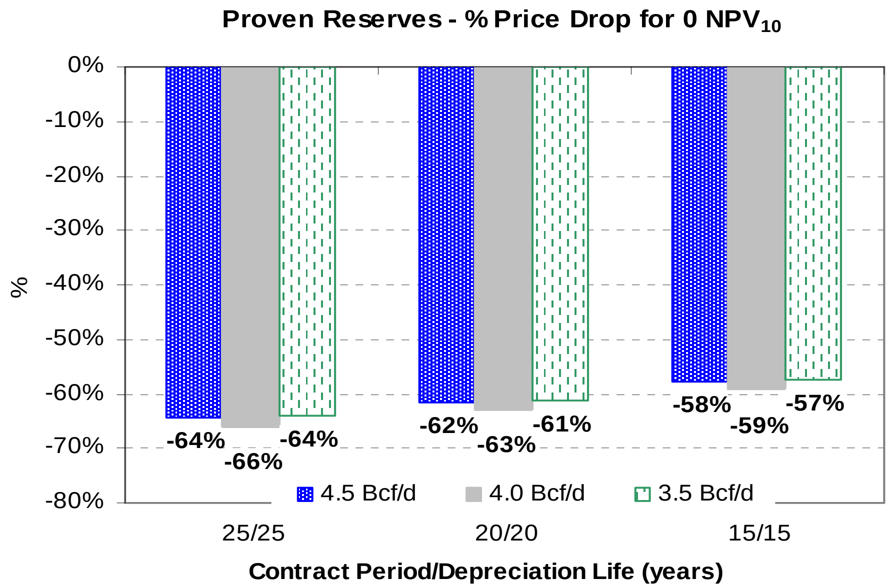
There is always a risk natural gas prices could decline or that costs could increase. However, the Project would be economic for the Major North Slope Producers even if prices are considerably lower than those projected by Wood Mackenzie. Indeed, to generate NPV_{15} of zero—meaning the Major North Slope Producers would earn a return of 15% on their gasline related investments—natural gas prices would have to drop by at least 62% in the Conservative Base Case, and 62% in the Proposal Base Case, from those forecast by Wood Mackenzie (and assuming no change in Project costs).[119]

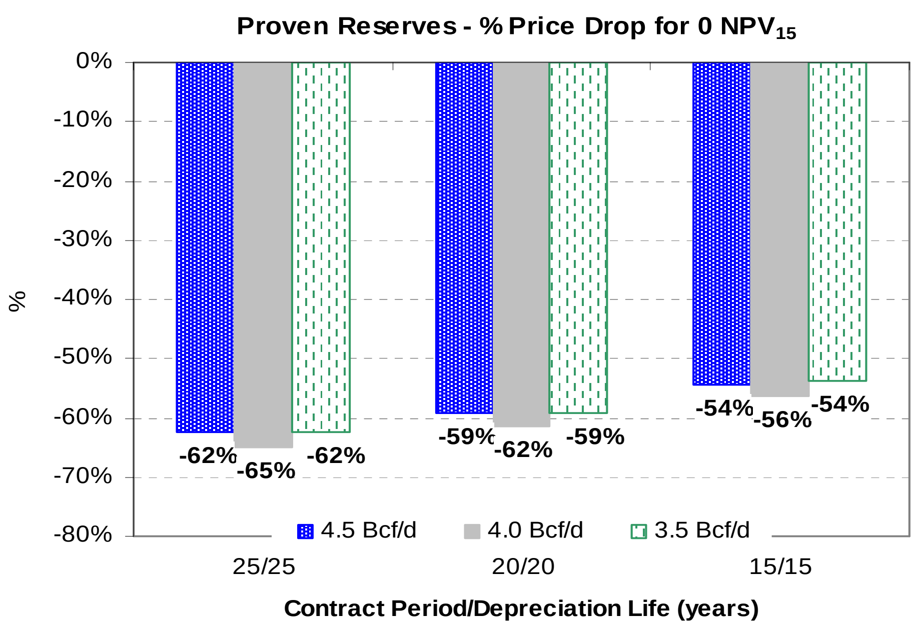
To generate an NPV_{15} of zero – meaning the Major North Slope Producers would earn a return of 15 percent on their gasline related investments – natural gas prices would have to drop by at least 62 percent in the Conservative Base Case, and 62 percent in the Proposal Base Case, from those forecast by Wood Mackenzie (and assuming no change in Project costs).

To put this in perspective, a price drop in excess of 60 percent in the price of gasoline would take pump prices from roughly $4 per gallon to under $1.60 per gallon.

[119] In this chart, the Conservative Base Case is represented by the middle grey bar: 4.0 Bcf/d throughput, assuming 20-year contracts and a 20-year depreciation life. The Proposal Base Case is represented by the left blue bar: 4.5 Bcf/d of throughput, with 25 year contracts with a 25 year depreciation life. The results assume that project costs are held at their mid-point probability (P50) levels.

Figure 3-47. Percentage Price Drop Necessary to Generate NPV of Zero For Producers' Proved Reserves



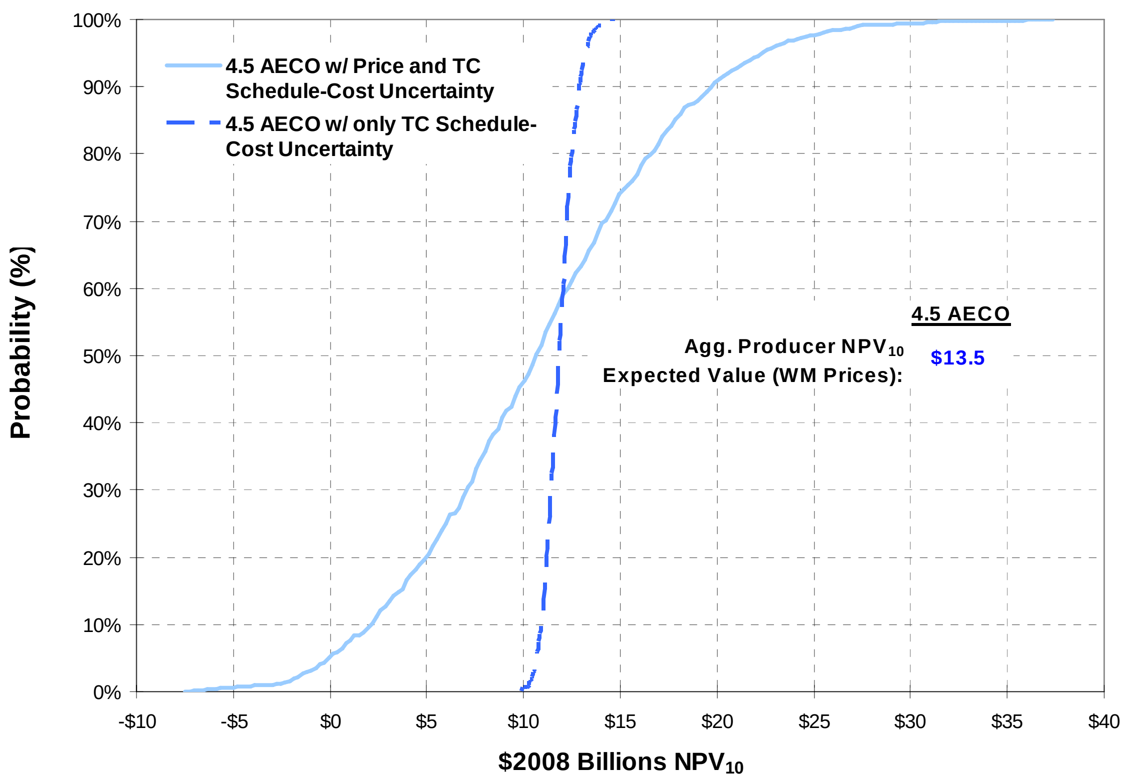


Source: Black and Veatch, Appendix G1, Section 6.5

To put this in perspective, a price drop in excess of 60% in the price of gasoline would take pump prices from roughly $4 per gallon to approximately $1.60 per gallon.

How unlikely is it that prices would drop this low? If one assumes that the Black and Veatch probability distribution over prices is correct, the chance is about 5%. The following chart shows the effect of price and cost uncertainty, considered separately, for the Proposal Base Case. The light blue-solid line shows the effects of price uncertainty while holding costs at their mid-point probability level.[120]

Figure 3-48 Aggregate Producers NPV_{10} - 4.5 BCF/d Proposal Base Case With and Without Price Uncertainty



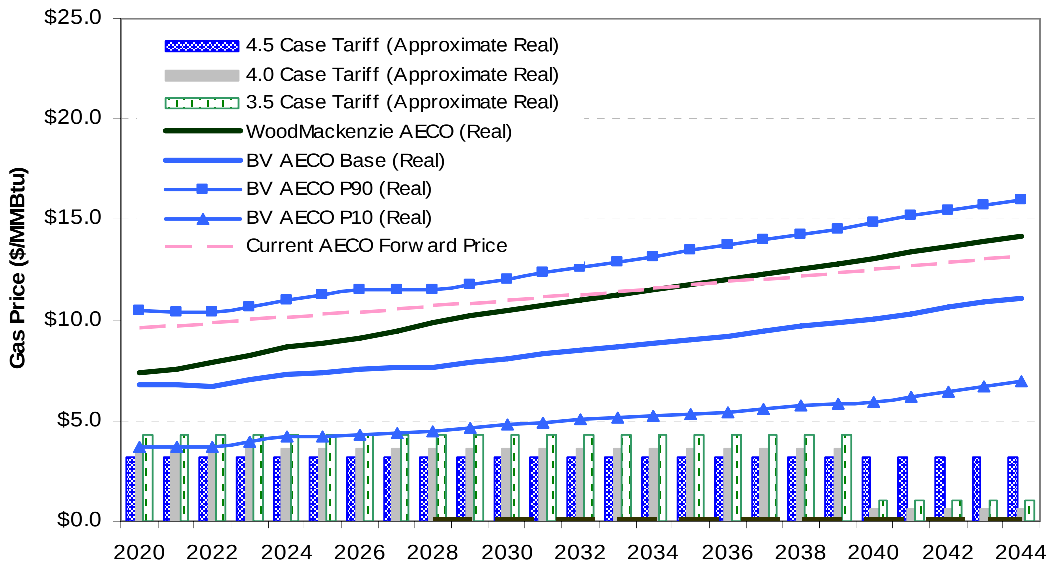
Source: Black and Veatch, Appendix G1, Section 5.7

Over the life of the project, there appears to be essentially no chance that overall Producer profits will be negative.

120 The dark blue-dashed line shows the effects of cost uncertainty while holding prices at their mid-point (P50) levels.

Out of concern that these results were being potentially driven by our assumptions on inflation (for gas prices) and cost escalation (for pipeline construction costs), the risk that net backs would be insufficient to cover the tariffs was further scrutinized. We considered the case of zero cost escalation and zero price escalation. The analysis was performed for the Proposal Base Case, the Conservative Base Case, and the Low Throughput cases. The results are shown in Figure 3-49.

Figure 3-49. Real AECO Price Forecasts vs. Tariff + Fuel

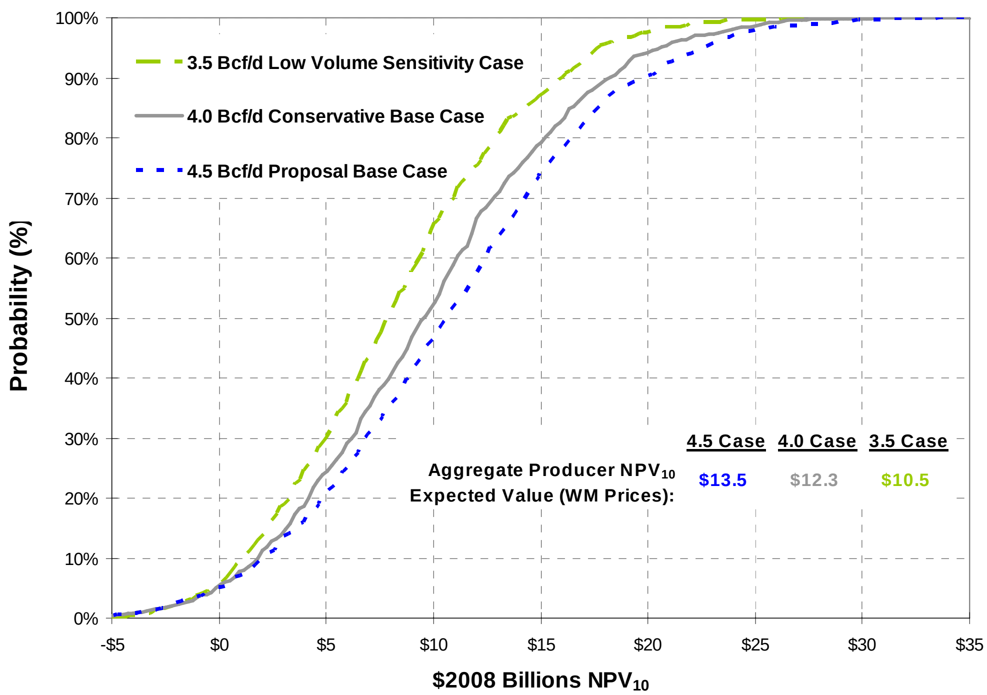


Source: Black and Veatch, Appendix G1, Section 6.7

The results indicate there is a better than 90% chance that prices will be sufficient to cover transportation costs *in each and every year* for both Proposal and Conservative Base Cases.

If one puts price, capital cost, and schedule risks together, the overall likelihood of the Project returning negative values is still only around 5%. Figure 3-50, shows the probability that the Major North Slope Producers, in aggregate, would receive different NPV_{10} at different project sizes. It indicates that, across the Proposal Case, the Base Case, and Low-volume scenarios, for NPV_{10} to be zero would require a “perfect storm.”

Figure 3-50. Aggregate Producers NPV_{10} Uncertainty for the 3.5, 4.0, and 4.5 Bcf/d Cases



Source: Black and Veatch, Appendix G1, Section 6.7[121]

The foregoing probability charts embody only Project cost risks associated with uncertainty in Project scope. As indicated earlier (Figure 3-23), uncertainty associated with Project cost escalation is more important. We did not attempt to capture escalation cost risk in Monte Carlo probability analyses, such as the one shown above, because of the inability to provide good estimates of the probability distributions over future project cost escalation rates. The risk of Project cost escalation is real. It is always conceivable, though quite unlikely, that Project costs would significantly escalate and yet prices would be soft.

However, we also believe that the risk of Project cost escalation—at least in terms of its ability to generate catastrophic results—is one that can be significantly managed. At the conclusion of the Project's Development Phase, TC Alaska will be in a position to sign many of the supply contracts required to begin construction (Application 2007, Section 2.2.1(2)(a)). The bounds of how costs may change will have significantly narrowed. Under the terms of the precedent agreement negotiated between TC Alaska and its shippers, shippers will at that time have the

[121] The chart assumes Black and Veatch price probability distribution (*see* Appendix G1, Section 6.7.3), and the project cost scope and schedule risks developed by the Technical Team (See Appendix F, Exhibit D).

ability to withdraw from their shipping commitments (Application 2007, Section 2.2.3.3).[122] A shipper would only be expected to exercise such rights in the event that a major Project cost escalation had occurred, or a major decline in prices were expected, such that the Project was determined to be uneconomic.

Reserve Risk

To have a successful pipeline project, there must be sufficient gas to fill the pipeline. There are more than enough economically recoverable natural gas resources on the North Slope to fill TC Alaska's proposed 4.5 Bcf/day pipeline for twenty-five years (or much longer), as discussed above in Chapter 2(B)(5). However, the amount of gas reserves at Prudhoe Bay and from other existing state production fields, while substantial, is not sufficient to fill the pipeline under either the Proposal or Conservative Base Cases. That means additional gas must be found and produced in order to fill the pipeline for the twenty-five year term of the firm shipping commitments proposed by TC Alaska.

After carefully analyzing this issue, the commissioners conclude that the risk of insufficient reserves is not a risk that should negatively impact the likelihood of success of the Project. First, it is important to understand how profitable the opportunity to produce the Prudhoe Bay gas alone truly is to the Major North Slope Producers. Project economics, while affected by the YTF gas finds, does not appear dependent upon them. As noted earlier, even if no YTF gas is developed, at expected prices Project revenue appears to be sufficient to cover the transportation commitments. The Major North Slope Producers would receive a significantly positive NPV and make a very profitable rate of return even if the only gas they ever produce on the North Slope is the Prudhoe Bay and state existing gas (Appendix G1, Section 5). Thus, the Project could proceed even without the exploration and production of additional gas.

The Major North Slope Producers would receive a significantly positive NPV and make a very profitable rate of return even if the only gas they ever produce on the North Slope is the Prudhoe Bay and state existing gas. Thus, the Project could proceed even without the exploration and production of additional gas.

[122] In its initial offer, TC Alaska has proposed that shippers would have to bear their pro rata share of Development costs if they withdraw. The proportionate sharing of such development costs is an area that could well be subject to future negotiations; *see* Application 2007, 2.2.3.3, Appendix G2, Section 4.

However, it appears highly likely that additional gas will be found and produced from state YTF areas. The NETL study and other sources indicate that the quantity of economically recoverable gas is more than enough to fill the Project for decades after the Prudhoe Bay gas is fully produced. Compared with other projects, the reserve picture is favorable (Appendix J, Section 3). Meanwhile, over a significant range of prices the economics associated with producing YTF gas and shipping it on the TC Alaska Project appear to be profitable (Appendix G1, Section 5). YTF economics, as modeled, appear to be internationally competitive (Appendix K). Thus, the risk of not finding and producing sufficient gas to fill the 4.5 Bcf/day capacity of the Proposal Base Case or of the Conservative Base Case, does not appear sufficient to deter the Project from moving forward.

If shippers are concerned about reserve risk, and they wish to manage that risk by accepting higher tariffs, they could opt to make shipping commitments that support a smaller throughput project. Accordingly, a project of only 3.5 Bcf/d was considered. Even under this smaller capacity scenario, however, the Commercial Team report demonstrates the Project would produce significantly positive NPVs, although somewhat less than for a larger project (Appendix G1, Section 6).

For these reasons, the commissioners believe the risk of insufficient gas reserves should not ultimately be a barrier to the Project's likelihood of success.

Fiscal Risks

The Major North Slope Producers have consistently asserted that they cannot construct an Alaska gasline themselves, or sign firm shipping contracts with an independent gas pipeline, unless the state provides them with "fiscal certainty." For example, in its public comments, BP argues that AGIA "does not sufficiently address the resource framework, the key enabler for a project to be successfully financed" (Appendix A, BP Comments). Similarly, Exxon argues that "[a]n appropriate fiscal regime must be negotiated between the state and the [Major North Slope] Producers" (Appendix A, Exxon Comments) In addition, referring to the risk of signing firm shipping contracts and other risks, ConocoPhillips maintains that "[n]o commercially reasonable party will take these unprecedented investment risks until a number of conditions have been met, including the establishment of a predictable gas fiscal framework."[123]

The Major North Slope Producers' continued demand for "fiscal certainty" echoes their position during the prior Administration. In 2004, the Producers negotiated a contract which provided them with billions of dollars in tax concessions,[124] and would have effectively required the state to surrender a significant portion of its sovereignty for decades, in exchange for a pledge by the Major North Slope Producers to merely study the feasibility of a gas pipeline.

The commissioners acknowledge the possibility that future state governments will change the fiscal structure in a way adverse to the Major North Slope Producers' interests. However, the first thing to note here is that, in regard to royalty, fiscal certainty already exists. The royalty rate is established by contract, and cannot be changed. While some risk exists associated with the state's ability to switch between taking its royalty in value or in kind, AGIA mitigates this risk for shippers that obtain capacity in an AGIA project's first binding open season. (AS 43.90.310.).[125]

With regard to production taxes, we note that it was precisely in response to producer concerns about this risk that AGIA provides ten years of fiscal certainty to any shipper that participates in the first open season of the AGIA project. For the first ten years of pipeline operations, any shipper that commits gas during the first open season will pay whatever production tax rate was in effect at the time of the first open season. (AS 43.90.320(a))

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[123] [123] See Jan. 24, 2008 Letter from Mr. J. L. (Jim) Bowles, President of ConocoPhillips Alaska, Inc. to The Honorable Sarah Palin, at page 5. We also noted that ConocoPhillips is a joint venture partner with TransCanada in the Keystone oil pipeline project.

[124] *See* Pulliam 2006.

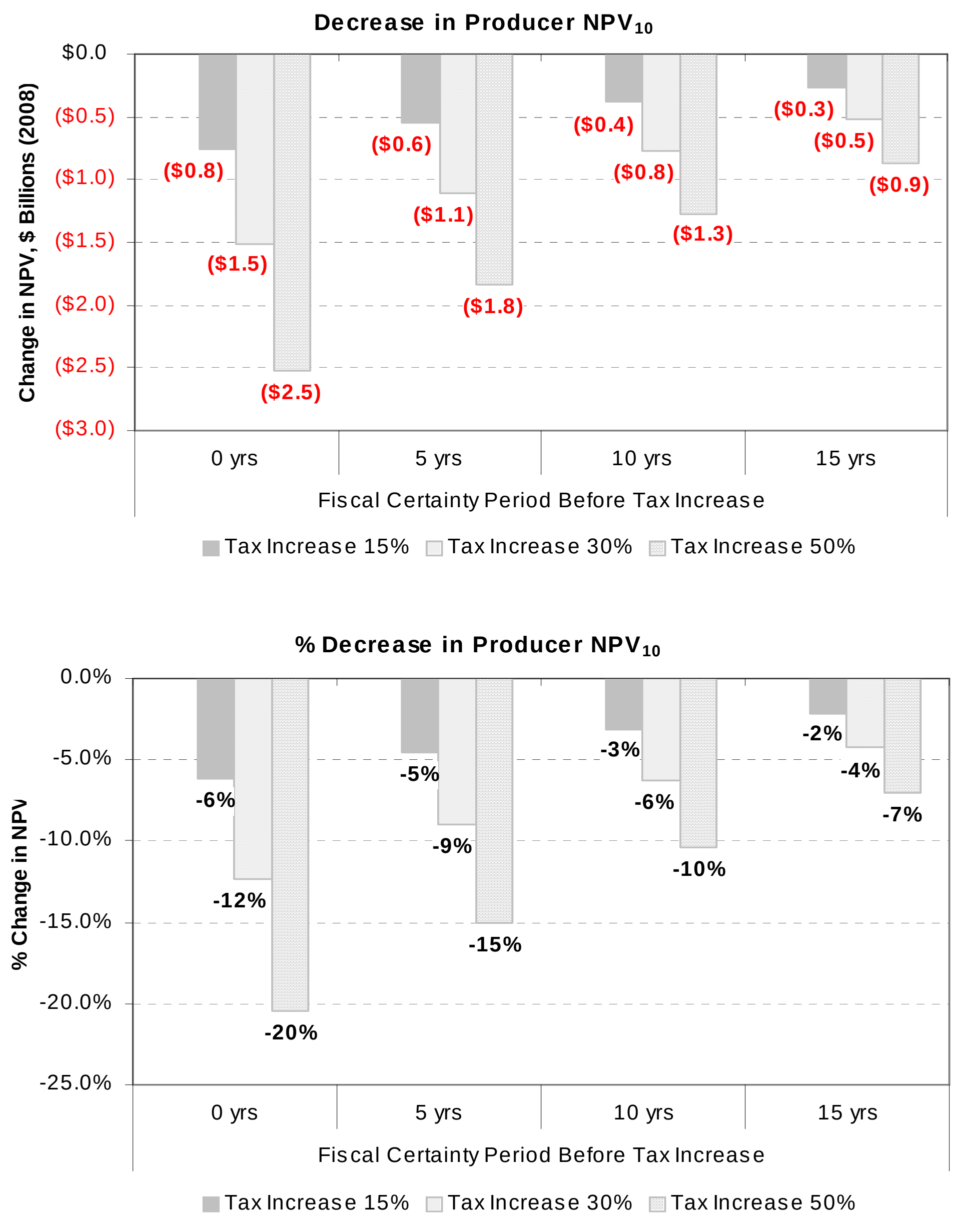
[125] Minor producer risk exists concerning how royalty value should be calculated due to the state leases' "higher of" provisions.. However, AGIA provides an avenue to resolve this uncertainty for those that commit gas to the first open season. AS 43.90.310

In Alaska the Major North Slope Producers do not face the risk, as they do in some countries, that the state will nationalize their production facilities. But in any case, the risks associated with state government action appear to be significantly overstated, especially when considered in the broader international context. As a democratic republic, Alaska's political system provides an inherent protection from the threat of a tax system that is unresponsive to producers' profit needs. In fact, from 1975 through 2006 the state's general history involved a gradual decline in production tax rates. As demonstrated throughout this Finding, the current fiscal regime provides for robust profits for modeled new gas development.

In addition, it does not appear that fiscal risk is the crucial one facing the project. The chart below shows the effect to Producer NPV of potential tax increases of 15, 30, and 50% that are modeled to occur at different periods after first gas flows under the Proposal Base Case. Further, for gas that is committed at the initial open season of the TC Alaska project, the legislature has committed to not change the tax rate for the first ten years of operations. From the chart we see that a tax increase as large as fifty percent imposed at year ten reduces Producer NPV by ten percent.

Although these changes are material, in context of other risks they do not appear to be the project's main risk factors. Other factors—such as price and project escalation risks—have a much greater effect on overall project economics. Moreover, the tax rate *increases*—especially large ones—do not seem likely, for several reasons.

Figure 3-51. Impact of Different Periods of Fiscal Uncertainty for Producer NPV_{10}



Source: Black and Veatch, Appendix G1, Section 6.7

First, project returns have been modeled under the current production tax law (ACES). However, ACES has a supplemental tax, or "progressivity" feature, that is triggered off a fixed marker of $30 per barrel oil equivalent. This marker is not indexed for inflation. Over time, general inflation will cause ACES' progressivity feature to bite harder and harder. It seems highly probable that in coming decades the trigger level will be revised upwards, thereby *reducing* taxes.

This conclusion is reinforced when one considers that the timing of the need for YTF gas to enter the project roughly coincides with the expiration of AGIA's fiscal stability period. Given that the state's future is dependent upon a vibrant exploration and development environment, it would be directly contrary to the state's interests to raise taxes prohibitively just when YTF gas economics are most relevant. Indeed, much of AGIA's rationale has been based on ensuring that the economics of YTF gas, including that for expansions, will be favorable.

Given that the state's future is dependent upon a vibrant exploration and development environment, it would be directly contrary to the state's interests to raise taxes prohibitively just when YTF gas economics are most relevant. Indeed, much of AGIA's rationale has been based on ensuring that the economics of YTF gas, including that for expansions, will be favorable.

The NPV analysis discussed earlier in these Findings demonstrates that fiscal changes should not be necessary for the Major North Slope Producers to support a pipeline to the AECO Hub. The significant estimated NPV of the Project makes the Major North Slope Producers' request for fiscal certainty unnecessary. As demonstrated above in Figure 3-33 the Project would enable the Major North Slope Producers to earn \$12.3 billion (NPV_{10}) under the Conservative Base Case and \$13.5 billion (NPV_{10}) under the Proposal Base Case (Appendix G1, Section 6.4), with a very large internal rate of return, *without any changes to the state's existing production tax and royalty structure.*

iii. Risks to TC Alaska's Project Due to the Producer Project

The Project's economics are robust. Risks to the Project economics do not provide a reasonable explanation for why the Major North Slope Producers have filed comments opposing the TC Alaska Project. However, if the Project economics are favorable (even spectacular for Prudhoe Bay gas), and the Project is supported by other factors including TransCanada's fine record as a gas pipeline operator, then it is logical to ask why the Producers would continue to oppose the Project.

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At least a partial answer may lie in the fact that BP and ConocoPhillips, after TC Alaska submitted its AGIA proposal, proposed their own Producer Project. In Chapter 5 of these Findings, the commissioners explain why the state needs TC Alaska's Project despite the recent

BP/ConocoPhillips proposal.[126] Assuming BP and ConocoPhillips truly pursue their Producer Project to completion, it would have a significant negative impact on TC Alaska's likelihood of success, simply because TC Alaska would probably be unable to attract the necessary firm shipping commitments without the reserves leased by BP and Conoco. Of course, under that scenario, the state would finally get a gasline, although it would be one built outside the AGIA process and without the benefits that an AGIA pipeline would provide to the state and its citizens, including genuine open access and increased jobs due to expansion and rate commitments that will maximize exploration and development of the North Slope.

Neither BP nor ConocoPhillips have abandoned their previous insistence that the state provide them with major fiscal changes and fiscal certainty before any pipeline project can proceed. In announcing their own pipeline concept, BP and ConocoPhillips carefully avoided saying anything about fiscal terms. However, their public comments filed on March 6, 2008 regarding TC Alaska's Project make clear that significant fiscal changes by the state are the "key enabler for a project to be successfully financed" (Appendix A, BP Comments), and that the producers believe "[n]o commercially reasonable party will take these unprecedented investment risks until a number of conditions have been met, including the establishment of a predictable gas fiscal framework.."[127]

> Assuming for the sake of analysis that the Major North Slope Producers truly need fiscal changes and fiscal certainty, the means for the Producers to achieve their fiscal objectives is to support TC Alaska's Project as firm shippers and, if equity ownership is an attractive option to them, negotiate with TC Alaska to become a partial equity owner in the pipeline.

It thus is reasonable to expect that, even if BP and ConocoPhillips "commit" to sign firm contracts on their own pipeline project, they will condition those commitments, and their commitment to pursue their project, on the state's agreement to massive changes in fiscal terms. Until they have supported

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[126] As discussed later in Chapter 5, rejecting the Project due to the promises made by BP and ConocoPhillips to pursue a producer-owned pipeline would leave the state in the same leveraged position it was in the prior Administration: with an unenforceable pledge by BP and ConocoPhillips to pursue a pipeline, but with no enforceable milestones and only on the condition that the state relinquish a large portion of its sovereignty by agreeing to "fiscal certainty". There is a strong possibility that, absent the existence of TC Alaska's Project, the BP/ConocoPhillips pipeline would not have been proposed, and would not be pursued. As a result, it is important to continue the competitive AGIA process with TC Alaska regardless of the new producer-owned pipeline concept that has been floated by BP and Conoco.

[127] In the alternative pipeline proposal that it publicized just prior to the AGIA application deadline on November 29, 2007, ConocoPhillips expressly stated that it could not construct its proposed pipeline without receiving fiscal concessions from the state. Letter from ConocoPhillips CEO J. Mulva to Governor Palin at 2. See also ConocoPhillips Proposal at Section IV., at 4-5 (November 30, 2007).

their need for fiscal certainty with economic facts demonstrating that they will be unable to realize a reasonable profit without changes in state tax laws, those conditions should be viewed as attempts to gain leverage in a negotiation with the state. In light of the fact that the analysis above shows that the Project would enable the Major North Slope Producers to realize billions in profits and an extremely large rate of return from the Prudhoe Bay field, they are unlikely to be able to support the need for fiscal changes at this time.

Assuming for the sake of analysis that the Major North Slope Producers truly need fiscal changes and fiscal certainty, the means for the Producers to achieve their fiscal objectives is to support TC Alaska's Project as firm shippers and, if equity ownership is an attractive option to them, negotiate with TC Alaska to become a partial equity owner in the pipeline. We will explain in the following sections why various Producer objections to becoming equity partners with TC Alaska (or shippers) on the TC Alaska Project lack merit.

TC Alaska has opened the door to the possibility that the Producers can become equity partners in the Project, a constructive offer which enhances the likelihood of success of its Project. In addition, assuming TC Alaska becomes the AGIA Licensee, it will be the state's partner in achieving an Alaska gasline. The state would surely take any such partnership seriously, and indeed could not support another pipeline project, including offering fiscal changes to BP/ConocoPhillips and their Producer Pipeline concept, without subjecting itself to the penalty exposure provided under AGIA.[128] Thus, it is important to understand that the path to fiscal changes, should any be necessary in the future as market conditions unfold, is through the TC Alaska Project, not through the Producer Project.

iv. Producer Objections to the TC Alaska Project Lack Merit

The foregoing discussion presumes that BP and ConocoPhillips are serious about developing the Producer Project. However, it is also possible that the Producer Project is merely a vehicle intended to either provide "cover" for the Producers while they object to the issuance of an AGIA license to TC Alaska, or to enable the Producers to increase their negotiating leverage with TC Alaska should they decide to become shippers on the Project (Appendix G2, Section 5). In fact, the Major North Slope Producers, in their AGIA comments, legislative testimony, and other public statements, have advanced several reasons which attempt to explain why they cannot

[128] AS 43.90.230

support an independent pipeline in general, and TC Alaska's Project in particular. This section analyzes the principal remaining producer objections to the Project.

(1) Producers Suggest Only They Can Build an Alaska Gas Pipeline Project

During the AGIA process, the Major North Slope Producers have argued that only they have the ability to construct an Alaska gasline, implying that producer-owned pipelines are the norm in the U.S. However, while they could probably construct (or, more likely, hire a third-party to construct) an Alaska gasline if they wanted to, the Major North Slope Producers lack experience in constructing long-distance, regulated natural gas transportation facilities in the U.S. In fact, even though the U.S. natural gas pipeline grid is many times larger than the proposed Project, none of the major interstate natural gas pipelines in the U.S. are majority-owned by the Major North Slope Producers. This is probably explained, in part, by the fact that interstate natural gas pipelines provide a much lower regulated rate of return than the return earned by the Major North Slope Producers for producing oil and gas (Appendix N). As a result, owning an interstate pipeline would dilute their earnings and growth profile.

Because their focus is on oil and gas production instead of natural gas pipeline ownership, the Major North Slope Producers do not have a great deal of experience in constructing, owning or operating interstate gas pipelines.[129] Independent pipeline companies like TC Alaska, not the Major North Slope Producers or their counterparts, have constructed and operate most of the natural gas pipeline facilities in the U.S (Appendix R7). As demonstrated in the earlier discussion of background information about TransCanada and TC Alaska, TransCanada alone owns and operates gas pipelines that collectively have several times more capacity than the capacity of the proposed Project. It thus is a better position to successfully construct and operate an Alaska gasline than the Producers.

The Major North Slope Producers have also suggested in the past that as a result of their financial strength, only they can construct a "mega-project" like the Alaska gasline project. The profitability and resources of Major North Slope Producers cannot be disputed. However, it would be a mistake to conclude that only they have the ability to construct an Alaska gasline. As discussed earlier, the commissioners retained Goldman Sachs to assess the critical issue of

[129] The Major North Slope Producers own pipelines that gather gas they have produced and deliver it into major interstate natural gas transmission lines. However, the pipelines owned by the Major North Slope Producers are largely an adjunct to their production business, and by and large are not major interstate natural gas pipelines.

whether TC Alaska has the ability to obtain financing for the Project. At the commissioners' direction, Goldman Sachs carefully assessed this issue, including a review of the financial elements of the proposed Project, an assessment of TC Alaska's ability to fund the Project, and an evaluation of TC Alaska's plan to use the Federal Loan Guarantee. After conducting its review, Goldman Sachs concluded that the Project is financeable on the basis outlined in the TC Alaska proposal, as follows:

- TransCanada is a well-capitalized, highly expert sponsor with strong incentives to complete the Project.
- Although the scope and complexity of the Project are significant, the shipping contracts are key to the credit strength of the financing, and the most likely shippers (the Major North Slope Producers) have very strong financial profiles.
- Based on a review of other major projects (such as the Alliance and Maritimes pipelines), and recognizing that exactly comparable projects or precedents do not exist, Goldman's view is that the proposed Project *can* be funded in the project finance market, even though the size and length of construction will test the market's capacity for project financing
- The elements of the proposed Project that relate to financing—including the plan to obtain shipping contracts, the proposed debt/equity ratio, the general financing plan, and the plan to use the Federal Loan Guarantee—all create the basis for a financially viable project and project financing. Goldman Sachs' report is based on the assumption that TC Alaska will obtain firm shipping contracts for the full capacity of the Project, again underlining the critical importance of that issue.
- Goldman Sachs also assumes TC Alaska will obtain the Federal Loan Guarantee that Congress authorized when it passed ANGPA in 2004, and Federal Loan Guarantee are used as outlined in the TC Alaska Proposal. This would enhance the financial position of the Project (Appendix H).
- The proposed debt/equity ratios—70/30 during construction, and 75/25 upon FERC approval of the final capital costs—will be acceptable to the capital and banking markets.
- TC Alaska has the financial resources to fund the equity requirements of the Project, including 100% of those requirements if necessary. According to Goldman Sachs, the

Project's financeability also is enhanced because TC Alaska is a strong pipeline operator.

Based on these factors, and as discussed more fully at Appendix H, Goldman Sachs concludes the Project proposed by TC Alaska can be funded in the project finance market, assuming key credit features like firm shipping contracts, and the Federal Loan Guarantee, are in place and that obstacles to the Project can be surmounted. Accordingly, the commissioners disagree with any suggestion that only the Major North Slope Producers can construct a project of this scope and size.

(2) Producers Suggest They Are Insufficiently Protected from Cost Overruns

In their public comments, the Major North Slope Producers argue that TC Alaska's proposal inadequately protects them from the risk of cost overruns (Appendix A, BP Comments). The issue of cost overruns has been extensively discussed earlier in this Chapter. The discussion here will provide a brief additional response to the Producers' argument.

As a threshold matter, it is important to understand the impact of potential cost overruns on the profitability of the Project to the Producers. Based on the Commercial Team's analysis, the commissioners agree that cost overruns could have a material impact on Project economics. However, even assuming a significant cost overrun scenario, the Project would still permit the Major North Slope Producers to earn substantial profits on the sale of natural gas. Specifically, if the Project experiences a 40% cost overrun ($12.5 billion, capital cost $2008), and assuming for the sake of argument that the Major North Slope Producers did not have the protection of the U.S. loan guarantee, the Commercial Team's analysis demonstrates the Major North Slope Producers would still earn an attractive rate of return and realize an NPV of approximately $11 billion if the other assumptions in the Proposal Base Case scenario, including gas price projections, remain unchanged (Appendix G1, Section 5.7.8).

Even assuming a significant cost overrun scenario, the Project would still permit the Major North Slope Producers to earn substantial profits on the sale of natural gas.

In reality, the Major North Slope Producers' risk of cost overruns will likely be materially lower, because even under TC Alaska's proposal, TC Alaska has offered to bear part of the cost overrun risk by adjusting its return on equity downward by up to 200 basis points for the first five years of the Project (Application 2007, Section 2.2.3.6). In addition, its public comments, ExxonMobil has correctly characterized TC Alaska's proposed commercial terms as a mere "opening offer" to the Producers (Appendix A, ExxonMobil Comments). As a result of the significant bargaining power possessed by the Major North Slope Producers, it is reasonable to assume that after they make an appropriate counteroffer and engage in rigorous negotiations with TC Alaska over the initial rates and terms proposed by TC Alaska, they will require TC Alaska to bear a materially larger portion of the risk of Project cost overruns.

> Based on the bargaining power of the Major North Slope Producers and their experience on other pipelines, there is every reason to conclude that the Major North Slope Producers would not be required to bear an inordinate share of the cost overrun risk.

In addition, and as discussed above in the analysis of TC Alaska's proposed commercial terms in this chapter of these Findings, pipelines often offer to bear a material part or in some cases the entire risk of cost overruns themselves, by agreeing to negotiated rate agreements that shift all or part of the risk of cost overruns to the pipeline. In fact, the Major North Slope Producers themselves have entered into numerous negotiated fixed rate contracts on pipelines in the U.S.[130]

Accordingly, based on the bargaining power of the Major North Slope Producers and their experience on other pipelines, there is every reason to conclude that the Major North Slope Producers would not be required to bear an inordinate share of the cost overrun risk. Although the risk of cost overruns is without question a significant issue facing any Alaska gasline project due to the sheer scope and extended timeline of the project, it does not appear to constitute an insurmountable barrier to the success of the Project, including the initial open season.

(3) Producer Concerns That TC Alaska Has Done Insufficient Design Work Leading to Cost Uncertainty

In its public comments, Exxon expresses concern that TC Alaska has not planned to spend the funds necessary to develop a reliable estimate of what the Project ultimately will cost. The commissioners agree that obtaining a reliable cost estimate is very important. However, as indicated earlier, the biggest cost risk is the risk that the price of steel and other project cost components will increase for reasons that are beyond TC Alaska's control or ability to predict.

[130] In evaluating the Major North Slope Producers' comments on the cost overrun issue, it is important to recall their prior arguments on this same topic. In opposing the passage of AGIA in 2007, the Major North Slope Producers argued that it is imperative that they own the Alaska gas pipeline because, if the gasline were constructed by an independent pipeline company, the producers would bear the entire risk of cost overruns. As discussed above, that is inconsistent with the Producers' experience on other pipelines. Appendix R6.

In other words, even if TC Alaska spent a considerably higher amount to generate its project cost estimate prior to the open season, it would not materially increase the reliability of these areas of the cost estimate.

Large increases in steel prices and related costs are a significant factor in pipeline economics in the current market environment. As shown earlier, cost escalation risk dwarfs the risk of increased costs due to inadequately defined or managed project scope. But the risk factor of cost escalation, or increases, is not hugely diminished merely through the conduct of extensive engineering work. That is because, after open season, a multi-year regulatory process must still be conducted (Appendix F Exhibit D). The risks of substantial year-over-year cost escalation—such as what the industry has suffered in the last few years—will remain.[131]

There are two obvious ways to mitigate such escalation risk. First, if detailed design work is indeed performed, and if the Project proponents are willing to commit to purchase long-lead items after the open season so that their prices can be secured, then a significant portion of cost escalation risk can be avoided. Doing this, however, entails its own risks as the project scope may be forced to change as a result of the regulatory process. The Major North Slope Producers have not, to date, indicated a willingness to take this risk.[132] Second, precedent agreements signed at open season between the shippers and the pipeline owners can permit shippers with “off ramps” or “outs” if costs appear to have increased above some threshold. The commercial question facing such contract provisions is the sharing of development costs should the project not go forward. Having TC Alaska as an additional commercial party—not to mention the state, through its $500 million matching contribution under AGIA — at least creates the prospect for sharing this cost escalation risk.

Accordingly, the commissioners do not agree with the contention that TC Alaska’s proposed level of design costs should impede the Project’s likelihood of success.

[131] See Erman, Michael; 2008. Oil industry costs continue steep rise: CERA. Reuters. http://www.reuters.com/article/sphereNews/idUSHO44071720080514?sp=trueandview=sphere

[132] For evidence of this concerning projects in which they are pipeline sponsors, see, e.g., BP/ConocoPhillips. 2008. Denali gas pipeline PowerPoint announcement. http://www.denali-thealaskagaspipeline.com/images/pdf/Denali_Presentation%20FINAL.pdf. at Slide 10; *see also* Department of Revenue, 2006 at 59. [Interim Findings and Determination. November 16, 2006.]

(4) Producer Objections to Rolled-in Rates and AGIA's Expansion Provisions

As discussed earlier in this chapter in the analysis of the Project's NPV, the Major North Slope Producers would be exposed to relatively little of a reduced NPV due to the AGIA rolled-in rate provisions. The fact is that expansions due to the addition of compression — which would be the initial vehicle for expanding the Project by nearly 50% above initial Proposal Base Case thoughput — has very little potential to materially increase the Project rates and would generally reduce the Project rates to the benefit of the Major North Slope Producers (Appendix G1, Section 4.7.8.6). For this reason, the commissioners do not believe the AGIA rolled-in rate provisions would have a material impact on producer profitability and thus do not constitute a valid reason for the Producers to oppose TC Alaska's Project.[133]

(5) Producers Arguments Concerning The Withdrawn Partner Issue

Another reason given by the Major North Slope Producers for not supporting the Project involves TransCanada's alleged obligations to a partnership formed by TransCanada affiliates under New York law in the late 1970s to construct an Alaska natural gas pipeline pursuant to the Alaska Natural Gas Transportation Act (ANGTA). To understand the Producers' arguments, some brief background facts about the situation are necessary, which are summarized below and discussed in more detail in Appendix R1.

In 1978, TransCanada affiliates and several other companies formed a partnership called the Alaskan Northwest Natural Gas Transportation Company (ANNGTC). Each partner was required to make an initial contribution of capital of up to $24 million to ANNGTC, and additional annual contributions as necessary (Appendix D, TransCanada letter dated January 24, 2008). Over the intervening decades, all of the ANNGTC partners have withdrawn from the partnership except for two TransCanada affiliates. The total investment by the TransCanada partners and the now-withdrawn partners in ANNGTC was approximately $200 million (Appendix H, Section VIII B) with the TC Alaska partners accounting for approximately 30% of the total (Appendix D, TransCanada letter dated January 24, 2008 Data Response, and Alaskan Northwest Natural Gas Transportation Company, General Partnership Agreement).

[133] In theory, if the Project costs are much less than what has been projected, rolled-in rates could have an impact. But in that unlikely event, the Project would be even more profitable to the Major North Slope Producers, as a result of the lower costs. Appendix G1, Section 3.7.5.1.

As discussed in more detail at Appendix R1 of these Findings, the ANNGTC partnership agreement provides that if ANNGTC ever builds the 1970s project, then it must repay any withdrawn partners their original contributions plus interest at the rate approved by FERC (14% annually), provided that certain conditions are met, including the condition that such payments can be made without "undue hardship" to the partnership (Appendix D, TransCanada letter dated January 24, 2008; ANNGTC Partnership Agreement at Section 4.4.4(i)). Due to the compounding of interest at 14% for about 30 years, ANNGTC's contingent "obligations" to withdrawn partners have grown rapidly and currently total approximately $10 billion, with the number expected to grow to over $35 billion in the next ten years.

In their public comments, the Major North Slope Producers have asserted that if TC Alaska builds the Project, there is a significant risk the withdrawn partners could sue ANNGTC, TC Alaska and any party that becomes an equity partner in the Project or signs a firm transportation contract with the Project. According to ConocoPhillips, for example, this obligation "will constitute an insurmountable risk for potential shippers on a TransCanada project, for potential new associates advancing a project with TransCanada, for potential financiers of a TransCanada project, and for the State of Alaska."

BP filed similar comments, asserting that "TransCanada potentially faces a multi-billion dollar liability to withdrawn partners associated with an earlier attempt to advance an Alaska pipeline project." Neither BP nor ConocoPhillips included in their public comments any discussion of the legal theories behind such claims. Although ConocoPhillips stated in a letter to Governor Palin that it had asked its law firm "to prepare a memorandum to your Administration that identifies many of the withdrawn partner liability risks," *id.*, ConocoPhillips failed to provide the commissioners or the state with that memorandum, and refused the state's request for a copy of the memorandum.[134]

Of the prospective shippers on the Project, only the Major North Slope Producers raised this issue. Other prospective shippers on the Project, such as Anadarko or BG, did not raise the issue.

[134] Although ConocoPhillips refused to provide the memo, they did allow the state's outside counsel to discuss the issue with ConocoPhillips' outside counsel (See Bowles, Jim Jan. 24, 2008 ConocoPhillips Letter to the Honorable Sarah Palin).

In addition, in March 2008, the LB&A Committee asked each of the withdrawn partners not affiliated with TC Alaska whether they would waive their rights as withdrawn partners and whether the Project proposed by TC Alaska violated those rights.[135] On April 1, one of the withdrawn partners, Sempra, filed a response. In its response, Sempra stated that while it would not waive any rights it has as a withdrawn partner, it was not aware of anything that TC Alaska has proposed in its AGIA Project that would violate Sempra's rights as a withdrawn partner. To our knowledge, none of the other withdrawn partners has responded to LB&A's request. However, Sempra's statement appears to contradict the claims by ConocoPhillips and the other Major North Slope Producers that the withdrawn partner issue constitutes "an insurmountable risk for potential shippers on a TransCanada project, for potential new associates advancing a project with TransCanada, for potential financiers of a TransCanada project, and for the State of Alaska."

Notwithstanding the fact that the Major North Slope Producers failed to include in their public comments any legal analysis in support of their claims regarding ANNGTC, the commissioners asked their legal counsel (Greenberg Traurig) to analyze this issue and provide a public analysis of the issues raised by ConocoPhillips and other commenters, including an assessment of the risk of lawsuits by withdrawn partners against TC Alaska and any entity that helps advance the Project either by signing a firm contract, partnering with TC Alaska, or financing the Project. That analysis is set forth at Appendix R1 of these findings, and is summarized below. For the reasons discussed above and in that analysis, the commissioners believe that concerns about the risk of litigation are significantly overstated, and that the potential legal claims by withdrawn partners are, at best, weak and unlikely to succeed. For example:

- FERC would probably refuse to allow most of the $10 billion to be recovered in rates, assuming ANNGTC were ever actually built. The Major North Slope Producers failed to address this issue in their comments. FERC rules only permit a pipeline to recover from customers the interest accrued on funds used "during construction."[136] Here, it is

[135] See February 29, 2008 letters from LB&A Committee to the Loews Corporation, MidAmerican Energy Holding Company, NiSource, Inc., Pacific Gas and Electric Corporation, Sempra Energy, and The Williams Companies.

[136] *See* Definition (17) of Gas Plant Instruction 3. of the FERC's Uniform System of Accounts, 18 C.F.R. Part 201 at 611 (2007) ('Allowance for funds used during construction' includes the net cost *for the period of construction* of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, ..." (Emphasis added.)). *E.g.*, *Metropolitan Edison Co.,* 11 FERC ¶ 61,027 at 61,042 (Classifying plant as construction work in progress and accruing an allowance for funds used during

undisputed that ANNGTC has not constructed anything, and that any work on the project ended more than twenty years ago. Consequently, because the interest on the contingent liability, which comprises most of the $10 billion, has not been accruing during construction, it would likely not be recoverable in rates under FERC rules and precedent. Accordingly, as explained in Appendix R1, payment of the vast majority of the contingent liability would not be required under the Partnership Agreement. At most, FERC would probably only permit recovery of the book value of any assets that could truly be used to build the ANNGTC project. The value of those assets for withdrawn partners not affiliated with TransCanada is approximately $200 million or less. No party—not even the Major North Slope Producers—contends that a liability of that much lower amount would pose an insurmountable barrier to the Project.

- In addition to the fact FERC rules likely would drastically reduce the real amount at issue in any potential dispute, there are other major weaknesses in any potential claims against TC Alaska. For example, the ANNGTC partnership agreement does not require TC Alaska to make payments to the withdrawn partners unless it constructs the project contemplated in the partnership agreement (Appendix R1). In fact, TC Alaska is building a project under a different set of FERC authorizations than applied to the ANNGTC project. *Id.*. The ANNGTC partnership agreement also does not contain any language that expressly prohibits TC Alaska from pursuing a new project.
- Taken to its ultimate conclusion, the Major North Slope Producers' argument goes too far because it would ultimately, and probably unlawfully, preclude TC Alaska from *ever* constructing an Alaska gasline. Assuming for the sake of argument that the $10 billion contingent liability actually exists, the ANNGTC project probably could never be built because the Project would be uneconomic if the cost of the alleged liability (which will be more than $33 billion in the year 2016) (Appendix A, ExxonMobil) had to be recovered in the project's rates. At the same time, under the theory of ConocoPhillips and the other Producers, TC Alaska cannot pursue its new Project without violating an alleged duty to the ANNGTC withdrawn partners to construct the old project. By effectively precluding TC Alaska from building either the new Project or the old ANNGTC project, the Major

construction when such plant is in fact not under construction obviouly [sic] deviates from the descriptive definition and function of those accounts."), *modified on other grounds*, 13 FERC ¶ 61,142 (1980).

North Slope Producers' theory overreaches. Courts strongly disfavor contract interpretations which unreasonably restrict a party from competing in the marketplace.[137]

- TC Alaska's potential liability is even more remote because a strong argument can be made that withdrawn partners have waived any claims they may have against TC Alaska, either by pursuing new Alaska gasline projects themselves, or by failing to file public comments during the AGIA process opposing the Project due to the alleged existence of the ANNGTC "contingent liabilities." Even though they had notice of the issue, none of the withdrawn partners filed comments.[138]

For these reasons, and as more fully explained in the analysis in Appendix R1, the risk of litigation concerning the ANNGTC contingent liability issue is not a reasonable basis for the Major North Slope Producers to refrain from partnering with TC Alaska or contracting with the Project. Nor would it necessarily present an impediment to financing the Project.

In addition, the commissioners further conclude that, should litigation be necessary to gain additional clarity regarding this issue, such litigation could be resolved in a time frame that would not have a materially adverse impact on either the NPV or likelihood of success of the Project. For example, the state or some other party could ask FERC to issue a declaratory order ruling that it would disallow most of the ANNGTC costs, particularly the interest that has accrued during a period when no construction has occurred. Assuming FERC acts on the petition, a FERC ruling could be issued within several months from the time of the filing, and help to eliminate most of the alleged liability, reducing it to a much smaller and more manageable level that would not have a material adverse impact on the marketing or financing of the Project.[139] Similarly, TC Alaska or another party could ask a court in Alaska (or potentially

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[137] *See* Restatement (Second) Contracts § 186 (1979) ("A promise is unenforceable on grounds of public policy if it is unreasonably in restraint of trade. A promise is in restraint of trade if its performance would limit competition in any business or restrict the promisor in the exercise of a gainful occupation."). *See also In re American Preferred Prescription, Inc.*, 186 B.R. 350, 354 (E.D.N.Y. 1995) ("Courts generally look with disfavor on restrictive covenants not to compete."); *Technical Aid Corp. v. Allen*, 134 N.H. 1, 8, 591 A.2d 262, 265 (1991) ("This court has stated that the law does not look with favor upon contracts in restraint of trade or competition." (Internal quotation omitted.)).

[138] Given that they failed to file public comments or otherwise raise this issue with TransCanada prior to the public comment deadline, any effort by the withdrawn partners to assert claims against TransCanada, or against its future partners and shippers in the Project, could subject the former partners to a claim by the state that they have tortuously interfered with the state's license relationship with TransCanada, assuming TransCanada receives the AGIA License.

in New York), to issue a declaratory judgment regarding whether the construction of the Project would breach a fiduciary duty to the ANNGTC withdrawn partners.

In sum, the potential claims against TC Alaska regarding the ANNGTC issues are extremely weak. Accordingly, the ANNGTC withdrawn partner issue would not pose a significant threat to the success of the Project (Appendix H, Section VIII).

e. Other Factors Which Indicate TC Alaska's Project Has A Reasonable Prospect of Securing Firm Shipping Commitments

Despite the pendency of the BP/ConocoPhillips Producer Project and the Major North Slope Producers' stated objections to the TC Alaska Project, several factors support the conclusion that there is a reasonable chance the Producers will not withhold their gas indefinitely, and will eventually decide to negotiate firm shipping agreements with TC Alaska which will enable the TC Alaska Project to obtain financing. This analysis is supported by the various Appendices to these Findings. Simply put, the commercial, legal and political risks of a failed open season are simply too great for the stakeholders to permit the TC Alaska Project to fail.

Despite the pendency of the BP/Conoco Phillips Producer Project and the Major North Slope Producers' stated objections to the TC Alaska Project, several factors support the conclusion that there is a reasonable chance the Producers will not withhold their gas indefinitely, and will eventually decide to negotiate firm shipping agreements with TC Alaska which will enable the TC Alaska Project to obtain financing.

As a threshold matter, if the TC Alaska Project fails due to a lack of shipper support and despite the robust profits the Project would produce, the Major North Slope Producers would risk the loss of their leases which give them the right—and the obligation—to produce and market natural gas located on land owned by the State of Alaska. A hydrocarbon leaseholder has a duty to produce and market oil and gas when it would be reasonably profitable to do so.[140] Under the terms of their leases with the state, the Major North Slope Producers do not have the option of delaying the production and sale of natural gas, if committing to the Project now would provide them with the opportunity to make a reasonable profit on gas shipped over the pipeline. According to our NPV analysis, even using conservative price and cost projections and under

[139] FERC's ruling would be subject to rehearing at FERC and a court appeal.

[140] See, e.g., Williams and Myers, Oil and Gas Law § 853 (2006). "[L]essee is ordinarily under an implied duty to use due diligence to market the product."

the current state tax and royalty structure, the Major North Slope Producers would reap billions of dollars of profits if the Project were constructed, a huge internal rate of return at Prudhoe Bay, and a significant rate of return in other North Slope production areas. Because the infrastructure to produce gas at Prudhoe Bay is already in place, incremental production costs would be extremely low at that important location.

TC Alaska's Project gives the Major North Slope Producers the ability to sell their gas produced from state lands at an extraordinary profit. As a result, absent a valid excuse, they would have a duty to produce and sell the state's gas, which would require them to sign firm shipping contracts with the Project.

In the past, the Major North Slope Producers have proffered a variety of explanations for why they cannot support an independent pipeline. The foregoing discussion addresses a number of those explanations. For example, the Producer Project proposed by BP and ConocoPhillips is likely contingent upon a demand for fiscal certainty that is unnecessary, and thus would not constitute a valid reason not to support TC Alaska's Project.[141] Three additional possible explanations for why the Major North Slope Producers currently oppose the Project also merit brief discussion.

First, the Major North Slope Producers may maintain that the rate of return that participation in or shipping over the Project would generate is insufficient to clear their internal "hurdle" rates—the minimum rate of return the Producers must achieve to pursue a project. A lessee's internal hurdle rate, however, is irrelevant to the duty to produce and sell gas from leased state lands. So long as participation in the Project would provide the Major North Slope Producers the ability to earn a reasonable profit, they must provide assurances to support the Project—or *unequivocally* commit to some other means of commercializing the gas—regardless whether those profits would surpass their internally set hurdle rates.[142]

[141] The state, as lessor, should consider demanding assurances that the NS Producers will fulfill their obligations to produce either by firmly committing to ship over the TC Alaska Project or by committing unconditionally to build the Denali project.

[142] Because the Project is so solidly "in the money," the Major North Slope Producers also face the risk that, in any open season for the Project, an independent marketer will sign a firm contract (subject to the condition that the Producers agree to sell their gas to the marketer). That would further expose them to the risk of a claim that they breached their duty to produce the state's natural gas.

Second, the Major North Slope Producers' opposition to the Project reflects their evident desire to control any Alaska gasline. The recent Producer Project by BP and ConocoPhillips provides a concrete indication of this intent. Chapter 5 of these Findings fully discusses the competitive dangers inherent in producer ownership of any Alaska gasline, similar to the state's experience with TAPS. Apart from those dangers, however, the mere desire to control the pipeline (and thereby achieve "basin control" over the North Slope production basin itself), is not a valid reason for refusing to support the Project, not when the Project would produce extraordinary profits for the Producers.

A third possible explanation for the Major North Slope Producers' opposition to the Project involves prices and profits on other natural gas resources they control. The Major North Slope Producers may be concerned that, by signing firm shipping contracts with the Project, they would increase the actual and projected supply of natural gas in the U.S. market, moderating the price of natural gas and possibly reducing their rate of return on other sales of natural gas they make in the U.S., including sales of liquefied natural gas (LNG) imported from other countries. The Major North Slope Producers control approximately 40% of the natural gas sold in the U.S. (Gas Daily, 2008). The Major North Slope Producers have also made huge investments in overseas LNG projects, including major projects in unstable areas of the world such as the Middle East. Exxon, for example, has reportedly spent $3.2 billion developing a massive LNG project in Qatar, which when completed will produce 61.6 million gross tons per year of LNG for export to markets in the U.S. and other world markets.[143]

Thus, one of the key benefits of the Project—the ability to moderate the price of natural gas in the U.S.—may not be in the interests of the Major North Slope Producers. The EIA has projected that the construction of an Alaska gasline would reduce the price of natural gas by approximately 20 cents (*See* Chapter 5, *supra).* Even though the Producers stand to earn huge profits from the sale of Alaska gas if the Project were constructed, a reduction in the natural gas price of 20 cents could also impact the profitability of their other gas production. It is reasonable to assume the Major North Slope Producers are well aware of this fact. Indeed, the commissioners are aware that ICF, a major international consulting firm, performed a study for

[143] ExxonMobil Corporation 2006 Annual Report at 41 (2007); ExxonMobil Corporation, 2007 Financial and Operating Review at 56 (2008). Similarly, BP's Bontang, Indonesia LNG plant, one of the largest in the world, produced 18.4 million gross tons per year in 2007 and Conoco's QatarGas3 Joint Venture, scheduled to be completed in 2009, is projected to produce 7.8 million gross tons per year.

the Major North Slope Producers assessing the impact that an Alaska natural gas pipeline would have on the prices of natural gas and LNG in the U.S (ICF 2008).

Thus, it is reasonable to conclude that, even though the Project would increase the amount of natural gas sold by the Major North Slope Producers, they may wish to delay the Project for fear it would reduce the margins on their other existing sales of natural gas. That, however, is not a valid excuse under Alaskan law. The Producers have a duty to produce Alaska's natural gas if they would earn a reasonable profit on the sale of that gas, regardless whether such sales might moderate the prices they receive for sales of other gas supplies. In light of their obligations under Alaskan law, there is a reasonable prospect that the Major North Slope Producers, as rational commercial actors, will ultimately choose to support the TC Alaska Project rather than risk being found in violation of their duty to produce.

> It is reasonable to conclude that, even though the Project would increase the amount of natural gas sold by the Major North Slope Producers, they may wish to delay the Project for fear it would reduce the margins on their other existing sales of natural gas.

Supporting TC Alaska's Project would also enable the Major North Slope Producers to avoid exposure to other risks. In addition to the lost revenue opportunity associated with loss of their leases, the Major North Slope Producers would also lose the opportunity to book a sizeable amount of proved reserves. This is a growing problem in the oil industry, which could affect the market's perception of how profitable these companies will be in the future. For example, Exxon has been struggling to replace the oil and gas it produces with new reserves it can produce in the future.[144] The loss of Alaska's reserves due to revocation of the existing leases would exacerbate this growing problem. Again, it is reasonable to assume that, as rational commercial actors, the Major North Slope Producers ultimately will choose to support the Project and thereby achieve the ability to book a significant amount of new reserves.

A decision by the Major North Slope Producers to withhold their reserves from shipment over the Project could also have adverse political ramifications for the Producers. For example, a refusal by the Producers to participate in the open season for the Project could result in an effort in the Alaska Legislature to pass a "reserves tax." Under a reserves tax, the Major North Slope Producers would pay a tax on their natural gas reserves, even if they do not actually produce

[144] See, e.g., Business Wire, Exxon Mobil Corporation Announces 2007 Reserves Replacement (Feb. 15, 2008), available at http://news.morningstar.com/newsnet/ViewNews.aspx?article=/BW/20080215005650_univ.xml.

and sell those reserves. The potential for a reserves tax should provide the Major North Slope Producers with additional incentive to participate meaningfully in an open season, and to negotiate firm shipping agreements Alaska on reasonable terms.

Moreover, if the Major North Slope Producers collectively decide not to participate in the Project open season, that collusive conduct could subject them to scrutiny under federal and state antitrust laws. Given their domination of leased natural gas reserves on Alaska's North Slope and sales of gas and LNG in the remaining United States, the Major North Slope Producers must expect that the state would request the Alaska Attorney General, as well as the U.S. Department of Justice and Federal Trade Commission to investigate any apparent agreement among the Producers to refuse to participate in the AGIA effort to bring competitive gas to the market, or other joint or unilateral anticompetitive activity that impedes or delays the construction of a gasline.[145] A statement by the Major North Slope Producers that they refuse to support the TC Alaska Project, because they prefer their own pipeline project, would be problematic, given the anticompetitive issues inherent in a producer-owned pipeline, which we discuss in Chapter 5 in comparing the two proposals.

If the Major North Slope Producers collectively decide not to participate in the Project open season, that collusive conduct could subject them to scrutiny under federal and state antitrust laws.

Similarly, the actions or inactions of the Major North Slope Producers could, depending on the specific facts and circumstances, implicate the statutes and regulations enforced by FERC. In general, FERC has been charged with ensuring that interstate natural gas and electricity prices are "just and reasonable." In the wake of recent highly publicized manipulation of electricity markets, FERC has been charged with for preventing and punishing manipulation of natural gas as well as electricity prices, including any collusion for the purpose of market manipulation.[146] The state could either request an investigation by FERC, or file a complaint at FERC. Again, it would be premature at this time to speculate on specific claims that could be brought or theories that could be investigated. However, there is no reason that a FERC action should need to be

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[145] For example, a joint agreement to withhold goods or services in order to coerce more money from a government entity would violate Section One of the federal Sherman Act, 15 U.S.C. § 1 and its counterpart in the Alaska Restraint of Trade and Monopolies Act, AS §§ 45.50.562-596. *See, e.g., FTC v. Superior Court Trial Lawyers Ass'n*, 493 U.S. 411 (1990) (per se illegal for bar association to agree not to represent indigent defendants unless the government increased lawyers' compensation).

[146] *Prohibition of Energy Market Manipulation*, 114 FERC ¶ 61,047 (2006).

pursued, when the rational alternative for the Major North Slope Producers is to pave the way to reap billions in profits by negotiating firm shipping agreements with TC Alaska.

Finally, a refusal by the Major North Slope Producers to take advantage of the unique opportunity presented by the Project would almost surely subject them to intense political scrutiny, at both the state and federal level. Skyrocketing energy costs, coupled with record profits by oil and gas producers, have already prompted calls by some in Congress to take legislative action, including proposals for windfall profits taxes and other initiatives. The profits for ExxonMobil alone in 2007 eclipsed the $40 billion mark (ExxonMobil 2007). If, at a time of record energy prices and record profits, the Major North Slope Producers are perceived to be preventing or stalling the development of perhaps the greatest untapped natural gas resource in the United States, which could help moderate natural gas and electricity prices, satisfy growing demand, and provide energy independence and other benefits to U.S. consumers and taxpayers, the prospect of intense congressional scrutiny seems likely. Indeed, some members of Congress have been highly critical of the FTC for what they consider the "rubberstamping" of major oil and gas mergers, and for failing to uncover collusion in the setting of gasoline prices. Similarly, the FERC received heavy congressional criticism for allegedly failing to do enough to prevent the California market manipulation and resulting energy crisis in 2000-2001.[147] Calls for FTC and FERC investigations can be expected if the Major North Slope Producers refuse to support the Project and cause its open season to fail.

The purpose of analyzing the risks of a failure to negotiate firm shipping agreements with TC Alaska is not to demonize the Major North Slope Producers. The Major North Slope Producers and other oil and gas producers have brought significant benefits to Alaska and the Nation. These companies perform incredible feats of engineering on a daily basis to produce and bring Alaska's oil supplies to market, in some of the most extreme conditions on Earth. For that, they deserve great credit, not only from Alaskans but from the Nation as a whole. Too often, the contributions of energy companies such as these to our state and our Nation are overlooked, including their hard work to keep the lights on at night, provide heating for homes in the winter, and supply the fuel that runs the U.S. economy. The state and the Major North Slope

[147] Pelosi, N. 2008. Letter to the Honorable William G Kovacic, April 25, 2008. Available at http://speaker.gov/newsroom/pressreleases?id=0628. See also *Study Faults U.S. Regulators In Aftermath of Power Crisis*, New York Times, Section C, Page 1 (June 18, 2002); *See also Government Developments*, Oil and Gas Journal, August 20, 2001 (stating that "the [Federal Energy Regulatory] Commission came under intense criticism and congressional scrutiny for its handling of California's electricity crisis").

Producers have been partners for several decades, and there is every reason to be hopeful that this partnership will continue and grow.

Notwithstanding the important role the Major North Slope Producers have played in developing Alaska's oil reserves, the analysis discussed in this chapter demonstrates that the time for an Alaska natural gas pipeline project is long overdue. Record or near-record natural gas prices, both now and projected into the future, combined with an economic tariff rate for the Project, provide compelling project economics for the Major North Slope Producers and the state, as well as other stakeholders including the federal government and TC Alaska. Under these circumstances, it is reasonable to conclude that the Major North Slope Producers ultimately will decide not to withhold their supplies by refusing to negotiate firm shipping commitments, and that the other major stakeholders will take reasonable actions to do what is necessary to help achieve that goal.

In sum, the commissioners fully recognize the Major North Slope Producers do not support the Project at the present time, and that there will be many challenges to overcome before success is achieved. In the final analysis, however, the commissioners believe it is reasonable to conclude that the Major North Slope Producers, as rational commercial actors, will ultimately decide to commercialize Alaska's gas by supporting the Project instead of taking the tremendous risks associated with refusing to participate. Accordingly, the commissioners believe it is reasonable to conclude that the Project has a significant likelihood of success because the major stakeholders are likely to find a path that resolves these issues.

F. Summary

TC Alaska's Project is likely to produce a very significant cash flow and positive NPV for the State of Alaska and for the other major stakeholders in the Project, including the Major North Slope Producers. Specifically, The State of Alaska would realize an estimated cash flow of $261.5 billion, and an estimated NPV of approximately $66 billion at a discount rate of 5%. The Major North Slope Producers would realize an estimated cash flow of $147.4 billion, and an estimated NPV of approximately $13.5 billion at a discount rate of 10%.[148]

TC Alaska's Project also has a significant likelihood of success, for several reasons. TransCanada is a highly experienced, independent natural gas pipeline company, with the necessary experience (operating within the U.S., Mexico, Canada, and in arctic conditions) and financial resources to complete its Project. It has also proposed commercial terms that contain several attractive features, including the offer to share the risk of cost overruns, which are likely to improve significantly after TC Alaska negotiates commercial terms with the Major North Slope Producers.

In addition, TC Alaska will likely be able to successfully overcome the key barriers to the Project, including the need for firm shipping agreements with the Major North Slope Producers. The commissioners conclude TC Alaska has a significant prospect of obtaining firm shipping commitments even in light of the Producer Pipeline project recently proposed by BP and ConocoPhillips. The potential benefits to be gained from the TC Alaska Project, and the risks to all of the parties of not taking reasonable actions to make the Project a success, are simply too large for the parties to allow the Project to fail.

148 As explained more fully herein, the Producer NPV would be significantly higher at the same 5% discount rate used for the State.

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Chapter Four — LNG

Table of Contents

A. Introduction and Summary of Analysis of LNG Project Options....4-1
B. Background....4-3
C. The LNG Project Options....4-7
D. The Y Line Option....4-9
E. Analysis of the NPV of the LNG Project Options....4-12
1. Calculation of LNG Prices....4-12
2. LNG Volumes....4-20
3. Costs and Schedule Related to LNG Scenarios....4-20
4. Comparison of LNG and TC Alaska Costs and Tariffs....4-28
5. Estimated State NPV_5....4-34
6. Comparison of Estimated NPVs Produced by the TC Alaska Project and the LNG Options....4-35
F. TC Alaska's Project Has a Greater Likelihood of Success Than Any of the LNG Options....4-43
1. An LNG Project Would Be Significantly More Complex, and Thus More Risky, Than an Overland Route....4-43
2. An LNG Project Would Be More Difficult To Finance Than an Overland Route....4-46
3. There Is a Significant Risk LNG Would Not Provide Open Access to Future Explorers, In Contrast With the TC Alaska Project....4-47
4. The Major North Slope Producers Have Indicated Their Preference for An Overland Route Over the LNG Options....4-48
5. An LNG Project Will Require Proven and Committed Reserves (Certified by Experts) to be Dedicated to the Project....4-50
6. Exporting LNG To Asia Presents Regulatory and Political Barriers That the TC Alaska Project Would Not Face....4-50
7. An Overland Route Has a Better Opportunity than an LNG Project To Spur a Petrochemical Industry....4-52
G. Conclusion....4-54
H. References....4-56

Figures

Figure 4-1. Asian LNG Price Formula: The Historical Period....4-13
Figure 4-2. Japanese 'S' Curve for LNG Pricing: The Historical Period....4-14
Figure 4-3. More Recent Japanese, Korean, Tawainese, and Chinese LNG Prices Related to Crude Oil Price....4-15
Figure 4-4. Asian LNG and Henry Hub Prices in the Different Scenarios (Real 2007)....4-17
Figure 4-5. Historical Oil to Gas Price Ratio....4-18

Figure 4-6. Cost-Risk Profile for the LNG Base Case GTP Plant Construction..................4-21
Figure 4-7. Cost-Risk Profile for the LNG Base Case Delta Junction to Valdez Pipeline Construction 4-22
Figure 4-8. Cost-Risk Profile for the LNG Base Case LNG Plant Construction..................4-24
Figure 4-9. Execution Cost Probability Distribution for a 4.5 Bcf/d Integrated LNG Project..4-26
Figure 4-10. Tariff Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case 4-28
Figure 4-11. Fuel Loss Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case 4-29
Figure 4-12. Tariff Comparison Including Estimated Incremental Fuel Costs: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case 4-30
Figure 4-13. Tariff with Incremental Fuel Costs and Shipping Costs...................................4-31
Figure 4-14. Tariff Build Up...4-33
Figure 4-15. State Net Present Value Under Different LNG Project Configurations.............4-34
Figure 4-16. Margins of LNG Project versus a Pipeline Project...4-35
Figure 4-17. State NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions.....4-36
Figure 4-18. Major North Slope Producers' NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions..4-37
Figure 4-19. Price vs. Tariff for a 4.5 Bcf/d LNG Project and the 4.5 Bcf/d Proposal Base Case Pipeline Project 4-38
Figure 4-20. Comparative State NPV_5 Distributions Associated with Project Cost Risk.......4-39
Figure 4-21. Comparative Producer NPV_{10} Distributions Associated with Project Cost Risk 4-40
Figure 4-22. State NPV Under LNG and TC Alaska Pipeline Cases...................................4-42

Tables

Table 4-1. Liquefaction Plant Cost Ranges 4-25
Table 4-2. Stakeholder NPV for 4.5 LNG Project Under Alternative Scenarios-Base Case LNG 4-41

A. Introduction and Summary of Analysis of LNG Project Options

To assess whether TC Alaska's proposed pipeline from the North Slope to Alberta will sufficiently maximize the benefits to the people of Alaska and merits issuance of the AGIA License, the commissioners have evaluated several LNG project options. For many years, proponents of Alaskan LNG projects have highlighted specific benefits that may accrue to the people of the State of Alaska from an LNG project. LNG supporters have argued in comments that LNG offers superior benefits when compared to an overland project like the one offered by TC Alaska in its AGIA Application. Alaskans must have confidence that the right path is chosen for working to commercialize North Slope gas. Therefore, a close look at possible LNG options and comparison of those options with the TC Alaska Project is necessary before determining whether awarding a license to TC Alaska will sufficiently maximize the benefits to the people of Alaska.

LNG proponents assert that an LNG project offers superior economics and job opportunities. In particular, they identify an earlier in-service date and access to premium markets in Asia that combine to generate a higher NPV for Alaska. LNG supporters expect additional opportunities for jobs, compared with an overland pipeline into Canada, due to the operation of a liquefaction plant and the development of an in-state petrochemical industry that utilizes natural gas liquids.

This Chapter of the Findings discusses the analysis of possible LNG options and the benefits such options could offer to the state under AGIA—including the estimated NPV to the state and the likelihood of success of the LNG options. It also compares the benefits offered by the LNG options to the benefits offered by the TC Alaska Project.

The analysis of the LNG options shows the following:

- <u>Positive NPV.</u> Several LNG project configurations would likely provide the state with a positive NPV. Putting aside any likelihood of success issues or any comparison with TC Alaska's project, a properly configured and managed LNG project would be economic.
- <u>Likelihood of Success Challenges.</u> Several factors negatively impact the likelihood of success of the LNG project options. For example, an LNG project would be a much larger undertaking, involving not just a pipeline and gas treatment plant (GTP) but also a costly liquefaction plant, tankers to ship the LNG overseas, and the need to secure long-

term gas sales contracts with creditworthy customers. Each of these factors complicates the ability to finance and arrange an LNG project.

Besides the technological difficulties, the commercial complications are substantial.[1] There are simply many more links in the chain including acquisition of a firm, long-term gas supply, securing long-term firm purchase agreements, and negotiating for pipeline as well as tanker capacity (Appendix I, Section 9). In addition, the myriad commercial provisions must come together essentially simultaneously.

LNG options also face an additional hurdle because the Major North Slope Producers appear to continue to view an overland route to Canada as economically preferable. Finally, LNG options face several other significant barriers, including the lack of an obvious route to open access for explorers, and political/regulatory issues which could prevent an LNG project from obtaining the necessary export authorizations.

- After reviewing several LNG alternatives, the Y Line concept is clearly the best LNG option. It provides the most likely way to solve the problems of obtaining export authority by providing substantial deliveries of gas to North American markets in conjunction with the export project. It provides for the maximum market diversification options and allows for substantial sharing of essential pipeline and gas treatment costs, and also results in fewer technical elements (e.g., essential pipeline and treatment facilities) having to be designed/constructed/installed together at the same time as the liquefaction plant.

> The Y Line concept is clearly the best LNG option. It provides the most likely way to solve the problems of obtaining export authority by providing substantial deliveries of gas to North American markets in conjunction with the export project.

[1] As discussed in Appendix F, Section 2.1.4 and Section 2.4 of the Addendum, an LNG liquefaction terminal is more technically complex than just a pipeline project and subject to significant and material additional risks.

B. Background

For almost as long as Alaskans have discussed a natural gas pipeline, they have talked about transporting North Slope gas south along the existing Trans-Alaska Pipeline System corridor to a tidewater facility where it would be chilled into a liquefied natural gas (LNG) form, and then transported by ship to market. As far back as the 1970s, when an Alaskan LNG project sought necessary FERC (then Federal Power Commission) authorizations, to the mid-1980s, when the Yukon Pacific Corporation was first formed with the help of former Governors William Egan and Walter Hickel, the prospect of an LNG project has intrigued resource developers and Alaskans alike. Indeed, in 1975, Senator Ted Stevens sent out a questionnaire which received 45,000 responses. The question posed: “Do you support a trans-Alaska gas pipeline as opposed to a trans-Canadian line?” The results were: Yes—85%; No—8%; and Undecided—9% (TC Alaska Application 2007, page 4). Recent surveys appear to confirm this conclusion, showing that the concept of an “all-Alaskan” LNG line has enjoyed broad support among Alaskans for many years.

By the mid-1990s, two of the major North Slope producers, BP Exploration (Alaska) Inc. and ARCO Alaska Inc., began publicly discussing plans to begin an LNG project with the expectation that gas could be landed in East Asian markets by roughly 2007.

Like other North Slope gas commercialization options, including various sizes of overland pipelines routed through Canada and into North American markets, the economics of an LNG option have historically been stressed. The combination of abundant sources of affordable natural gas supply closer to consuming regions and the costs of steel and labor challenged every project’s economic viability. In 1999, the Alaska Gasline Port Authority (Port Authority) was created as a municipal entity. It is comprised of the Fairbanks North Star Borough, the North Slope Borough and the City of Valdez, and was formed “to develop, build or cause to be built, …a project to monetize Alaska’s North Slope natural gas which would include a trans-Alaska gas pipeline, liquefaction and gas processing facilities and related infrastructure for the transportation of North Slope natural gas to market…” (AGPA 2007)

In 2002 the Alaska State Legislature re-introduced and extended the Stranded Gas Development Act (SGDA). The Port Authority was among the interested parties that submitted an SGDA application for an LNG project as a prelude to negotiations with the state. Like other independent pipeline project proponents, the proposed Port Authority project was not supported by the administration of the time. Though rejected by then-Governor Murkowski in favor of exclusive negotiations with the Major North Slope Producer consortium, the Port Authority continued to make the case publicly that it, along with all interested project sponsors, should be allowed a seat at the table. The Port Authority's argument, one embraced by many in the State of Alaska including then-gubernatorial candidate Sarah Palin, was that Alaskans stand to benefit considerably when developers and investors compete for the opportunity to monetize the state's resources.

Alaskans, both inside and outside the Alaska Legislature, recognized that preserving the state's options was essential to striking a fair deal with whomever would ultimately begin the project. The Port Authority and those supportive of its efforts were instrumental in trying to protect the state from becoming highly leveraged in gas pipeline negotiations conducted exclusively with Alaska's three largest producers. After the failure of the SGDA negotiation process, the legislature passed AGIA to create an open and competitive process that secured state needs and thereby ensured that state "gives" were made in exchange for essential state "gets."

The story of resource development in Alaska is one that has been told using words like "partnership" and "cooperation." Equally important, however, are the principles of competition and fairness. Without a comparative analysis between the economics of an integrated pipeline like that proposed by the North Slope Producers and the independent pipeline projects, whether overland to Canada or liquefied at Alaskan tidewater, Alaskans could not be expected to make an informed decision about how to cast their lot for the next several generations. In many ways the tireless efforts of Alaskans like the Port Authority and its supporters laid the groundwork for the competitive process developed through AGIA.

In many ways the tireless efforts of Alaskans like the Port Authority and its supporters laid the groundwork for the competitive process developed through AGIA.

1. Selection of LNG Options for Analysis

Both the Port Authority and Little Susitna Construction Company submitted LNG-based proposals under the AGIA process. Neither the Port Authority's LNG project, nor that submitted by Little Susitna, are eligible for formal consideration under AGIA for the reasons documented in Appendix C. Nevertheless, the commissioners determined that the LNG option was so important to so many Alaskans that it merited consideration as a possible alternative.

Therefore, while not required under the terms of AGIA, a number of conceptual LNG project options were reviewed. The project configurations considered were based upon the only market signal available: the project configurations for LNG submitted by AGIA applicants, including the Port Authority, Little Susitna, and TC Alaska. In the LNG analysis, the GTP and pipeline cost data developed from the analysis of the TC Alaska application (see Chapter 3 for discussion) were used to ensure an apples-to-apples comparison of costs and cost risk with the TC Alaska Project. Costs and cost risks for the liquefaction plant were developed by LNG project experts contracted by the commissioners. These were compared, for reference purposes only, with the cost figures developed by the Port Authority and Little Susitna. Thus, in their January 30, 2008 letter to the Port Authority, the commissioners stated that they "recognize the importance to the state of undertaking a thorough evaluation of [LNG] project options, and are committed to undertaking such an evaluation before determining whether a pipeline that goes through Canada will sufficiently maximize the benefits to the people of Alaska and merits issuance of a license." (Appendix C) The analysis greatly informed the overall Findings and Determination.

2. Analysis of LNG Options

AGIA requires a determination of whether a project being considered for award of the AGIA License sufficiently maximizes the benefits to the people of the State of Alaska (AS 43.90.180). Accordingly, under the supervision of the commissioners, the Technical, Commercial, Financial and Legal Teams—including London-based Gas Strategies Consulting, an experienced LNG consulting firm—conducted a thorough analysis of LNG project options. The analysis included a comparison between LNG project options and TC Alaska's Project. Two basic factors are critical to understanding that analysis: (1) the integrated nature of an LNG project, and (2) the fact that the primary market for Alaskan LNG supplies would likely be in Asia, not in North America.

LNG comprises a series of elements forming a delivery chain, all of which must be in place in order to have a viable project (Appendix I, Sections 2 and 7.2). These elements include one or more sources of supply (fields), feed pipelines, liquefaction plant, ships and access to regasification plants. The commercial arrangements linking each of these elements are interdependent and must all be agreed to simultaneously before any firm commitments to financing or construction are made. In practice all the agreements must be signed simultaneously. For Alaska that would mean long term North Slope gas supplies, a pipeline across the state to transport that gas supply, a liquefaction terminal located at tidewater and tankers to ship the gas to Asian markets. Unlike an overland pipeline in which shippers can simply sell gas into a very liquid market on a long or short term basis as suits their needs, the

LNG project sponsor(s) must negotiate long-term contracts for the sale of the LNG to customers, typically large utilities. Each of the elements in this chain must be completed successfully for an LNG project to proceed.

The likely market for an Alaskan LNG project is Asia.[2] (Appendix I, Sections 4.1 and 4.6) Japan (the world's leading LNG importer), Korea and Taiwan lack domestic gas supplies and currently import significant quantities of LNG. Because of the lack of domestic gas supplies, future growth in the energy needs of these markets is projected to result in a growing demand for LNG. China, India and other countries in Asia also are emerging as significant potential markets. By contrast, no LNG import terminals exist on the U.S. West Coast due primarily to local opposition; other legal barriers or economic challenges also exist to shipping LNG from Alaska to U.S. West Coast markets.[3] One LNG import terminal exists in Baja California in Mexico, although that is relatively small and has relatively limited uncontracted capacity, and as currently configured, could not fully accommodate the volumes of gas contemplated here. Moreover, the price that can be obtained for LNG in Asian markets, both currently and in the future, is likely to be generally higher than at the Mexican terminal or other North American terminals that might be constructed. (Appendix I, Section 4.3) Thus, the focus of the analysis here is on the Asian market, which provides higher prices and a higher NPV for sales of LNG than potential markets in North America.

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[2] The fact that both LNG applications under AGIA proposed the Asian Pacific as the market of choice further confirms this; see the ANGPA and LSCC Applications under AGIA at: http://www.dog.dnr.state.ak.us/agia/

[3] An additional consideration for any Alaska LNG project is the applicability of the "Jones Act" (coastwise merchandise statute, 46 U.S.C. App. § 883) to any shipments of LNG to an LNG terminal located on the west coast of the United States. The Jones Act may also be a factor in the instance of LNG shipments from Alaska to Canada or Mexico that may re-enter the U.S. market.

The Jones Act requires that any freight being transported between points in the United States, "either directly or via a foreign port," be transported on a ship built in and documented under U.S. laws and owned by persons who are citizens of the United States (Id.). Thus, any transportation of LNG from Alaska to regasification terminals along the United States' west coast would be required to meet these requirements for vessels and their ownership. The only exceptions to the statute are scenarios in which an entity transports its own freight between two terminals that it also owns (which would be unlikely in an LNG scenario), or in the instance of freight being transported to a foreign port, where the cargo is then manufactured or processed into another identifiably new and different product, and then is transported back to the U.S. Natural gas that results from the regasification of LNG would most likely not be considered such a "new and different" product to qualify as an exception to the Jones Act requirements.

Additionally, the statutory language ("no merchandise…shall be transported…between points in the United States…either directly or via a foreign port…") may be interpreted as also requiring any LNG shipped to a terminal in either British Columbia or the coast of Mexico, to comply with the Jones Act if such LNG were to be regasified and transported via pipeline back to the United States.

C. The LNG Project Options

There are an infinite number of potential LNG project configurations that could be considered. To analyze in-state LNG options, the state decided to base its analyses upon the LNG project configurations submitted by AGIA applicants, including the Port Authority, Little Susitna, and TC Alaska. It did so for two reasons. First, the AGIA process provided an important market signal. The resulting LNG applications reflected the judgment of project proponents who had taken the time and expense to submit applications around project configurations that they believed were best. Second, the AGIA process provided a reasonable source of reference data for the state's analysis.

The AGIA-submitted project configurations provided the basis for considering a number of different project sizes and in-service dates (including project expansions). The following LNG project alternatives, which will be referred to in these Findings as the "LNG project options," were analyzed:

- <u>4.5 Bcf/day Option</u>: This option assumes a 4.5 Bcf/day LNG project using a 48-inch diameter pipeline from the North Slope to Valdez.[4]
- <u>2.7 Bcf/day Option</u>: This option assumes a 2.7 Bcf/day LNG project using a 48-inch diameter pipeline from the North Slope to Delta Junction, and a 42-inch diameter pipeline from Delta Junction to Valdez.[5]
- <u>2.7 Bcf/day Expansion Option:</u> One would not build a 42-48 inch diameter pipeline if the total volume of LNG that one contemplated selling was restricted to 2.7 Bcf/d. This base pipeline design makes sense only if one expects future expansions. Accordingly, the state considered a variation of the 2.7 Bcf/day project in which a capacity expansion to 4.5 Bcf/day occurs three years after the initial in-service date. This provides an optimistic ramp-up scenario, but one that is more realistic than the initial 4.5 Bcf/d case. (Appendix I, Section 2)

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[4] This scenario is similar to the volume and pipeline facilities proposed in Little Susitna's incomplete application. In addition, the cost and schedule uncertainty associated with a 4.5 Bcf/d project, configured (as was the Port Authority's) with a 48" pipeline to Delta Junction and a 42" pipeline from Delta Junction to Valdez, was also assessed; see "Case 1b" as discussed in Appendix F, Addendum A and Exhibit D, LNG Options Analysis. However, we did not run project economics on this case, as its costs were marginally greater than the other 4.5 Bcf/d, 48" pipeline case that we did model.

[5] This scenario is similar to the volume and pipeline facilities proposed in the Port Authority's incomplete application.

- Y Line Option: The state also analyzed a 4.5 Bcf/day project to Alberta (like the TC Alaska project), expanded to 6.5 Bcf/day capacity through the addition of a 2.0 Bcf/day expansion from the North Slope to Delta Junction and addition of a pipeline to Valdez after the initial in-service date of the project.[6]

Direct comparison of the TC Alaska 4.5 Bcf/day project and an LNG project is in some ways best facilitated by considering the 4.5 Bcf/day LNG project. Volumes are the same, and project timing is similar. This brings the comparative net backs into focus. Accordingly, we consider the 4.5 Bcf/day LNG project configuration as the LNG Base Case. However, the LNG Base Case overstates the NPV that the state might achieve through an LNG project, because such large initial volumes cannot be practicably brought to the Asian Pacific market (Appendix G1, Section 7.12.4).

The LNG Base Case, as modeled, is highly unlikely to occur. It is very unlikely that such large volumes of LNG could be brought to the Asian Pacific market all at once; LNG volumes would very likely have to be phased in over eight to ten years (Appendix I, Sections 2 and 6.2). This is due to the Asian market's inability to absorb an incremental 4.5 Bcf/day as quickly as the very liquid AECO (North American) market.[7] This ramp up was not directly modeled in the NPV analysis, but it is a reality.

Further, the 4.5 Bcf/day scenario is also made unlikely because Asian Pacific buyers typically require certification of twenty years' worth of reserves (Appendix I, Section 4.6). In addition, if Point Thomson gas were not available to be committed to the LNG project, then twenty-year contracts at even 3.5 Bcf/d would still require new gas reserves to be brought on-line, raising questions about the viability of a project this size (Appendix G1, Section 6).

Before discussing the 4.5 Bcf/day LNG Base Case, we will address in the following section the unique issues raised by the Y Line LNG option.

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[6] The cost and schedule uncertainty associated with an initial 6.5 Bcf/d Y Line project was assessed, along with a later Y Line expansion; see "Case 2" and "Case 2a" as discussed in Appendix F, Addendum A and Exhibit D LNG Options Analysis. Such a project configuration is consistent with TC Alaska's Application (see Application at 2.2.3.14). However, economics were run only on the Y Line expansion, rather than an initial 6.5 Bcf/d Y Line project. On balance, proved gas resources do not appear sufficient to support 6.5 Bcf/d at initial operations.

[7] For discussion of AECO Hub market liquidity, see Appendix G2.

D. The Y Line Option

In its application, TC Alaska has stated a willingness to consider constructing, in addition to its mainline to AECO, a lateral to the Valdez area if market demand for a Y Line option is expressed by potential shippers during an open season. Specifically, TC Alaska states that "[w]hile its proposal does not include an LNG option, [it] is willing to consider offering gas treatment and gas transportation services from Prudhoe Bay to an LNG terminal should Shippers commit sufficient volumes to support such services in the initial binding open season."[8]

As discussed by TC Alaska in their application, the Y Line option assumes a 48-inch diameter pipeline through Delta Junction to Alberta where it could be connected to the AECO Hub with an initial capacity of 4.5 Bcf/day, and a 30-inch diameter pipeline from Delta Junction to a liquefaction plant in Valdez with a capacity of 2.0 Bcf/day (TC Alaska Application 2007, Appendix D). TC Alaska offered to construct the 2.0 Bcf/day pipeline to Valdez as part of the initial Project if sufficient volumes were committed in an initial open season (TC Alaska Application 2007, page 13).

A Y Line option could be viable even if volumes for the LNG portion were not committed at the time of an initial open season. TC Alaska would have the commercial motivation to expand their Project facilities if, at some later date, a producer or group of producers wished to market their gas as LNG. But even if TC Alaska did not wish to facilitate an LNG Y Line, TC Alaska would be required to expand the project as far as Delta Junction under AGIA's expansion provisions (AS 43.90.130). From there, given FERC interconnection policy (FERC 2000), a different sponsor could construct the Y Line lateral and necessary liquefaction facilities.

1. Benefits of the Y Line Option

This Y Line alternative would give Alaskans several distinct benefits. A Y Line could piggyback on, and enjoy the superior likelihood of success of, TC Alaska's proposed project to the AECO Hub. It could also, from a portfolio approach, provide superior economics for Alaskans. The optionality created by having a lateral which supplies an LNG project at Valdez could act as a "hedge" against the risk that pricing projections do not turn out as expected. Much in the way

[8] See TC Alaska Application, Executive Summary, p.5 and pp. 16-17. TC Alaska also provided, as part of its Application, a discussion of a study it performed of the Y Line option, and of related tariffs for the GTP and pipeline associated with that option. See TC Alaska Application.

that a diversified portfolio of several stocks is less risky than holding only a single stock, a Y Line would leave the state less exposed to the risk that the price in any one particular market would fall below expectations. A Y Line may also be attractive to gas producers who would prefer access to Asian markets. The factors that go into a producer's identification of a preferred market go beyond NPV. There may be significant strategic advantages to pursuing LNG that a particular producer may decide outweigh NPV considerations.

By working with TC Alaska, LNG proponents would also secure the benefits provided by AGIA for the pipeline and GTP components of the LNG project. These include open access and expansion provisions that would help encourage the maximum development of the state's abundant natural gas reserves on the North Slope. As explained later in this Chapter, absent an overland route to North American markets, an LNG project pursued outside of the AGIA process would probably not provide all the open access and expansion benefits mandated by AGIA.

The Y Line option would have another, related benefit: more jobs. A Y Line would create additional jobs needed to construct and operate the liquefaction plant at Valdez. In addition, the larger 6.5 Bcf/day project would require more exploration and development on the North Slope and would generate significant new employment. A Y Line would need producers and explorers to develop, in addition to the gas resources at Prudhoe Bay, other substantial resources located on the North Slope. The access and expansion provisions mandated by AGIA are essential to ensuring that such development does in fact occur.

A Y Line would also provide the state and its citizens with additional revenue. As discussed in the Commercial Team Report, a 6.5 Bcf/day Y Line would provide the state with a significant additional NPV on top of the NPV provided by TC Alaska's 4.5 Bcf/day project into the AECO Hub. While the NPV of the Y Line would not be as high as the NPV of a 6.5 Bcf/day expanded pipeline to AECO, a Y Line could, as explained above, be a more attractive option for some producers and would provide the state with a more diversified "portfolio" with less exposure to the risks of fluctuations in gas prices (Appendix G1, Section 7).

Ultimately, whether an overland project to AECO is expanded to transport additional gas through the AECO Hub or through a Y Line that supplies an LNG terminal in Alaska will be determined by a variety of economic, technical, regulatory, and political factors. This analysis takes no position regarding which of these two expansion options should be favored by the

State of Alaska. Indeed, the state's essential position is that the decision will likely best be made by the relevant commercial parties.

TC Alaska's statement of its willingness to listen to competitive market forces in determining whether the Y Line option should be pursued provides the state with an intriguing option. Given the additional obstacles facing an LNG project at this time in comparison with an overland route, in the commissioners' view the best way to increase the possibility of a future Alaskan LNG project is to encourage the initial construction of an overland route. Once an overland route is under development, the momentum created by that project may create the environment needed to overcome the additional barriers facing an LNG project. Once an overland pipeline project is under way or in place, the LNG project will be able to share the cost of the gas treatment facilities and pipeline from the North Slope to Delta Junction, and will not bear all of those costs alone. This fact alone also reduces the financing requirements related to the LNG project. Further, once Alaskan gas is flowing (or about to flow) into North American markets, the chances are higher that U.S. agencies will allow export of domestic energy supplies to foreign markets. Putting this as simply as possible, the best way to get an LNG project is to first get the TC Alaska overland project.

The best way to get an LNG project is to first get the TC Alaska overland project.

E. Analysis of the NPV of the LNG Project Options

The calculation of the estimated NPV of the various LNG projects involves the same basic factors discussed in Chapter 3 with respect to the TC Alaska Project.[9] For ease of comparison with the TC Alaska 4.5 Bcf/day Base Case, and because it produces a higher estimated NPV than the other LNG options, the following discussion summarizes the NPV analysis with specific regard to the 4.5 Bcf/day Base Case LNG Project scenario, described in Section C above. Details concerning the economics of the 2.7 Bcf/day LNG cases (with and without expansion) are provided in Appendix G1.

1. Calculation of LNG Prices

One cannot simply look up "the price" of LNG in the Asia Pacific market. Instead, the vast majority of gas is sold under long-term (e.g., 20-year), take-or-pay, bilateral negotiated contracts. The terms of these contracts are, in the main, confidential (Appendix I, Section 4). This is very different from the natural gas market in North America, where there are public and transparent prices at numerous natural gas trading "hubs." Accordingly, to better understand LNG prices, the state retained Gas Strategies, an international consulting firm, to analyze the question of the potential price that Alaskan LNG could command in Asia.[10] Because it has been and continues to be directly involved in a number of actual LNG deals, Gas Strategies has the market intelligence to gauge not only the terms under which past contracts have been struck, but also to reasonably assess where they are going, and why.[11]

The need for bilateral contracts is driven, in part, by the structure of Asian markets' demand. The North American market is both significantly larger and interconnected; the Asian LNG market is really a collection of segmented markets which in aggregate are about half the size.

[9] Price is the first factor in the NPV calculation: price times volume less cost equals net cash flow, which after adjustments for the project's schedule and discount rates equals NPV.

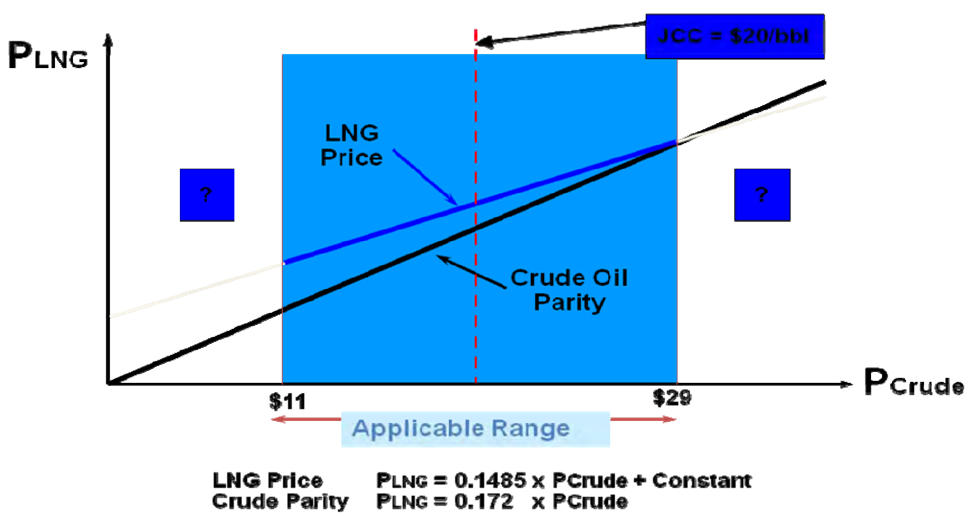
[10] In addition to analyzing LNG prices, Gas Strategies also provided details on other relevant issues, including the structure of LNG markets, particularly in Asia, (see Section 4 and Exhibit A of Appendix I), as well as the structure of LNG business arrangements (see Section 7 of Appendix I) and financing (see Section 8 of Appendix I). In addition, the state relied upon Gas Strategies' market intelligence and industry expertise for estimates of LNG shipping costs between Alaska and Asia (see Appendix I, Section 5.8). The analysis of LNG options also considered input from Goldman Sachs on the structure of LNG arrangements and financing LNG projects. (See Section VI.C of Appendix H).

[11] Gas Strategies' general conclusions about historical contract terms were generally verified by Wood Mackenzie's subscription-accessed database of inferred LNG contract terms.

Total North American demand in 2007 was roughly 30 Tcf; total Asian demand for LNG (which spans disconnected markets in Taiwan, South Korea, Japan, and China) is in the neighborhood of 14 Tcf. (EIA 2008a; NEB 2007; Appendix I, Section 5.3).

The particular pricing terms established in a given contract will be a function of the demand and LNG supply conditions that exist *at the time that the bilateral contract is being negotiated*. Once those terms are struck, the buyer and seller are largely stuck with them, subject to periodic (and potentially limited) reopeners. This places certain risks on both buyers and sellers of LNG. If, as a seller, you are negotiating your contract during a period of tight supply, then you may be able to lock in favorable terms. However, the converse can also occur. For illustration we briefly review the Asian LNG pricing history provided by Gas Strategies (Appendix I, Section 4.5.2). In Asian markets, as a general rule, prices are set by a formula that links gas price to crude oil price (normally Japanese import prices, known as JCC). For many Asian contracts struck from 1986 until 2001, LNG was priced off crude oil in a formula that provided a premium (on an energy basis) to crude oil for oil prices below about $29, and a value decrement for prices over $29.

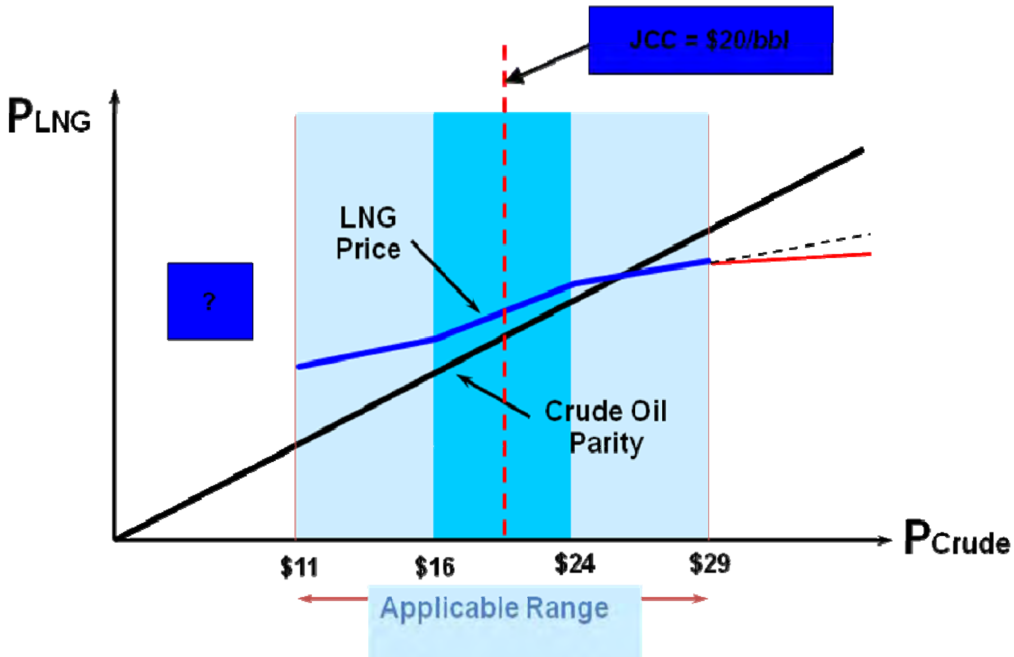
Figure 4-1. Asian LNG Price Formula: The Historical Period



Source: Gas Strategies Consulting; *(Gas Strategies, Section 4.5.2.1)*

Some contracts during this period were priced off crude oil that generated “S-curve” LNG price movements as crude oil prices change. In such contracts the LNG price premium (on an energy basis) was greater at lower oil prices, but was reversed at about $25 oil.

Figure 4-2. Japanese 'S' Curve for LNG Pricing: The Historical Period



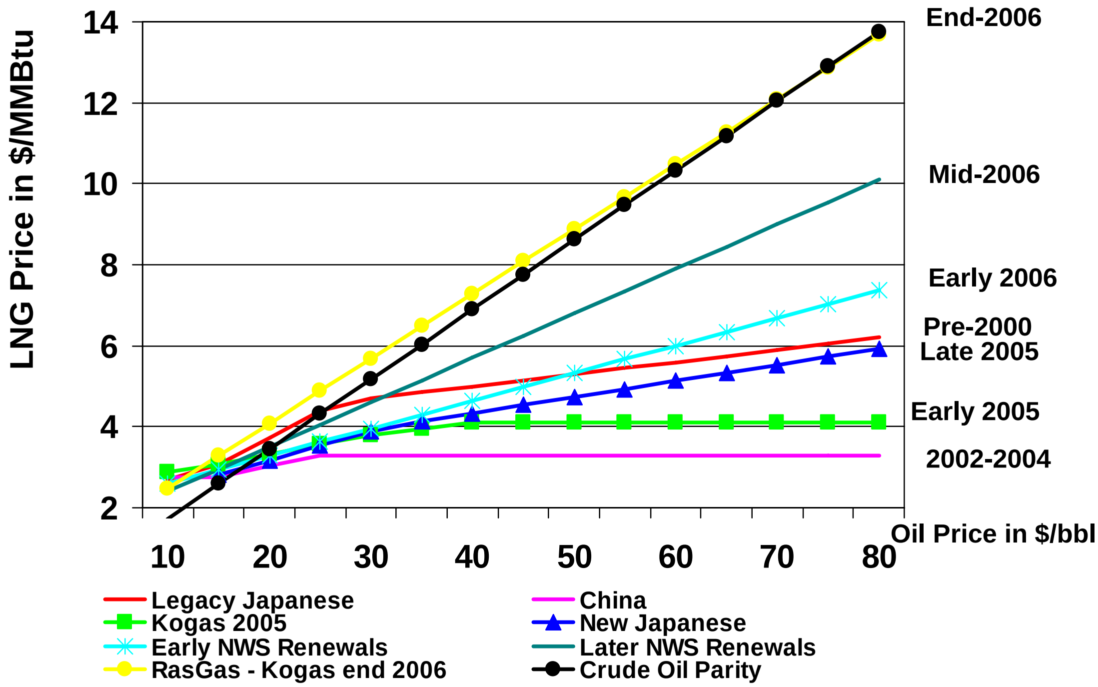
Source: Gas Strategies Consulting; *(Gas Strategies, Section 4.5.2.1)*

However, from 2001 to 2004, there was a shortage of buyers of LNG in the Asian market. LNG buyers were able to negotiate contracts with hard ceilings, such that gas prices (though by formula linked to oil) would top out when oil hit $25. At current oil prices the ceilings mean that these contracts are enormously more favorable to the buyers than the contracts negotiated in the earlier period.

Since 2005, LNG sellers have enjoyed significantly better terms, and are currently obtaining values very close to crude oil parity (on an energy basis).

LNG pricing terms need to be understood as being "sticky." Once the deal has been done, the supply becomes essentially locked into the market for the full duration of the contract; prices can only be readjusted toward the prevailing market level at roughly five-year intervals (Appendix I, Section 4.6). Accordingly, much hinges on market conditions at the time that the contracts are negotiated.

Figure 4-3. More Recent Japanese, Korean, Tawainese, and Chinese LNG Prices Related to Crude Oil Price



Source: Gas Strategies Consulting; *(Gas Strategies, Section 4.5.2.1)*

a. Forecasting LNG Price Scenarios

To develop a projected LNG price for purposes of evaluating the NPV of the LNG project options, Gas Strategies developed three price scenarios—a Base Case, a High Case, and a Low Case. These phrases—"Base," "High," and "Low"—do not refer to the LNG prices that will be realized. Rather, they refer to the general LNG contract terms in relation to crude oil prices. Within a given contract's pricing terms (be it "Base," "High," or "Low"), if crude oil prices are high then, all else equal, LNG prices will also rise. If crude oil prices are low then, all else equal, LNG prices will fall.[12] Accordingly, as a general matter a "High" contract regime will result in a higher LNG price for a given oil price than does a "Low" contract regime.

The Base Case price scenario expects that there will be a balance between LNG supply and demand in Asia, such that sufficient LNG projects will be developed to satisfy the market. This scenario has generally existed for most of the last 40 years (with instances of market

[12] All else is not equal in the Low Price contract scenario. Under such contract LNG prices become tied, not to crude oil, but to Henry Hub prices.

imbalances reflected in the wide disparity of contracts compared to the price of oil). This is a reasonable scenario considering that the structure of the LNG business in Asia is grounded on long-term contracts, meaning that new LNG projects typically cannot proceed until they have secured long-term LNG sales contracts. As a result, it is difficult for supply and demand to be out of balance for a sustained period of time (Appendix I, Section 5.2). Gas Strategies recommended that, for our Base Case evaluation, the contract terms used to derive a delivered price should be: LNG Price = 0.1485 x (Brent price of crude oil) + $0.90 (Appendix I, Section 5.4).[13]

The High Case price scenario projects that the current LNG supply tightness in Asia will continue, even though it represents a divergence from the market conditions that have tended to exist for several decades. This recent tight supply situation is due, in part, to problems with Japanese nuclear reactors, decline of Indonesian supplies, high liquefaction plant costs, environmental opposition to new projects, social and political challenges in producing countries, and strong economic growth driving energy consumption in the market area (Appendix I, Section 5.5). Gas Strategies recommended that for our High Case evaluation, the contract terms used to derive a delivered price should be: LNG Price = 0.162 x (Brent price of crude oil) + $1.00 (Appendix I, Section 5.5).

The Low Case price scenario requires a sustained recession that slows energy and other demand for LNG in Asia with reduced development costs, leading to an oversupply of LNG. This scenario could lead to an extremely low LNG price, and would require a "profound period of stagnation in the US and/or Europe similar at least to the problems of Japan post 1990…" (Appendix I, Section 5.6). Gas Strategies recommended that, for our Low Case evaluation, the contract terms used to derive a delivered price should: LNG Price = 0.9 x (Henry Hub price of gas) - 0.5 (Appendix I, Section 5.6).

To turn Gas Strategies' pricing formuals into a forecast of actual LNG prices, a forecast of Brent crude oil and Henry Hub prices is necessary.[14] For these the state relied on Wood Mackenzie's forecasts. As discussed in Chapter 3, Wood Mackenzie's views of these particular commodity

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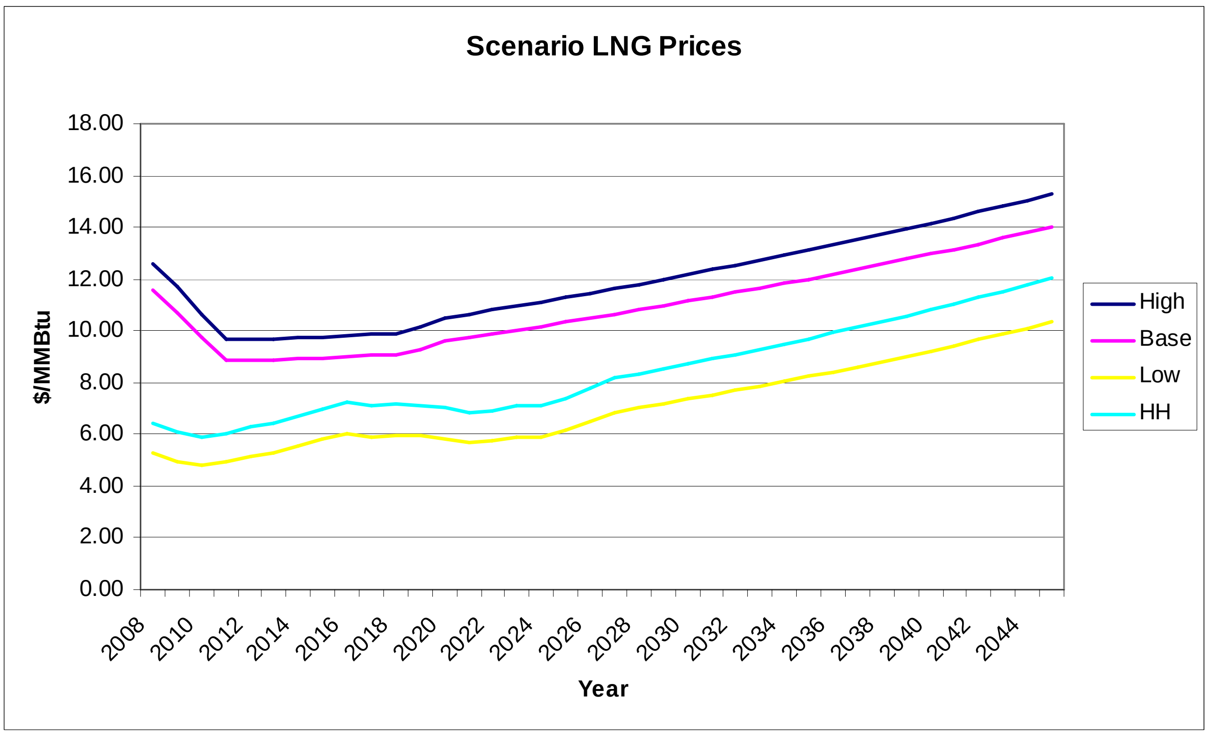
[13] The 'Brent price of crude oil' is an internationally-used benchmark for oil produced in Europe, Asia, and the Middle East. The Brent price is similar to the West Texas Intermediate price, which is the benchmark price often quoted for oil produced in the Americas.

[14] These prices are the variables on the right hand side of the contract-formula equations. If values for these variables are entered, then an LNG price results.

prices is logically and internally consistent with their views of AECO Hub commodity prices. This permits an “apples to apples” comparison of prices between the AECO Hub (for the TC Alaska Project) and Asian Pacific LNG prices (for an LNG option).

Assuming Wood Mackenzie’s forecasts of oil and Henry Hub prices are valid, the resulting Base Case price for LNG in the Asian Pacific market in 2020 (in constant 2007 dollars) shows a premium of approximately $3.00 over Henry Hub prices. The High Case price for LNG in 2020 (in constant 2007 dollars) shows a premium that is approximately $4.00 over Henry Hub prices in 2008. The Low Case price for LNG reflects a discount of approximately $2.50 from Henry Hub prices (Appendix I, Section 5.7). This is depicted in the following chart:

Figure 4-4. Asian LNG and Henry Hub Prices in the Different Scenarios (Real 2007)

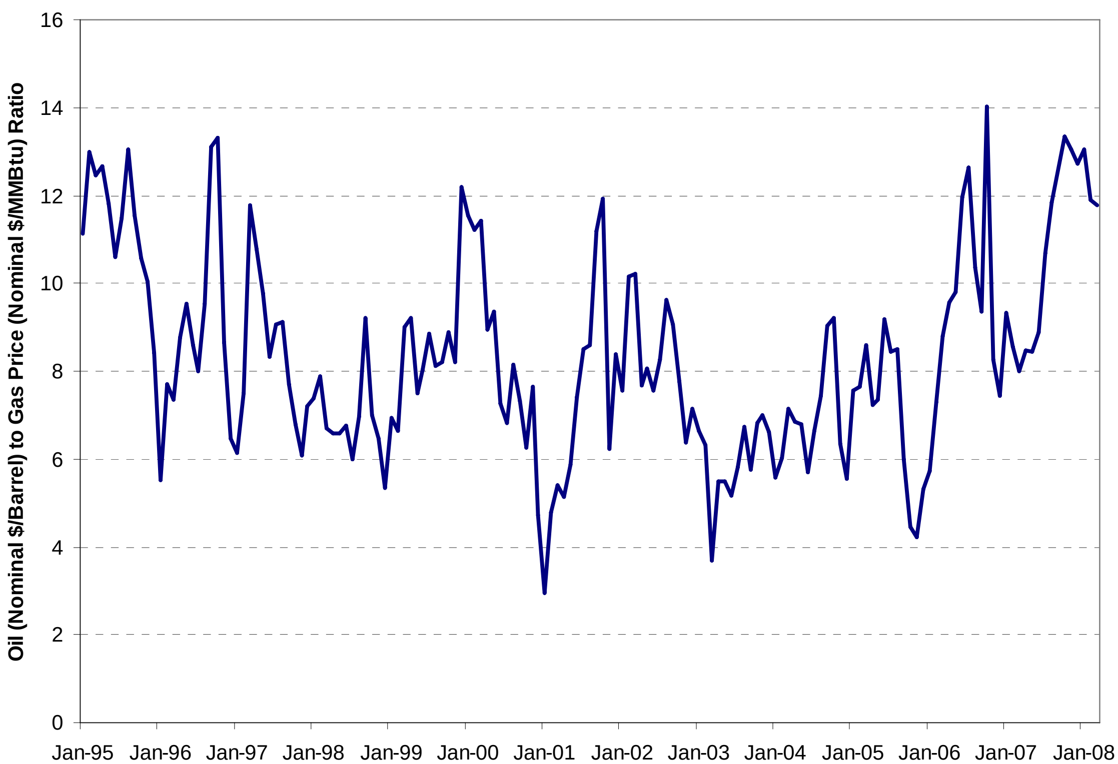


Source: Gas Strategies Consulting/Wood Mackenzie

Recent spot prices and recently negotiated contract prices in the Asian Pacific markets are trading at a greater premium (sometimes as high as $10) than the $3.00 premium generated by our Base Case. At today’s oil prices and gas prices, the premium provided by the Base Case is closer to $7/MMBtu.[15] That is, if an LNG contract for Alaska gas could be struck today at the Base Case contract price, then the premium over Henry Hub prices would be around $7. In trying to think about LNG prices more than ten years into the future, the relevant question becomes two-fold: what contract terms might one receive, and what would be the price premium in the Asian market relative to Henry Hub?

The extent to which Base Case or High Case contract terms yield an Asian LNG price premium depends significantly on the relationship of the price of oil, on an energy equivalent basis, to the price of gas in North America. In historical terms, oil is currently trading at a significant premium to North American natural gas. The oil price to gas price ratio fluctuates over time. For the period of January 1995 to March 2008, the ratio was as high as 14 to 1 and as low as 3 to 1, with an average 8 to 1 (Appendix G1; Section 7.15.4.3).

Figure 4-5. Historical Oil to Gas Price Ratio



Source: Black and Veatch 2008, Appendix G1, Section 7.15.4.3

[15] Based on *Oil Daily's* reported spot prices for Brent ($120.82) and Henry Hub ($11.52) on 5/14/2008. *Oil Daily*; 58 (94):2. May 15, 2008.

There are good reasons to think that the current price relationship—in which oil is priced significantly higher than North American gas—is unlikely to persist over the relevant time frame.

Gas Strategies predicts the current higher premium is not likely to continue, and that during the relevant time frame of any Alaskan LNG project, LNG and North American natural gas prices will likely converge somewhat, trading at prices closer to Henry Hub (and AECO) prices. According to Gas Strategies, “it is unlikely that supply would be as tight as it is at present for a full 20 year period. In practice we would expect the high prices to pull forward enough supply to bring the market back into balance within 5 to 10 years.” (Appendix I, Section 5.6)

There is more than enough new LNG supply coming on stream over the next four or five years to eliminate the projected shortfall in Asia. These quantities are targeted to supply the U.S. or U.K. markets, but because these markets are liquid and flexible some or all of the LNG could be diverted to Asia. These diversions would clearly weaken prices in Asia and strengthen them in the U.S. (the rigid Asian contracts would strongly inhibit the reverse happening). In other words, as the United States becomes more dependent on LNG supplies in the next decade, LNG customers in the U.S. will have to pay a (higher) competitive price to attract LNG away from other world markets.[16] (Appendix I, Section 4.7.) Growing global competition for reliable gas supplies, including an increased North American reliance on LNG, will create upward price pressure on LNG. Higher LNG prices will also tend to increase AECO and Henry Hub prices, because sellers will only introduce LNG cargoes to those locations if they can demand a price similar to the price received in competing LNG markets. For example, an LNG supplier is unlikely to dispatch a tanker to North America unless either (a) all of the alternative markets were fully supplied and the only remaining demand was in North America or (b) the market in North America was price competitive with other markets. Accordingly, LNG will act as a force to re-link oil and North American gas prices. (Kelly, 2008)

While Gas Strategies predicts that the current premium is not likely to continue, it believes that the Asian Pacific markets will continue to pay some premium over the Henry Hub price for LNG to ensure the security of its supplies because it does not enjoy the flexibility provided by the diversity of supplies and the significant gas storage facilities that exist in the United States. As a

[16] In actual fact prices will not rise to attract imports on a transactions basis. Rather, the widely-forecasted supply gap in North America will cause prices to rise, which in turn will create incentives for LNG suppliers to sell LNG into the North American market. Still, the effects are the same: it is “as if” North American consumers were paying a higher price to attract LNG cargoes.

result of these factors, Gas Strategies believes its projected Base Case price, which represents a moderate easing of the currently very tight market situation, is appropriate (Appendix I, Section 5.4).

Another driver behind that eventual convergence, independent of the fundamental commodity supply-demand relationship between LNG and natural gas, is the relative price of oil and North American natural gas. As the price of oil diverges from North American natural gas, resources—drilling rigs, geological and engineering expertise—are diverted from North American natural gas exploration and development to pursue more profitable oil opportunities. Given scarce expertise and equipment in the oil and gas sector, divergently high oil prices will tend to reduce resources devoted to developing North American gas. The result of the migration in exploration and development resources will be a reduction in North American natural gas reserves replacement. Depletion without replacement, again considering the relative inelasticity of North American natural gas demand, should begin to tilt the scales such that the value of domestic natural gas rises (Appendix G1, Section 7.15.4).

A detailed discussion of pricing relationships between North American gas and oil prices is contained in Black and Veatch's expert report (Appendix G1, Section 7.15.4). It concludes that, while the price relationship is uncertain, it is more likely that North American natural gas prices will tend to return to their historical average relationship with oil. If Black and Veatch, Gas Strategies, and Wood Mackenzie's views are correct, then the substantial current-day premium received for Asian LNG is likely to narrow significantly.

2. LNG Volumes

The second factor in the NPV calculation is volume. The primary LNG scenario addressed here has the same production volume used to analyze the TC Alaska Project Base Case. Gas volumes for the other LNG project options discussed above are summarized in Appendix G1, Sections 7.4, 7.5 and 7.6.

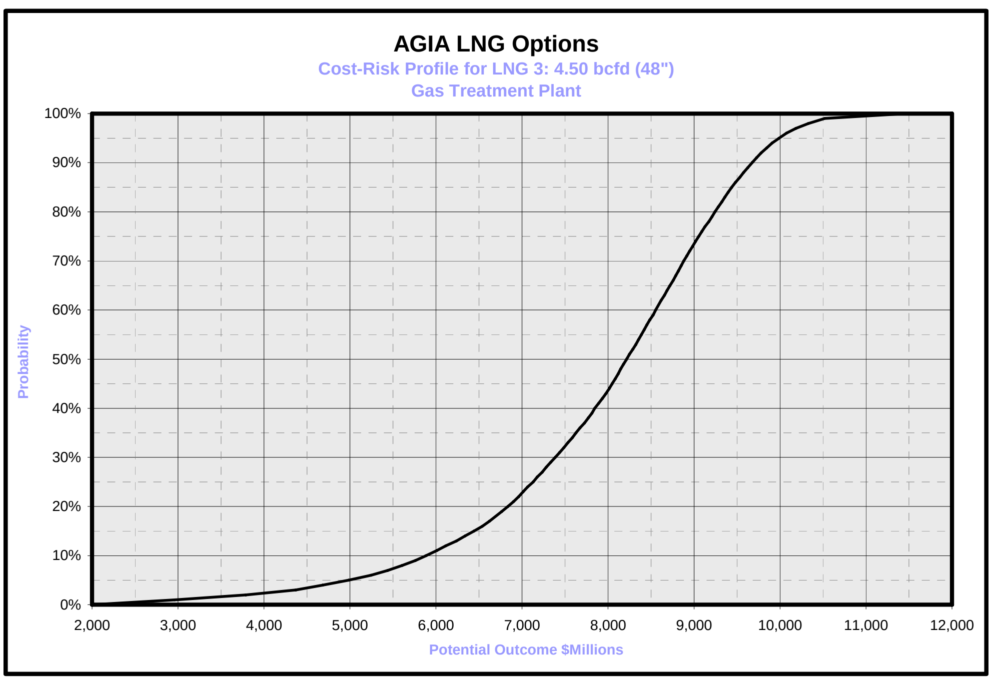
3. Costs and Schedule Related to LNG Scenarios

The third factor in the NPV calculation is cost. There are three main cost components for an Alaskan LNG project: (1) the cost of the pipeline and GTP; (2) the cost of the liquefaction plant in Alaska; and (3) the cost of tankers to transport the LNG to on the market.[17] Those three cost components are summarized below.

Pipeline and GTP Costs. The commissioners' Technical Team estimated a cost and schedule for the GTP and pipeline system (Appendix F, Exhibits B and C). For purposes of estimating the GTP and pipeline costs, the Technical Team used much of the data and analysis that it had already developed while analyzing the TC Alaska Project. This ensured that the GTP and pipeline components of LNG project options were, to the extent possible, based on the same cost assumptions used to analyze the TC Alaska Project (Appendix F, Sections 2.2, 2.3, and Exhibit B). Those data were used in the Technical Team's Monte Carlo simulation; the results of that process were provided to the Commercial Team for its NPV analysis of each scenario.

For the 4.5 LNG Base Case, the current-dollar GTP costs are essentially the same as for the TC Alaska Application (Appendix F, Addendum A Sections 2.2 & 2.3; LNG Options Analysis Exhibit D).

Figure 4-6. Cost-Risk Profile for the LNG Base Case GTP Plant Construction

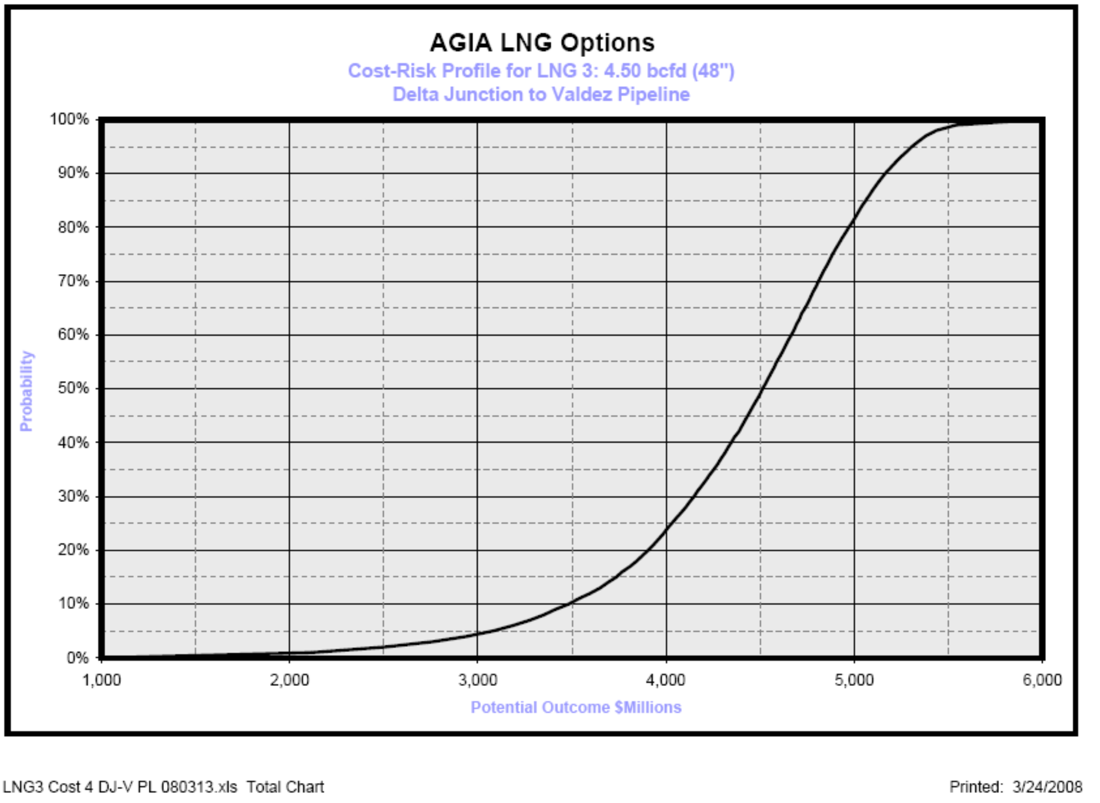


Source: Westney 2008. Appendix F, Addendum A.

[17] The state's NPV analysis of LNG project options modeled LNG prices into the regasification terminal; accordingly, there is no need to consider regasification costs in the "net back" calculation.

For NPV modeling purposes, cost ranges for the pipeline subprojects for the LNG project options are, on a per mile basis, essentially the same as that of the Alaska portion of TC Alaska's pipeline subproject. The Monte Carlo based probability distributions of pipeline costs for the Delta Junction to Valdez pipeline subproject are shown below.

Figure 4-7. Cost-Risk Profile for the LNG Base Case Delta Junction to Valdez Pipeline Construction



Source: Westney 2008. Appendix F, Addendum A.

<u>Liquefaction Plant Costs.</u> The process of establishing a probability distribution for the liquefaction plant differed somewhat from that used for the GTP and pipeline subprojects. The Technical Team did not have an AGIA-compliant application to directly evaluate regarding the cost of the liquefaction. Accordingly, they could not follow the process used to generate Monte

Carlo probability distributions for the pipeline and GTP (Appendix F, Addendum A, Section 2.4).[18]

Therefore, rather than trying to generate a probability distribution of costs from the "bottom up," based on subproject cost components, their ranges, and their probability distributions, the Technical Team chose to generate a cost estimate from the "top down." That is, the approach relied on existing data on liquefaction costs from actual projects around the world to generate a representative distribution of liquefaction costs per ton for an Alaskan LNG project.

As a first step, the Technical Team mined data contained in the Westney proprietary data base that shows the costs per ton of LNG output for several recently constructed and operating LNG plants. These liquefaction plants vary in size from about 3.25 million tons per annum (mtpa) to 8.9 mtpa (0.42 Bcf/d to 1.16 Bcf/d), and went into service between 2003 and 2007 (or are currently under construction).[19] The cost per ton of LNG for these plants ranges from a low of less than \$350 to over \$1,300 for the Snohvit project in Norway (Appendix F, Addendum A, Section 2.4).

Because the projects were constructed at different times, cost components for each LNG plant (*e.g.,* compressors, vessels, pipe, electrical, etc.) were reviewed on a commodity basis and then escalated to 2007 dollars. Because the projects in the data set are generally located in developing countries and in tropical climates, each project cost was adjusted to an Alaska basis for the costs of construction (i.e., using projected labor rates and productivity factors for Alaska). Finally, the highest and lowest costs of liquefaction were excluded from the Westney data set as being unrepresentative. The remaining data were then reviewed and confirmed against the global LNG data base of Merlin Associates (Appendix F, Addendum A, Section 2.4).

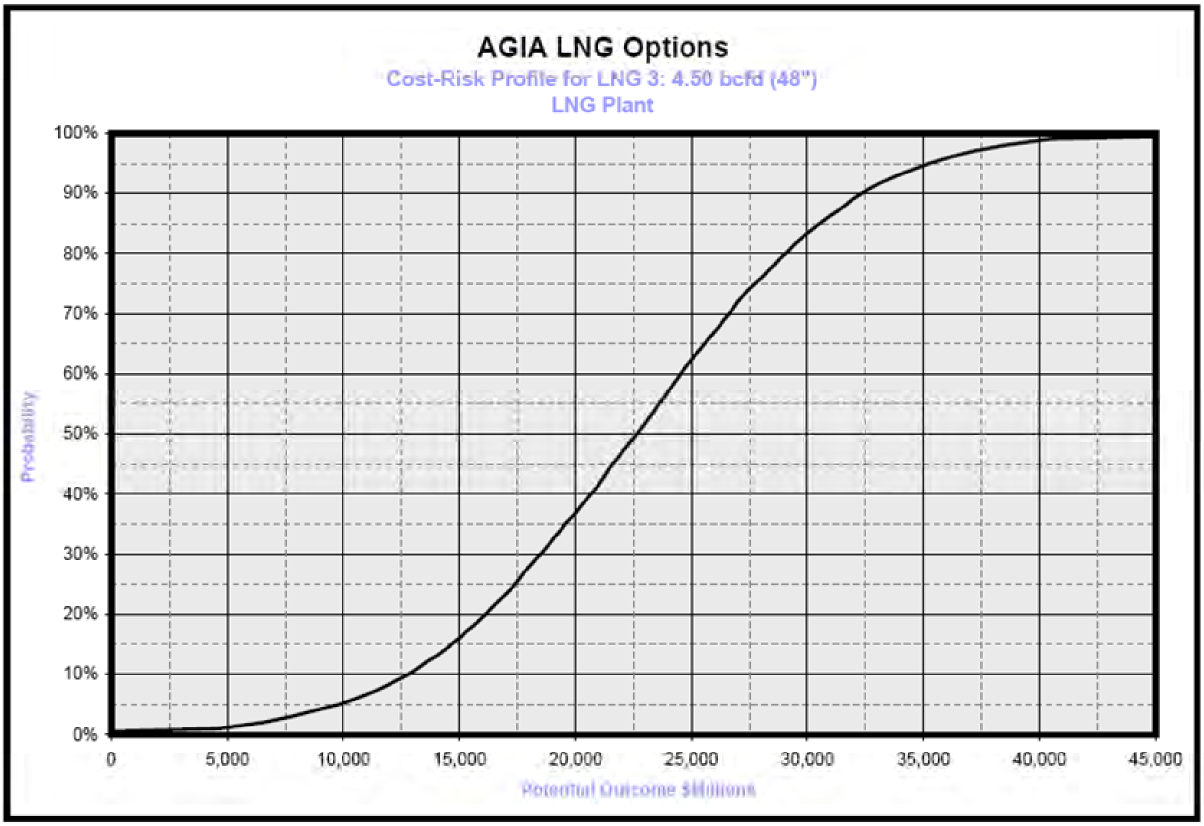
Based on an adjusted data set of liquefaction costs, the best cost case and the worst cost case were used, together with an assumed normal (or "bell shaped") probability distribution, to generate a full probability distribution of Alaskan per ton liquefaction costs. The train sizes for the relevant LNG case under consideration then determined the entire Monte Carlo-based

[18] For the TC Alaska subproject cost estimates, the Technical Team started with "base case" cost estimates of the major components. These were used to establish an overall Monte Carlo based probability distribution based on separate "best" and "worst" case ranges of each of the major cost components and distributions. This process could not be followed for the liquefaction estimate in part because, absent an AGIA-compliant applicant, there was no ability to engage in the necessary clarification process of estimates and assumptions.

[19] One mmtpa of LNG is approximately equivalent to 140 MMcf per day of gas.

probability distribution for the liquefaction plant costs. The result for the 4.5 Bcf/day LNG project is shown below.

Figure 4-8. Cost-Risk Profile for the LNG Base Case LNG Plant Construction



Source: Westney 2008. Appendix F, Addendum A.

Figure 4-8 indicates that the midpoint (or "P50") probability cost of the LNG liquefaction plant is approximately $22.5 billion. The entire range of possible costs is very wide. This is due both to the location and unusual market conditions that have affected liquefaction plant costs for the data set used to assess plant cost risks. But it is also due to the fact that liquefaction plants are quite complex (See discussion in Appendix F, Section 2.4). Because the cost range is wide, the Technical Team recommends that the middle 50% of the probability range—excluding the top 25% and bottom 25% of costs—provides a more useful lens for considering project cost risk. This generates a range of $17.5 billion to $27.5 billion.

Liquefaction cost ranges for other LNG project configurations are summarized in the following table.[20]

Table 4-1. Liquefaction Plant Cost Ranges

Cases	LNG Volume	P25 Value (75% probability of exceeding value)	P75 Value (75% probability of not exceeding value)
2.7 Bcf/day	19 mmtpa	$10.8B	$17.6B
	(2.45 Bcfd)	568 $/T	926 $/T
2.7 Bcf/day Expansion Option	31.5	$17.4B	$27.9B
	(4.06 Bcfd)	552 $/T	885 $/T
Y Line Option	13.9	$8.1B	$13.7B
	(1.79 Bcfd)	582 $/T	985 $/T
4.5 Bcf/day	31.5	$17.4B	$27.9B
	(4.06 Bcfd)	552 $/T	885 $/T

Source: Westney Consulting. Appendix F, Addendum A, Section 2.4.

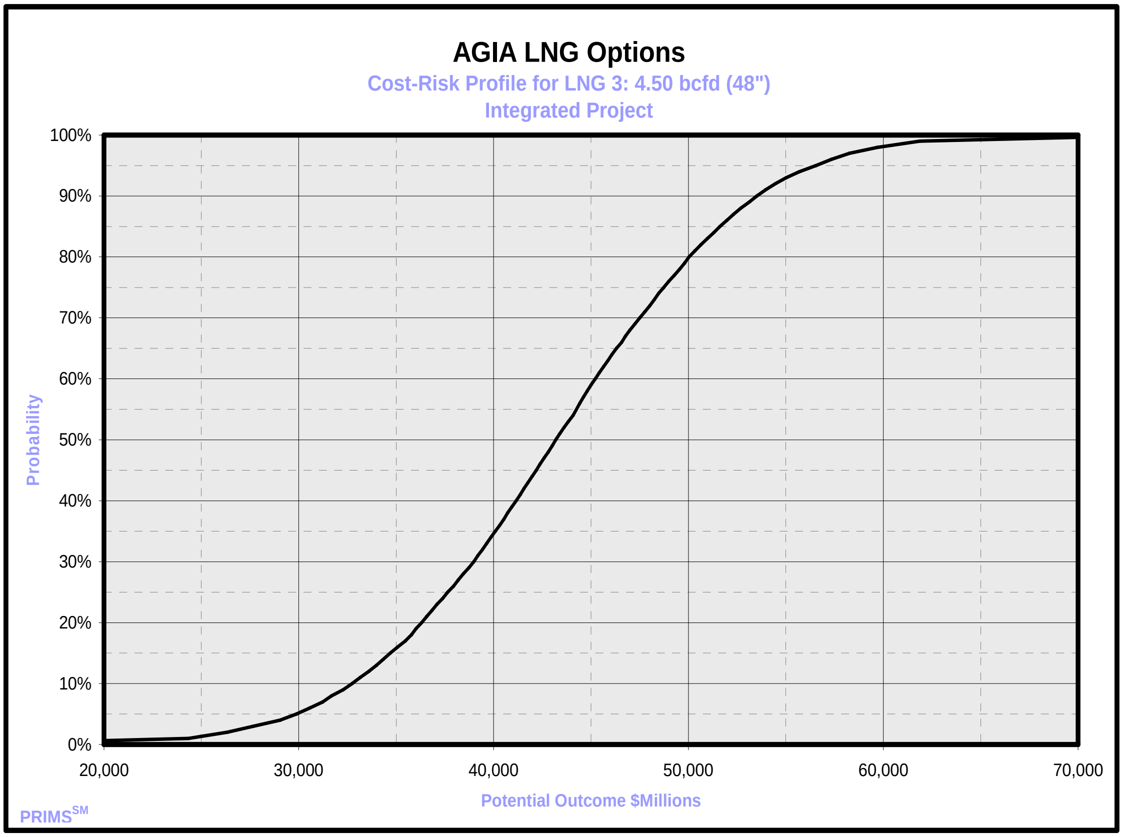
At "P25" there is a 25% likelihood that the actual costs could be lower than stated; at "P75" there is 75% likelihood that the costs would be lower than stated.[21]

Putting all of the pieces together, the risk distribution of the integrated capital costs of a 4.5 Bcf/day project are shown below.

[20] The volumes of each of these cases assume no natural gas liquids ("NGL") extraction, in order to meet the minimum quality requirements of the Asian Pacific markets which is consistent with the market analysis of Gas Strategies (Appendix I, Section 2). However, the Technical Team determined that propane in the quantity required to supply the current and near-term future market in Alaska can be extracted without significant reduction of either the volumes or heating value of LNG. (Appendix F, Addendum A, Section 2.4)

[21] As an additional point of reference, the Port Authority and Little Susitna applications estimated the cost per ton of liquefaction capacity at approximately $550 and $520 respectively, which put them very close to the P25 estimates above. These estimates included a reasonable allocation of their estimated overhead and related costs to facilitate a fair comparison.

Figure 4-9. Execution Cost Probability Distribution for a 4.5 Bcf/d Integrated LNG Project



Source: Westney 2008. Appendix F, Addendum A.

Not including the development schedule, the figure indicates that the mid-point (P50) cost estimate is approximately $43 billion in current dollars. There is less than a 10% probability that costs will be below $32.5 billion.

Schedule

The process for assessing project schedule risk for the pipeline and GTP subproject components was the same as used for the analysis for the TC Alaska project except for the risks associated with the Canadian regulatory process. To assess schedule risk for the liquefaction plant, the Technical Team analyzed the number of LNG trains that would be needed for the entire project at the largest size commercially available (so as to obtain the greatest economic efficiency and minimize the overall installation time and expense).[22] This analysis

[22] An "LNG train" is a complete process unit that turns natural gas into a liquid. The "train" consists of a collection of sub-units and equipment that cleans, compresses and cools natural gas into a liquid. The exact mix of sub-units and

was predicated on the fact that there is a necessary lag between the completion of one train and the time that a follow-up train can be completed. This is because of the necessity to ensure that all of the systems for the first train are fully operational on an integrated basis before adding another train. For purposes of the analysis it was also assumed that three months was the shortest period that could reasonably be expected between completion and a train being fully operational (even though it is likely that a longer period would be necessary; see Appendix F, Addendum A, Section 2.4). The schedule range based on the number of trains was used in the Technical Team's Monte Carlo simulation and the results provided to the Commercial Team for conducting the NPV analysis of the various cases (See Appendix F, Addendum A, Section 1.1).

A comparison of the "P50" schedule for the 4.5 Bcf/d LNG case and the 4.5 Bcf/d TC Alaska Project Base Case shows that the LNG project will require approximately two additional years before the in-service date or before first gas flows. There are two primary factors behind this delay. First, it was assumed that a new state process—including, possibly, a new round of applications under AGIA—would be required for an LNG project, because it was assumed that an LNG project sponsor would require some type of state support to advance the project. This was assumed to push the start date for an LNG project back by one year to provide time for (1) an LNG project sponsor to prepare and submit a new application or proposal to the state and (2) the administration and legislature to review, analyze and approve the granting of an AGIA license. The second factor affecting the timing of an LNG project is the additional time needed to complete and place the multiple LNG trains required for a 4.5 Bcf/d project into service.

Tanker Costs. Tanker costs are a significant component of an LNG project. Gas Strategies estimated that, based upon extrapolations from existing shipping rates, total shipping would come to 99 cents/MMBtu (expressed in real dollars) (See Appendix I, Section 5.8 for discussion).[23] This component is included in the comparison of the estimated cash flow and NPV that would be produced by the TC Alaska Project and the LNG project options (Appendix G1, Sections 1.1 and 7.1).

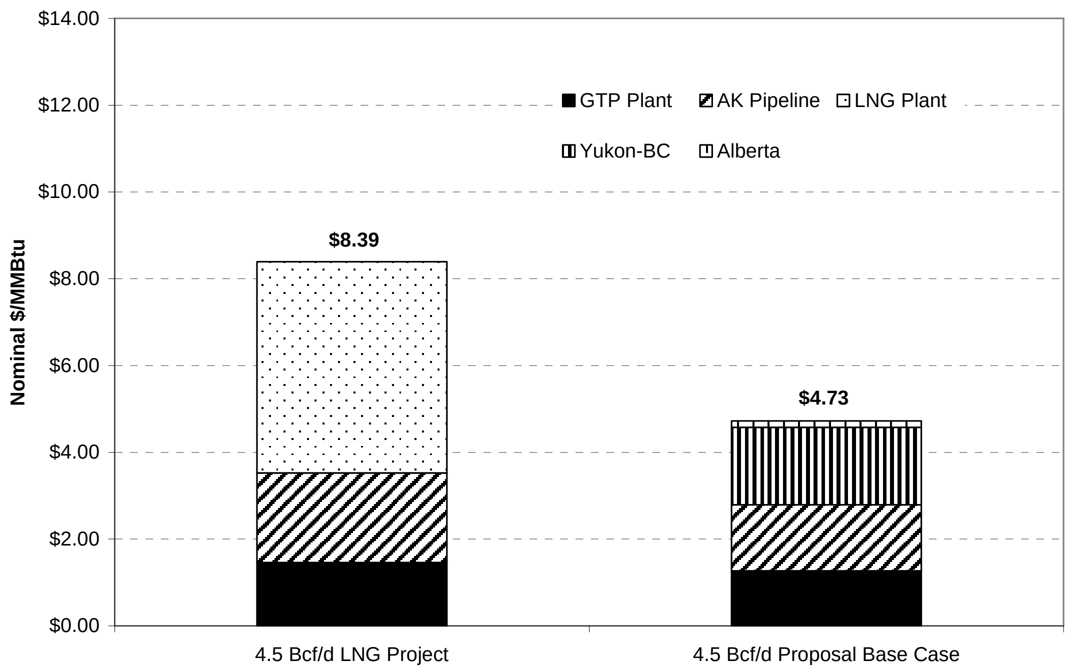
equipment varies depending on which proprietary technology is used. An LNG plant consists of one or more "trains" plus support facilities such as utilities, storage tanks and jetties.

[23] Gas Strategies assumed somewhat larger sized tankers than did the AGIA applicants proposing LNG projects. (See, e.g. LSCC AGIA Application at p. 58). Accordingly, the tanker costs assumed here are on the conservative side.

4. Comparison of LNG and TC Alaska Costs and Tariffs

Based on the Technical Team's cost and schedule projections, a hypothetical levelized rate (or tariff) was constructed for each LNG option.[24] The costs to move gas from the North Slope to Valdez, including the cost of liquefaction at Valdez, would be significantly higher than the costs to transport gas from the North Slope to Alberta, even without considering the costs of shipping the LNG in tankers from Valdez to the Asian market. This is because the LNG options require a capital-intensive liquefaction facility. As shown in the chart below, there is a $3.66 per MMBtu cost difference between the LNG pipeline, GTP and liquefaction costs for a 4.5 Bcf/day LNG scenario and a 4.5 Bcf/day pipeline to Alberta (The TC Alaska Proposal Base Case).

Figure 4-10. Tariff Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case



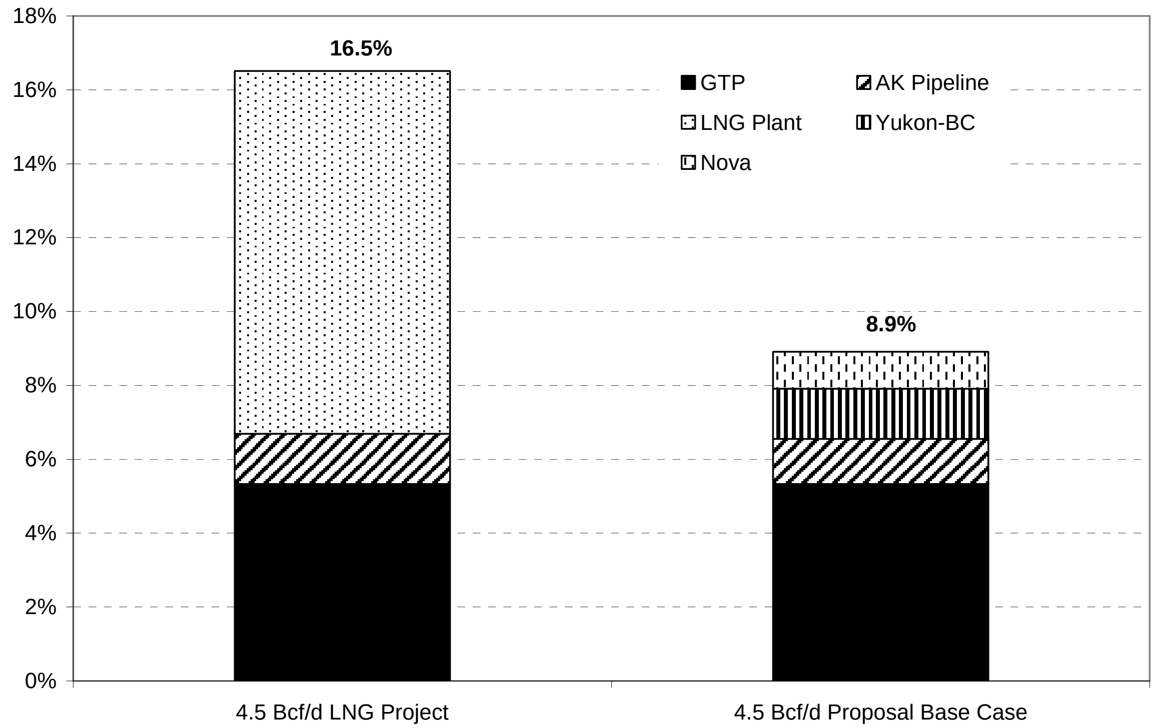
Source: Black and Veatch. Appendix G.1, Figure C-2.

In addition, these costs do not include the substantial amount of shrinkage associated with LNG liquefaction. Making LNG consumes substantial volumes of natural gas, which reduces the amount of gas (or LNG) that is available for sale. As shown in the chart below (Figure 4-11), the

[24] In fact, the costs would be recovered in potentially different charges reflecting the GTP, Alaska pipeline, and liquefaction segments. They are presented here as a single hypothetical cost-based tariff charge to simplify the presentation.

difference in shrinkage between a 4.5 Bcf/day pipeline to Alberta and a 4.5 Bcf/day LNG project is material: 8.9% for the TC Project pipeline to Alberta line versus 16.5% for an LNG project.

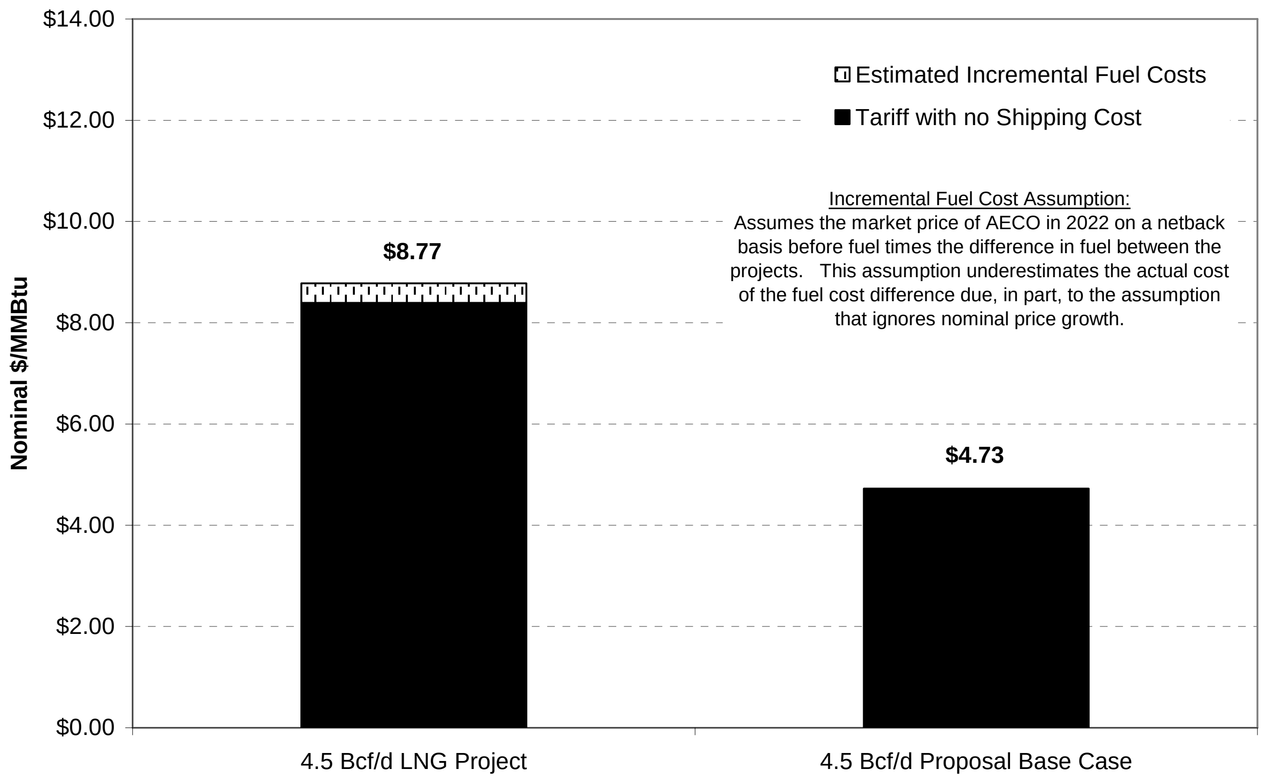
Figure 4-11. Fuel Loss Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case



Source: Black and Veatch. Appendix G.1, Figure C-3.

In essence, an additional 7.6% of the original gas volume is lost in the transportation and manufacture of LNG versus the TC Alaska pipeline. The value of this incremental 7.6% depends, of course, on how the gas is valued. If it is valued against the AECO price, then the lost gas is calculated as the AECO net back multiplied by 7.6%. Figure 4-12 compares the TC Alaska Project's per unit transportation cost with the LNG project cost to Valdez, including the cost of incremental fuel "lost" to manufacturing the LNG.

Figure 4-12. Tariff Comparison Including Estimated Incremental Fuel Costs: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case

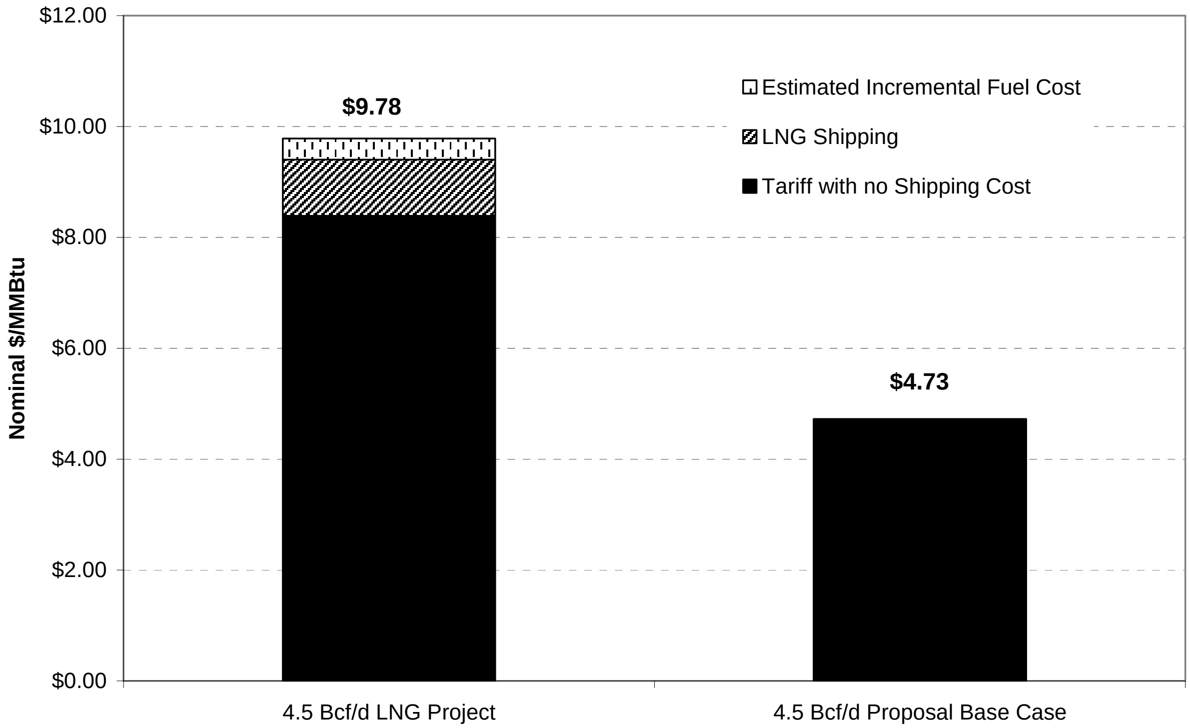


Source: Black and Veatch. Appendix G.1, Figure C-4.

This increases the cost of the LNG project by $.37/MMBtu.

Additional costs associated with shipping LNG to market through LNG tankers must be included. Gas Strategies estimates that LNG tanker and receiving port charges add up to an additional cost of approximately $0.99 per MMBtu (in real, 2008 dollars) of LNG shipped (Appendix I, Section 5.8). As shown on the chart below (Figure 4-13), this increases the cost advantage that the TC Alaska Project has over the LNG project options.

Figure 4-13. Tariff with Incremental Fuel Costs and Shipping Costs



Source: Black and Veatch. Appendix G.1, Figure C-5.

Based on the information presented above, the commissioners conclude that a cost-of-service based tariff for the 4.5 Bcf/d LNG project would be significantly higher than a 4.5 Bcf/d pipeline project to the AECO Hub (Appendix G1, Section 7).[25]

Indeed, under Base Case assumptions, the transportation cost for a 4.5 Bcf/d project into AECO is less than half the cost (48%) that of the LNG project (Appendix G1, Sections 1.1 and 7.3).[26] This is perhaps surprising, given that difference in the integrated project construction cost, in current dollars, between the TC Alaska project and the LNG project is 38%. Factors that lead to a disproportionately higher LNG tariff include the following:

[25] Of course, there may be no tariff for a liquefaction plant. Moreover, open access tolling for liquefaction is not the model, worldwide, for LNG projects (Appendix I, Section 7.8). However, for royalty and tax calculations a liquefaction deduction would be required. The numbers used here reasonably approximate what those deductions might be. If anything, these figures are conservative as they presume a capital structure for tariff calculation purposes.

[26] Critical assumptions, such as cost escalation and inflation, were held constant across the two cases to permit an "apples to apples" comparison.

1) Project capital costs. The capital costs of a 4.5 Bcf/d LNG project are $12.0 billion greater than the costs of constructing a similarly-sized pipeline project to the AECO Hub. Holding everything else between the LNG option and the TC Alaska Project fixed, the greater cost increases the LNG project tariff by $1.97/MMBtu relative to the pipeline project.

2) Volumes delivered to market (fuel losses). The fuel usage/retention of a 4.5 Bcf/d AECO pipeline project is 8.91%, compared with the similarly sized LNG project of 16.5%. Based on the Base Case price assumption from Wood Mackenzie and the Base Case Gas Strategies LNG price, this results in an approximately $0.38/MMBtu increase in the LNG tariff (assuming a 2020 start date).

3) Operations and Maintenance costs. Operations and Maintenance costs for an LNG project will be significantly greater than a pipeline project, owing to the significantly greater complexity of the liquefaction plant. The expected impact to the LNG tariff rates from these higher expenses is $0.36/MMBtu.[27]

4) Property taxes. Property taxes for an LNG project are higher due predominantly to the higher installed capital value of the liquefaction plant.[28] This further raises the LNG tariff by about $0.30/MMBtu.

5) Later in-service date. The Technical Team estimates that an additional two years (for a P50 case) is expected for completion of an LNG project. The rising cost of manufacture coupled with the delay has a negative impact on all sections of the project. The LNG tariff is expected to be $0.11/MMBtu higher due to the GTP delay, $0.16/MMBtu higher due to the pipeline project delay, and $0.36/MMBtu higher due to the liquefaction/terminal facility delay.

6) Interest rate for debt. An LNG project serving Asian markets will probably not qualify for the Federal Loan Guarantee provided under the ANGPA statute.[29] Accordingly, the LNG project will have a higher cost of debt. A higher cost of debt on the project, as assessed

[27] See Appendix F, Addendum A LNG Options Analysis, p. 64 for base line costs, derived from study at pp. 109-113; see Appendix G1 for explanation of how total O&M costs were converted to per unit terms.

[28] In addition, property taxes on the LNG project are greater because a greater percentage of the project is in Alaska and Alaska has a greater tax rate than do Canadian provinces.

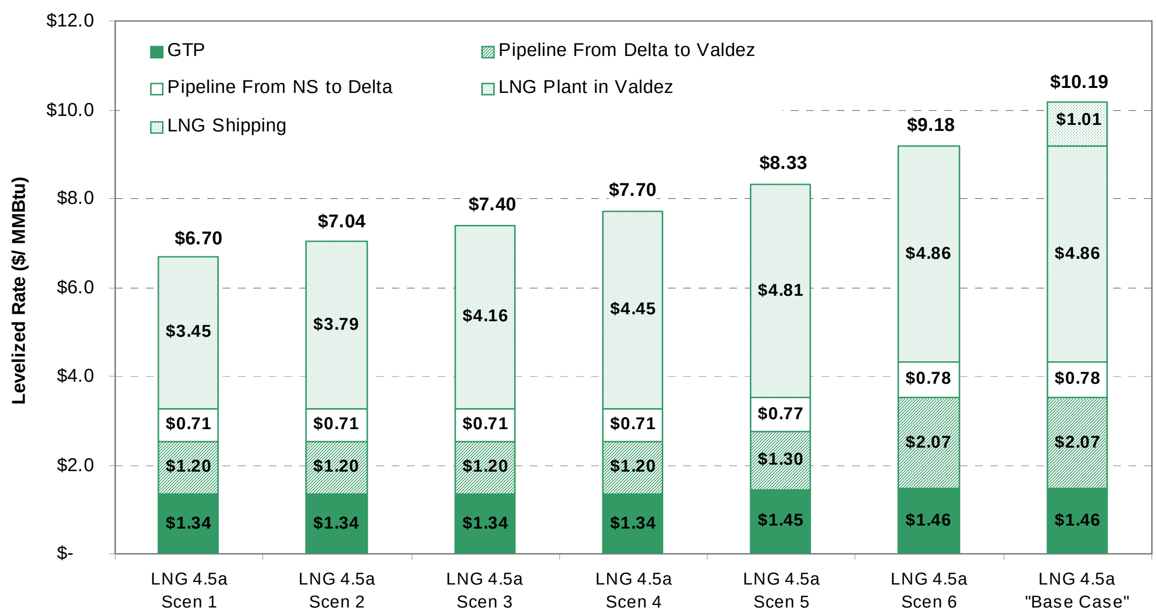
[29] The Port Authority's AGIA application recognized that this would likely be the case: "because the project is an export project the Port Authority has not counted on qualifying for federal loan guarantees under the Alaska Natural Gas Pipeline Act of 2004" (AGPA, 2007)

by Goldman Sachs, is estimated to have an adverse impact on the LNG tariff relative to the TC Alaska Project (Appendix H, Section VI.C). The size of this impact depends on which cases are being compared.

7) Shipping costs. The cost of shipping would be approximately $0.99 per MMbtu (Appendix I, section 5.8).

Figure 4-14 shows how these factors build to ultimately make up the full tariff. The first bar shows the different tariffs for different components of the transportation chain that results from the 4.5 Bcf/d LNG project costs, not accounting for any of the other factors. The second bar adds in the effects of the increased LNG shrinkage at the liquefaction plant. The third through seventh bars progressively add in the effects of higher LNG O&M costs, higher property taxes, delayed in-service date, higher borrowing costs, and the requirement to ship the LNG from Valdez to Asian Pacific markets.

Figure 4-14. Tariff Build Up



Scenario Settings

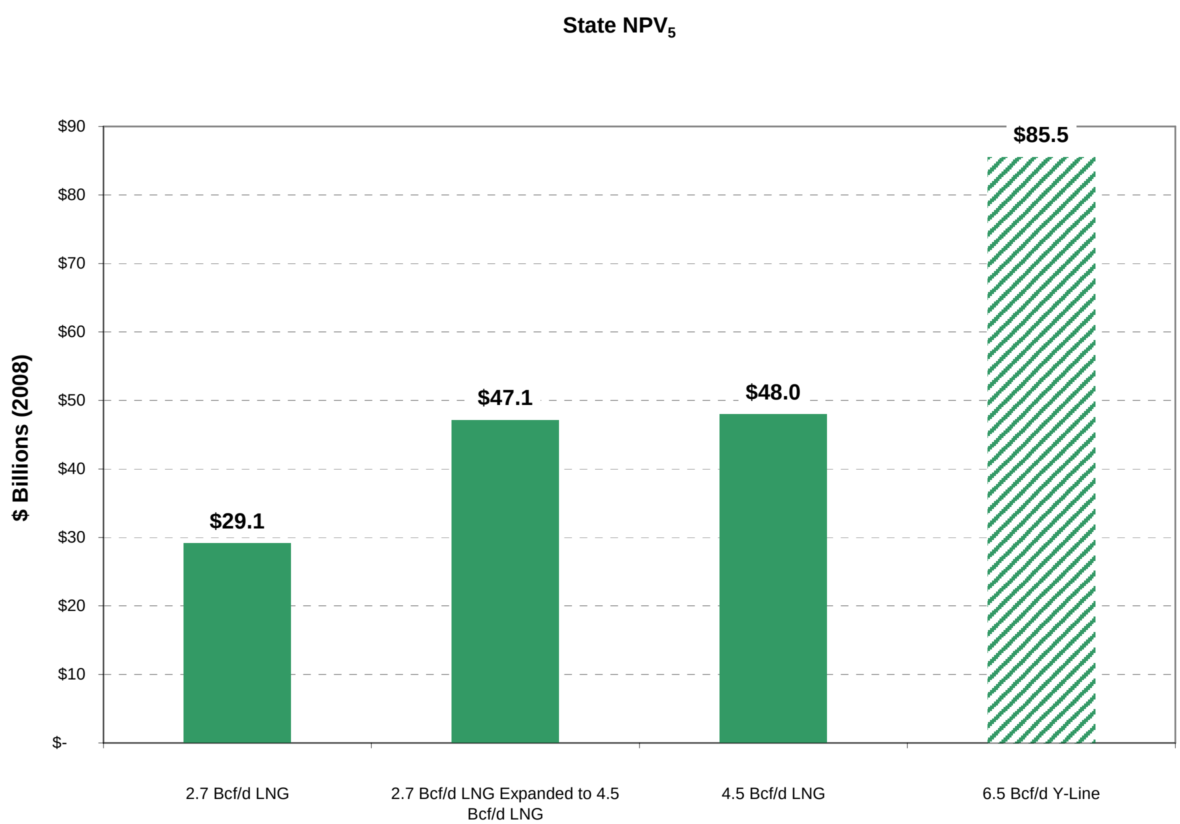
Capital Costs in 08 Dollars	$43,253	$43,253	$43,253	$43,253	$43,253	$43,253	$43,254
Case Volume	Same as AECO	LNG Volumes	LNG Volumes	LNG Volumes	LNG Volumes	LNG Volumes	LNG Volumes
O&M	Same as AECO	Same as AECO	LNG O&M	LNG O&M	LNG O&M	LNG O&M	LNG O&M
Property Tax	Same as AECO	Same as AECO	Same as AECO	LNG Property Tax	LNG Property Tax	LNG Property Tax	LNG Property Tax
In-Service Year	2020	2020	2020	2020	2022	2022	2022
Interest Rate	7.06%	7.06%	7.06%	7.06%	7.06%	7.18%	7.18%
LNG Shipping	N/A	N/A	N/A	N/A	N/A	N/A	$1.01

Source: Black and Veatch. Appendix G1, Section 7.8.3.

5. Estimated State NPV_5

Despite the increased costs associated with transporting, liquefying, and shipping LNG, each of the LNG options reviewed could produce a positive NPV_5 for the state and for the Major North Slope Producers.[30] For example, under the Base Case set of assumptions, a 4.5 Bcf/day, 48-inch diameter pipeline LNG project would produce an NPV to the state of approximately $48 billion, and a NPV to the Major North Slope Producers of approximately $8.6 billion (Appendix G1, Section 7.11). The NPV results to the state for each of the LNG project options, using Base Case assumptions for contract terms, costs, escalation rates, and the like, are summarized in Figure 4-15.

Figure 4-15. State Net Present Value Under Different LNG Project Configurations



Source: Black and Veatch. Appendix G1, Figure C-6.

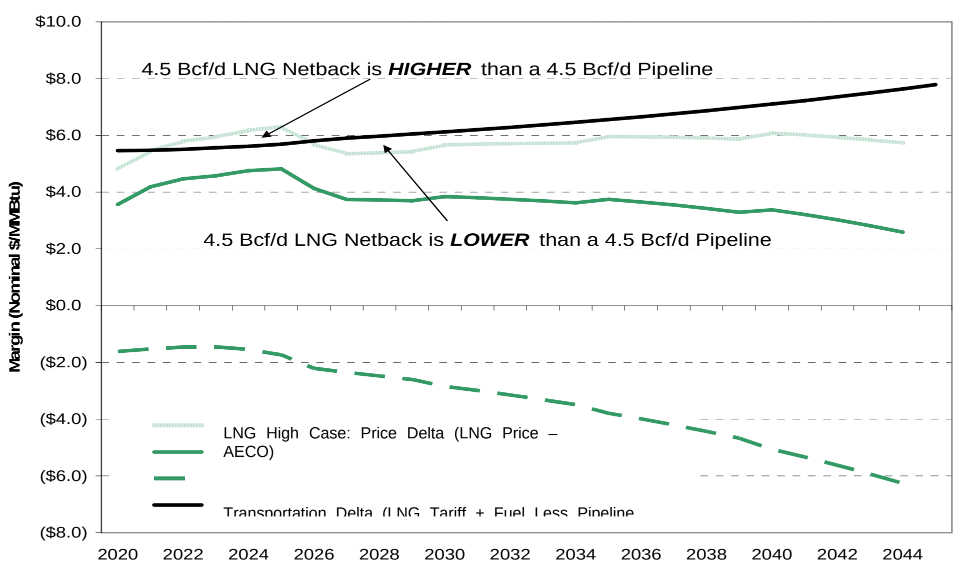
[30] "NPV_5" refers to the NPV calculated using a 5% discount rate.

In sum, although the LNG project options have higher costs than the overland project options, they would still produce a positive NPV under the pricing and cost assumptions discussed above.[31] Because of the likely need to ramp up volumes over an eight to ten year period, rather than the 3 year period assumed in the 2.7 to 4.5 Bcf/d expansion case, the actual configuration of a stand-alone LNG project is likely to provide an NPV_5 of somewhere between the two left-most cases in Figure 4-15.

6. Comparison of Estimated NPVs Produced by the TC Alaska Project and the LNG Options

Under Base Case assumptions for the TC Alaska Project and the LNG options, the TC Alaska Project Base Case has a higher estimated NPV than the LNG options (Appendix G1, Section 7.12.2). In general, this is because the price premium that LNG is likely to enjoy in Asian Pacific markets, relative to prices at the AECO Hub, is generally insufficient to overcome the greater total costs of transporting the LNG to market. This dynamic is graphically shown in Figure 4-16. The black line shows the LNG price level necessary for the LNG project to deliver superior net backs compared to the TC Alaska Proposal Base Case.

Figure 4-16. Margins of LNG Project versus a Pipeline Project



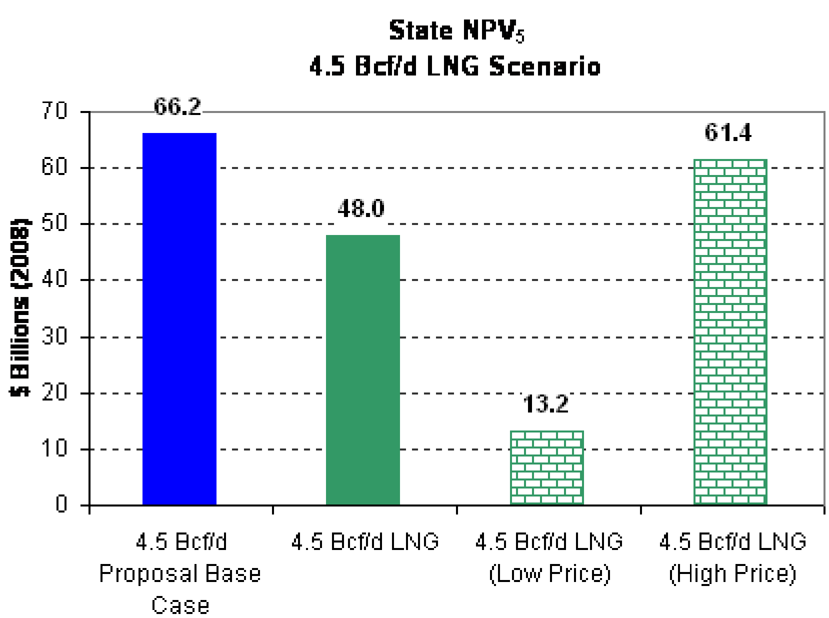
Source: Black and Veatch. Appendix G1, Section 7.12.2.

[31] As with the TC Alaska Project, the estimated NPVs would improve or decline if more optimistic or pessimistic assumptions are used.

Under the high contract price scenario (see Figure 4-16, for the price formula), there are a few years in which the Asian Pacific LNG market is sufficient to overcome the higher transportation costs. However, even in this unlikely High contract price case (Appendix I, Section 5.5), net backs are generally lower than under the TC Alaska Proposal Base Case. Under the Base and Low contract cases net backs never exceed those provided by the TC Alaska Proposal Base Case.

As a result, the TC Alaska Proposal Base Case generates a higher NPV_5 than the comparable Base Case LNG project option under each contract price assumption. This conclusion is depicted in the chart below (Figure 4-17):

Figure 4-17. State NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions

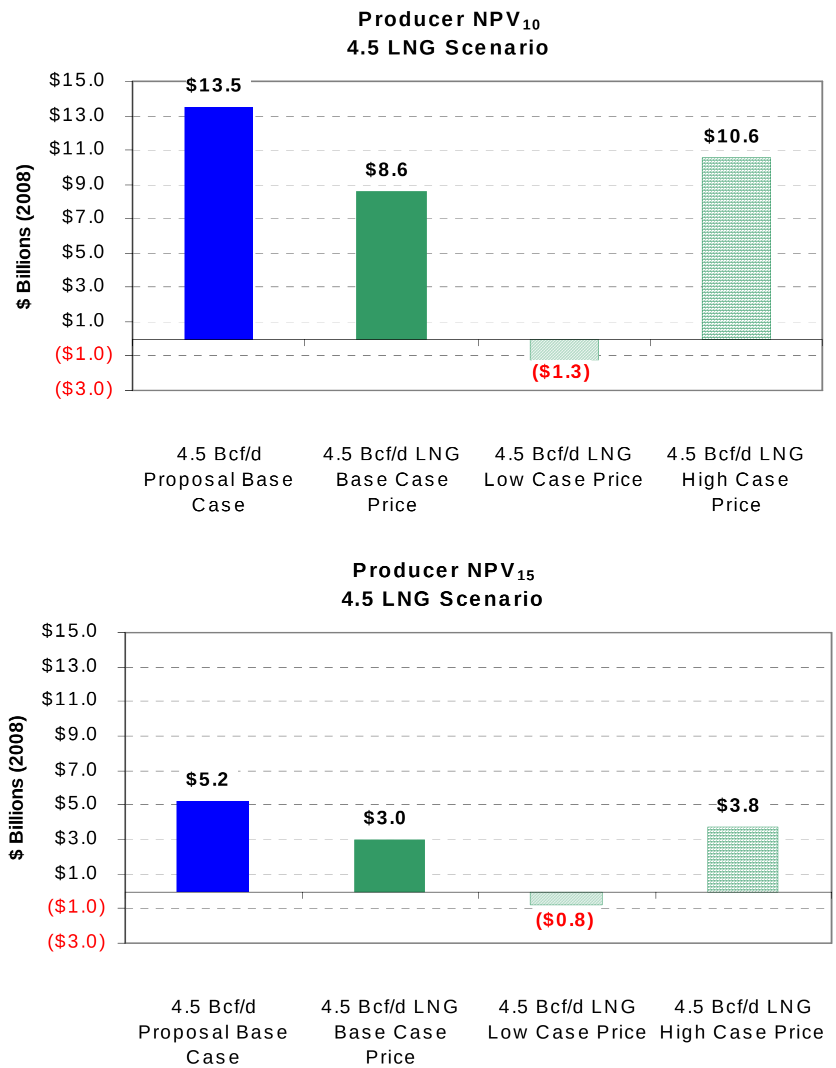


Source: Black and Veatch. Appendix G1, Section 7.12.3.

Figure 4-17 demonstrates that the TC Alaska Project would produce a significantly higher NPV for the State of Alaska than the LNG project across a range of long-term LNG contract arrangements. Under the Base Case set of assumptions, the LNG project would generate for the state an NPV_5 of approximately $48 billion, while the TC Alaska Project would produce a NPV_5 of approximately $66 billion.

The results are directionally similar for the Major North Slope Producers. Under Base Case assumptions, the NPV to the Producers, at both 10 and 15% discount rates, are greater under the TC Alaska Project than under the 4.5 Bcf/d LNG option. Indeed, for the Low Contract price case, the LNG option fails to deliver positive returns to the producers.[32]

Figure 4-18. Major North Slope Producers' NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions

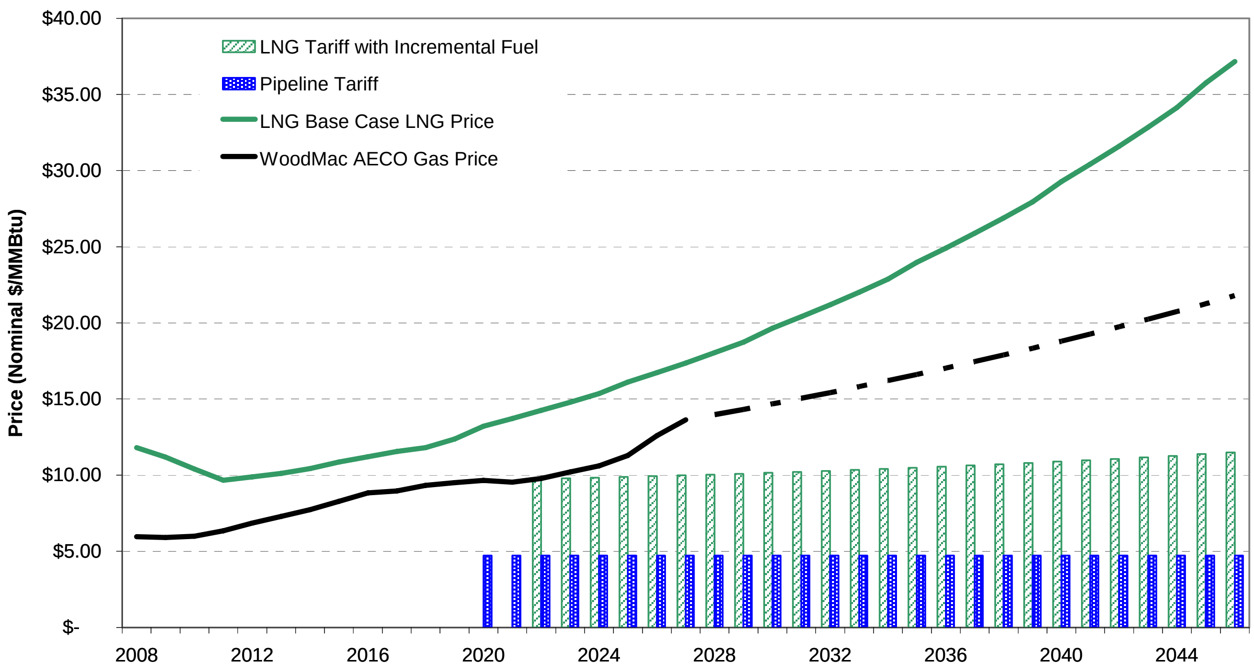


Source: Black and Veatch. Appendix G1, Section 7.12.3.

[32] This result differs directionally from the state's results for several reasons. For one, the state receives property taxes and corporate income taxes from the pipeline and liquefaction projects, while these are net costs for the Producers. In addition, both 4.5 Bcf/d cases significantly rely upon YTF resources. As modeled, under base case assumptions, YTF gas is found, developed and produced to enter the projects to keep them full, regardless of their economics. Because margins under the Low Price contract assumption are poor, the damage to YTF economics serves as a drag on Producer NPVs.

In addition, because LNG transportation costs are higher, the LNG project options considered are more susceptible than TC Alaska's Proposal Base Case to price risk. For a given net back margin, it takes a smaller percentage decrease in Asian Pacific LNG prices to stress an LNG project than it does to stress an overland pipeline project. This result can be visually inferred from Figure 4-19. A 50% drop in the price of LNG prices (the green line) "bites into" the LNG transportation cost (green bars) and thus leads to greater negative net backs than a 50% price drop in AECO Hub prices (the black line) "bites into" overland transportation costs (blue bars).

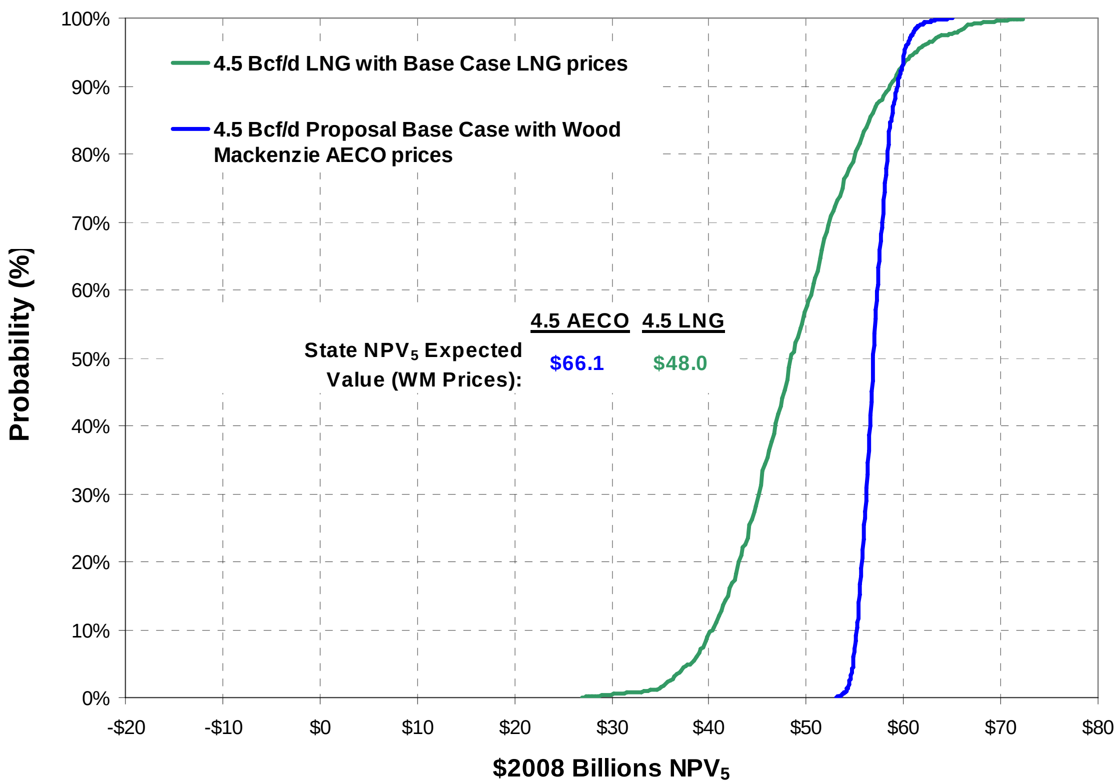
Figure 4-19. Price vs. Tariff for a 4.5 Bcf/d LNG Project and the 4.5 Bcf/d Proposal Base Case Pipeline Project



Source: Black and Veatch. Appendix G1, Section 7.12.1.

The analyses presented here are premised on both the TC Alaska and LNG cases coming in at mid-point probability (P50) cost levels. If costs for an LNG project come in lower than expected, then it would be better able to benefit from the expected higher Asian Pacific LNG prices. Figure 4-20 shows the state NPV_5 probability distribution that is generated from Base Case prices (for both LNG and the TC Alaska Project) and uncertain project costs. It shows the NPV uncertainty that derives from cost uncertainty associated with project scope.[33]

Figure 4-20. Comparative State NPV_5 Distributions Associated with Project Cost Risk



Source: Black and Veatch. Appendix G1, Section 7.12.2.

Figure 4-20 shows that under the Base Case price assumption, there is less than a 10% likelihood that LNG project costs would be low enough for the LNG Base Case NPV_5 to exceed the NPV_5 of a TC Alaska 4.5 Bcf/d project.

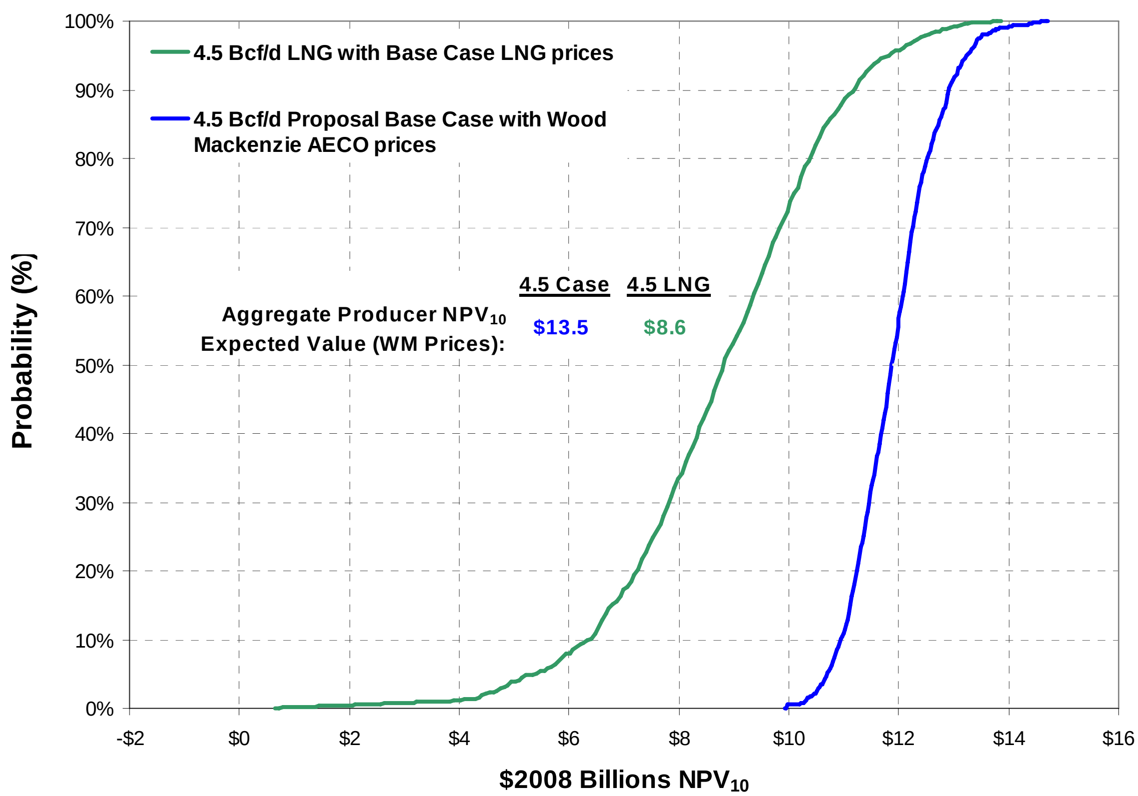
Similar results hold for comparative returns to the Major North Slope Producers from the 4.5 Bcf/d LNG project and a 4.5 Bcf/d pipeline project into Alberta.

There is essentially no chance that construction costs, as measured in current-day dollars and before figuring escalation risk, could be low enough to make an LNG project more profitable for

[33] Uncertainty of the cost escalation in inputs to construction, such as labor, steel, and the like, is addressed subsequently.

the Major North Slope Producers under the Base Case Contract price assumptions. This may help explain why, since at least 2001, the Major North Slope Producers have demonstrated so little interest in pursuing an LNG project for Alaska gas.

Figure 4-21. Comparative Producer NPV_{10} Distributions Associated with Project Cost Risk



Source: Black and Veatch. Appendix G1, Section 7.12.2.

There is another way, besides beating the odds on construction costs, that the 4.5 Bcf/d LNG project could provide better returns to the state than the TC Alaska Project's Base Case. As noted earlier, the extent to which Base Case or High Case contract terms yield an Asian LNG price premium depends significantly on the relationship of the price of oil, on an energy equivalent basis, to the price of gas in North America. As the oil to gas price ratio rises, the price premium generated by the Asian Pacific Base and High Case LNG contracts also rises. Accordingly, a high oil to gas price ratio could improve the relative economics of an LNG project. (See Appendix G1, Section 7.15.4, for a discussion of these points.)

Table 4-2 calculates the NPV difference to the state that would be provided by a 4.5 Bcf/d LNG project compared with the TC Alaska Project Base Case. It shows these differences under different assumptions about the oil to gas price ratio during the projected period of project operations. It indicates that, if the oil to gas ratio was sustained at ten or above, an LNG project of this magnitude could generate superior returns to the state as compared with an overland project.[34]

Table 4-2. Stakeholder NPV for 4.5 LNG Project Under Alternative Scenarios-Base Case LNG

Scenario 4.5 Bcf/d LNG Project	**State** NPV_5	**U.S. Government** NPV_5	**Producer** NPV_{10}	**Producer** NPV_{15}
4.5 Bcf/d Base Pipeline Case NPV	$66.1	$30.5	$13.5	$5.2
Base Case LNG Price	($18.1)	($3.7)	($4.9)	($2.2)
8 to 1 Oil to Gas Ratio	($18.4)	($5.1)	($6.1)	($2.7)
9 to 1 Oil to Gas Ratio	($4.4)	($0.5)	($3.4)	($1.7)
10 to 1 Oil to Gas Ratio	$11.4	$3.5	($1.2)	($0.9)
11 to 1 Oil to Gas Ratio	$28.6	$7.0	$0.7	($0.2)

Source: Black and Veatch. Appendix G1, Section 7.15.6.

However, a price ratio of at least 11 would be required to generate a superior NPV for the Producers. Compared with the state, the Major North Slope Producers have a greater sensitivity to the price ratio because an LNG project's costs only detract from their revenues.[35] Here again, these results may help explain why the Major North Slope Producers have shown comparatively little interest in pursuing an LNG project.

Compared with the state, the Producers have a greater sensitivity to the price ratio because an LNG project's costs only detract from their revenues. Here again, these results may help explain why the Major North Slope Producers have shown comparatively little interest in pursuing an LNG project.

It is possible that, going forward, the oil to gas price ratio could be sustained at an average of ten to one. However, as noted earlier, the oil to gas price ratio fluctuates over time (See Figure 4-5, page 4-18). For the period of January 1995 to March 2008, the ratio was as high as 14 to 1 and as low as 3 to 1, with an average 8 to 1 (Appendix G1; Section 7.15.4.3). Recently the oil to gas price ratio has been nearly 12 (Oil Daily 2008b).

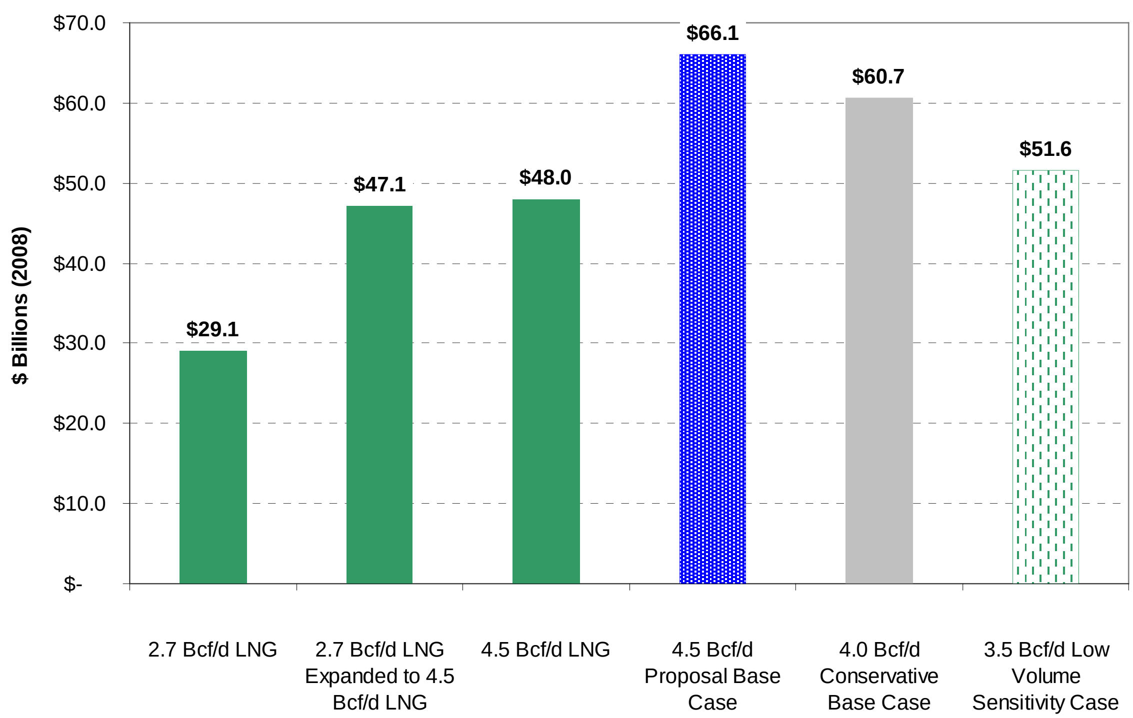
[34] We note again that the 4.5 Bcf/d Base LNG project contemplates initial volumes that are unrealistic. Actual volumes would need to be ramped up over an eight to ten year period. This would significantly decrease the revenue that the state would receive.

[35] The greater sensitivity derives from the fact that, for the producers, higher project costs only reduce their profits. In contrast, increased property tax receipts associated with greater in-state property balances mean that the state enjoys some degree of off-setting benefit from an LNG project's higher costs.

However, the commissioners see no reason to believe that this ratio will continue to depart, on a sustained basis, from historical averages. The current high oil to gas ratio is indicative of the natural volatility experienced for more than a decade. Meanwhile, as discussed previously, there are fundamental market forces that give good reason to believe that, over the relevant time frame, the oil to gas price ratio will more closely approximate its historical norm (Appendix G1, Section 7.15; Appendix I, Section 4.7; Kelly 2008).

Finally, the commissioners note that the volume uncertainty affects the TC Alaska Project just as it does an LNG project into the Asian Pacific. The volume of gas is sensitive to the commitments that gas shippers make. Accordingly, we can also compare returns to the state generated by lower volume TC Alaska projects with a range of LNG projects. The results are shown in Figure 4-22.

Figure 4-22. State NPV Under LNG and TC Alaska Pipeline Cases



Source: Black and Veatch. Appendix G1, Section 7.12.3.

The TC Alaska project generates superior returns compared to any of the LNG projects under Base Case assumptions. Even the 3.5 Bcf/d Low Volume TC Alaska scenario generates a greater state NPV than does the 4.5 Bcf/d LNG project.

F. TC Alaska's Project Has a Greater Likelihood of Success than Any of the LNG Options

In addition to producing a materially higher estimated NPV to the state than the LNG options, the commissioners conclude that the TC Alaska Project has a greater likelihood of success than the LNG options. The stand-alone LNG options face unique, significant challenges to their likelihood of success. Those issues, along with a comparison of the LNG options with the TC Alaska Project, are summarized below.

1. An LNG Project Would Be Significantly More Complex, and Thus More Risky, Than an Overland Route

There are a number of unique challenges that negatively affect the likelihood of success of any LNG project. First and foremost, an LNG project constitutes a significantly more complex undertaking than an overland project such as TC Alaska's, on several levels. As Goldman, Sachs and Co. states in its report, "LNG projects are inherently more complex than gas pipelines. Simply put there are more steps in the 'value chain' which translates into more parties involved, more contractual arrangements, and more technology and construction complexity." (Appendix H, page 43)

For example, to obtain financing, an LNG project, or its shippers, must secure long-term sales contracts for the LNG, in the form of a long-term take-or-pay market contract (Appendix H, Section VI.C). An LNG project cannot go forward without these long-term gas sales contracts. By contrast, the shippers on an overland pipeline project do not need to secure long-term gas sales contracts; instead, they can simply sell their gas into the market at the AECO Hub due to the liquidity of that market. For this reason alone, it would be considerably more difficult for an LNG project sponsor to obtain financing without firm long-term take-or-pay contracts than it would be for an overland pipeline project such as the TC Alaska Project (Appendix I, Sections 8.2 and 9.1).

The long-term sales contracts required for an LNG project will likely require a minimum of 20 years of proven and committed gas reserves dedicated to the project (with the reserves being certified by experts) to support the contracts (Appendix I, Section 4.6). Again, this type of long-term demonstration of sufficient gas reserves would not be required by the parties that are purchasing Alaskan gas at the AECO Hub. To be sure, an overland project, like an LNG project, will have to demonstrate a certain level of available reserves in order to obtain financing. But, aside from the showing required to obtain financing, an LNG project would have to demonstrate adequate, long-term gas reserves to its customers as a result of the enhanced need of customers in Asia for security of supply, given that they have few if any available alternative supplies. Thus, TC Alaska's Project to the AECO Hub would have a somewhat lower hurdle to clear regarding demonstration of gas reserves than an LNG project.

Several other factors contribute to the enhanced risks and complexity facing an LNG project as compared to the TC Alaska Project. For example, in contrast with the TC Alaska Project to the AECO Hub, the LNG project options will require the design, construction and financing of very costly liquefaction facilities, in addition to establishment of the associated ownership structure and commercial terms and contracts to support the liquefaction facility (Appendix I, Section 7.2). Unlike the TC Alaska Project, an LNG project also requires costly marine transportation arrangements through ownership of or contracting for a significant number of LNG tankers. (Appendix I, Section 5.8). In addition, an LNG project will require that arrangements be made (typically by the buyer) for compatible regasification facilities or services at the market end of the transaction (Appendix I, Section 7.3).

Each of these project elements presents additional complexity and material risks in comparison to the TC Alaska Project, including, as the case may be, cost, technology, completion, currency, country and jurisdictional/choice of law risks. As Goldman Sachs states:

> *"From a comparative standpoint (i.e., [over]land gas line project versus an LNG alterative), injecting this broad range of incremental credit issues and risk factors substantially raises the bar in terms of obtaining investment grade ratings, favorable financing rates and ultimately developing a viable financing plan."* (Appendix H, p. 45)

There are simply more links in the chain that must be completed for an LNG project than for an overland pipeline project. And, even more challenging is that fact that all the links in the chain must be assured simultaneously. Indeed, Gas Strategies states that "[t]he need for proponents of LNG projects, usually the owners of upstream gas reserves, to be assured of all elements in the LNG chain at the time of the investment decision is a key driver in the structuring of LNG projects" (Appendix I).

> There are more 'links' in the project development chain that must be completed for an LNG project than for an overland pipeline project.
>
> Even more challenging is that fact that all the links in the chain must be assured simultaneously.

As a result, an LNG option would inevitably involve a longer schedule than the TC Alaska Project to negotiate all the project arrangements into place prior to the commencement of construction and potentially throughout the project. These challenges are not faced by an overland route. The typical structure of an LNG project involves several different ownership entities that must first agree to the elements of the project and then coordinate their activities to assure the earliest possible start date (Appendix I, Sections 2, 6.1, and 7.2). In many cases, for example, while the consortium of producers often is responsible for construction of the facilities through the liquefaction stage and loading terminal, if the tankers are chartered, another company may be responsible for delivery of the required tankers and still a third entity, the buyer of the LNG, would be responsible for arranging for the receiving terminal and regasification services. Thus, the project manager has a significant challenge to coordinate the various elements of the project and a very heavy negotiating burden.

Moreover, each entity (including each joint venture partner developing the project) would be subject to its own risks and have its own priorities. Such complications, while not guaranteeing that unexpected delays would arise, substantially increase the risks of delays occurring. If they do, the economic basis for the choice of an LNG project would be further eroded (Appendix I, Section 9.1). By contrast, the TC Alaska Project essentially faces none of these risks, but does have right-of-way and regulatory challenges of its own as discussed more fully in Chapter 3.

This is not to suggest that an LNG project could not overcome these barriers. LNG liquefaction projects have been constructed in other challenging areas of the world, and an Alaska project could be successful under the right set of conditions.[36] However, an LNG project involves several, interrelated elements—pipeline/GTP, liquefaction plant, long-term gas sales contracts, demonstration of long-term gas reserves, LNG tanker arrangements—which collectively are more complicated than the challenges facing the TC Alaska Project, and which must be achieved before a project can obtain financing (Appendix H, Section VI. C). The complexity of these multiple factors contributes to the lower likelihood of success for the LNG project options relative to the TC Alaska Project.

[36] That said, unlike most other LNG projects where the gas reserves are located at or near the liquefaction terminal, an Alaskan LNG project would have to construct a lengthy and costly pipeline from the producing area to the LNG liquefaction terminal. This makes the challenges facing an Alaskan LNG project even more complex than for most competing LNG projects located elsewhere in the world.

2. An LNG Project Would Be More Difficult To Finance Than an Overland Route

According to Goldman Sachs' analysis, an LNG project may be able to obtain financing, and could in rare circumstances potentially have a higher NPV than the TC Alaska Project depending on the price of LNG. However, as a result of the complexity and other factors discussed above, it will be quite challenging, and more difficult to finance an LNG project than the TC Alaska Project (Appendix H, Section VI. D). Thus, Goldman Sachs states that "it is difficult to reach a definitive conclusion at this stage about viability of the LNG-based cases," citing the "[a]bsence of key project elements upon which to base analysis." An in-depth analysis of the financeability of an LNG project would require, at a minimum, information about the project's:

- Defined business structure/finance plan.
- Equity sponsor/developer.
- Gas purchaser.
- Ship builder/operator.
- Committed gas volumes to supply the project. (Appendix H)

None of this information is available at this time.

In addition to the relative complexity of an LNG project, the Goldman Sachs report also identifies other issues that we believe would constitute barriers to financing an LNG project.

First, the sheer size of an LNG project makes it more difficult to finance than an overland route. According to the Goldman Sachs report:

> *"Comparing the 4.5 Bcf Proposal Base Case to the 4.5 Bcf LNG case provides a clear cost/per capacity measure. The [TC Alaska] Base Case has an all-in financing requirement of $56 billion, which in and of itself will be a challenge in terms of financing market capacity. The LNG project with comparable capacity requires $85 billion in funding. The second key comparison is between fully loaded transportation costs. In the case of the [TC Alaska] Base Case, the transportation cost is $4.73. For both the 4.5 Bcf and the 2.7 Bcf all LNG projects, the transportation cost is estimated to be between $9.51 and $9.74. In the case of the 4.5 Bcf project, this is driven by larger capital costs; in the case of the 2.7 Bcf project, capital costs are roughly the same as the TC Alaska Base*

Case but are spread over fewer units of throughput resulting in a higher transportation cost." (Appendix H, p. 47)

Second, Goldman Sachs assumes that the Federal Loan Guarantee would not be available to an LNG project (Appendix H, Section VI. D). The TC Alaska Project can take advantage of an $18 billion Federal Loan Guarantee that Congress made available to qualified project through its passage of ANGPA in 2004, and that due to indexing will escalate to approximately $32.9 billion in the year 2020 (Appendix H, p. 50). An LNG project, however, would not have the ability to use the Federal Loan Guarantee if the LNG would be shipped to Asia instead of the U.S. (ANGPA 2004, Section 116). While this does not mean an LNG project could not obtain financing under the right set of circumstances, it makes it more difficult to obtain financing, and again places an LNG project at a disadvantage relative to the TC Alaska Project.[37]

Finally, LNG projects are most typically financed primarily with equity (Appendix I, Section 8.1). This is due largely to the complicated, interrelated nature of the many commercial and financial elements of a project that have to be tied together with contracts in a project financing (Appendix H, Section VI. C). Only the original two trains of the RasGas project in Qatar have raised significant quantities of bond finance (Appendix I, Section 8.3). Given the very high costs of an LNG project, it is unclear from where the equity for the project would come.

3. There Is a Significant Risk LNG Would Not Provide Open Access to Future Explorers, In Contrast With the TC Alaska Project

There is a significant risk LNG would not fulfill the state's interest in achieving a gasline project that can be reasonably expanded on an open access basis for explorers and producers. As explained in detail in Appendix R3, FERC does not require LNG terminals to operate on an open access basis. Thus, FERC does not require LNG terminal owners to allow other parties that may wish to bring additional gas supplies to market to use an LNG terminal. In fact, in the Energy Policy Act of 2005, Congress codified FERC's policy and went a step further by establishing that FERC cannot impose open access requirements on an LNG facility, which the

[37] The lack of loan guarantees would also increase the cost of any LNG project due to the fact that the interest rate on any financing will be higher to reflect the greater project risk that exists because the U.S. government is not guaranteeing the project debt in the event of a project failure (Appendix H, Section VI.D.). This increased cost is reflected in the NPV analysis discussed earlier in this Section.

Act defined to include an LNG export facility.[38] Thus the state could not impose its own open access terms on the LNG facility. Indeed, the only LNG export facility currently operating in the U.S. resides in Alaska (Nikiski) and it is neither FERC jurisdictional nor is it operated on an open access basis (EIA 2008b).

Assuming private ownership of the liquefaction facilities, it is unclear how the state could ensure open access. If the Major North Slope Producers, or any other producer, owned the liquefaction plant (as is typical in many LNG projects), they would be under no obligation as a matter of FERC regulation to provide access to the plant for other explorers and producers, or to expand the plant to allow third-party access (See Appendix I at Section 9.2.1). Accordingly, even though the state or FERC could impose open access conditions on the GTP and pipeline facilities upstream of the LNG plant, the liquefaction plant could operate as a "pinch-point" for third parties. Without access to liquefaction, access to the pipeline and GTP plants is irrelevant.

If the lack of open access prevents an LNG project from being expanded, then any hypothetical jobs advantage for an LNG project would be substantially diminished, relative to the TC Alaska project, because of the reduced potential for exploration and production. This problem would be even greater for a smaller LNG project.

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If the lack of open access prevents an LNG project from being expanded, then any hypothetical jobs advantage for an LNG project would be substantially diminished relative to the TC Alaska project, because of the reduced potential for exploration and production.

4. The Major North Slope Producers Have Indicated Their Preference for An Overland Route Over the LNG Options

Another factor in comparing an overland project to the LNG options is an understanding of which approach the Major North Slope Producers would prefer. In the Major North Slope

[38] See Section 311(c)(2) of the Energy Policy Act of 2005 (codified at 15 U.S.C. § 717b(e)(3)(B)(ii)(I)). Section 311 of The Energy Policy Act of 2005 also gives FERC the exclusive authority over the siting, construction, expansion or operation of an LNG terminal. (Appendix R3, p. 6)

Producers' proposal under the SGDA process, in ConocoPhillip's November 30, 2007 proposal, and most recently in the Producer Project unveiled by BP and ConocoPhillips, the Major North Slope Producers have consistently favored an overland route over an LNG project. It is reasonable to assume that economics play a large role in their decision. Indeed, as shown above, the TC Alaska Project would produce a materially higher estimated NPV for the Major North Slope Producers than would an LNG project, and would engender significantly lower risks (See Appendix G1, Section 7 for further details). Thus, while both TC Alaska and an LNG project face the challenge of convincing the Major North Slope Producers to commit to transport gas on them, any LNG project would face the additional challenge of convincing the Major North Slope Producers to pursue something they have clearly rejected since their major 2001 study of Alaskan gas options.

On top of what appear to be inferior economics for the LNG projects, as discussed previously, securing gas commitments from the Major North Slope Producers for an LNG project may be especially difficult because each has gas reserves in the Pacific and Middle East regions which the companies may also wish to develop as part of their worldwide supply strategy (Appendix I, Section 9.1). Each company will have a different perspective on the priority it puts on developing Alaskan LNG. As a result, there is a risk that at least one of the Major North Slope Producers may not want to push ahead the development of an Alaskan LNG project. As Gas Strategies explains:

> *"In the absence of a strong economic incentive companies will prefer a pipeline project over LNG. This is driven by concerns over project delays and costs arising from their divergent strategic objectives in the Asia Pacific region and the need to secure long term sales contracts. This contrasts with their ability independently to transport gas to the North American market where volume risk is minimal and sales contracts are not required before investing in pipeline capacity."* (Appendix I, p. 4)

In addition, Gas Strategies concludes that the Major North Slope Producers "will be aware of the Federal desire to have Alaskan gas contribute to the energy security of the USA. Protecting their wider US interests may drive a reluctance to be seen to be promoting gas export from Alaska." (Appendix I, p. 54.) These reasons, coupled with the NPV advantage that an overland route would have over the LNG options, help to explain why the Major North Slope Producers have expressed, and likely will express in the future, a preference for an overland route instead of an LNG project.

5. An LNG Project Will Require Proven and Committed Reserves (Certified by Experts) to be Dedicated to the Project

As earlier noted, promoters of an LNG project will have to commit, in advance, to long-term (generally 20-25 year) sales contracts. Buyers will expect these to be backed by sufficient proven and committed reserves to fulfill the contract obligations; they will require a reserves certificate to demonstrate it (Appendix I, p.27). Banks providing funding will, as well, require evidence that sufficient reserves of proven gas are dedicated to the project to fulfill the sales contracts and a gas supply contract that is back-to-back with the LNG sales commitments (Appendix I, p.54-55). This is quite unlike an overland project, where gas shipping commitments from individual parties are sufficient to support financing. As noted earlier, it does not appear that proved reserves are sufficient to support such certificates for a 4.5 Bcf/d project; without Point Thomson gas there would even be challenges for a 3.5 Bcf/d project.

The magnitude of the reserves that will be required to be both proven and dedicated to support any LNG option are significant. More than 5 Tcf of natural gas are required for a 0.65 Bcf/d (5 mtpa) train to operate for 25 years (Appendix I, p. 46). The sponsor will be required to own or have binding contracts to acquire all of the gas to support the project (as well as firm pipeline access to move it to tidewater) at the time the project is structured and financed. This creates a further burden for an LNG project compared to an overland project.

6. Exporting LNG To Asia Presents Regulatory and Political Barriers That the TC Alaska Project Would Not Face

As discussed earlier, the most likely market for an Alaskan LNG project is in Asia. This is due to several factors, including the lack of any LNG receiving terminals on the West Coast of the U.S. or Canada, the fact that there is only one Mexican LNG receiving terminal, and, perhaps most importantly, the fact that LNG prices in Asia are (and are projected to be) higher than natural gas prices in U.S. West Coast markets due to the relative lack of other supply alternatives in Asia. Because Asia would be the primary destination market for Alaskan LNG, it is important to understand the special barriers that an Alaskan LNG project would face in attempting to export LNG to Asia.

The fact that a Federal Loan Guarantee is available for an overland route but is not available for an LNG export project is indicative of the political and regulatory obstacles facing any project which seeks to export LNG outside of North America. There are significant regulatory and political barriers to exporting LNG to Asian markets, whereas the TC Alaska Project does not face similar barriers.

> The fact that a Federal Loan Guarantee is available for an overland route but is not available for an LNG export project is indicative of the political and regulatory obstacles facing any project which seeks to export LNG outside of North America.

For example, Section 3 of the Natural Gas Act effectively provides that an export to a NAFTA country (Canada or Mexico) shall be approved (Appendix R2). Based on this provision, and past practice by the U.S. Department of Energy (DOE), it would appear to be relatively routine for the shippers on TC Alaska's Project to receive the necessary export authorization.[39] In addition, although TC Alaska will not control any of the sales of natural gas that its shippers make, TC Alaska assumes that a large quantity of the gas initially exported to Canada will eventually be re-imported back into the U.S. after being transported through pipelines that receive gas at the AECO Hub (TC Alaska Application 2007, pp. 2.1-11). Canada is currently a net exporter of natural gas to the United States. As such, the introduction of a substantial incremental volume of natural gas from a pipeline transporting Alaskan gas to Canada would simply reinforce or enhance that exporter status.

By contrast, LNG projects would face several problems in obtaining the necessary authorizations to enable them to export LNG to Asian markets. The authorizations include DOE export authority, which is required to send Alaskan natural gas to a non-NAFTA country such as Japan, Korea, Taiwan or China.[40] As discussed in Appendix R2, although DOE authorized an export of LNG from Prudhoe Bay to Asia approximately 20 years ago that authorization occurred during a period when the supply and demand balance in the U.S. natural gas market was much different than it is today and is projected to be in the future.[41] Supply in the U.S. has struggled to keep pace with demand. Due to these fundamental supply and demand changes, there is a significant risk that DOE would not permit the export of significant quantities of Alaskan LNG to Asia (Appendix R2).

[39] See *Maritimes & Northeast Pipeline, L.L.C.*, *Order Granting Blanket Authorization to Import and Export Natural Gas from and to Canada,* DOE/FE Order No. 1212 (1996)

[40] See Appendix R2 and 15 U.S.C. 717b (2006)

[41] See *Yukon Pacific Corporation*, DOE Opinion and Order No. 350, 1 FE ¶ 70,259 (1989)

Other export regulations also suggest that any effort to export LNG to Asia could face additional regulatory hurdles.[42] In addition, as a practical matter, any effort to export gas to Asia would face political opposition in both the U.S. and Canada.[43] Because of the political sensitivity of sending domestically-produced energy supplies to markets outside North America, particularly during a period of rising energy prices and declining domestic supplies, a material risk exists that any effort to export LNG to Asian markets would not receive the necessary regulatory approvals (Appendix R2).[44]

Although these export barriers would exist for any project seeking to export North Slope LNG outside of North America, a project seeking to export LNG to China might face additional political and regulatory hurdles. U.S. Congressional opposition to a Chinese company's effort to acquire Unocal was significant. (Lohr 2005). Meanwhile, Sinopec's involvement in the Little Susitna Construction Company's AGIA application caused some in Congress to suggest that an export ban could ensue. (Bolstad 2007) As discussed in Appendix R2, those hurdles create serious doubt that a project could obtain the authority to export North Slope LNG to China.

But in any case, China would probably not be the most attractive buyer for LNG supplies (Appendix I). China is more price sensitive than the other major Asian markets and there are creditworthiness questions around some of the smaller gas buyers. As an emerging gas market, China would need to develop not only the infrastructure to receive and market LNG but also the pipeline and distribution systems to move it from the terminal to the end users (Appendix I). The implications as to the preferred destination market—China or Canada/US—are clear: Canada via an overland pipeline provides sponsors and the state with much more certainty and likelihood of realizing the best value for Alaskan natural gas.

7. An Overland Route Has a Better Opportunity than an LNG Project To Spur a Petrochemical Industry

The specifications for LNG sold to Japan, Korea and Taiwan differ from LNG sold to the U.S. (and European) markets in terms of Gross Heating Value (GHV). The gas distribution systems

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[42] Among these are the Naval Reserves Petroleum Act, 10 U.S.C. § 7420; section 28 of the Mineral Leasing Act, 30 U.S.C. § 185; and Foreign Investment and National Security Act of 2007 ("FINSA") at 50 App. USCA 2170.

[43] See Appendix R2, page 8.

[44] See also Appendix I, page 57 (noting that the Major North Slope Producers "will be aware of the Federal desire to have Alaskan gas contribute to the energy security of the USA. Protecting their wider US interests may drive a reluctance to be seen to be promoting gas export from Alaska.").

in these Asian markets require a higher GHV than do U.S. systems (Appendix I, Section 4.4). The Btu per cubic foot of gas required in these three principal Asian markets range from 1050 to 1170[45] (Appendix I, Section 4.4). This is higher than in most U.S. markets where the required GHV ranges from 980 to 1070 Btu. As a consequence, it is unlikely that such a project will spur the development of a major petrochemical industry in Alaska. A petrochemical industry would require that the gas liquids (propane, butane, ethane, and other liquids or liquefiables that increase the heating value of the natural gas stream) be stripped out of the gas stream for separate sales. However, this could not be accomplished while at the same time meeting the Asian market's GHV requirements.[46]

That being said, however, the analysis of LNG liquefaction processes reveals that an LNG project would be compatible with meeting in-state demand for propane. The cost and schedule impact of removing propane from the gas stream, for sale to Alaskans, is minimal. Meanwhile, total Alaskan needs for propane are modest. Accordingly, propane could be stripped from the LNG bound for Asia and diverted to the Alaskan market without falling afoul of Asian Pacific GHV requirements. The impact of propane extraction from both "lean gas" and "rich gas" cases described in the AGIA RFA is shown in Section 2.4 of the LNG analysis.

While an LNG project would not support a major petrochemical industry in the state, an NGL processing plant *could* be installed on TC Alaska's overland project to strip out the gas liquids. (TC Alaska Application 2007, pp. 2.2-2.77). Thus, there is more potential for creation of a petrochemical industry in Alaska via the TC Alaska Project than via an LNG project designed to move gas to Asian markets. Although as currently proposed, the TC Alaska project contemplates processing of NGLs in Alberta, the location of liquids processing will be determined by market forces.

There is more potential for creation of a petrochemical industry in Alaska via the TC Alaska project than via an LNG project.

[45] Prudhoe Bay gas has a Btu content that generally ranges between 1067 and 1118 Btu.

[46] The difference in GHV also reduces the interchangeability of destination markets for an Alaskan LNG project since gas with the heating value to meet Asian requirements will exceed US requirements.

G. Conclusion

As discussed above, the analysis shows that although LNG project options could produce positive benefits to Alaska, TC Alaska's Project would provide the state and its citizens with greater benefits than the LNG options, including the following:

- Higher NPV. Under the Base Case set of assumptions for each alternative, the NPV to the state would be greater from TC Alaska's Project than from any stand-alone LNG project options. The stand-alone LNG options would only have a higher NPV to the state if future LNG prices significantly exceed the level that are likely to occur in the future on a sustained basis.

- Higher Likelihood of Success. The TC Alaska Project has a greater likelihood of success than a stand-alone LNG project, and accordingly offers a better chance at providing the state with benefits important to Alaskans—including jobs, in-state gas, an open access project, a source of state revenues, and getting a gasline as quickly as possible. For example:
  - The TC Alaska Project is less complex and involves fewer hurdles than an LNG project. In contrast with the TC Alaska Project, which must develop the pipeline/GTP, LNG projects require the development of the entire supply chain—including gas supply, pipeline/GTP, liquefaction plant, and access to LNG tankers and regasification facilities—before a project can obtain financing.
  - Unlike an overland route to Canada, an LNG project must have long-term gas sales contracts with creditworthy customers before it can be financed. By contrast, the shippers on an overland pipeline to Canada can simply make short-term gas sales in the spot market at the AECO Hub.
  - LNG options may also be disadvantaged because the Major North Slope Producers, based on their prior actions and recent indications, view an overland route as economically preferable to an LNG project.
  - While TC Alaska must obtain regulatory authorizations in both the U.S. and Canada, a stand-alone LNG project would have greater difficulty obtaining authorization to export gas from the U.S. to Asian countries, the most likely destination market for Alaskan LNG.

Analysis shows that stand-alone LNG project options are less desirable for the state than the TC Alaska Project. Even if one presumes the simultaneous occurrence of a number of unlikely economic events which could generate a greater NPV for a stand-alone LNG project option, the TC Alaska Project continues to enjoy a significantly higher likelihood of success. Accordingly, TC Alaska has a better chance than the stand-alone LNG options of providing benefits to Alaskans, including jobs, in-state gas deliveries, open access for explorers, and greater revenues for the state and its citizens.

The TC Alaska proposal does improve significantly the prospects of an Alaskan LNG project—the Y Line option. The TC Alaska Project provides Alaska with its best opportunity for a successful LNG project, as a Y Line option. The TC Alaska Project proceeding first will reduce costs and lessen financial and contracting hurdles associated with an LNG project. Coming after gas is already bound for U.S. markets, a Y Line may be able to overcome political opposition to exporting gas. Accordingly, the commissioners believe that the best route to an Alaska LNG project runs through the TC Alaska proposal.

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Chapter Five — Comparison of the TC Alaska Project with the Producer Project

Table of Contents

A. Introduction and Summary of Conclusions 5-1
B. The History of SGDA and TAPS Illustrates the Risks Posed by a Producer-Owned Pipeline 5-4
  1. The State's Experience Under SGDA 5-4
  2. TAPS....................5-7
C. TC Alaska—Commitments; Producer Project—No Commitments....................5-9
  1. Capital Structure 5-9
  2. Expansion 5-13
  3. Rolled-in Rates....................5-14
  4. Commitments To Hold an Open Season and File at FERC, and Other Issues That Could Result in a Delay of the Producer Project....................5-17
D. A Producer-owned Pipeline Has an Incentive to Act in Ways That Are Contrary to the Best Interests of the State....................5-20
E. Both TC Alaska and the Producer Projects Lack Firm Shipping Commitments....................5-24
F. Comparison of the Costs to the State Following the TC Alaska Project Path or the Producer Project Path....................5-26
G. TC Alaska's Offer of Equity Partnership....................5-29
H. The Upstream Inducements Provided by AGIA are Valuable and Incentivize the Producers to Commit Gas to the TC Alaska Project 5-30
I. It is in the State's Interest to Pursue the TC Alaska Project....................5-32
J. Conclusion 5-33
K. References....................5-34

Figures

Figure 5-1: Impact of Capital Structures on Tariff Rates....................5-11
Figure 5-2: Impact of 50/50 debt to equity ratio 5-12

A. Introduction and Summary of Conclusions

This section of the Findings compares the Producer Project with TC Alaska's proposed project. The purpose of this comparison is to analyze whether the state's interests would be better served by awarding an AGIA license to TC Alaska or by relying on the Producer Project as the state's vehicle to obtain a gas line.

On April 8, 2008, BP and ConocoPhillips announced they have combined efforts to pursue a project they call "Denali - The Alaska Gas Pipeline™" (BP/ConocoPhillips 2008). According to a BP/ConocoPhillips press release and a 12-page PowerPoint presentation describing the project (which provides the only information formally available from the sponsors regarding the project), the Producer Project would have a capacity of approximately 4.0 Bcf/day. According to BP and ConocoPhillips, the pipeline would extend from the North Slope to Alberta, Canada, and from there to a destination point in the Lower 48 states if doing so would improve project success or reduce transportation costs. BP and ConocoPhillips assert that they plan to spend $600 million to reach the first major project milestone, an open season commencing before December 31, 2010. If the open season is "successful" (a term which is not defined or explained by either the BP/ConocoPhillips press release or the PowerPoint presentation), BP and ConocoPhillips state they intend to obtain FERC and NEB certifications. BP and ConocoPhillips have proposed the Producer Project outside the AGIA process.

> This section of the findings analyzes whether the State's interests would be better served by awarding an AGIA license to TC Alaska or by relying on the Producer Project as the state's vehicle to obtain a gas line.

As explained below, rejecting TC Alaska's Project in order to pursue the path offered by BP and ConocoPhillips would not be in the state's interests. TC Alaska has made binding, enforceable commitments to take various actions that will provide real benefits and value to the state. The commitments made by TC Alaska include commitments to (1) hold an open season and file for regulatory permits by specific dates, which will enable the state to get a gasline as quickly as possible; (2) provide transportation at reasonable rates, which will encourage exploration and development and also maximize revenues to the state and its citizens; (3) expand its system on reasonable terms, which will promote the full exploration and development of Alaska's natural gas resources, thereby maximizing jobs for Alaskans; and (4) accept the critically important FERC certificate once it becomes final and no longer subject to judicial review.

By contrast, the sponsors of the Producer Project have made no binding, enforceable commitments to advance a project on terms that are in the best interests of Alaska. In addition, as demonstrated by the history of the failed SGDA negotiations and SGDA contract, the sponsors have economic incentives that conflict with advancing a project that is in the best interests of the state. They are motivated to maximize the commercial value of the project for themselves, and can be expected to demand large concessions from the state. Further, as demonstrated by the history of the TAPS oil pipeline, the Producer Project sponsors have incentives to engage in behavior that will frustrate the state's goal of obtaining a competitive exploration and production industry on the North Slope.

Reliance on any project that does not include legally enforceable commitments made by the project sponsor similar to those made by TC Alaska would deprive the state of a real opportunity to achieve its objectives. Rejecting the TC Alaska Project would leave the state no other option but to negotiate with BP and ConocoPhillips to obtain pipeline terms similar to those contained in AGIA that benefit the state and its citizens. However, such negotiations would be conducted from a position of ever-increasing weakness as time goes by, as oil production and related revenues decline, and as the state becomes more and more desperate for whatever new revenue it can obtain from a gas pipeline.

There is no need to imagine what might happen in that circumstance. One needs merely to look back at the terms of the draft SGDA contract presented to the Alaska Legislature in 2006 for evidence of what will be required of the state if the producers have that kind of commercial negotiation leverage over the state. The Major North Slope Producers extracted billions of dollars in concessions from the state with no binding commitments from the Producers. This is far more than the $500 million investment under AGIA that secures the valuable commitments from TC Alaska to build a natural gas pipeline that serves the state's interests in exploration, jobs, revenues and other issues of importance to the state.

> Reliance on any project that does not obligate the sponsors to provide the legally enforceable commitments made by TC Alaska would deprive the state of a real opportunity to achieve its objectives.

The commissioners also recognize that the Producer Project may be pursued to completion outside the AGIA process and without state fiscal concessions. The Producers have an obligation to market their gas when it is reasonably profitable to do so; they do not have an obligation to transport the gas through any particular project. If the Producer Project proceeds to an open season, the TC Alaska project would compete with the Producer Project for gas commitments. However, the Producers have stated that they need concessions from the state to enable them to commit gas to any gas pipeline project. AGIA ties upstream incentives to gas committed at the initial open season of the AGIA project, to provide the state with the benefits Alaskans require. The state will have the opportunity throughout this process to evaluate the need to increase the value of the AGIA upstream incentives, when justified. The state's primary interest is ensuring that any concessions be provided in exchange for real value.

In sum, the commissioners strongly believe that if the state forgets the history of the SGDA process, the state will be risking a repeat of the SGDA results. If it pursues the Producer Project alternative instead of the TC Alaska Project, the state will be forced into negotiations that will resemble those that produced the SGDA Contract. The sponsors of the Producer Project have economic interests that are fundamentally at odds with adopting the types of commitments made by TC Alaska, including effective open access provisions. Because those commitments are so important to the long-term economic interests of the state it would be a terrible mistake to abandon the results of the AGIA process and turn back to reliance on the Producers who are not, and cannot ever be, totally aligned with the state on very fundamental policies affecting the natural gas pipeline. The Producer Project does not reach the level of protecting the state's interest nor does it warrant further consideration because it lacks commitments necessary for the state to adequately compare or evaluate.

B. The History of SGDA and TAPS Illustrates the Risks Posed by a Producer-owned Pipeline

Before comparing the TC Alaska Project and the Producer Project, it is useful to briefly recall and summarize the state's history of dealings with producer-owned pipelines. The history of the failed SGDA process and the TAPS oil pipeline provides a strong indication of what the state's (and the Nation's) experience will be if the state elects to follow the path of reliance on a producer-owned pipeline instead of the TC Alaska Project. That history certainly does not support the prudence of such a decision, as shown below.

The history of the failed SGDA process and the TAPS oil pipeline provides a strong indication of what the state's experience will be if the state elects to follow the path of reliance on a producer-owned pipeline instead of relying on the TC Alaska proposal.

1. The State's Experience Under SGDA

In 1998, the state enacted the SGDA to support the development of an LNG project in Alaska through an application and negotiation process. The law was amended in 2003 to allow the state to provide natural gas and property tax incentives to parties who would move Alaska's gas to market via a pipeline through Canada.

In 2004, MidAmerican Energy Holdings Company, a subsidiary of Berkshire Hathaway, filed an application under the SGDA to negotiate incentives with the state for developing a gas pipeline from the North Slope to markets in the Lower 48. Shortly after the state accepted MidAmerican's application, the Major North Slope Producers filed a competing SGDA application. Enbridge, The Alaska Gasline Port Authority, and affiliates of TransCanada Corporation also submitted applications.

The proposed SGDA contract consisted of an unbalanced set of state concessions that were broad, material, long-term, and binding. They surrendered multiple aspects of the state's sovereign rights and prerogatives and harmed and frustrated the state's interests in promoting the full exploration and development of natural gas resources in Alaska, limiting the potential for the creation of new exploration and development jobs on the North Slope.

During the ensuing process, the Murkowski administration undertook negotiations with (1) MidAmerican, (2) the Major North Slope Producers, and (3) TransCanada Corporation. Ultimately, the Murkowski administration chose to negotiate a contract exclusively with the Major North Slope Producers. Those negotiations resulted in a proposed SGDA contract in the spring of 2006 regarding the possible development of a natural gas pipeline from the North Slope to the Lower 48.

The proposed SGDA contract consisted of an unbalanced set of state concessions and so-called producer "commitments." The concessions made by the state under the contract were broad, material, long-term, and binding. They swept across fiscal and regulatory authorities and surrendered multiple aspects of the state's sovereign rights and prerogatives. Furthermore, the terms harmed and frustrated the state's interests in promoting the full exploration and development of natural gas resources in Alaska, limiting the potential for the creation of new exploration and development jobs on the North Slope.

The state was required to give up (for up to 45 years) its sovereign rights to change oil and gas taxes and to determine the royalties it would be paid for its oil and gas. The state was required to take its royalty gas in-kind. The state was also required to take its production tax payment in gas, was required to contract for capacity in the pipeline (and upstream gathering pipelines), and to market its own gas, all of which exposed the state to new and substantial costs and risks. The state was also required to waive numerous taxes to which the Major North Slope Producers would normally be subject.

Regulatory concessions crossed multiple agencies within state government. The Department of Natural Resources was deprived of its authority to regulate lease activities and Plans of Development. The SGDA contract also drastically reduced the authority of the Alaska Oil and Gas Conservation Commission, particularly related to Point Thomson. In addition, the orders of the Regulatory Commission of Alaska affecting the proposed line were made virtually meaningless by an indemnification provision guaranteed by the state.

In monetary terms, the state's quantifiable concessions to the Major North Slope Producers under the SGDA contract were estimated to be more than $10 billion.[1] Additional non-quantifiable concessions were granted, exposing the state to tremendous economic risk. The Producers claimed all these concessions were essential for them to proceed with a pipeline project.

[1] Following the recent enactment of the ACES production tax changes, the $10 billion estimate of quantifiable concessions would likely be much higher.

Even more troubling, the state's numerous concessions did not secure any binding, enforceable commitments by the Major North Slope Producers to actually build a gas pipeline project, or to apply for the necessary regulatory permits on a fixed timeline. The Major North Slope Producers merely committed to commence planning of a natural gas pipeline project, with no requirement to ever hold an open season or obtain the necessary FERC certification to go forward with developing a natural gas pipeline.[2]

The SGDA contract did not include any enforceable commitments by the Major North Slope Producers on issues that were critical to protect the state's interests in promoting the maximum development of the state's North Slope natural gas resources and ensuring maximum revenues from our royalties and production taxes. The SGDA contract did not contain any commitments regarding tariff and rate issues such as capital structure. The contract also was silent on when, if ever, the sponsors would consider an expansion of the project. In addition, unless expansion reduced rates for existing shippers, the expansion would have to be priced on an incremental basis or it could not be undertaken. Additionally, an expansion could be precluded by the sponsors if the expansion would "adversely affect" the financial or economic viability or overall operations of the project—with no material limitations on these impacts.

Other significant omissions were the lack of any binding commitments of the Major North Slope Producers' leased gas to the project or to the size, route, or destination of the project.

In sum, the provisions of the proposed SGDA contract bound the state to unacceptable contract obligations for decades, including the surrender of state sovereignty and billions of dollars in fiscal concessions, but without commitments by the Major North Slope Producers to any:

- Timelines or benchmarks to advance the project.
- Expansion terms that provide effective open access to foster exploration and development of Alaska's natural gas resources.
- Tariff terms that protect the state's interests.

[2] Section 5.2 of the SGDA Contract which addressed Project Implementation merely committed the parties to "begin project planning" and to "advance the project planning activities by Diligence" and to conclude such activities "with a decision on whether to begin preparation of regulatory applications and planning for an Open Season."

The proposed SGDA contract between the Major North Slope Producers and the state was never approved by the Alaska Legislature.

From the demise of the proposed SGDA contract in 2006 until late 2007 there were no proposals by any of the Major North Slope Producers for any pipeline project. During the 2007 legislative session the legislature enacted AGIA. All three of the SGDA sponsors actively opposed AGIA. Only after TC Alaska proposed its project did BP and ConocoPhillips come forward with their proposal to move a project forward outside the AGIA process.[3]

2. TAPS

The state's experience with the FERC-regulated, producer-owned TAPS oil pipeline also sheds light on the path offered by the Producer Project. Although the state has a long history with the TAPS line, two brief points about that history merit particular mention here.

First, producers that merely ship oil on the TAPS line and that do not hold an ownership interest in the line have long complained that the TAPS transportation rate structure established by the producer-owners of TAPS impedes non-owner producers' ability to explore for and produce oil in Alaska (Anadarko 2004). Some third-party (non-TAPS owner) producers and explorers have even left the state. Indeed, in 1985, ConocoPhillips (then an independent producer on the North Slope with no ownership stake in TAPS) began producing oil from the Milne Point field. In late 1989, ConocoPhillips suspended production at Milne Point citing low oil prices, technical difficulties with producing oil from the field, and the high tariffs charged for shipping oil through TAPS. In 1993, ConocoPhillips traded Milne Point to BP and left the state. Conoco's president and CEO at the time, Archie Dunham, was quoted as saying that "[a]ll the value of that property was taken away from us in the pipeline tariffs." (Haines 1996) In effect, ConocoPhillips argued that an independent company (i.e., a non-TAPS owner/producer) could not profitably produce and market oil from its North Slope leases largely because the TAPS tariffs made it uneconomic for ConocoPhillips to get its oil to market.

Second, the producer-owned TAPS pipeline has charged excessive rates, which may have impeded the full exploration and development of the state's North Slope oil resources. In 2002,

[3] The commissioners note that on the eve of the AGIA application deadline, ConocoPhillips did release a plan to study a natural gas pipeline. The plan included a condition requiring the state to negotiate a new "fiscal framework" before any advancement of the project. The administration declined the request, and the plan was withdrawn.

the Regulatory Commission of Alaska determined that the TAPS owners had overcharged shippers receiving intrastate service by almost $10 billion between 1977 and 1997 (Appendix R4).[4] That decision has been affirmed by the Alaska Supreme Court. Further, an Administrative Law Judge at FERC has held that the rates for interstate service as well as the intrastate service on the line are also substantially overstated.[5] This ruling is pending; a decision by the full FERC is expected soon. In sum, the conclusion that shippers have been overcharged has been reached by the Regulatory Commission of Alaska, an Alaska Superior Court judge, the Alaska Supreme Court, FERC staff, and a FERC Administrative Law Judge (ADN 2004).

[4] *See*, P-97-4 Order No. 151, In the Matter of the Correct Calculation and Use of Acceptable Input Data to Calculate the 1997, 1998, 1999, 2000, 2002 and 2002 Tariff Rates for the Intrastate Transportation of Petroleum over the Trans Alaska Pipeline System, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates. (November, 2002).

[5] *BP Pipelines (Alaska), Inc.,* 119 FERC ¶ 63,007 (2007)

C. TC Alaska—Commitments; Producer Project—No Commitments

In contrast with the excessive transportation rates charged by TAPS and the SGDA contract which failed to contain effective commitments by the Major North Slope Producers to advance a gas pipeline project, TC Alaska has made binding, enforceable commitments to pursue a natural gas pipeline project with reasonable transportation rates and on other terms that are important to the state. TC Alaska's Project includes commitments to base its rates on a reasonable structure that will promote full exploration of North Slope resources, which should maximize the opportunities for long-term exploration and development jobs for Alaskans. Although TC Alaska has made numerous, binding commitments in its application, each of which provides substantial value to the state, this section briefly examines four of those commitments. By contrast, the sponsors of the Producer Project have not made any binding commitment, on these or any other issues.

TC Alaska has made binding, enforceable commitments to pursue a gasline project with reasonable transportation rates and on other terms that are important to the state. TC Alaska's proposal includes commitments to base its rates on a reasonable structure that will promote full exploration of North Slope resources.

1. Capital Structure

Section 130(10) of AGIA requires that a potential Licensee commit to use a capital structure with at least 70% debt and no more than 30% equity to determine the project's rates. The reason a capital structure with less equity is critically important to the state – and why a low ratio of equity to debt is required by AGIA – is that it helps to ensure lower transportation rates on the pipeline. As explained below, lower transportation rates help to maximize the state's revenues and encourage full exploration and development of the North Slope, thereby increasing the number of long-term job opportunities for Alaskans.

All other things being equal, the greater the amount of equity in the capital structure used to determine the pipeline's transportation rates, the higher the rates will be. This stems from the fact that equity is a much more expensive means of financing a pipeline than debt. The return on equity for a new gas pipeline allowed by FERC is approximately 13% to 14%. By contrast, debt can be financed at current interest rates of approximately 7% to 8%. (Appendix J; Appendix G1) As a result, even if two pipelines have identical construction and operating costs, a pipeline which uses a lower equity ratio for ratemaking purposes will have a lower transportation rate than a pipeline which uses a higher equity ratio.

TC Alaska has committed to use the 70/30 debt/equity capital structure required by AGIA through the initial construction phase of the project. Even better, TC Alaska enhanced its proposal, from the state's perspective, by committing to use an even lower 75/25 debt/equity capital structure in its negotiated rates upon approval by FERC and the NEB of the Project's final capital costs.

A capital structure with less equity is critically important to the state.

TC Alaska committed to use the 70/30 debt/equity capital structure required by AGIA.

The sponsors of the Producer Project have not made any commitment to a capital structure for ratemaking purposes.

By contrast, the sponsors of the Producer Project have not made any commitment to a capital structure for ratemaking purposes.[6] Further, even if BP and ConocoPhillips assert in the future that they plan to use a particular capital structure, their assertion would not be enforceable or binding. BP and ConocoPhillips ultimately could adopt whatever capital structure suits their needs, not one that suits the state's needs or the needs of shippers for the lowest possible transportation rates.

Thus, one possible outcome of abandoning the TC Alaska Project in favor of the Producer Project is that the rates on the pipeline will be much higher than they could or should be. This risk would appear to be significant based on the state's experience with other pipelines in which BP and/or ConocoPhillips have ownership interests. For example, on the TAPS oil pipeline, the producer-owners (including BP and ConocoPhillips) have recently advocated at FERC a capital structure of 70% equity and 30% debt—the polar opposite of what AGIA requires and

One possible outcome of abandoning the TC Alaska Project in favor of the Producer Proposal is that the rates on the pipeline will be much higher than they could or should be.

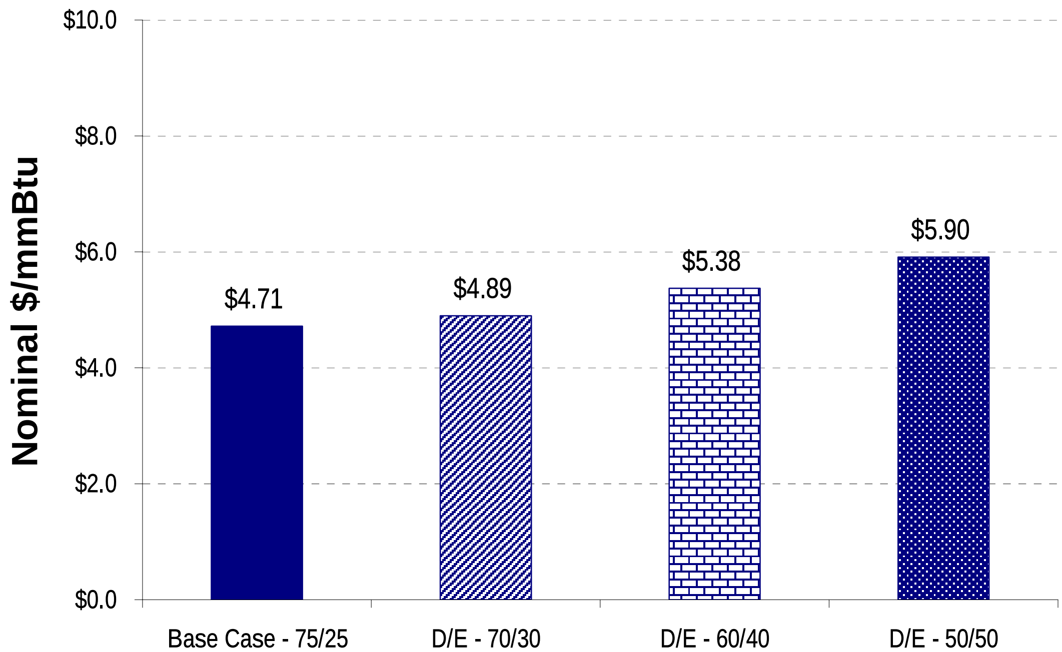
This will result in lower revenue and royalties to the state, and could negatively impact the timely development of the state's natural gas resource.

[6] We note that the November 30, 2007 ConocoPhillips proposal (which appears to have been withdrawn) stated that the company intended "to target a minimum overall debt/equity ratio of 70/30 *to the extent such leverage is achievable at commercially reasonable terms in the market at the time of issuance.*" Proposal at § VII p. 1, emphasis added. A "target" of course, is not enforceable, nor is an undefined concept such as "achievable at commercially reasonable terms at the time of issuance."

what TC Alaska has committed to do.[7] Similarly, for the Rockies Express project in which ConocoPhillips owns a minority ownership interest, the pipeline has a capital structure of 55% equity and only 45% debt.[8]

The impact of the debt to equity ratio on the tariff for an Alaska gasline can be seen in the following chart (taken from Appendix G1) that shows the significant impact of four different capital structures on rates for an Alaskan gasline.

Figure 5-1: Impact of Capital Structures on Tariff Rates



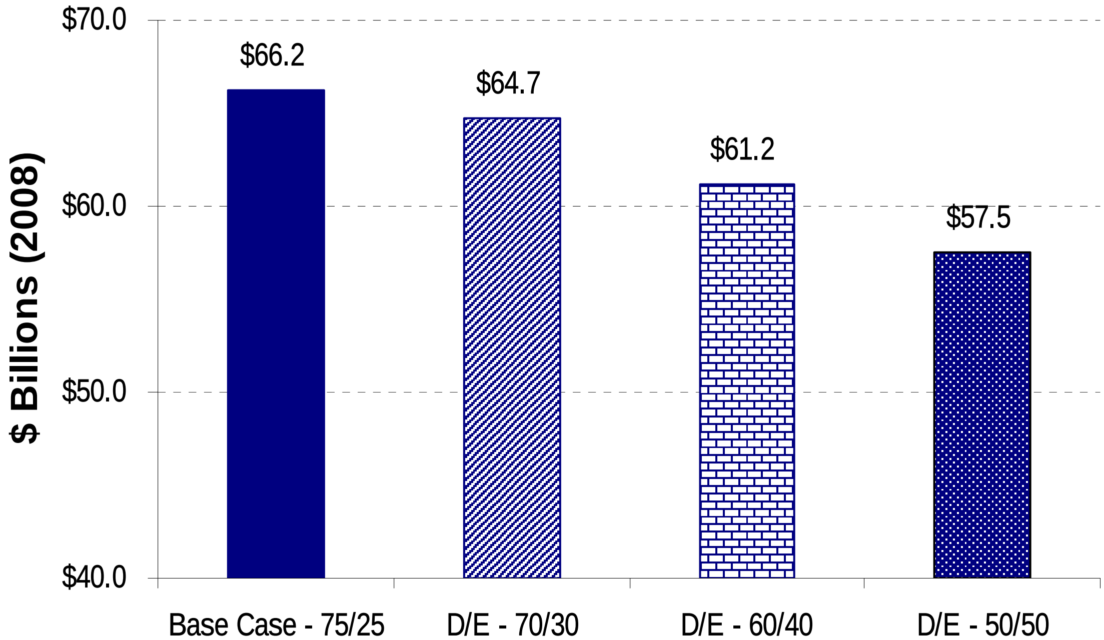
Source: Black and Veatch. Appendix G1, Section 5.7.8.5.

[7] *See BP Pipelines (Alaska), Inc.,* 119 FERC ¶ 63,007 at P 183 (2007)

[8] There is precedent at the FERC for relatively high equity ratios to be used to set rates for gas pipelines: Williams Natural Gas Co., 77 FERC ¶ 61,277 (1996) (64.26 % equity); Panhandle Eastern Pipe Line Co., Opinion No. 404, 74 FERC ¶ 61,109 (1996) (59.97 % equity); Panhandle Eastern Pipe Line Co., Opinion No. 395, 71 FERC ¶ 61,228 (1995) (61.79 % equity); Northwest Pipeline Corp., 71 FERC ¶ 61,253 atp. 61,989 (1995) (55 % equity); Transok Inc., 70 FERC ¶ 61,177(1995) (58.49 %equity); Pacific Gas Transmission Co., 62 FERC ¶ 61,109 (1993) (68.86 % equity); and Midwestern GasTransmission Co., 31 FERC ¶ 61,317 (1985) (77.94 % equity) and Transcontinental Gas Pipeline Company, 90 FERC ¶ 61,279 (60.2% equity) This indicates generally that historically the bounds for the upper end of the range encompass common equity ratios for gas pipelines regulated by the FERC is between 55% and 77.94%.

As can be seen in the figure above, capital structure has a major impact on the transportation rate. Perhaps more importantly, it also has a major impact on state revenues and the state's NPV. The impact on state revenue and state NPV is shown in the following figure:

Figure 5-2: Impact of 50/50 debt to equity ratio



Source: Black and Veatch. Appendix G1, Section 5.7.8.5.

As Figure 5-2 shows, a change from the base case to a 50/50 debt/equity ratio reduces the state's NPV by more than $8 billion. Stated differently, by committing to a 75/25 debt/equity ratio instead of a 50/50 ratio, TC Alaska has improved the value of its application to the state by the same $8 billion amount.

The Major North Slope Producers' consistent opposition to the AGIA requirements and their advocacy of higher equity ratios for their own oil pipelines at FERC directly conflicts with their past argument that they have a greater incentive to keep the tariff rate low than an independent pipeline. As demonstrated by the history of TAPS, the Producer-owners of a pipeline have an incentive to establish a high tariff rate. By keeping the tariff rate high, BP and ConocoPhillips can reduce the net back price, which would reduce the state's revenues because of the reduction in state royalties and taxes that are based on the lower net back price. The reduction in royalties and taxes would result in a corresponding revenue increase to BP and ConocoPhillips and higher profits because they (through ownership of the project) would also collect the higher tariff rate resulting from the higher equity ratio used for ratemaking purposes. Essentially, by moving money from their producer pocket into their pipeline pocket, BP and ConocoPhillips would increase their profits significantly at the state's expense by avoiding state royalty and production tax obligations.

> A high tariff rate on the gas pipeline would be a benefit for BP and ConocoPhillips, and a detriment to the state.
>
> A high tariff rate would tend to deter entry by competing producers, leading to "basin control."

Finally, an added benefit of a high tariff rate for BP and ConocoPhillips—and an added detriment to the state—is that it would tend to deter entry into Alaska's gas basins by competing producer companies. This has previously been referred to in the SGDA hearings as "basin control," which is the ability of the Major North Slope Producers to control the North Slope producing basin and discourage competitor producers from initiating and/or increasing their exploration and production activities in the basin due to potentially high tariffs and uncertain access to essential pipeline capacity to move their new production to markets. The problem is similar to the problem the state has already experienced on TAPS, and would discourage explorers from developing North Slope natural gas resources to their fullest potential. Basin control would also discourage diversity in the companies that are exploring for and developing gas on the North Slope. The addition of new companies to the exploration and development business there creates competition—competition for leases and competition for capacity in the pipeline.[9] This competition can result in increased long-term employment opportunities for Alaskans on the North Slope through more exploration and development activity.

2. Expansion

Expansion terms are also critical elements of AGIA and any AGIA-licensed project that guard against the risk of basin control. A vibrant exploration and development industry cannot develop unless producer companies explore for more gas. Despite the abundant gas resources on the North Slope—which some estimates put at more than 224 Tcf, enough gas to fill TC Alaska's Project for more than 100 years—such exploration is unlikely to occur if explorers do not have

[9] As discussed more fully later in this chapter, antitrust enforcers are concerned about the ability of one competitor to increase the costs of doing business of competing firms. In this case the ability of a producer-owned pipeline to increase the transportation costs of competing gas producers would raise concerns of anticompetitive behavior.

confidence that expansion capacity to move gas they find will be added when needed. (See Chapter 3, Section 3 in this document.)

AGIA requires binding commitments by the Licensee that it will pursue expansions by conducting non-binding open seasons at least every two years after the license is issued (AS 43.90.130 (5), Appendix B). If demand for new capacity exists, AGIA requires that the Licensee expand the project in reasonable engineering increments under commercially reasonable terms. These provisions *ensure* that explorers have (1) the opportunity to communicate their capacity needs to the pipeline, and (2) the assurance that expansion capacity will be available when needed, thus enabling explorers to make drilling commitments. This increased development of the North Slope translates directly into more jobs for Alaskans, more royalty and tax revenue for the state, and a secure economic future for years to come.

TC Alaska has made binding, enforceable commitments to the expansion requirements of AGIA. Thus, the state would obtain real value and the real prospect for new jobs and increased revenue by pursuing the path offered by TC Alaska.

In contrast, BP and ConocoPhillips have not made any commitment to expansion policies. Furthermore, no assertion that they might make in the future regarding expansion policies would be enforceable by the state because their project has been proposed outside the AGIA process.

TC Alaska has made binding, enforceable commitments to the expansion requirements of AGIA. Thus, the state would obtain real value and the real prospect for new jobs and increased revenue by pursuing the path offered by TC Alaska.

In contrast, BP and ConocoPhillips have not made any commitment to expansion policies.

3. Rolled-in Rates

AGIA also requires that a licensed project utilize rolled-in rate treatment for the costs of expansions provided that such treatment does not raise the rates of incumbent shippers by more than 15% above the project's initial rates (AS 43.90.130 (7))[10]. Like the expansion provisions discussed above, AGIA's rolled-in rate provisions encourage expansion. The rolled-in pricing required by AGIA produces lower rates for expansion shippers (new gas shippers)

[10] See Appendix S3 for a detailed discussion of rolled-in rates, including the importance of the AGIA rolled-in rate provisions to the state.

than incremental pricing would for expansions when substantial new pipe must be laid (referred to as "looping") or when major new components are required for the Gas Treatment Plant (GTP) as a result of new demand. By reducing the transportation rates which would have to be paid by explorers that find and develop new natural gas reserves on Alaska's North Slope, AGIA's rolled-in rate provisions provide the greatest opportunity for new producers and explorers to utilize the system, and gives an increased incentive for producers and explorers to invest in exploration and development of new natural gas fields.

One need not look further than FERC's Order No. 2005 for evidence that rolled-in pricing is good for explorers and the state. There, the FERC adopted a rebuttable presumption that voluntary expansions of the Alaska line must reflect rolled-in pricing.[11] This means that the FERC will expect that owners of the Alaskan gasline will propose rolled-in treatment for expansions and will likely accept such proposals (or order rolled-in treatment on its own motion if it is not proposed) unless parties can show good reason why rolled-in pricing is not appropriate on this pipeline. This is a complete departure from FERC's policies in the Lower 48 and signals how important FERC views the pricing policies of the Alaskan pipeline sponsors to be. In adopting this presumption favoring rolled-in pricing, the FERC was in fact following the dictates of Congress which had required that FERC's rules regarding access to the Alaskan gas pipeline that must "promote competition in the exploration, development and production of Alaskan natural gas.[12] Clearly, rolled-in pricing for expansions—especially expansions that would otherwise result in higher rates for new shippers than for incumbent shippers—is fully consistent with the desire to encourage exploration and development of North Slope natural gas reserves. AGIA's rolled-in rate provisions protect against the risk that FERC would require incremental rate treatment instead of rolled-in rate treatment for voluntary or involuntary expansions of an Alaska natural gas pipeline.

> TC Alaska, unlike the sponsors of the Producer Project, has committed to using rolled-in pricing for expansions as required by AGIA.
>
> Because of this, TC Alaska's proposal is more likely than the Producer Project to encourage expansions that will the North Slope basin, which will benefit the state through more drilling, more jobs, more royalties and more revenues.

[11] Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, 110 FERC ¶ 61,095, Order No. 2005 at P 123.

[12] ANGPA 2004, § 103(e)(2)(c)

Rolled-in rates are required in Canada. As discussed in Appendix S2, the National Energy Board has required rolled-in pricing even where expansions have resulted in a doubling of the pipeline's rate base which produced a dramatic increase in rates for incumbent shippers. Rolled-in rate treatment, however, has encouraged pipeline expansions in Canada and the creation of a competitive gas exploration and development industry in Alberta.

TC Alaska has committed to the rolled-in pricing for expansions as required by AGIA. However, the sponsors of the Producer Project have not made any commitment, enforceable or not, regarding the pricing of expansion capacity.[13] Therefore, TC Alaska's Project is more likely than the Producer Project to encourage pipeline expansions that will facilitate full development of the North Slope basin, which will benefit the state through more drilling, more jobs, more royalties and more tax revenues. Indeed, the prospect that rolled-in pricing could raise the shipping rates of the BP and ConocoPhillips entities that might hold shipping contracts on the pipeline would clearly discourage the Producer-owners of the proposed project from proposing rolled-in rates.[14]

[13] Further, the Major North Slope Producers not only refused to commit to rolled-in rates in the 2006 SGDA Contract but actively opposed the inclusion of any rolled-in rate requirement in AGIA before it was enacted. In addition, it should be noted that while the apparently withdrawn ConocoPhillips November 30, 2007 proposal did indicate it would use rolled-in rates up to 105% of the pre-existing rate, that proposal fell significantly short of AGIA's requirement that rolled-in rates be used up to 115% of the initial rate. In addition, the mere statement that ConocoPhillips would use rolled-in rates was completely unenforceable by the state or expansion shippers if ConocoPhillips for whatever reason had decided later not to use rolled-in rates.

[14] As shown in Appendix G1, Figure 5-55, the Commercial team projects that expansions of the TC Alaska line up to a capacity of about 6.5 Bcf/day will result in rate reductions to incumbent shippers compared to the rates projected for the 4.5 Bcf/day original project. At a point, however, looping will be required if the capacity is to be increased, and that will be very expensive (compared to merely adding compression). At that point the use of rolled-in pricing for expansions will become critical to whether or not the gasline will continue to be expanded. Without rolled-in rate treatment new shippers will be responsible for the entire cost of the expansion and it will be uneconomic for those shippers to contract for expansion capacity. This will mean that as the pipeline is expanded through the addition of compression up to 6.5 Bcf/day and perhaps somewhat beyond that level, explorers will become less willing to invest new capital exploring for or developing reserves unless it is clear, up front, that looping expansions will be priced on a rolled-in basis rather than incrementally. However, rolled-in pricing of looping expansions comes at a cost to the shippers already using the system—their rates will go up somewhat in order for new shippers' rates to be more reasonable. Inasmuch as a producer-owned pipeline is largely motivated to generate the greatest bottom-line profit from the sale of its own (or its affiliates') production the prospect of raising the rates of incumbent shippers will be adverse to the owners' bottom line interest. Given that a producer-owned pipeline does not have a strong interest in expanding the line to serve others (as discussed above) and has a clear economic *disincentive* to pursuing expansions that require looping, the commissioners are necessarily concerned about whether the sponsors of the Producer Project will ever support the rolled-in pricing that will become necessary for the full development of the pipeline. It is simply not in their economic interest to do so.

4. Commitments To Hold an Open Season and File at FERC, and Other Issues That Could Result in a Delay of the Producer Project

In part to avoid a repeat of the SGDA experience, in which the Major North Slope Producers refused to make concrete commitments to pursue a pipeline project, AGIA required an applicant to make enforceable commitments to advance a project. Specifically, AGIA required applicants to make enforceable commitments to commence an open season, initiate the FERC pre-filing process, and file for a FERC certificate regardless whether the initial open season is successful, by specific dates. Further, AGIA required that the Licensee must agree to accept the certificate issued by the FERC once it becomes final and is not subject to further judicial review. If TC Alaska fails to adhere to these commitments, TC Alaska will be subject to sanctions with adjudication in Alaska courts.

In accordance with those requirements, TC Alaska has committed to hold an open season by September 30, 2009, and to file for a FERC certificate by December 2011, regardless whether its open season is successful, as required by AGIA.[15] By contrast, BP and ConocoPhillips have made an unenforceable claim that they plan to hold an open season by 2010 (BP/ConocoPhillips 2008). They claim they will file for a FERC certificate if the open season is "successful," but this implies that they will not file for a certificate if the open season is "unsuccessful." (ConocoPhillips/BP 2008) Significantly, there is nothing in the BP/ConocoPhillips press release or PowerPoint presentation that even defines what a "successful" open season might actually entail (i.e. there is no indication as to the minimum amount or proportion of capacity that will have to be subscribed in the open season in order for the sponsors to pursue FERC/NEB certification). Thus there is nothing that would bind BP or ConocoPhillips to any concrete action as a result of any open season they would conduct. By contrast, TC Alaska, through its AGIA application, has made enforceable commitments to move its project forward through a binding open season, filing for the critical FERC certificate and acceptance of that certificate.

The commissioners recognize that BP and ConocoPhillips have stated their intention to spend $600 million over a three-year period as part of an initial development and planning phase of the

[15] In its Application, TC Alaska premised these dates on receiving the AGIA License by April 1, 2008. Assuming the License is issued to TC Alaska later this year, these dates may need to be adjusted. However, for ease of reference in these Findings we will continue to refer to the original dates used by TC Alaska in its Application.

Producer Project. However, they announced their plans only after TC Alaska proposed its project. The commissioners believe that if the state rejects TC Alaska's Project, there is a significant risk that BP and ConocoPhillips will delay further work on the Producer Project until the state agrees to provide financial concessions.

In addition, the fact that BP and ConocoPhillips have not made any binding commitments to advance the project on a fixed timeline is problematic due to the large volume of natural gas sales they make in the North American market. As two of the largest producers of natural gas in the U.S. and the world, BP and ConocoPhillips have a clear interest in controlling the schedule of any Alaska gas pipeline construction project and having power over the timing of shipping natural gas to North American consumers. The commissioners must assume that these sophisticated companies take into account the impact that bringing 4 or 4.5 Bcf/day of additional natural gas to market will have on the price of other natural gas these companies sell.[16] The commissioners know that the Energy Information Administration (EIA) has predicted and forecasts that gas prices in North America will somewhat decrease (at least initially) once Alaskan gas comes on line.[17] An Alaska gasline thus would somewhat reduce the value of the other North American gas production and reserves these Producers own. It would be naïve to think that BP and ConocoPhillips (or any other producer companies that might become investors in the Producer Project) will not manage their overall gas portfolio in the best interests of their shareholders even if it means delaying an Alaska gasline.

The commissioners also know that both BP and ConocoPhillips have significant investments in projects to bring LNG to the U.S. For example, ConocoPhillips has a 30% ownership interest in Qatargas 3—a $5.8 billion LNG project bringing 1.4 Bcf/day equivalent of LNG to the U.S. starting in 2009. ConocoPhillips also has an interest in the Golden Pass LNG regasification

[16] Indeed, the commissioners are aware that ICF International, a major international consulting firm, "evaluated [for Alaskan gas producers] the effect of Alaska and Mackenzie Delta gas on US and Canadian gas markets prices and pipeline flows [and evaluated] various scenarios to assist the [Alaskan] North Slope producers in understanding the implications of different assumptions and configurations for bringing frontiers (sic.) supplies to market." (http://www.icfi.com/Markets/Energy/fuels-markets.asp#1) The commissioners would fully expect that many other similar studies have been undertaken by or on behalf of BP and ConocoPhillips (and other North Slope producers) in order for them to manage their overall gas portfolios, of which Alaskan gas is only one piece.

[17] In February 2004 EIA was specifically requested to evaluate the impact on U.S. gas prices if Alaskan gas does not flow. The conclusion was that Lower 48 gas prices would be approximately 20 cents higher than if Alaskan gas was available. Energy Information Administration, *Analysis of Restricted Natural Gas Supply Cases* at 8 (2004). While not specifically discussed, the 2007 Annual Energy Outlook implies a similar result.

facility near Sabine, Texas that will be supplied by Qatargas 3 according to the company's "*Fact Book.*" (ConocoPhillips, undated)

BP's website states that it imports LNG shipments into existing LNG terminals in the Lower 48 and will supply Indonesian gas to the Energia Costa Azul project that will supply markets in the U.S. and Mexico. (BP 2008) The economics of these and other LNG projects may also be affected by whether the price of gas in North America is decreased by the addition of the Alaskan gas to the overall supply. As a result of the potential adverse impact an Alaska gasline could have on the LNG investments of BP and ConocoPhillips, there is a significant risk the producers would delay the Alaska gasline until such time as it would have the optimal impact for their shareholders, which is not necessarily as soon as the State of Alaska would prefer. This fact suggests the state should not rely on BP and ConocoPhillips to move forward a gasline project.

Another significant schedule issue facing the Producer Project is the Canadian regulatory process. First, TransCanada Corporation has the largest natural gas pipeline network in Canada, having obtained NEB approval for the construction of virtually its entire system. Neither BP nor ConocoPhillips have anything approaching the same level of experience as the TransCanada in obtaining Canadian regulatory approvals to construct natural gas pipelines.

Second, any effort by the Producer Project to obtain Canadian regulatory approvals would probably become ensnared in litigation based on TransCanada's claims to have the first right to construct an Alaska gas pipeline project under Canadian law. If TransCanada's claim has merit (an issue on which the commissioners take no position) and if TransCanada prevails in its arguments, the Producer Project might never advance. This would be true even if BP and ConocoPhillips decide to include a different Canadian pipeline company, such as Enbridge, in their project.

Third, TransCanada has already obtained a right-of-way in the Yukon, whereas the Producer Project has not. Thus, the Producer Project may not be able to obtain the necessary regulatory approvals to construct an Alaska gas pipeline through Canada as quickly as TransCanada.

D. A Producer-owned Pipeline Has an Incentive to Act in Ways That Are Contrary to the Best Interests of the State

The failure of BP and ConocoPhillips to make any enforceable commitments to advance the project is compounded by the fact that a producer-owned pipeline has an inherent incentive to act in a way that is contrary to the interests of the State of Alaska in facilitating the full expansion of an Alaska gasline. There is a significant risk that the sponsors of the Producer Project would not act in a way that is consistent with the state's interests with respect to low transportation rates, an explorer-friendly expansion policy, and full development of North Slope reserves. Indeed, there is a significant risk that the producer-owners of the project could become entangled in litigation as a result of the serious competitive issues that would be raised by producer-ownership of an Alaska gas pipeline.

> A producer-owned pipeline has an inherent incentive to act in a way that is contrary to the interests of the State of Alaska with respect to facilitating the full expansion of an Alaska natural gas pipeline, establishing low transportation rates, implementing an explorer-friendly expansion policy, and ing Alaska's North Slope natural gas resource.

A producer-owned pipeline has an inherent ability and incentive to discriminate against third-party producer-shippers that do not own the pipeline.[18] By raising the pipeline's rates or engaging in acts of discrimination against third-party producer-shippers, the gasline could be used to discourage entry by other producers and explorers. As discussed earlier, the state's experience with the TAPS oil pipeline illustrates this point. Third-party producers have long complained that the TAPS rate structure impedes their ability to explore for and produce oil in Alaska.[19] The owners of the gasline could attempt to achieve a similarly anticompetitive situation.[20] Access to an oil pipeline such as TAPS is not an issue because oil pipelines are "common carriers" and not "contract carriers" as are gas pipelines (Appendix R4). Because of this, the basin control risk that competing producers face is greater in the context of a FERC-

[18] The competitive problems associated with a producer-owned pipeline are fully discussed in the memorandum prepared by Greenberg Traurig dated December 21, 2006, entitled "Updated Competitive Analysis of Producer-Owned Alaska Natural Gas Pipeline", http://lba.legis.state.ak.us/sga/doc_log/2006-12-21_alaska_antitrust_memo.pdf. A copy of the Greenberg Traurig memorandum is attached to these Findings as Appendix R4

[19] *See, e.g.,* Protest and Complaint of Anadarko Petroleum Corp., filed in FERC Docket No. OR05-3, Dec. 16, 2004.

[20] Interestingly, referring to the pipeline proposal by ConocoPhillips on November 30, 2007 (which ConocoPhillips withdrew when it and BP announced Denali), Anadarko asserts that "the rate estimate provided by TransCanada is considerably lower than the rate proposed by the ConocoPhillips proposal for comparable service." See Appendix A.

regulated gasline than in the context of a FERC-regulated oil line, such as TAPS.[21] In TAPS, they face the potential of high rates. In the gasline they face that risk as well, but also the risk that they will be denied meaningful access to pipeline expansions in order to ship the production from their exploration and development activities to market.

One of the goals of AGIA is to ensure these types of competitive problems do not occur in the development of North Slope natural gas reserves. AGIA provided an opportunity for any company, including a producer, to obtain the incentives associated with the AGIA License. However, to help avoid the problems experienced with TAPS and the inherent competitive problems associated with a producer-owned gas pipeline, AGIA essentially requires the Licensee to act like an independent pipeline. For example, an independent pipeline has an incentive to expand its system and increase its profits.[22] By contrast, a producer-owned pipeline may be incented to control the production basin and to delay or thwart expansion as a way to limit competition by competing producers (Appendix R4). AGIA's expansion and rate provisions seek to prevent this problem from occurring. By virtue of the producer-owners' interests that are at odds with the state's interest (as set out in AGIA), and by failing to commit to follow those provisions, the Producer Project is less likely than TC Alaska to result in the full development of the state's North Slope natural gas reserves.[23]

[21] The rates for interstate service on the TAPS line are regulated by FERC. As an oil pipeline subject to regulation under the Interstate Commerce Act TAPS is a "common carrier" pipeline. That means that it must provide service to every party seeking to move oil through the line, even if doing so means that other shippers' capacities must be reduced. Under FERC regulations of natural gas pipelines under the Natural Gas Act, however, the Alaskan project will become a "contract carrier." *Regulation of Natural Gas Pipelines After Partial Wellhead Deregulation*, Order No. 436-A, 50 Fed. Reg. 52,217 (1985). This means that new shippers do not have any right to firm capacity once the capacity is fully contracted to others. The significance here is that the TAPS owners cannot deny <u>access</u> to potential shippers whereas owners of the gasline can deny access by refusing to expand to accommodate new shippers (unless they can successfully petition FERC to require an expansion). Thus, a party seeking service on the Alaskan gasline may be denied access to the line in the event that capacity to move its gas is not available because other parties have contracted for the capacity but such a circumstance could never arise on TAPS because capacity must be made available. However, on both the TAPS line and an Alaskan gas pipeline producer-owners can seek to increase rates in the line in order to make production of Alaskan gas uneconomic as a way to exercise basin control.

[22] This is because regulated gas pipelines make their profit (their return on equity) based on the amount of investment they have in the pipeline (referred to as "rate base"). As a result of depreciation, rate base is continually being eroded which means the pipeline's earnings base is being continually eroded. The way that gas pipeline companies overcome such erosion of their earnings potential is through adding new facilities (*i.e.*, expanding the pipeline).

[23] It is possible that BP and ConocoPhillips will eventually expand their Denali partnership to include a third-party pipeline (such as Enbridge). Whether that step would cure the competitive problems inherent in a producer-owned pipeline would depend on how the partnership is structured, although a complete cure is unlikely. For example, if one or more of the producers could veto a commercially reasonable expansion, the inclusion of a third-party pipeline company in the Denali partnership would not fix the problems. Moreover, Denali still would have failed to commit to the requirements of AGIA.

There is also a risk that a pipeline owned by BP and ConocoPhillips would be exposed to litigation or investigations either by FERC, the Department of Justice, the Federal Trade Commission, or potential private plaintiffs. For example, the Department of Justice, headed by the U.S. Attorney General, warned in the 1970s that producer ownership of an Alaska natural gas pipeline would raise serious competitive concerns. This warning relates to basin control - the ability of a producer-owner of an Alaskan gas pipeline to discriminate against rival producers, including delaying or limiting pipeline expansions needed to serve rival producers. That issue resulted in the Department of Justice's recommendation in 1977 that producers be completely barred from owning any equity interest in an Alaskan pipeline.[24] That eventually gave rise to a requirement that, for any project built under the ANGTA legislation, "any agreement on producer participation [in the Alaskan pipeline] may be approved by the [FERC] only after consideration of advice from the Attorney General and upon a finding by the [FERC] that the agreement will not (a) create or maintain a situation inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the Alaska segment of the [proposed pipeline]."[25] (Minesinger 2007)

Based on these same concerns, there is a significant likelihood that FERC-imposed conditions on any certificate (assuming BP and ConocoPhillips file for a certificate) may be necessary to ensure that the project ultimately serves the public interest, not just the interests of BP and ConocoPhillips. FERC has the power to place conditions on any certificate it issues when it finds that such a condition is necessary to ensure or protect the "public convenience and necessity." However, while AGIA requires that the Licensee actually accept the certificate that is issued by the FERC once it becomes final and is no longer subject to judicial review, BP and ConocoPhillips have no such obligation. Thus if the FERC imposes conditions on the certificate it might issue to the Producer Project in order to protect the public interest, BP/ConocoPhillips could reject the certificate because of the conditions. In that case, Alaska would find itself with no gas pipeline at all.

[24] Public Papers of the Presidents of the United States, Reagan, Ronald, 1981 Pub. Papers at 935 (1981).

[25] Pub. L. No. 97-93, 95 Stat. 1204, 1981

The prospect of FERC conditions designed to minimize or eliminate competitive concerns was addressed in a January 28, 2005, letter from the then-FERC Chairman to Representative Ethan Berkowitz of the Alaska Legislature:

> In authorizing an Alaskan gas pipeline under the NGA, the Commission will seek to promote investment in and the development of Alaskan gas reserves to expedite the delivery of these reserves to markets in and out of Alaska, in conformity with antitrust laws. In doing so, the commissioners will be mindful of the congressional and presidential pronouncements you referenced in your letter.

Continuing, the FERC Chairman stated:

> Currently, the Commission does not have before it any application for authority to construct an Alaskan natural gas transportation pipeline. Thus, it is not possible to respond specifically to issues, including antitrust matters, which may arise once such an application is filed. However, all such issues will be carefully assessed by the Commission when an application is submitted for a pipeline project, and *the Commission will do everything it can to preclude antitrust abuses and promote competition in the authorization, construction, and operation of a future Alaskan natural gas pipeline . . . [I]t would be prudent to conclude that the antitrust issues which concerned Congress and the President over twenty years ago are still valid and will be addressed by our Commission in our proceedings.*[26]

This statement highlights the potential that FERC would impose a certificate condition unacceptable to BP and ConocoPhillips, which could cause them to delay or even abandon the project. It also indicates BP and ConocoPhillips, as owners of the project, could face additional scrutiny from federal antitrust agencies, and possibly from the State Attorney General, who is charged with enforcing Alaska's antitrust laws. BP and ConocoPhillips would also face the risk of antitrust litigation by private plaintiffs seeking to prevent the development of an anticompetitive market structure or anticompetitive activity that could impede or distort the development of North Slope natural gas reserves.

[26] FERC Docket No. RM05-2, January 28, 2005 Letter at 2 (emphasis added)).

E. Both TC Alaska and the Producer Projects Lack Firm Shipping Commitments

Neither TC Alaska Project nor the Producer Project has firm shipping commitments to support their respective projects at this time. It might be assumed that the Producer Project (owned by BP and ConocoPhillips) would have the ability to obtain firm shipping commitments from its owners. The commissioners acknowledge that, at first glance, the Producer Project would appear to have an advantage over TC Alaska in convincing BP and ConocoPhillips to sign firm shipping commitments on their own project.[27]

A significant problem, however, is that BP and ConocoPhillips have consistently insisted, including in their AGIA comments, that the state must provide them with major fiscal concessions before an Alaska gasline project can proceed. ConocoPhillips stated in a January 24, 2008 letter that, with regard to firm shipping commitments and other issues, "[n]o commercially reasonable party will take these unprecedented investment risks until a number of conditions have been met, including the establishment of a predictable gas fiscal framework,…" (ConocoPhillips 2008).

As a result of these demands for fiscal certainty, the Producer Project is unlikely to obtain unconditional firm shipping commitments that are not conditioned on or dependent upon such concessions from the state. Chapter 3 of these Findings demonstrated that, even under the state's current fiscal structure, the Major North Slope Producers would earn billions of dollars in profits and an extraordinary rate of return by signing firm contracts on the TC Alaska project (which presumably will have similar costs to those that would be incurred by the Producer Project), even if the only North Slope gas they ever produce is from the Prudhoe Bay Unit.

[27] We also acknowledge that BP and ConocoPhillips unquestionably have the financial resources to construct the Denali project. In the presentation which accompanied the Denali announcement, BP and ConocoPhillips emphasized their financial strength, pointing to their combined $300 billion market capitalization. *See* BP/ConocoPhillips Denali PowerPoint presentation, at slide 11, April 8, 2008. These companies' financial strength and their ability to finance a large-scale project cannot be doubted. On the other hand, while TransCanada is also a major energy company, its market capitalization is not as large as the combined market capitalization of BP and ConocoPhillips. *See* Appendix H at Section 4. Nevertheless, Goldman Sachs concludes that TransCanada has the financial resources to obtain financing of the Project. *See* Appendix H at Section 4. Accordingly, while BP and ConocoPhillips may have more financial resources than TransCanada, both projects have the necessary financial wherewithal to succeed, assuming other barriers to financing (such as the need to obtain firm shipping commitments) can be overcome.

In comparison, the TC Alaska project will include upstream fiscal inducements provided through AGIA for any gas committed at the initial binding open season for the project. These inducements increase the likelihood that TC Alaska's project will attract commitments from the Producers even with the existence of the Producer Project. In addition, prior to the TC Alaska open season, the state may choose to increase the value of those inducements, if proven necessary.

F. Comparison of the Costs to the State Following the TC Alaska Project Path or the Producer Project Path

Some have suggested the state would be better off pursuing the Producer Project instead of the TC Alaska Project because the Producer Project would allegedly "save" the state up to $500 million. In other words, the argument is that the Producer Project is offering the state a better deal because it would build a natural gas pipeline without any state matching funds, whereas TC Alaska would be entitled under AGIA to receive $500 million for qualified expenses incurred to develop its Project. This argument is flawed, for several reasons.

> The State of Alaska will receive a net benefit from its $500 million inducement if the TC Alaska project is constructed.

First, as discussed in Chapter 3, the state would actually realize a *higher* NPV as a result of paying the $500 million to TC Alaska. In other words, the state will not only get the $500 million back, but will make more than a 5% return on the investment. This is because the matching funds will not be included in the transportation rates TC Alaska would charge for the Project. As a result, TC Alaska will charge lower transportation rates, which in turn will increase net backs and producer profits, and in turn increase state royalty and tax revenues which depend heavily on the level of Producer profits.

Thus, contrary to the argument that the state would be better off abandoning AGIA and avoiding what some consider the unnecessary expenditure of $500 million of state funds on the TC Alaska project, this analysis demonstrates that the state would actually receive a net benefit if the TC Alaska project is constructed compared to the Producer Project.

In addition, the state will receive significant benefits and commitments from TC Alaska in exchange for the matching funds. For example, as demonstrated above, TC Alaska's commitment to a 75/25 debt to equity structure would increase the value of the project to the state by more than $8 billion over a possible Producer Project structure. These benefits also include values that cannot be as easily quantified. Examples of these benefits include enforceable commitments by TC Alaska to expand its pipeline when commercially reasonable, to hold an open season by a date certain, to file for a FERC certificate on a fixed timeline and regardless whether the initial open season is successful, to hire state workers to the extent permitted by law, and to provide in-state deliveries of natural gas at reasonable rates. The Producer Project has not made any enforceable commitments. Critics of the $500 million fail to recognize the "quid" the state will receive for the $500 million "quo."

Even if one ignores the benefits the state stands to receive for the $500 million, the cost of those funds pales in comparison to the billions of dollars in concessions that the Major North Slope Producers demanded the state provide them during the SGDA negotiations as a precondition to even considering a pipeline project. In their AGIA comments, BP and ConocoPhillips have renewed their insistence that the state make significant fiscal concessions as a precondition to moving a natural gas pipeline forward. Thus, it is reasonable to conclude that the expenditure of up to $500 million of state matching funds on the TC Alaska project would be significantly less than the amount the state would be required to spend or forego to induce construction of the Producer Project.

> AGIA's $500 million inducement pales in comparison to the billions of dollars in concessions which the Major North Slope Producers demanded during the SGDA negotiations.

Those concessions are likely to be even more substantial if the legislature rejects the TC Alaska Project. As discussed earlier, the state found itself in an untenable negotiating position with the Major North Slope Producers in the SGDA negotiations. The prior administration terminated negotiations with the other applicants under SGDA and elected to negotiate exclusively with the Producers. By eliminating its options or alternatives to a negotiated agreement with the Producers, the previous administration gave up any leverage that it had, and thus was unable to negotiate an agreement that protected the state's interests.

AGIA provides a clear path to move the natural gas pipeline project forward. TC Alaska has committed to take this project through the acceptance of certificates from the FERC and Northern Pipeline Agency/National Energy , complying with all of the requirements of AGIA. Due to the favorable economics of the TC Alaska project, including the extraordinary profits it would generate for Producers, it should be unnecessary for the state to have to take action regarding any failure by the Producers to support TC Alaska's project. However, the state has a strong fallback position if the Producers, TC Alaska, and the state cannot agree to terms in the interim.

> TC Alaska's commitments to obtain permits and authorities to construct and operate a pipeline will position the state to require that the Major North Slope Producers fulfill their obligations to produce and market the state's natural gas resources.

Finally, if in the future the Major North Slope Producers can make a convincing case, based on market conditions at that time, that fiscal concessions by the state in addition to those already attached to the TC Alaska project are needed to move the project forward, then AGIA provides the vehicle for that to occur. Having elected to issue a License to TC Alaska, the state would have a strong interest in taking all actions necessary to see the TC Alaska project succeed, so long as such actions are reasonable and consistent with the state's interests. Those actions could include fiscal changes, although as stated above no need for any fiscal changes has been demonstrated at this time.

G. TC Alaska's Offer of Equity Partnership

In its Application, TC Alaska has indicated a willingness to offer equity participation opportunities to any shipper that participates in the initial open season. According to TC Alaska, offering shippers an equity ownership opportunity will enhance the chances its project will have a successful open season and will align the interests of TC Alaska and its shippers. It is thus quite possible that one or more of the Major North Slope Producers may eventually participate in the TC Alaska Project as an owner. Indeed, in its comments ExxonMobil states that it "agrees with [TC Alaska's] suggestion that it would be useful for the [Major North Slope Producers] to be involved as co-owners in the project" (Appendix A, comment #269). An example of a joint pipeline/producer ownership structure involving a major new natural gas pipeline project is the recent Rockies Express pipeline, in which the majority owner is an independent pipeline company (Kinder Morgan), while ConocoPhillips is a minority owner (along with Sempra).

AGIA supports the possibility of offering equity participation opportunities to shippers. Depending on the facts and circumstances, including the structure of and specific rights associated with any equity ownership position, equity ownership in the TC Alaska project by shippers that make firm shipping commitments on the Project could be consistent with AGIA.

The commissioners believe TC Alaska's willingness to include firm shippers as equity partners in its AGIA project is a positive step, as is ExxonMobil's favorable reaction. The commissioners strongly encourage the parties to discuss ways of collaborating on an AGIA-compliant project.

H. The Upstream Inducements Provided by AGIA are Valuable and Incentivize the Producers to Commit Gas to the TC Alaska Project

The question can fairly be asked, "What will cause the North Slope Producers to commit natural gas production to TC Alaska's project and why should the state even consider investing up to $500 million in that project?" This is especially relevant in light of the Producer Project.

The answer lies in the provisions of AGIA that provide meaningful and valuable benefits to parties that commit their gas to the AGIA licensed project in the first binding open season (AS 43.90.310 and .320). Those provisions give to holders of state leases that commit gas to the AGIA-licensed project the assurance that, for ten years after the commencement of commercial operations by the licensed pipeline, their production tax rates will not change from those in effect at the close of the first binding open season. The Producers can also obtain the benefit of future royalty regulations that the state will establish prior to the close of the first binding open season for the licensed project. These royalty regulations will establish a method for determining fair market value; minimize the retroactive adjustments to the monthly determination of value for the state's royalty share; and define the state's rights to switch between taking royalty gas in-kind versus in-value.

AGIA inducements represent real value to the producers that is "here and now," not speculative.

These provisions of AGIA are available only to producers who commit gas to the first binding open season of the AGIA licensed project. They are not available to producers who commit their gas to any other project—in this case, to the Producer Project.

Historically, the Producers have insisted on much more sweeping (frequently unspecified) concessions by the state with respect to taxes and royalties (and, under SGDA, many other major concessions). As discussed in Chapter 3 of the Findings, there is no reason for the commissioners to believe at this time that any concessions on the state's part are needed over and above those already available to producers who commit gas to the AGIA project during its first open season. The upstream inducement provisions of AGIA, however, are available now - and those inducements will be locked in if all of the producers commit their production to the AGIA project.

Given the fact that no basis currently exists to support the state's providing any additional concessions to induce parties to commit their gas to a gas pipeline, the availability of the upstream inducements of AGIA represent real value to the Producers. The value is "here and now" and not speculative. Given the NPV that the commissioners believe will flow to the major North Slope Producers under the TC Alaska Project, it is reasonable to believe that the Producers will act as rational commercial players and commit gas to the TC Alaska Project in order to secure the benefit of the upstream inducements of AGIA.

I. It is in the State's Interest to Pursue the TC Alaska Project

It should be clear that Alaska is better served by obtaining a natural gas pipeline that will provide the many benefits that will flow from an AGIA-licensed project. However, nothing in AGIA prevents or limits the rights of BP/ConocoPhillips to pursue their own project; in fact, the competition between the TC Alaska project and the Producer Project probably moves the state closer to a natural gas pipeline.

However, if, at the end of the day, for whatever reason the Producer Project wins out and obtains shipper support, regulatory approvals and financing, and builds the project, the state is better off than if no line is constructed. Based on prior experience (TAPS and SGDA) it is not likely that this circumstance will occur without having the TC Alaska Project supported by the state. The presence of the TC Alaska Project will constantly force the Producers to move forward with the Producer Project, join the TC Alaska project, or face the risks outlined in Chapter 3 associated with failure to commercialize Alaska's North Slope gas.

> Competition is good—The presence of the TC Alaska project will constantly force the Producers to move forward with the Producer Project, join the TC Alaska project, or face the risks outlined in Chapter 3 associated with failure to commercialize Alaska's North Slope gas.

J. Conclusion

The commissioners' objective is to find a project that maximizes benefits to Alaskans. On balance, the commissioners believe it is in the state's interests to rely on the binding commitments made by TC Alaska rather than on the Producer Project. The sponsors of the Producer Project, by contrast, have not made any comparable commitments and, as evidenced by the history of the failed SGDA contract and TAPS, are unlikely to pursue their project on a basis that fully achieves the state's interests.

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Chapter Six — Findings and Determination

Table of Contents

Commissioners' Findings 6-1
Commissioners' Determination 6-2

Commissioners' Findings

Based on the analysis provided in the previous chapters, the Appendices, and in the supporting documentation, the commissioners find that the TC Alaska Project:

- Is Alaska's best opportunity for expediting construction of a natural gas pipeline that commercializes North Slope gas resources.
- Maximizes jobs and long-term careers for Alaskans by promoting exploration and development of oil and gas resources on the North Slope.
- Maximizes access to affordable energy for Alaskans.
- Sufficiently maximizes revenues to the State of Alaska.
- Encourages oil and gas lessees and other persons to commit to ship natural gas from the North Slope to a gas pipeline system for transportation to markets in this state or elsewhere.

Commissioners' Determination

Development of the North Slope natural gas basin is key to Alaska's long-term economic security and to the state's and the nation's energy security. The Alaska Gasline Inducement Act (AGIA) offers an opportunity to maximize Alaska's prospects for getting a natural gas pipeline and to maximize benefits for Alaskans when it comes to developing and marketing Alaska's gas resources.

One of the primary purposes of AGIA is to move the pipeline project forward through defined benchmarks so as to eliminate the project's uncertainties. At each step of the process more information will be gathered and, with that additional knowledge, appropriate decisions can be made to keep the project moving through to construction. With the uncertainties eliminated, and the project's economic potential even better defined, there will be increased predictability and incentives for the Major North Slope Producers to participate as gas shippers – without concomitant concessions by the state on the fiscal terms associated with natural gas production (such as royalty values and the state production tax).

The commitments required of an AGIA Licensee are geared toward achieving a vibrant oil and gas industry on the North Slope now and in the future. The AGIA requirements are based on what is commercially reasonable as well as what is in Alaskans' interests: getting a natural gas pipeline, maximizing jobs and long-term careers, maximizing affordable energy for Alaskans, and sufficiently maximizing state revenues.

In the course of the evaluation process, the commissioners found that the pipeline project proposed by TC Alaska is the project that has the greatest likelihood of moving forward in a timely manner with terms that most sufficiently maximize benefits to Alaskans. In comparison, the commissioners found that an LNG project will provide less revenue to the state and is less likely to move forward to construction because, among other issues, an LNG project (1) is extremely complex and requires that all elements, from production to the market destination, be in place prior to financing; (2) would likely cost more to construct than the TC Alaska project; (3) is less likely to get firm transportation commitments from North Slope producers; and (4) would face significant hurdles in obtaining federal approval to ship LNG to foreign ports.

The commissioners also found that the Producer Project would not protect the state's interests or maximize benefits to Alaskans to the same extent as the TC Alaska Project. The Producer Project provides no legally enforceable commitments that the project will continue to move forward or provide the reasonable tariff and expansion terms needed to maximize North Slope exploration and development. Furthermore, it is highly likely that, at some point, the Producer Project proponents will seek significant concessions from the state prior to moving the project forward to construction.

Through the evaluation process, and consideration of public comment, the commissioners have found that the TC Alaska Project is economically and technically viable; that it will generate significant value for the state, the producers, the federal government, and the pipeline company; that the Project is likely to succeed; and that TC Alaska has made the necessary commitments to maximize benefits to Alaskans.

> **Commissioners' Determination: Based on the analysis and discussion set forth in the Executive Summary, Chapters 1 through 5, the Appendices including Public Comment and Responses, and other supporting documents to these Findings, the Commissioners of the Departments of Natural Resources and Revenue determine that TC Alaska's application proposes a project that will sufficiently maximize the benefits to the people of this state and merits issuance of a License under AGIA (AS 43.90).**

Because of the sheer volume of material incorporated into the Findings and Determination, the commissioners reserve the right to provide errata to correct errors or omissions that do not have a material effect on the Determination itself.

This Findings and Determination, Appendices, and associated License will be submitted to the presiding officers of each house of the Alaska Legislature on June 3, 2008. In addition, the Findings and Determination and Appendices will be publicly noticed and made available on the state's website at http://www.gov.state.ak.us/agia/. Hard copies of the Findings and Determination and Appendices on CD will be available for review at Department of Natural Resources Public Information Centers and Legislative Information Offices. Upon legislative approval of issuing the License proposed by the commissioners, the License will be issued to TC Alaska as soon practicable after the effective date of the legislation.

On the effective date of a bill approving issuance of the AGIA License, this determination becomes a final agency decision for purposes of an appeal to Superior Court. (AS 43.90.180(a)(1)) A person affected by this final order and decision may appeal to Superior Court within 30 days of the effective date of the bill approving issuance of the AGIA License in accordance with Appellate Rule 602(a)(2) of the Alaska Rules of Appellate Procedure.

Pursuant to AS 43.90.420, "[a] person may not bring a judicial action challenging the constitutionality of this chapter or the constitutionality of a License issued under this chapter unless the action is commenced in a court of the state of competent jurisdiction within 90 days after the date that a License is issued."

______________________________ 27 May 2008

Commissioner Thomas E. Irwin Date

Alaska Department of Natural Resources

______________________________ 27 May 2008

Commissioner Patrick Galvin Date

Alaska Department of Revenue