

Corrections

June 17, 2009

This document includes the following corrections to the AGIA Gas Pipeline Project Report originally issued on April 30, 2009

Page 2: Date changed from “December 5, 2009” to “December 5, 2008”

Page 2: Deleted “\$20 million in training for gas pipeline related jobs” because this benefit was pursued through supplemental appropriation and not as part of the AGIA license

Page 6: Date changed from “December 5, 2009” to “December 5, 2008”

Page 19, lower table: Title changed from “Cost Estimate for Development Phase” to “Cost Estimate for Execution Phase”



AGIA Gas Pipeline Project Report



April 30, 2009

Prepared by: State of Alaska
Department of Revenue
Department of Natural Resources

Introduction

This report from the Department of Revenue (DOR) and Department of Natural Resources (DNR) is submitted as a supplement to reporting required under AS 43.90.400, the Alaska Gasline Inducement Act (“AGIA” or “the Act”).

AGIA was ratified by the legislature on May 16, 2007 to encourage expedited construction of a natural gas pipeline from Alaska’s North Slope. The Act instructed the DOR and DNR Commissioners to solicit applications for a license to receive certain inducements from the State. After review of the submitted applications, the Commissioners recommended a license be jointly issued to TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd (for purposes of this report will be jointly referred to as “TC Alaska”). The recommendation was approved by the legislature on August 1, 2008 and the license issued and signed by the Commissioners on December 5, 2008.

In exchange for making certain schedule, tariff and expansion commitments to advance the project, the AGIA licensee is entitled to receive certain inducements including:

1. The assistance of a dedicated AGIA Coordinator with authority to expedite permitting;
2. Fixed tax and royalty terms for a specified period of time for gas which is committed during the first Open Season of the project; and
3. Up to \$500 million reimbursement from the AGIA fund for qualified expenditures

AS 43.90.400 requires the DOR and DNR Commissioners to submit a report to the legislature on the status of reimbursements within the first 10 days of each regular session. The report must include a list of all disbursements made from the AGIA fund during the preceding fiscal year, a written justification for each disbursement and the projected amount of money that will be required for future disbursements during each of the next three fiscal years.

In addition to information required under AS 43.90.400, this report includes information related to the progress of the pipeline project, and updates on natural gas markets and capital cost expectations. Subsequent reports and other related information can be accessed online at <http://www.gov.state.ak.us/agia/>.

Index

1	AGIA Reimbursements	4
1.1	Requested Reimbursements	4
1.2	AGIA Fund Disbursements	4
1.3	Estimated Project Spending	4
2	Project Status Report	6
2.1	Schedule and Timeline	6
2.2	Major Achievements and Milestones	8
2.3	Amendments or Modifications of Project Plan	9
3	Alaska Workforce and Business Participation	11
3.1	Alaska Hire and Contracting	11
3.2	Workforce Development	11
4	Market Update and Cost Expectations	13
4.1	North American Natural Gas Market Update	13
4.2	Costs Estimate	16
4.3	Capitalization Plan	19
5	Conclusion	20

1. AGIA Reimbursements

In mid-February, the Department of Revenue contracted with PangoMedia, Inc. to develop a system to track and manage reimbursement of qualified expenditures in accordance with the Alaska Gasline Inducement Act (AGIA).

During the first phase of this project, PangoMedia is working with DOR staff to develop two key documents. The first details the processes and workflows of the entire reimbursement process. The second document details the business and regulatory requirements identified as necessary to develop a custom reimbursement management system.

Following the analysis effort, the Department plans to solicit proposals for building the system according to the specifications defined during the previous phase. This process will allow the state to efficiently track and evaluate and project expenditures so that reimbursements and audits may be conducted in an accurate and timely manner.

1.1 Requested Reimbursements

As of the date of this report, no reimbursements have been requested by TC Alaska. It is expected that TC Alaska will submit its first reimbursement request during May or June of 2009. TC Alaska anticipates cumulative expenditures for Q1 to total approximately \$11 million, of which \$5-6 million would be reimbursable by the state (See Section 1.3 below).

1.2 AGIA Fund Disbursements

No disbursements have been made from the AGIA Fund.

1.3 Estimated Project Spending

The following expenditures are based on TC Alaska's First Quarter 2009 Budget Report Update, and show total actual and forecasted spending through the term of TC Alaska's commitment under the AGIA license.

Estimated Project Spending Through FERC Certification (Thousands \$)¹

Fiscal Year	2009	2010	2011	2012	2013	2014	TOTAL
Total Annual	24,797	53,951	134,568	137,128	137,128	137,128	
TC Alaska	12,612	28,395	21,593	20,700	20,700	20,700	
State of Alaska	12,185	25,556	112,975	116,428	116,428	116,428	
Total Cumulative	24,797	78,748	213,316	350,444	487,572	624,700	624,700
TC Alaska	12,612	41,007	62,600	83,300	104,000	124,700	124,700
State of Alaska	12,185	37,741	150,716	267,144	383,572	500,000	500,000

¹ Numbers are based on TC Alaska's Q1 Budget Report. The report was prepared in Canadian Dollars and converted to US dollars @ 1.15 FX rate (based on Dollar @ December 2008). Estimates are also based on TC Alaska's proposed Standard Labor Rates for TC Alaska employees. Comparative spending after 2010 reflects a change in the state's matching contribution from 50/50 to 90/10 following the open season.

2. Project Status Report

Earlier this year the State of Alaska issued an RFP for assistance with monitoring of compliance with the AGIA Licensee's (TransCanada) gas pipeline project plan. The State awarded a contract to Pingo International Inc. whose principle, Patrick Anderson will provide the technical monitoring service.

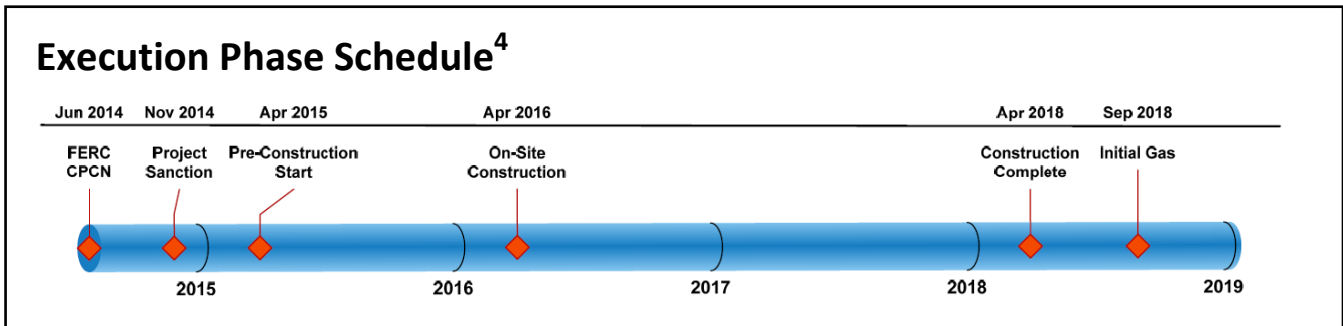
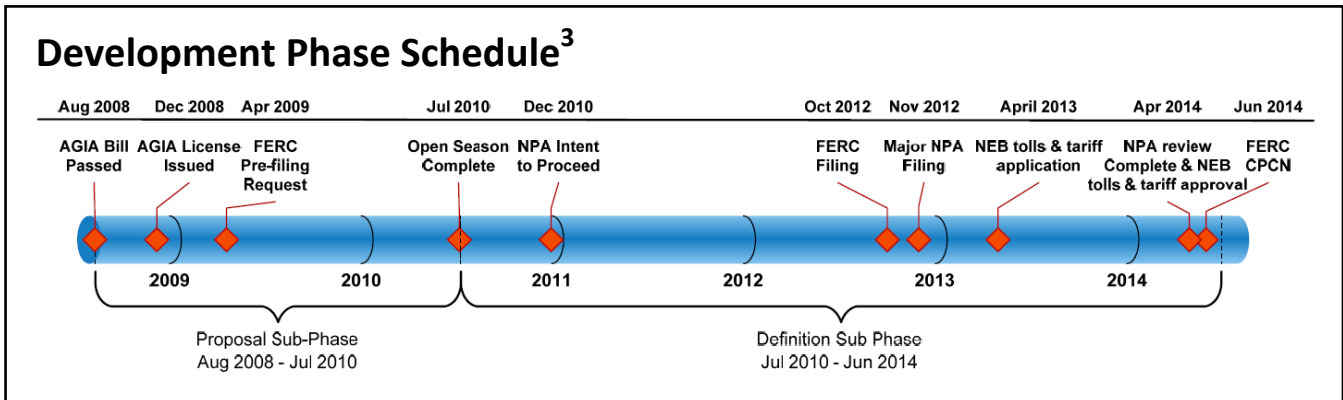
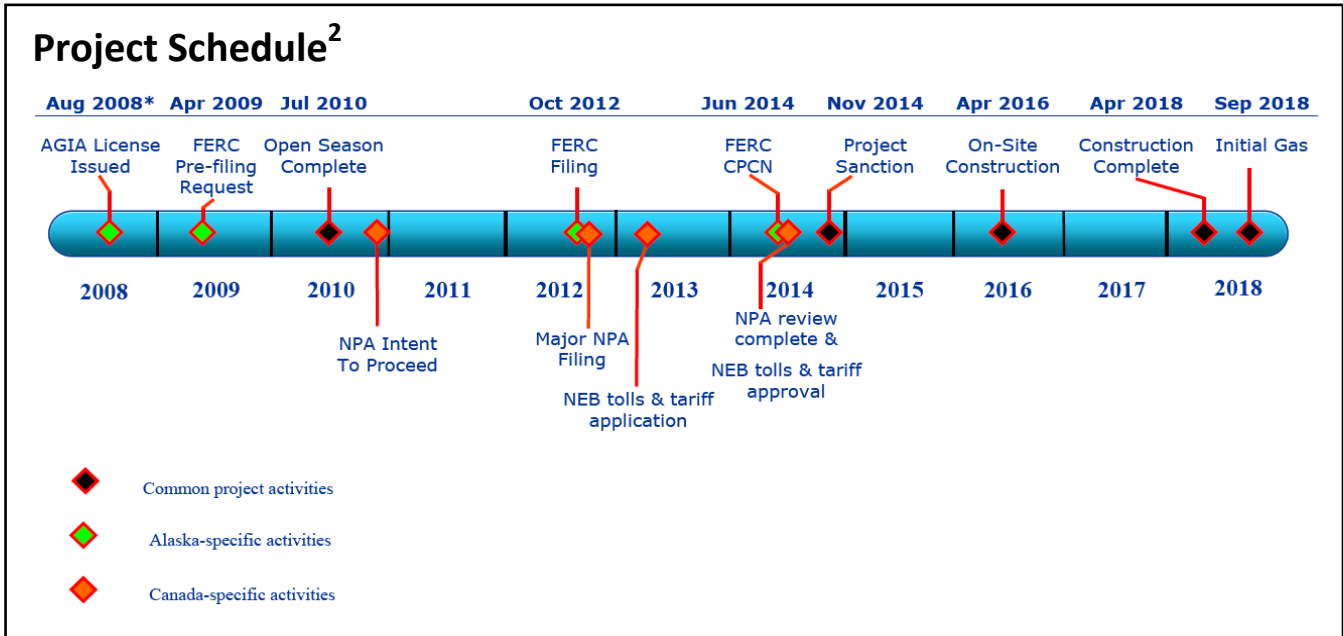
Mr. Anderson has almost 40 years experience working in the pipeline industry with extensive experience dealing with the issues presented by large diameter, high pressure pipelines being constructed and operated in arctic terrain. Mr. Anderson was a member of the State's Technical Team that evaluated the applications received through the AGIA process.

The Technical monitoring process has begun and will include, among other activities, regular meetings with TC Alaska's Project Leaders to discuss ongoing progress and future plans. This provides an indication of the quality and cost effectiveness of the work being completed by TC Alaska and their contractors.

The program indicates that TC Alaska is making good progress and has assembled a high quality team to implement their project plan.

2.1 Schedule and Timeline

The following timelines are from TC Alaska and were based on a license issuance date of August 2008. As a result of the delayed effective date of AGIA, the AGIA license was not formally issued until December 5, 2008. Upon a request for updated schedules from the AGIA Coordinator, Mark Myers, TC Alaska has committed to pursue the schedule as presented before the legislature during special session testimony on the AGIA license. (Also see Section 2.3)



² TransCanada, *Updated Project Schedules*: Submitted April 27, 2009

³ TransCanada, *Updated Project Schedules*: Submitted April 27, 2009

⁴ TransCanada, *Updated Project Schedules*: Submitted April 27, 2009

2.2 Major Achievements and Milestones

The following summary represents TC Alaska's major achievements on Alaska gas pipeline between August 2008 and April 30, 2009.

Engineering

- Completed detailed plans for technology development, engineering, construction infrastructure, logistics and cost estimating
- Acquired aerial photography for Alaska leg, including LNG alternative spur leg
- Completed terrain mapping for Alaska
- Completed 360° video along Canadian portion of the pipeline route
- Planned and executed implementation of winter geotechnical field program (~120 borehole samples) in Alaska; TC Alaska already has geotechnical information for Canadian portion)
- Collected arctic engineering test data and research on frost heave

Environmental

- Established GIS platform to support environmental planning and permitting
- Completed preliminary environmental constraints analysis for Alaska routing, Alaska and Canada construction planning
- Completed initial route update review in Canada

Regulatory / Permitting

- Completed preliminary environmental permitting strategy for Alaska and Canada
- Completed permitting for winter geotechnical field program in Alaska
- Conducted multi-agency meetings in U.S. and Canada
- Submitted FERC pre-filing request

Commercial

- Continued discussions with potential shippers

Administrative

- Opened Alaska project HQ in Anchorage on December 1, 2008
- Hired local office manager
- Established reimbursement agreements with Alyeska, BLM (Alaska) and JPO
- Established project website:
http://www.transcanada.com/company/alaska_pipeline_project.html

2.3 Amendments or Modifications of Project Plan

AGIA provides for amendments of, or modifications to, the licensee's project plan if they meet certain criteria and are approved by the Commissioners.⁵ In the Request for Applications (RFA), which is incorporated into the AGIA license, the provision is interpreted to apply to any amendment or modification that is a "substantial departure" from the specifications set out in the licensee's application, but not to "each and every change to the Project."⁶

Updated Project Schedule

As a result of the delayed issuance of the AGIA license, the AGIA Coordinator, Mark Myers, requested that TC Alaska submit updated schedules for the project. This was done to determine whether any adjustments to the project plan caused by the delayed issuance of the license, would constitute a substantial departure from the project plan such that they might be subject to a review under the AGIA statute.

TC Alaska's AGIA application included both the project plan timeline and 'dates certain' required for a project within FERC jurisdiction. In their application, TC Alaska committed to the following dates certain:

- Conclude a binding open season by September 30, 2009
- Apply for FERC approval to use the pre-filing procedures by June 30, 2010
- Apply for a FERC certificate of public convenience and necessity by December 30, 2011

Both the timeline and dates certain provided in TC Alaska's application were conditioned on the license being issued by April 1, 2008, the date by which the commissioners had anticipated an

⁵ AS 43.90.210 states:

Subject to the approval of the commissioners, a licensee may amend or modify its project plan if the amendment or modification improves the net present value of the project to the state, is necessary because of an order or requirement by a regulatory agency with jurisdiction over the project or by the Alaska Oil and Gas Conservation Commission, or is necessary because of changed circumstances outside the licensee's control and not reasonably foreseeable before the license was issued. An amendment or modification approved under this section must be consistent with the requirements of AS 43.90.130 and, except for an amendment or modification required because of an order or requirement of a regulatory agency with jurisdiction over the project or by the Alaska Oil and Gas Conservation Commission, may not substantially diminish the value of the project to the state or the project's likelihood of success.

⁶ The RFA, at Section 4.11, clarifies that under AS 43.90.210:

An amendment or modification of the project plan by the Licensee requiring the Commissioners' approval under AS 43.90.210 is an amendment or modification which would constitute a substantial departure from the specifications set out in the Application. However, while the term "project plan" includes the major components of the Project, the Commissioners do not interpret AS 43.90.210 to require Commissioner approval of each and every change to the Project.

For example, estimates unless otherwise stated are not commitments. Thus, changes to estimates would not require the Commissioners' approval because they are not changes to the "project plan." Similarly, a change in the pipeline route which does not change the primary markets to be served by the Project (e.g., rerouting the pipeline around a particular landowner's property, or adjusting the location of a river crossing) would not require Commissioners' approval.

AGIA license would be issued,⁷ and noted that the dates may be adjusted to accommodate delays in the issuance of the license.⁸

During the 2008 special sessions, when it became clear that the license would not be awarded as early as had been anticipated, TC Alaska provided the legislature with the updated schedule shown in section 2.1 of this report, assuming that the license would be awarded by August 2008. The Alaska Legislature subsequently approved issuance of the AGIA license to TC Alaska based on the new dates.

Due to unexpected delays in the AGIA application evaluation and an extended legislative approval process, the Act approving issuance of the license did not become effective until late November, eight months later than was initially anticipated.⁹ The AGIA license was issued to TC Alaska on December 5, 2008.

TC Alaska subsequently submitted the updated schedule and timeline shown above for review by the DOR and DNR Commissioners. TC Alaska's current schedule includes an even earlier FERC pre-filing than TC Alaska had previously committed to. A request to commence the pre-filing process was filed with the FERC on April 23, 2009, over a year earlier than the original commitment. With regard to the initial binding open season, and FERC CPCN filing, the current schedule matches that provided by TC Alaska to the Alaska Legislature during last year's hearings on approval of the license.

The DOR and DNR Commissioners reviewed TC Alaska's current schedule and determined that the changes are consistent with the AGIA application in that the application provided that the timeline and schedule would be adjusted to the extent that the issuance of the AGIA license was delayed beyond April 1, 2008. The Commissioners further found that the schedule adjustments did not constitute a substantial departure from the project plan. Therefore, an amendment or modification under AS 43.90.210 was not required.

⁷ TC Alaska Application, Page 2.1-2.

⁸ TC Alaska Application, Page 2.2-85.

⁹ SLA CH 3 4SSLA 08.

3. Alaska Workforce and Business Participation

3.1 Alaska Hire and Contracting

On December 1, 2008, TC Alaska opened its new project headquarters in downtown Anchorage. A local office manager was also hired to run the Alaska office.

Subsequent to the AGIA license being passed in August 2008, approximately 42 Alaskans have been employed on the project either directly by TC Alaska or via its contractors. All of these individuals were hired in the state. During this early phase of the project, the number of full time positions in Alaska is limited. TC Alaska continues to conduct a large part of its development work from its Calgary headquarters.

TC Alaska has contracted with a number of Alaska businesses to provide various services on the project, including:

- Aerial Photography – Aero-Metric Inc., Anchorage, Sub-contractor-Lounsbury & Associates Inc., Anchorage
- Terrain Mapping – R&M Consultants Inc., Anchorage
- Geotechnical fieldwork – Golder Associates Inc., Anchorage, Sub-contractor – Discovery Drilling Inc., Anchorage
- Environmental Planning and Permitting – ENSR AECOM, Anchorage, Sub-contract with ClarusTechnologies LLC, Eagle River for SHPO submission
- Geothermal Modeling and Support – Northern Engineering and Scientific, Anchorage, Sub-contractor geotechnical consultant – DMR
- Office setup and support – Peach Investments, LLC and GCI, Anchorage
- Gas Treatment Plant pre-FEED – URS Washington Division with sub-contract to ASRC

3.2 Workforce Development

The Department of Labor (DOL) has meanwhile completed its AGIA Training Strategic Plan, which presents a comprehensive strategy toward preparing Alaska workers for gasline jobs, before, during and after construction. The document identifies 113 project-related occupations on which the state will focus its training efforts.

DOL has acquired a number of funding source to help support these training efforts. DOL received a \$7.5 million federal grant and has received \$585,000 of state funding for fiscal years 09 and 10 specific to gasline workforce preparation. There have been significant additional legislative investments that connect with AGIA occupations, including \$3.5 million per year for construction academies in various communities in our state and \$8.7 million in state funding toward a comprehensive pipeline worker training facility in Fairbanks.

During fiscal year 2010, the DOL's Research and Analysis Section intends to undertake a comprehensive occupational forecast for the gasoline, using data provided by TC Alaska and the Denali Project.

The department has also been advocating on behalf of the University of Alaska's engineering program, which has seen significant funding increases over the past two fiscal years in an effort to double the number of engineering degree recipients.

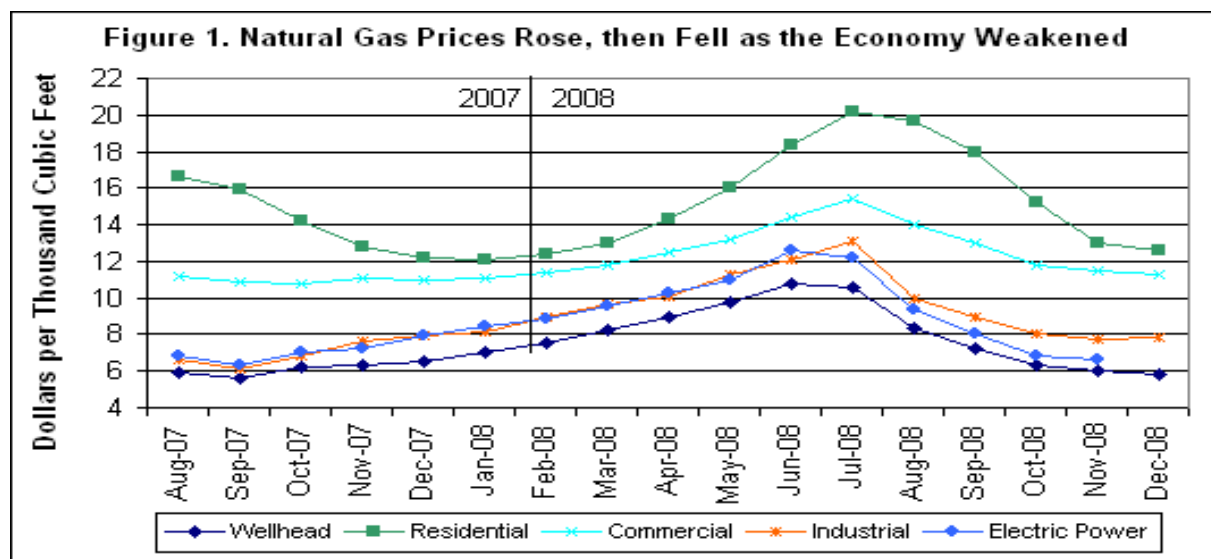
4. Market Update and Cost Expectations

The following market summary highlights events over the previous year which may be relevant to the project, but does not constitute an analysis of the project’s economic viability. 2008 began a challenging period for the U.S. and global economies with dramatic price fluctuations in the energy, commodity and financial markets. Despite this recent volatility and current low gas prices, long-term prospects for U.S. natural gas demand continue to support advancement of an Alaska natural gas pipeline.

4.1 North American Natural Gas Market Update

Natural gas prices were exceptionally volatile during 2008 and reached unprecedented summer highs. This resulted from both a modest tightening of the supply/demand balance, and from financial fundamentals associated with the broader economic turmoil.¹⁰ Other forces have also helped shape domestic gas market, including likely changes to federal energy policy and new development of unconventional gas resources.¹¹

With few exceptions, average natural gas prices during 2008 were between 16% and 29% greater than the previous year. Prices at Henry Hub peaked at \$13.31/MMBtu on July 3rd, but fell to \$5.71 by the end of the year (U.S. FERC, 2009). At the time of this report, the average spot price during April is \$3.59.



¹⁰ Federal Energy Regulatory Commission, *2008 State of the Markets Report*, April 16, 2008 (Washington, DC: Office of Enforcement, 2009)

¹¹ U.S. Department of Energy, Office of the Fossil Energy, National Energy Technology Laboratories, *Modern Shale Gas, Development in the United States: A Primer*, (Oklahoma City, OK: Ground Water Protection Council and ALL Consulting, April 2009)

Figure 1: Energy Information Administration, *Natural Gas Year-In-Review 2008* (Office of Oil and Gas, 2009) http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngyir2008/ngyir2008.html#prices

Several events put upward pressure on gas prices during the first part of 2008 (U.S. FERC, 2009):

- A cold January led to the highest gas demand in 10 years and the largest withdrawal from storage in 11 years
- Net gas imports from Canada were down 14% during the first half of 2008, while LNG imports were off 64%
- The offshore Independence Hub had to shut down repeatedly during April and May, losing up to 900 MMcfd, or about 46 Bcf for the entire period
- A hot June led to a surge in gas consumption from power generators to meet air conditioning load

Similarly, a number of events contributed to lower prices in the second half of 2008(U.S. FERC, 2009):

- A relatively cool July and August helped moderate demand from power generators
- The economic downturn impacted liquidity and capital associated with “speculative” demand, which contributed to declining gas demand, particularly for the industrial sector during the final quarter of 2008
- Gas storage recovered to levels above the 5-year average

Although these events did contribute to market volatility, they are unexceptional and do not fully explain the exceptionally high and sustained summer gas prices.

The U.S. financial crisis affected the energy market in several ways. First, it limited the availability of credit. Many companies, particularly those with lower credit ratings, were unable to access commercial paper or other short-term credit markets. Those that were able to access credit markets faced higher borrowing costs. Many natural gas producers have recently announced plans to scale back capital expenditures in 2009 and beyond. While some of these planned reductions are almost certainly related to lower natural gas prices and a desire to rebalance supply and demand, the reduced access to capital and high borrowing costs have likely contributed as well.¹²

The financial distress during the second half of 2008 also had the effect of reducing trade in financial energy products. During the first part of 2008, the rise in natural gas prices had coincided with increases in global commodities prices. These price increases caused large pools of capital to flow into various financial instruments, thereby increasing commodity trading in natural gas. During the second half of 2008, trading of these investments decreased and financial institutions and energy marketers assumed a smaller role in the overall energy market (U.S. FERC, 2009). The reduced commodity trading combined with the reduced gas demand of the economic slowdown helped accelerate the downward trend in gas prices.

¹² Federal Energy Regulatory Commission, *2008 State of the Markets Report*, April 16, 2008 (Washington, DC: Office of Enforcement, 2009)

While these factors explain in part the recent gas price volatility, other dynamics have continued to reshape the domestic gas market and impact the long-term outlook for natural gas demand. Some of the more significant contributors include the addition of new pipeline infrastructure, alternative gas supplies and changes to state and national energy policies.

The completion of Phase II of the Rockies Express pipeline was of particular importance in helping to equalize prices between different regions in the country. The project brought 1.5 Bcf/d of natural gas from producing fields in Colorado and Wyoming to higher priced markets in the Midwest. Since commencement of operations, the price differential between the Rockies and midcontinent has declined and prices in the two regions have tracked more closely. This cheaper gas from the Rockies also helped to displace more expensive Canadian imports, which were down 12.5% from 2007. (U.S. FERC, 2009)

LNG imports have the potential to be another short and mid-term price driver. During 2008, the United States received less than 1 Bcf/d of LNG, as prices in the rest of the LNG-importing world were higher than the US. Asian and European demand was high, and there were occasional supply shortfalls. However, world LNG prices have fallen substantially since the end of 2008, to the point that northeast prices for natural gas were on par with the rest of the world by the end of March 2009. In addition, new LNG supplies are coming on-line and Asian and European demand has fallen off due to the global economic slowdown (U.S. FERC, 2009).

Unconventional gas supplies continued to grow in relation to overall U.S. gas reserves during 2008. While conventional gas production in the U.S. fell by 3% over the last year, production of unconventional gas increased nearly 14%. Overall, unconventional gas currently accounts for 51% of all domestic production. This trend is consistent with recent years and is expected to continue. While conventional reserves have been in decline, total domestic reserves have actually increased due to the addition of new supplies from shale gas, tight sands and coal bed methane (U.S. FERC, 2009).

These resources are generally more expensive to develop. However, economics have improved considerably in recent years due to positive long-term natural gas price forecasts, and through improvements in horizontal drilling and hydraulic fracturing technology. Only a limited amount of production cost information is available, but low-end break-even price estimates for unconventional gas resources range between \$3.30/MMBtu and \$5/MMBtu, while high-end price estimates range between \$5/MMBtu and \$7/MMBtu (U.S. FERC, 2009).

Given this range of break-even prices, the price of natural gas at the end of Q1 2009 are somewhat below the price needed to sustain drilling activity in most unconventional basins. Evidence of this can be seen in the dramatic plunge in the gas rig count in these basins during the fourth quarter of 2008. The number of operating rigs has declined from a peak of over 1,600 in early September to less than 800 currently.

Recent changes in both state and federal energy policy have also impacted the long-term prospects of natural gas markets. The electric generation capacity that was added during 2008

was dominated by wind and gas-fired units. This was likely driven by growing uncertainties regarding carbon regulation, state renewable energy portfolio standards (RPS) and federal production tax credits that facilitate development of wind generation (U.S. FERC, 2009).

During 2008, three states passed a new RPS, five jurisdictions amended or strengthened existing standards, four states with existing goals strengthened them, and four states adopted voluntary RPS or renewable goals (U.S. FERC, 2009).

Since taking office in January 2009, the Obama administration has stated its strong preference for carbon emissions regulation. The exact form of regulation – be it as a pollutant under the EPA, through carbon taxes or a cap-and-trade system – is still unknown. Regardless of the form, it is likely that any regulation of CO₂ will increase demand for natural gas, as energy users are driven away from more CO₂ intensive sources.¹³ The Obama Administration has further articulated its view of natural gas a preferred fuel for meeting consumer demand while alternative technologies are being advanced.

The Energy Industry Administration (EIA) projects natural gas consumption will decline by 1.8 percent in 2009 and remain relatively unchanged in 2010. This decline is due in large part to the broader economic slowdown and reduced gas consumption in the industrial sector, which is forecast to fall by 7.4 percent this year. In the residential and commercial sectors, where consumption is influenced more by weather than by macroeconomic conditions, natural gas use is expected to increase slightly in 2009. Consumption in the electric power sector is expected to increase 0.7% because of lower natural gas prices relative to coal.¹⁴

Many variables contribute to the high level of uncertainty in short-term energy markets. Nevertheless, long-term gas price forecasts remain supportive of the project, with stable or increasing price expectations. For example, the EIA's most recent long term gas price forecast is higher than the one issued one year ago. Because of the long lead time associated with an Alaska natural gas pipeline the recent price volatility will have little impact on the prospects of the project.

4.2 Cost Estimate

Recent market volatility has implications for the cost to construct an Alaska natural gas pipeline. Although costs increased considerably during the first part of 2008, more recent developments indicate that if the project were built today, it might actually be cheaper than originally estimated.¹⁵ However, the development schedule and magnitude of this project must look beyond short-term fluctuations and be based on conservative long-term gas price and capital cost projections.

¹³ Black & Veatch (2009), *Alaska National Economic Research*, Report prepared for the State of Alaska

¹⁴ U.S. Energy Information Administration, http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

¹⁵ This is based on recent declines in the prices for commodities and other key inputs, according to research by the Cambridge Energy Research Associates.

TC Alaska's construction cost estimates for the project are unchanged from what was presented in its original AGIA application. TC Alaska is still acquiring new information since receiving the AGIA license to provide an accurate update of cost expectations to the state. Its current phase of work is focused on development of a Class 4 cost estimate in preparation for the open season. We anticipate this refined estimate will be made available during the early part of 2010.

The rise of natural gas prices during the first part of 2008 coincided with a global increase in many commodity prices. The higher cost of key inputs like steel, cement and specialized labor, helped to drive up the cost over 10% for constructing some new projects during the first three quarters of the year. While the underlying input costs dropped substantially in the fourth quarter, the measure of construction costs maintained by the Cambridge Energy Research Associates (CERA), held steady. CERA attributes the absence of downward pressure on construction costs to the fact that equipment manufacturers and construction companies continued to have a backlog of orders. This Federal Energy Regulatory Commission has since confirmed this conclusion through separate conversations with market participants. It is expected, however, that once the industries have had a chance to catch up on backlogged orders, construction costs will fall in response to the lower demand.

As of the date of this report, no changes have been proposed to the project cost estimate. The most current estimate is from section 2.5 of TC Alaska's Application for License under the Alaska Gasline Inducement Act.¹⁶

Proposed Project Plan: *Project Cost Estimate (2.5)*¹⁷

The Project cost estimates are based on the conceptual design for a 4.5 bcf/d system to transport natural gas from Prudhoe Bay to the Alberta market hub. The estimates have been developed over time, using a number of engineering companies, internal TransCanada personnel and several different estimating methodologies. The cost estimates are classified as Class 5. For this Application, TransCanada is classifying all cost estimates based on the AACE International Recommended Practice No.17R-97.

The major focus of the cost estimating efforts has been on the Yukon-BC Section of the pipeline. Utilizing field data compiled by Foothills, "crew up" cost estimates were developed for the installation component for this section of the pipeline. The crew-up estimates incorporate union labor rates, equipment rates developed using manufacturers' quoted purchase prices and recommended rate development, and

¹⁶ The State contracted for an independent analysis of TransCanada's estimated project costs during the evaluation of TransCanada's AGIA application. This analysis established a range of costs for the project under different scenarios, some of which were higher than TransCanada's estimates. The results of this analysis is included in Appendix F of the Commissioners' Findings and Determinations on the AGIA license and can be accessed online at <http://www.gov.state.ak.us/agia/>

¹⁷ TransCanada, *Application for License* under the Alaska Gasline Inducement Act; November 30, 2007

pipeline construction industry accepted practices and productivity data. The costs have been updated utilizing market indices and escalators, and TransCanada's cost data and market intelligence, capturing current heated market conditions.

Installation costs developed in Canada were used as a base for developing the Alaska Section pipeline costs. Installation costs were applied to the varying terrain types as classified by Alaskan consultants. Site-specific conditions of the Alaskan landscape were incorporated into the estimate.

Major material costs including pipe, coatings, compressors, gas chilling equipment, aerial coolers and applicable logistical requirements were obtained from international suppliers. Compressor station and chiller costs were developed with the assistance of Alaskan and Canadian consultants and TransCanada's historical compression cost data.

Engineering, project management and construction management costs were based on bottom up manpower requirements developed from project specific organizational charts. North American engineering and environmental consultants recently assisted in identifying the requirements and costs to achieve the necessary deliverables of the AGIA Development Phase. Estimate contingencies were developed through a quantitative risk analysis process.

The high level costs for the GTP were developed by consultants based on a conceptual design using a combination of cost capacity factors, factors for major components of hydrocarbon plants located in the Arctic and direct estimates for major equipment costs.

All costs are expressed in Second Quarter, 2007 U.S. Dollars. In compliance with the RFA requirements, the U.S. dollar to Canadian dollar exchange rate was determined by averaging the last three years' (2004 to 2006) exchange rates of the two currencies. This calculation resulted in a conversion rate of \$1 U.S. dollar to \$1.2156 Canadian dollars. TransCanada used this exchange rate in developing the Project cost estimates.

It is TransCanada's intention to upgrade the cost estimates to Class 4 during the Development Phase, Proposal Sub-Phase, and to Class 3 during the Development Phase, Definition Sub-Phase, once the design reflects actual volumes committed in the initial Open Season.

Cost Estimate for Development Phase (2007 million \$)

	2008	2009	2010	2011	2012	2013	TOTAL
GTP	8	14	25	25	25	12	109
Alaska Section	21	38	67	66	67	33	292
Yukon-BC Section	11	21	41	41	41	20	175
Alberta Section	2	2	6	6	6	6	28
NGL Extraction	0	0	0	0	0	0	0
Annual Total	42	75	139	138	139	71	604

Cost Estimate for Execution Phase (2007 million \$)

	2013	2014	2015	2016	2017	2018	TOTAL
GTP	62	985	1,208	2,153	1,268	15	5,691
Alaska Section	166	1,265	2,229	3,773	2,327	32	9,792
Yukon-BC Section	104	1,085	2,173	3,547	2,112	21	9,042
Alberta Section	10	167	327	533	318	3	1,358
NGL Extraction	0	0	0	0	0	0	0
Annual Total	342	3,502	5,937	10,006	6,025	71	25,883

Note: State's contribution has not been deducted from the cost estimates for either phase. Development Phase costs are evenly distributed over the FEED period. A conversion rate of 1\$US = 1.2156 \$Canadian has been used.

Does not include Alaska property tax during construction. TransCanada estimates such taxes would be \$521 million (nominal dollars).

4.3 Capitalization Plan

TC Alaska has not submitted any updates to their Capitalization Plan to the state. The most current plan was included in section 2.8.2 of TC Alaska's Application for License under the Alaska Gasline Inducement Act.

Financial Plan: *Capitalization Plan (2.8.2)*¹⁸

TransCanada proposes a Recourse Rate capitalization plan of 70% debt and 30% equity for the initial build and 60% debt and 40% equity for all future expansions, changes in working capital and requirement for maintenance capital.

¹⁸ TransCanada, *Application for License* under the Alaska Gasline Inducement Act; November 30, 2007

For Negotiated Rates, the capitalization plan during construction would be 70% debt and 30% equity for the initial build. The Project would be recapitalized upon commencement of operation with 75% debt and 25% equity. All future expansions, changes in working capital and requirement for maintenance capital would be capitalized with 60% debt and 40% equity.

For both Recourse and Negotiated Rates, all initial build capital cost overruns would be funded with 100% debt if the U.S. government agrees to use the loan guarantee for capital cost overrun credit support, otherwise any capital cost overruns would be funded in accordance with the capitalization plans as outlined above.

4. Conclusion

In summary, the AGIA licensed project remains on track and on schedule. TC Alaska has advanced the project with a focus on keeping costs down and sticking to the committed schedule. They have also made a priority of hiring Alaska contractors and Alaskans. The State has initiated its efforts to rigorously monitor and enforce the provisions in the AGIA License, including diligent review, reimbursement and audit of TC Alaska's qualified expenditures. The economic outlook for the project remains strong despite the recent market volatility and short term drop in natural gas prices. The combination of stable long term price expectations and the reduction in project cost indicators keep the project on solid economic footing.