United States of America before the Federal Energy Regulatory Commission

TransCanada Alaska Company LLC -- Docket no. PF09-11-001

Request for commission approval of detailed plan for conducting an open season

January 29, 2010

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January 29, 2010

The Honorable Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: TransCanada Alaska Company LLC, Docket No. PF09-11-001

Dear Ms. Bose:

Enclosed for electronic filing in the above-referenced matter is the Request for Commission Approval of Detailed Plan for Conducting an Open Season, submitted by TransCanada Alaska Company LLC ("TC Alaska"). Also included and made a part of this submission are three files constituting a three-volume set of Open Season Plan Documents. Volume I of the Open Season Plan Documents contains the proposed Open Season Notice and, as Appendix A to the Notice, a proposed precedent agreement. Volume II contains, as Appendix B to the Notice, the In-State Needs Study required by 18 C.F.R. Section 157.34(b) and related exhibits. Volume III contains, as Appendix C to the Notice, the information required by 18 C.F.R. Section 157.34(c) and related exhibits A-L. The entire submission is Public.

This filing is being made pursuant to Section 157.38 of the Commission's Regulations governing Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.38, and Rule 204 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.204, in order to obtain Commission approval of TC Alaska's Plan for conducting the upcoming Open Season in connection with its Alaska Pipeline Project ("APP" or "Project"). Once completed, the Project will consist of a FERC jurisdictional gas treatment plant ("GTP") near Prudhoe Bay, Alaska, which will treat North Slope gas for pipeline transportation, and a FERC jurisdictional gas transmission pipeline from the outlet of the Point Thomson plant in Alaska to the GTP and from there, either to (1) the Alaska/Canada border for onward delivery to Alberta, Canada or (2) Valdez, Alaska. The Project is being advanced on behalf of TC Alaska by subsidiaries of TransCanada Corporation and Exxon Mobil Corporation. If approved by the Commission, the APP Open Season will commence on April 30, 2010, and conclude on July 30, 2010.

Section 157.38 of the Commission's Regulations provides that upon receipt of a request for approval of an open season plan, "the Secretary of the Commission shall issue a notice of the request, which will then be published in the Federal Register. The notice shall establish a date on which comments from interested persons are due and a date, which shall be within 60 days of receipt of the prospective applicant's request unless otherwise directed by the Commission, by which the Commission will act on the proposed plan."

In order to insure that the Commission has a complete, balanced record at the time it acts on the proposed plan, and is otherwise adequately informed, APP submits that, in addition to comments, the Commission should permit the filing of reply comments pursuant to its authority under Rule 213 (a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (a)(2). APP in particular desires an opportunity to reply to any comments that are submitted regarding the proposed Open Season Plan. Without the benefit of a reply from APP, the Commission's decision may be based upon incomplete or incorrect information.

Unless the Commission otherwise directs, it must act on the proposed plan within 60 days from today (*i.e.* by March 30, 2010). *See* 18 C.F.R. 157.38. APP proposes that this 60 days be allocated by giving interested parties 30 days to file any comments (*i.e.*, by March 1, 2010), APP 15 days in which to file reply comments (*i.e.*, by March 16, 2010) and the Commission 15 days in which to consider and act on any issues that are raised. Recognizing that the Commission may desire more than 15 days, APP requests that at a minimum it be allowed at least half as much time for reply comments as other parties are allowed to submit initial comments.

APP is submitting herewith a proposed notice establishing due dates for comments and reply comments as stated above.

If there are any questions, please contact me at (202) 736-8206.

Very truly yours,

Eugene R. Elrod

Eugene R. Elrod

Counsel for TransCanada Alaska Company LLC and Alaska Pipeline Project

ERE:daw

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
TransCanada Alaska Company LLC	**)**	**Docket No. PF09-11-001**
	)	

NOTICE OF REQUEST FOR APPROVAL OF PLAN
FOR CONDUCTING AN OPEN SEASON

Take Notice that on January 29, 2010, pursuant to Section 157.38 of the Commission's Regulations governing Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.38, and Rule 204 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.204, TransCanada Alaska Company LLC ("TC Alaska") filed a Request for Commission Approval of Detailed Plan for Conducting an Open Season.

The proposed Open Season is being held to solicit the submission and execution of binding Precedent Agreements for firm interstate natural gas transportation service and optional firm gas treatment service provided by TC Alaska's Alaska Pipeline Project ("APP" or "Project"). Once completed, the Project will consist of a FERC jurisdictional gas treatment plant ("GTP") near Prudhoe Bay, Alaska, which will treat North Slope gas for pipeline transportation, and a FERC jurisdictional gas transmission pipeline from the outlet of the Point Thomson plant in Alaska to the GTP and, from there, either to (1) the Alaska/Canada border for onward delivery to Alberta, Canada or (2) Valdez, Alaska. The Project is being advanced on behalf of TC Alaska by subsidiaries of TransCanada Corporation and Exxon Mobil Corporation. Pursuant to Section 157.38 of the Commission's Regulations, the Commission is to act on the Request within 60 days. If TC Alaska's Plan is approved by the Commission, the APP Open Season will commence on April 30, 2010, and conclude on July 30, 2010.

Any questions regarding the Request for Approval may be directed to:

Eugene R. Elrod – eelrod@sidley.com
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Any person desiring to intervene in or comment on this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211, 385.214. Comments will be considered by the Commission in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Commission's rules require that persons filing comments in opposition to the request provide copies of their protest only to the party or parties directly involved in the protest.

In addition to the filing of comments, the Commission will permit the filing of reply comments pursuant to its authority under Rule 213 (a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (a)(2).

The Commission strongly urges electronic filings of comments, protests, interventions and reply comments in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible online at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reading Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

COMMENT DATE: March 1, 2010
REPLY COMMENT DATE: March 16, 2010
COMMISSION ACTION DATE: March 30, 2010

Kimberly D. Bose
Secretary

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TransCanada Alaska Company LLC	)))	**Docket No. PF09-11-001**

REQUEST FOR COMMISSION APPROVAL OF DETAILED PLAN FOR CONDUCTING AN OPEN SEASON

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Date: January 29, 2010

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OPEN SEASON PLAN DOCUMENTS (submitted separately in three volumes)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
TransCanada Alaska Company LLC	)	**Docket No. PF09-11-001**
	)	

REQUEST FOR COMMISSION APPROVAL OF DETAILED PLAN FOR CONDUCTING AN OPEN SEASON

Pursuant to Section 157.38 of the Commission's Regulations governing Open Seasons for Alaska Natural Gas Projects, 18 C.F.R. § 157.38, and Rule 204 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.204, TransCanada Alaska Company LLC ("TC Alaska") hereby requests Commission approval of the Plan described herein for conducting an Open Season for the purpose of securing binding commitments from potential shippers for firm gas transportation service and optional firm gas treatment service to be provided by TC Alaska's Alaska Pipeline Project ("APP" or "Project"). As part of this Request for Approval, APP has separately submitted three volumes of Open Season Plan Documents which include the proposed APP Open Season Notice, with the following Appendices: (A) a proposed Precedent Agreement; (B) the In-State Needs Study required by 18 C.F.R. § 157.34 (b); and (C) the 21 items of information required by 18 C.F.R. § 157.34 (c), including an indicative tariff.

I. EXECUTIVE SUMMARY

Once completed, the Alaska Pipeline Project will allow for the transportation of natural gas from Alaska's North Slope to North American markets or global liquefied natural gas ("LNG") markets. The North Slope of Alaska holds approximately 35 trillion cubic feet ("Tcf") of currently proven natural gas reserves, and it is estimated that another 100 to 200 Tcf ultimately could be discovered.

TC Alaska, along with affiliates in Canada (collectively, the "Licensee"), are the holders of the license issued by the State of Alaska on December 5, 2008, pursuant to the Alaska Gasline Inducement Act, AS43.90 ("AGIA"). The Project is being jointly advanced on behalf of TC Alaska by TransCanada Alaska Development Inc. ("TransCanada Alaska Development") and ExxonMobil Alaska Midstream Gas Investments, LLC ("EMAMGI"), along with a respective affiliate of each company in Canada (collectively, the "APP Parties"), pursuant to the terms of a series of agreements among the parties executed on June 10, 2009.

The APP Parties and their respective affiliates (generally, "TransCanada" and "ExxonMobil") are uniquely situated to efficiently and effectively advance the Alaska Pipeline Project. Both TransCanada and ExxonMobil bring substantial financial strength to the Project. TransCanada has extensive North American pipeline construction experience, particularly in cold weather environments, and operates pipeline networks across Canada and in the United States. TransCanada also holds the certificates and right-of-way in the Yukon Territory under the Northern Pipeline Act ("NPA") to own and construct the Canada section of the Project, and has proven expertise in efficiently advancing pipeline projects through the regulatory process, construction and operation. ExxonMobil has proven global mega-project management experience and a long history of Arctic project successes and technological innovations. ExxonMobil has repeatedly demonstrated its ability to deliver world-class projects on time and within budget, and has proven expertise in innovative gas treatment, pipeline and compression technologies.

The Alaska Pipeline Project will consist of:

- A FERC jurisdictional gas treatment plant ("GTP") near Prudhoe Bay, Alaska, which will treat North Slope gas for pipeline transportation;
- A FERC jurisdictional gas transmission pipeline from the outlet of the Point Thomson plant in Alaska to the GTP and from there, subject to shipper confirmation during the Open Season process, to either:
    - The Alaska/Canada border (the "Alaska-Canada Pipeline"), where it will interconnect to a new pipeline in Canada that APP plans to design, permit and construct (the "Canadian Pipeline"); or
    - Valdez, Alaska (the "Valdez Pipeline").

With the Alaska-Canada Pipeline, shippers would have the ability to deliver gas to North American markets. With the Valdez Pipeline, shippers would have the ability to deliver into an LNG facility (to be developed by third parties), for onward delivery to global LNG markets. The Alaska-Canada Pipeline and the Valdez Pipeline are alternative proposals. Depending on customer interest as evidenced in the Open Season, APP will proceed with either the Alaska-Canada Pipeline or the Valdez Pipeline, but not both.

The Alaska Pipeline Project is a world-class undertaking in all of its aspects. The GTP as currently envisioned would be made up of four trains for the Alaska-Canada Pipeline and three trains for the Valdez Pipeline. The Alaska-Canada Pipeline segment from the GTP would be approximately 734 miles of 48-inch X80 steel (interconnected with 966 miles of the Canadian Pipeline). The base design capacity would be 4.5 Bcf/d, expandable with compression to 5.9 Bcf/d. Under the 4.5 Bcf/d base design, the system would include six compressor stations in Alaska and eleven in Canada, expanding to a total of thirty-three compressor stations under the 5.9 Bcf/d case. The Valdez Pipeline segment from the GTP would be approximately 803 miles of 48-inch X80 steel, all in Alaska, and would have two compressor stations in Alaska to support the base design of 3.0 Bcf/d. The pipeline will operate in areas of continuous and discontinuous permafrost, and therefore gas chillers will be installed at the GTP and on the outlet side of the compressor stations located in Alaska, as well as on the outlet of the first compressor station in Canada.

The APP Parties have undertaken extensive efforts to update cost and schedule estimates for the Project. These updated estimates conform to Association for the Advancement of Cost Engineering International ("AACEI") Class IV standards. The overall cost estimate range in 2009 dollars[1] is from $32 billion to $41 billion for the combined Alaska-Canada Pipeline and Canadian Pipeline, and from $20 billion to $26 billion for the Valdez Pipeline. Based on this cost range, the estimated rate range for a 25-year negotiated rate from Prudhoe Bay to Alberta is $3.02 - $3.89 per MMBtu in nominal dollars or $2.43 - $3.13 per MMBtu in 2009 dollars, and from Prudhoe Bay to Valdez is $2.76 - $3.59 per MMBtu in nominal dollars or $2.22 - $2.89 per MMBtu in 2009 dollars. These rate ranges include the cost of treating gas at the GTP. The estimated in-service date for both options is 2020 for initial gas and 2021 for full gas.[2]

The Open Season Plan, described below, in addition to satisfying the 21 informational elements required by 18 C.F.R. §157.34 (c), also includes TC Alaska's proposed Precedent Agreement, the Alaska-approved In-State Needs Study, and a complete indicative tariff.[3]

II. COMMUNICATIONS

Communications with regard to this Request for Approval should be directed to:

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[1] Unless otherwise indicated, all references herein to "dollars" are to U.S. dollars.

[2] Further details of the rate development can be found in Exhibits J and K to Appendix C of the Open Season Notice.

[3] Based on discussions with potential shippers, the results of the Open Season and the development of any updated information, TC Alaska reserves the right to amend the Precedent Agreement prior to submission of any executed Precedent Agreements to the Commission pursuant to Section 157.34(d) of the Open Season Regulations (18 C.F.R. § 157.34 (d)), and to amend the tariff prior to submission to the Commission in connection with the Natural Gas Act Section 7 application for a certificate of public convenience and necessity.

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III. OPEN SEASON PLAN

A. The Applicant

TC Alaska was incorporated in 2004 to pursue the development of the Alaska portion of an Alaska natural gas pipeline. In 2007, TC Alaska, jointly with Foothills Pipe Lines Ltd. ("Foothills") through its Canadian subsidiaries identified in the NPA as having responsibility for the various zones of the Project in Canada, submitted an application to the Alaska Commissioner of Natural Resources and the Alaska Commissioner of Revenue for a license pursuant to AGIA. The AGIA co-applicants are wholly owned subsidiaries of TransCanada Corporation.

TransCanada owns one of the largest, most sophisticated, remote-controlled natural gas pipeline networks in the world, with 36,500 miles of wholly-owned pipeline that transports nearly 30 Bcf/d of gas to every major natural gas consuming market in North America. TransCanada's pipeline project management capabilities and experience are unparalleled in North America. For example, in the 1990s alone, TransCanada and its subsidiaries managed large-scale pipeline expansion projects across the continent with costs totaling approximately

Cdn $14 billion. These capital projects included more than 6,500 miles of large diameter pipe, almost 3.2 million horsepower of compression, and 375 custody transfer meter facilities. TransCanada's Cdn $6.6 billion cross-Canada mainline expansion projects were delivered within a budget variance of 0.6 percent, and the overwhelming majority were completed on or before the original schedule. Similar performance was achieved on the company's Alberta expansion projects, as well as on its international projects.

TransCanada possesses several other unique capabilities or attributes that can provide significant advantages in the development of the Project:

- TransCanada Corporation, through its wholly-owned subsidiary Foothills, holds the certificate of public convenience and necessity to own and construct the Canada section of the Project. While there remains a significant compliance process to be conducted through the NPA, the fact that Foothills is the party certificated to proceed with the development of the Project constitutes a significant advantage over other potential applicants.

- Foothills has access rights to the lands acquired in the Yukon Territory by virtue of an easement that it has held since the early 1980s and continues to maintain through leasehold payments. In addition to these land rights, TransCanada is a recognized leader in building positive relationships with aboriginal communities in Canada.

- TransCanada has been an industry leader for more than 50 years in the development of cutting-edge gas transmission technology, including technology specialized for harsh, cold weather conditions like those that will be encountered by APP. For example, TransCanada has developed a comprehensive pipeline design methodology and models that combine hydraulic simulation with geothermal analysis to predict flowing gas temperatures, the amount of frost heave and thaw settlement, and the structural response of pipeline in permafrost. The pipeline design model, as well as other cold weather design, materials, and construction technologies and systems, has been successfully applied to difficult projects in northern discontinuous permafrost areas, resulting in project cost reductions and increasing pipeline reliability and safety in the extreme conditions in northern Canada.

On December 5, 2008, TC Alaska and Foothills were issued the AGIA license. The Alaska Commissioners found that: "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."[4]

On June 10, 2009, TransCanada and ExxonMobil entered into a series of agreements under which ExxonMobil will work with TransCanada to advance the Project. Both parties bring substantial financial strength to the Project. In addition, ExxonMobil has proven global mega-project management experience and a long history of Arctic project successes and technological innovations. ExxonMobil also has repeatedly demonstrated its ability to deliver world-class projects on time and within budget, and has proven expertise in innovative gas treatment, pipeline and compression technologies.

In endorsing the joint project arrangement, the Alaska Commissioners stated:

> ExxonMobil's actions show that they believe that working with TransCanada and the state through AGIA is the best opportunity for aligning the parties to move this project forward. They bring world-class expertise to the project in construction planning, regulatory and environmental work, as well as technical capability and prior study information that will enhance development of the Gas Treatment Plant. Their early collaboration with TC Alaska will accelerate pre-Open Season spending to roughly $150 million, and will help to ensure a project design that is tailored to meet the technical needs of potential gas shippers.[5]

This view was recently echoed by the AGIA Coordinator in a letter to the President of the Alaska Senate and Speaker of the Alaska House of Representatives:

> The [TransCanada-ExxonMobil] agreement offers tremendous synergies by merging TC's extensive sub-arctic pipeline construction experience, and its existing regulatory certificates for the project through Canada, with ExxonMobil's project management expertise, financial strength, expertise in the design

[4] *Written Findings and Determination by the Commissioners of Natural Resources and Revenue for Issuance of a License Under the Alaska Gasline Inducement Act*, issued May 22, 2008, at ES2.

[5] State of Alaska, Departments of Natural Resources and Revenue, Press Release, issued June 11, 2009.

> and construction of gas handling facilities, and its upstream expertise on Alaska's North Slope. ExxonMobil also brings to APP a prior producer gasline study and the large geothermal and environmental data set that it has access to as an owner of the TransAlaska Pipeline (TAPS).[6]

B. The Alaska Pipeline Project

The APP Parties propose to design, permit and construct a new natural gas pipeline system, subject to FERC jurisdiction, beginning near Point Thomson, Alaska, and extending through Alaska over one of two alternative routes. One route, the Alaska-Canada Pipeline, would extend from the outlet of the Point Thomson plant to points near Prudhoe Bay, Fairbanks, and Delta Junction, and then to the Alaska-Canada border, where the pipeline would interconnect to a new pipeline in Canada that the APP Parties plan to design, permit and construct. With the Alaska-Canada Pipeline, shippers would have the ability to deliver gas to North American markets through the Alberta Hub or other existing off-take capacity at or near the British Columbia/Alberta border. An alternative pipeline route, the Valdez Pipeline, would extend from the outlet of the Point Thomson plant through points near Prudhoe Bay, Fairbanks, Delta Junction, and then to an interconnection point with LNG facilities (to be built by third parties) near Valdez, Alaska. In either the Alaska-Canada Pipeline or the Valdez Pipeline alternative, a minimum of five in-state delivery points will be made available on a firm or interruptible basis to all shippers.

The gas transmission pipeline segment between the outlet of the Point Thomson plant and the inlet to the GTP will consist of a single 32-inch, X65 steel pipeline, approximately 58 miles in length, with no compression. The base-case capacity of this segment has been set at 1.1 Bcf/d

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[6] Letter from Mark D. Myers, PhD, AGIA Coordinator to The Honorable Gary Stevens, Senate President and the Honorable Mike Chenault, Speaker of the House, dated October 31, 2009, enclosing the second AGIA Gasline Project Report.

(expandable with compression), with an operating pressure of approximately 1030 psi at the Point Thomson receipt point.

The Alaska-Canada Pipeline gas transmission segment between the outlet of the GTP and the Canadian border would consist of a single 48-inch, X80 steel pipeline, approximately 734 miles in length, and six compressor stations. The base-case capacity of this segment has been set at 4.5 Bcf/d (expandable to 5.9 Bcf/d with additional compression), with an operating pressure of approximately 2500 psi along the entire route of this segment.

The Valdez Pipeline gas transmission segment between the outlet of the GTP and the LNG terminal facilities (to be built by third parties) near Valdez would consist of a single 48-inch, X80 steel pipeline, approximately 803 miles in length, and two compressor stations. The base-case capacity of this segment has been set at 3.0 Bcf/d (expandable with additional compression), with an operating pressure of approximately 900 psi at the Valdez LNG delivery point.

The APP Parties propose to design, permit and construct a new GTP located near Prudhoe Bay, as an integral component of APP's facilities and also subject to FERC regulation, that will operate in conjunction with either the Alaska-Canada Pipeline or the Valdez Pipeline. Shippers on the APP gas transmission pipeline will not be required to have their gas treated at the GTP, but shippers will be required to meet the pipeline gas quality specifications in TC Alaska's indicative FERC Gas Tariff.

The current GTP design for the Alaska-Canada Pipeline alternative is to treat approximately 5.3 Bcf/d of inlet gas, distributed to four trains, and deliver approximately 4.5 Bcf/d of pipeline quality gas with a CO_2 content between 1.5% and 2%, remove approximately 0.6 Bcf/d of acid gas, and consume approximately 0.2 Bcf/d of fuel gas. The GTP design for the

Valdez Pipeline alternative is to treat approximately 3.6 Bcf/d of inlet gas, distributed to three trains, and deliver approximately 3.0 Bcf/d of pipeline quality gas with a CO_2 content of $\leq$50 ppm, remove 0.44 Bcf/d of acid gas, and consume approximately 0.17 Bcf/d of fuel gas. The GTP will be designed for an inlet pressure of approximately 600 psi and can be expanded to treat additional gas.

C. The Open Season Offering

This Open Season is being held to solicit the submission and execution of binding Precedent Agreements for firm gas transportation service and optional firm gas treatment service. There will be receipt points at the outlet of the Point Thomson plant and the inlet of the GTP, with the possibility of other receipt points being added based on shipper interest. There will be a delivery point at the inlet of the GTP for the Point Thomson pipeline segment and at either the Canadian border or Valdez, depending on which alternative route is selected. In addition, there will be a minimum of five in-state delivery points based on the Alaska-endorsed In-State Needs Study.[7] Both negotiated and recourse rates are being offered in this Open Season.

The APP Parties have not executed any pre-subscription agreements, and all Alaska-Canada Pipeline or Valdez Pipeline capacity and GTP capacity will be offered to potential shippers through this Open Season. This Open Season is being conducted as part of a broader open season process under which APP is also separately soliciting shipper bids for capacity on the Canadian Pipeline.

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[7] For purposes of this Open Season, Exhibit A of the proposed Precedent Agreement specifies as delivery points the locations that were identified in the In-State Needs Study as the most likely off-take points based on expected demand. *See* p. 19 *infra*. The final determination of the in-state locations that will be served will depend on which alternative route is selected, the results of the Open Season and input from potential shippers.

D. The Conduct of the Open Season

1. Timing and Notice

The proposed APP Open Season Notice, with appendices, has been separately submitted in a three-volume set of Open Season Plan Documents. The APP Parties plan to issue the Notice no later than April 30, 2010. As discussed in detail below, the Notice complies with all applicable Commission regulations and includes all of the information specified in 18 C.F.R. Sections 157.34 (b) and (c). The Open Season will run a minimum of 90 days and is anticipated to close on July 30, 2010.

As required by Section 157.34 (a), the APP Parties will notify the public of the issuance of the Open Season Notice through press releases, direct mail solicitations and other advertising sufficient to assure that all parties interested in the Open Season will be made aware of its terms. The Notice will be accessible on the APP website, www.thealaskapipelineproject.com, and copies will be made available to any interested party. In addition, actual notice of the Open Season will be provided to the Commission, the State of Alaska and to the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects.

2. Bid Criteria

During the Open Season, any party interested in contracting for firm transportation service on either the Alaska-Canada Pipeline or the Valdez Pipeline alternative must execute and return the form of Precedent Agreement attached as Appendix A to the Open Season Notice. To be considered a bona fide bid, the Precedent Agreement must be signed by an authorized representative of the bidding company. The executed Precedent Agreement must include the following information:

- Maximum Daily Quantity ("MDQ") and optional Maximum Treatment Quantity ("MTQ"), exclusive of Fuel and Lost and Unaccounted for Gas ("Fuel"), by requested primary receipt and delivery points that bidders must indicate on Exhibit A to the Precedent Agreement.

- Whether the party intends to pay recourse rates or negotiated rates.
- Requested primary term of 20-25, 30 or 35 years for shippers selecting negotiated rates and 25 years for shippers selecting recourse rates.

APP reserves the right, on a not unduly discriminatory basis, to reject any bid that does not conform to the requirements set forth for bids or that modifies the substantive terms set forth in the Precedent Agreement.

3. Route Selection and Award of Capacity

Shippers will be notified, as soon as reasonably practicable following the completion of the Open Season, whether APP will proceed to seek to design, permit and construct the Alaska-Canada Pipeline and GTP or will proceed to seek to design, permit and construct the Valdez Pipeline and GTP. APP will make this determination in its sole discretion, and is entitled to delay providing shippers with this notice if it determines that commercial circumstances justify a later notification. Upon shippers' receipt of such notification, all terms of the Precedent Agreement are binding with respect to each shipper's elections on Exhibit A to the Precedent Agreement for service on the selected pipeline, and the shipper's service elections on Exhibit A to the Precedent Agreement with respect to the pipeline alternative that is not selected for development are thereafter without effect and are not enforceable by the shipper or by TC Alaska.

The APP Parties intend to design the Project, within certain economic and engineering design increments, to accommodate all capacity requests on a not unduly discriminatory basis from acceptable bids received during the Open Season. In the event qualifying bids from shippers for firm services received during the Open Season exceed the design capacity determined by APP, APP reserves the right to reduce the bidders' MDQs and MTQs indicated on

Exhibit A to the Precedent Agreements pro rata, based solely on each bidder's proportion of the total quantity of firm transportation capacity and firm treatment capacity reflected in bids received by APP, without regard to whether a shipper would qualify as a Foundation Shipper, has selected recourse rates or negotiated rates, or has specified in-state or export deliveries.

4. Precedent Agreements

After awarding capacity and (i) receipt of winning bidder(s)' sufficient written evidence of creditworthiness, as stipulated in Exhibit B to the Precedent Agreement, (ii) resolution of any outstanding commercial issues, and (iii) receipt of bidders' board approvals, TC Alaska will execute each binding Precedent Agreement previously submitted by a bidder and will return one copy to the bidder. If the amount of capacity awarded differs from the amount contained in the initial bid as a result of over-subscription, TC Alaska and the winning bidder(s) will execute amended Precedent Agreements reflecting the final award of capacity. The Precedent Agreement will bind the bidder(s) to execute a firm transportation service agreement ("FTSA") before Project construction commences and will condition the provision of service on satisfaction or express waiver of the transporter Conditions Precedent stipulated in the Precedent Agreement.

APP recognizes that bidders may desire to include certain conditions precedent ("CPs") to their bids that are outside the control of APP. Notwithstanding the bidders' execution of the Precedent Agreement during the Open Season, bidders will be allowed to negotiate CPs acceptable to the APP Parties and will have until December 31, 2010, to secure all necessary board approvals and internal authorizations. CPs that modify substantive terms in the Precedent Agreement may not be accepted.

This Open Season filing and the Project as described herein, including the cost, schedule and expenditure estimates, are conditioned on the timely execution of Precedent Agreements and the timely satisfaction of the CPs outside the control of APP, in each case, in a form acceptable to APP.

As required by Section 157.34 (d)(3) of the Commission's Regulations, within 10 days after Precedent Agreements have been executed by both parties, APP will make public on the APP web site (www.thealaskapipelineproject.com) and through press releases the results of the Open Season, including at least the name of the prospective shipper, the amount of capacity awarded, and the term of the agreement. As required by Section 157.34 (d)(4), within 20 days after Precedent Agreements have been executed by both parties, APP will submit to the Commission copies of each such Precedent Agreement and copies of any relevant correspondence with bidders who were not allocated capacity that identifies why such bids were not accepted. APP reserves the right to request confidential treatment of the Precedent Agreements submitted to the Commission pursuant to Section 157.34 (d)(4).

IV. REQUEST FOR COMMISSION APPROVAL

The APP Parties have devoted substantial time and effort to the preparation of this Plan to assure that it complies with all of the Commission's regulations and offers service on terms that are just, reasonable and not unduly discriminatory. The APP Parties are hopeful that there will be no serious objections to the Plan. However, if there are, the APP Parties stand ready to address any issues promptly, and they are confident that any concerns can be quickly resolved so that the Commission's review of this Plan will be uncontested and the Open Season may proceed on schedule and as planned. In this regard, the APP Parties invite interested parties to contact the APP Parties with any questions prior to the initial comment date.

Because this is the first request for pre-approval under the Open Season Regulations, there is no Commission precedent that directly addresses the scope of the Commission's review of the Plan or the criteria that the Commission should apply in assessing whether to approve the

Plan. Order No. 2005, however, provides guidance on this issue. As set forth below, the APP Plan fully meets the standards of Order No. 2005 and therefore should be approved.

A. Standard of Review

The purpose of the pre-approval process is to give the Commission an opportunity "at the earliest possible time" to address disputes that might arise "over the conduct of an open season and its conformance with the open season rules." Order No. 2005A, PP 64, 71. The pre-approval review to be conducted by the Commission, therefore, is quite limited. It is to focus on the "open season procedures,"[8] and specifically on whether the open season plan "conform[s] to the regulations." *Id.,* P 64. If the plan on its face complies with the regulations, and does not present concerns that are so obviously beyond remedy as to make the planned Open Season a nullity, the Plan should be approved.

The pre-approval review is not a Section 7 certificate proceeding or a Section 4 proceeding to determine just and reasonable rates or terms and conditions of service.[9] Those steps come later in the process, and the Commission's pre-approval of an open season plan now will not pre-judge any issues that may be presented in those later proceedings. Indeed, compliance with the Open Season Regulations will remain as one of the issues that must be

[8] *See* Order No. 2005, P 109 (concluding "that it is in the public interest to require pre-approval of open season procedures").

[9] Instead, the review that the Commission should conduct is more like that which the Commission conducts when deciding whether to accept or reject a tariff filing or certificate application. As the Commission is aware, a tariff filing or certificate application may be "rejected" only in narrow circumstances where it is "patently either deficient in form or a substantive nullity." *Municipal Light Boards v. FPC*, 450 F.2d 1341, 1345 (D.C. Cir. 1971). Pertinent to the current request, rejection "classically" has been considered as "a technique for calling on the filing party to put its papers in proper form and order." *Id.* at 1346. However, "[i]t may also be used by an agency where the filing is so patently a nullity as a matter of substantive law, that administrative efficiency and justice are furthered by obviating any docket at the threshold. . . ." *Id.*

addressed in the certificate application, *see* 18 C.F.R. § 157.33, and the issue will be subject to the Commission's review at that time. *See* Order No. 2005, PP 15, 25.[10]

The limited review to be conducted at this time follows directly from the thorough consideration given to the open season process in the rulemaking proceeding leading to Order No. 2005. In that proceeding, all interested parties were given an opportunity to express their views on how an open season should be conducted. Balancing these sometimes conflicting views, *see* Order No. 2005, P 16, the Commission adopted detailed regulations to govern the conduct of the open season process. These regulations "provide the framework for an open season process that will provide reasonable flexibility to pipeline sponsors, while ensuring sufficient exchange of information and regulatory oversight to ensure that the goal of fair, open competition in the transportation and sale of natural gas is met." Order No. 2005, P 17; *see also* Order No. 2005A, P 2. The Commission has thus already addressed from a policy standpoint how the open season is to be conducted, and those rulings are final.[11] Now, all that remains is for the Commission to determine whether the proposed Open Season Plan complies with the regulations that the Commission has adopted.

For purposes of the current request, there are four regulations in particular that are relevant:

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[10] *See also* Order No. 2005A, P 72 ("given the fact that participants in an open season will have the opportunity to object to the conduct of the open season after a certificate application is filed, as is our current practice, as well as the ability to seek rehearing and obtain appellate review of any Commission certificate orders, orders approving open season procedures will be interlocutory and not subject to rehearing").

[11] The pre-approval review process, therefore, clearly is not intended to give dissatisfied parties an opportunity to re-argue positions that were rejected in Order No. 2005 or Order No. 2005A. *See, e.g.*, Order No. 2005, P 52 (denying request to "impose a requirement that any open season must remain open to a particular point in time tied to other project activities"); P 95 (denying request to impose a cap on contract term bids).

- Section 157.34 (b) requires that a prospective applicant "conduct or adopt a study of gas consumption needs and prospective points of delivery within the State of Alaska and rely upon such study to develop the contents of the notice. . . . Such study shall be identified in the notice and if practicable, shall include or consist of a study conducted, approved or otherwise sanctioned by an appropriate governmental agency, office or commission of the State of Alaska. In its open season proposal, a prospective applicant shall include an estimate based upon the study, of how much capacity will be used in-state."

- Section 157.34 (c) specifies 21 items of information that must be contained in the notice. These information items are comprehensive, *see* Order No. 2005, P 56, and "in essence, define[] the information that all shippers will need to participate in an open season for capacity on an Alaska natural gas transportation project." *Id*., P 72.

- Under Section 157.35 (a), "[a]ll binding open seasons must be conducted without undue discrimination or preference in the rates, terms or conditions of service and all capacity allocated as a result of any open season shall be awarded without undue discrimination or preference of any kind."

- Sections 157.34 (c), (d) require that the unit of a prospective applicant conducting an open season function independent of the other non-regulated divisions of the project applicant as well as the applicant's Marketing and Energy affiliates and subject to certain standards of conduct.

As demonstrated below, the APP Plan for the TC Alaska Open Season satisfies all of these regulations and should therefore be approved.

B. The Open Season Plan Satisfies the In-State Needs Study Requirements

The Open Season Plan complies in all respects with Section 157.34 (b) of the Commission's regulations. At the request of TC Alaska, the consultant team of Northern Economics, Inc., Science Applications International Corp., and the Institute for Social and Economic Research at the University of Alaska, Anchorage conducted an *In-State Gas Demand Study* to evaluate natural gas requirements and prospective points of delivery within the State of Alaska. That Study is included with the Open Season Notice as Appendix B.[12]

[12] Included as Exhibits A and B to Appendix B are a letter from TC Alaska submitting the *In-State Gas Demand Study* to the Alaska Department of Public Resources and a letter from the Alaska Commissioners approving the use of the Study by TC Alaska "as a reasonable assessment of in-state natural gas consumption needs based on the facts currently available."

The *In-State Gas Demand Study* analyzes three demand scenarios categorized as No Industry, Current Industry, and Growth Industry. Recognizing that no in-state gas-intensive industrial load is very certain, the No Industry case represents in-state demand without a large industrial load. The Current Industry case represents a continuation of current trends, with a facility representative of the demand required by the Nikiski LNG terminal operating at full capacity. Finally, the Growth Industry case represents a scenario whereby the existing LNG facility will expand to double its current capacity, but no other greenfield (or new) projects will be built in years 1 to 5. Greenfield industrial projects are not assumed to be built at the same time as the pipeline because the simultaneous demand for labor and materials could significantly increase the capital costs for a new facility, causing it to be uneconomic. Furthermore, unless owners of the greenfield industrial projects were to secure gas supply and commit to pipeline capacity in the early open seasons, it is unlikely that they would have sufficient gas to support the greenfield projects in the initial years of pipeline operation. In years 10 to 15, greenfield projects with reasonably likely economic feasibility are included under the Growth Industry case.

For the first five years of pipeline operations, the projected in-state gas demand for the No Industry case, Current Industry case, and Growth Industry case, are 260, 490 and 740 MMcf/d, respectively; and the chances of these scenarios occurring are 29 percent, 38 percent, and 12 percent, respectively. *See In-State Gas Demand Study* at 74. The Valdez Pipeline is estimated to have a slightly higher gas demand than the Alaska-Canada Pipeline for the three demand scenarios due to the additional industrial demands in the Valdez area that will likely be created with the availability of natural gas. Specifically, for the first five years of pipeline operations, the projected demand levels for the No Industry case, Current Industry case, and Growth Industry case for the Valdez Pipeline, are 270, 500, and 750 MMcf/d, respectively; and the chances of these scenarios occurring are 61 percent, 30 percent, and 9 percent, respectively. *Id.*

Because the Current Industry demand scenario has the greatest chance of occurrence, the Study used that scenario for analysis of potential in-state off-take points and volumes. The analysis of potential off-take points and volumes also factored in the continued availability of gas from Cook Inlet sources, which will reduce the demand for North Slope gas. Utilizing this methodology, the Study projects total net in-state demand for North Slope gas in years 1-5 of pipeline operations to be approximately 340 MMcf/d for the Alaska-Canada Pipeline alternative and approximately 350 MMcf/d for the Valdez Pipeline alternative. *Id.* at 79. Based on these demand projections, the Study (*id.* at 84) identifies the most likely off-take points along the two alternative routes as follows:

Location	**Alaska-Canada Pipeline**	**Valdez Pipeline**
Livengood	√	√
Fairbanks	√	√
Parks Highway spur	√	√
Delta Junction area/Richardson Highway spur	√	√
Tok	√	n/a
Glennallen	n/a	√
Valdez	n/a	√

For purposes of the Open Season, APP has included in Exhibit A to the Precedent Agreement all of these locations as potential off-take points. The final determination of which locations will be served will depend on which alternative route is selected, the results of the Open Season and input from potential shippers.

C. The Proposed Open Season Notice Includes All of the Required Information

The proposed Open Season Notice includes all of the information that the Commission has determined is necessary to allow potential shippers to evaluate the APP Open Season offering and to make a determination on whether to bid for capacity. Each one of the 21 information items specified in Section 157.34 (c) of the regulations is separately addressed in Appendix C to the proposed Notice. To the extent that the information for the Alaska-Canada Pipeline differs from that for the Valdez Pipeline, each alternative is addressed.

1. The Required Information Has Been Provided

Items (1)-(5) of the information requirements relate to the description of the project, primarily from a technical standpoint. The required information includes the route of the pipeline, the size and design capacity, including a description of possible expanded designs, the maximum allowable and expected operating pressures, the delivery pressures and projected in-service date. All of this information is provided at pp. 1-15 of Appendix C.

Item (6) requires an estimated unbundled rate for each delivery point for each service offered, including reservation charges, interruptible transportation rates, usage rates, fuel retention percentages and other applicable charges. **Item (7)** requires information about the estimated cost of service upon which the rates are developed. This information is provided at pp. 16-19 and in Exhibits J and K of Appendix C.

Item (8) relates to the estimated transportation rate for deliveries in the state of Alaska. That information, for both the Alaska-Canada Pipeline and Valdez Pipeline alternatives, is provided at pp. 20-21 and in Exhibits J and K of Appendix C. These estimated in-state transportation rates are based on the same cost estimates as the other rates for firm transportation service, but do not include costs to make deliveries outside the State of Alaska. The rates have been developed utilizing a weighted average volume-mile cost allocation and rate design methodology. APP computed aggregate in-state volume-miles by adding the products of (1) the estimated MDQ for each delivery point, as derived from the *In-State Gas Demand Study* and (2) the miles from the outlet of the GTP to each delivery point. The resulting sum of in-state volume-miles was then divided by the total volume-miles (similarly computed) associated with firm transportation contracts for all deliveries within the state and to either the Alaska-Canada border or the Valdez LNG Facility. The resulting percentage was then applied to the total cost of service to determine the costs applicable to in-state deliveries. The costs applicable to in-state deliveries were then used to design in-state rates, by dividing such costs by in-state aggregate MDQs.

Item (9) requires the provision of information relating to negotiated rates and other rate options under consideration, including the rates and terms of any precedent agreements that have been negotiated outside this Open Season. The negotiated rate options being offered are addressed at pp. 22-24 and Exhibits J and K of Appendix C and described in detail in Exhibit A to the proposed Precedent Agreement. APP has not entered into pre-subscription or precedent agreements with any potential shipper.

Item (10) calls for the quality specifications and any other requirements applicable to gas to be delivered to the Project. Those specifications and requirements are set forth in Section 5 of the General Terms and Conditions of TC Alaska's indicative FERC Gas Tariff, which is attached as Exhibit I to Appendix C. Potential shippers will not be required to treat their gas at any designated plant or facility.

Item (11) requires information about the terms and conditions for each service offered. To satisfy this requirement, the APP Parties have prepared a complete indicative FERC Gas Tariff, which is attached as Exhibit I to Appendix C. Before the tariff is filed as part of a certificate application, it will be updated to reflect changes negotiated in connection with the Open Season, changes deemed necessary by TC Alaska, and changes to satisfy current North American Energy Standards Board ("NAESB") Standards.

Item (12) requires the specification of the creditworthiness standards, and any other collateral requirements, to be applied to prospective shippers. This information is contained in Exhibit B to the form of Precedent Agreement in Appendix A to the Notice. For purposes of developing the Project and conducting this Open Season, APP intends that certain parties shall be established as "Foundation Shippers." As specified in the Precedent Agreement, Foundation Shippers are shippers that make long-term capacity commitments equal to or exceeding 200,000 MMBtu/day in aggregate. Due to the requirements to finance a project of this magnitude, Foundation Shippers will be subject to a more stringent creditworthiness standard than non-Foundation Shippers as stipulated in Exhibit B to the Precedent Agreement. The creditworthiness provisions of the indicative tariff also reflect the standards deemed necessary to finance the Project.

Item (13) asks for the date by which potential shippers and the prospective applicant must execute precedent agreements. That information is provided at p. 28 of Appendix C.

Items (14) and (15) require a statement of a detailed methodology for determining the value of bids for deliveries within and outside the State of Alaska, and the methodology by which capacity will be awarded in the case of over-subscription. That information is provided at pp. 29-30 of Appendix C. Because there is no pre-subscribed capacity on the Project, the provisions in Item (15) regarding pre-subscribed capacity are not applicable.

Item (16) requires that the Notice contain the required bid information, whether bids are binding or non-binding, receipt and delivery point requirements, the form of a precedent agreement and time of execution of the precedent agreement, and definition and treatment of non-conforming bids. That information is provided at pp. 31-32 of Appendix C. All bids will be binding. APP's proposed Precedent Agreement is attached as Appendix A to the Notice. Exhibit A to that form of Precedent Agreement specifies the receipt and delivery point requirements.

Item (17) requires the projected date for filing an application at the Commission. As specified at p. 33 of Appendix C, the expected date for the NGA Section 7 certificate application filing is October 31, 2012.

Item (18) is the "catch all" that requires disclosure of all information in the prospective applicant's possession pertaining to the service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, or that the prospective applicant has made available to, or obtained from, any potential shipper, including affiliates of the prospective applicant. Although TC Alaska is the prospective applicant, the APP Parties are responding to this requirement as though it were applicable to APP, not just TC Alaska.

As described below in connection with the independent functioning requirement of Section 157.35 (c) of the Open Season Regulations, ExxonMobil has created an organizational unit for its participation in the Project that is entirely separate from the ExxonMobil entities that could be considered potential shippers, and has established firewalls that restrict the information flow between APP and ExxonMobil's production and marketing units. This organizational separation was put into place in May 2009, in anticipation of ExxonMobil's participation in the Project, and at that time there was a transfer of necessary and relevant information to APP from the ExxonMobil entities that had previously been involved in ExxonMobil's consideration of an Alaska natural gas pipeline. The information provided to APP included the 70-plus volume 2001

Alaska Gas Pipeline Producer Team ("AGPPT") Study. All project-related information that APP received at that time, and any such information APP has since received from a potential ExxonMobil shipper entity or any other potential shipper, has been logged in and inventoried. The relevant information APP has received from potential shippers, therefore, is readily identifiable and will be made available during the Open Season in response to Item (18).

In addition to the project-related information received from a potential ExxonMobil shipper entity, most of the information in APP's possession relating to the Project either has been created by APP or was received from TransCanada. To the extent specified in Item (18), this information will also be disclosed in connection with the Notice.

Items (19)-(21) relate to the organization of the prospective applicant's affiliates involved in the production of natural gas in the State of Alaska or the marketing of natural gas from the State of Alaska, and to the restrictions on the transfer of non-public Open Season information to those affiliates. Again, the information being provided as part of the Notice is not limited to the applicant TC Alaska, but also includes ExxonMobil's affiliates involved in the production of natural gas in Alaska or the marketing of natural gas from Alaska. That information is found at pp. 36-40 of Appendix C.

2. The Notice is Based on the Best Information Available

In Order No. 2005, the Commission recognized that a potential Alaska pipeline project applicant might find it necessary or appropriate to initiate an open season before some of the required information is available or can be finally determined. Order No. 2005, P 71. Indeed, given the necessary lead time between the open season process and the final completion of a project, it would be surprising if a Notice of Open Season could ever provide all of the project information specified by Section 157.34 (c) in a definitive form that is not subject to change.

That is particularly true of initial open season offerings, which in part are designed to test the interest in a project and determine whether the offering will be commercially viable.

These observations are applicable to APP. The basic parameters of the Project have been set based on current information regarding proven and probable reserves and estimates of market demand for transportation. While the APP Parties do not expect those parameters to change, that possibility nevertheless exists as additional information is acquired before Project completion, including information acquired during the Open Season. In addition, even if the basic parameters of the Project are not modified, existing information will continue to be refined.

Consistent with Section 157.34 (c), therefore, the information supplied in the Notice includes good faith estimates based on the "best information available" at the present time, including the recently updated cost and schedule estimates that conform to AACEI Class IV Standards. If new or different information becomes available during the Open Season, it will be provided.

3. Information Available in Data Rooms

In Order No. 2005A, the Commission recognized that the scope of the information specified in Section 157.34 (c)(18) is extensive. Therefore, rather than requiring that the Open Season Notice contain copies of all the documents specified in this section, the project notice may identify a location where such information is available for review. Order No. 2005A, P 106. In addition, the Commission recognized that some such information may be proprietary or confidential, and that access to this information would have to be addressed as it is in any commercial situation. *Id.*

The APP Parties have established data rooms that will be made available to potential shippers and certain other interested stakeholders, as well as interested U.S., Canada, and Alaska regulatory agencies, upon APP's issuance of its Open Season Notice on April 30, 2010. The data rooms will contain the information that APP has in its possession relating to the proposed service being offered, projected pipeline design and capacity, proposed tariff provisions, and cost projections. In addition, the data rooms will contain the information that APP has made available to, or obtained from, any potential shipper, including affiliates of the APP Parties prior to the issuance of the Notice of Open Season.

The data rooms will be located in the following locations:

- Houston, Texas – Main data room containing all required project information in electronic format or hard copy.
- Anchorage, Alaska – Adjunct data room containing all required information available in electronic format.
- Whitehorse, Yukon – Adjunct data room containing all required information available in electronic format.
- Calgary, Alberta – Adjunct data room containing all required information available in electronic format.

Due to the commercially and competitively sensitive nature of the information, all information contained in the data rooms that is not in the public domain will be treated as confidential information. Any person wishing to access such confidential information will be required to sign a confidentiality undertaking in the form attached as Exhibit G to Appendix C, and to comply with the data room procedures attached as Exhibit H to Appendix C. The data rooms will be set up on a hierarchical basis, as follows:

- All information in the public domain will be accessible through the APP website, www.thealaskapipelineproject.com, and available for review by anyone interested in accessing that data.
- Data contained in the physical data rooms will be broken into three levels of confidentiality.
    - The first level ("Tier 1") will contain confidential project information, not in the public domain, but which is of relatively lower commercial and competitive risk to the Project. All interested stakeholders granted access to the data rooms will have access to Tier 1 data.

- The second level ("Tier 2") will contain high risk, commercially sensitive data, such as project component cost projections, land access cost projections and the like. Such information will be made available only to potential shippers and regulatory agencies with Project oversight responsibilities.

- In addition, certain information ("Tier 3") contained in the data rooms is subject to third party confidentiality restrictions. Anyone seeking access to Tier 3 data will need to secure a release from such third parties in order to view such Tier 3 data.

D. The Open Season Plan Does Not Unduly Discriminate Against Any Class of Potential Shippers or Unduly Prefer Others

Recognizing that a principal objective of the Commission's Open Season Regulations is to ensure that all potential shippers are able to obtain transportation service on a proposed Alaska pipeline under terms that are not unduly discriminatory or unduly preferential, the APP Parties have designed the Open Season Plan to protect against undue discrimination or preference. APP's goal is to provide transportation to any and all shippers who are willing to make the commercial commitment necessary to assure the financing and successful operation of the Project. The Open Season Plan is not unduly preferential to any potential shipper (whether or not an APP affiliated entity) or class of potential shippers. Nor is the Plan unduly prejudicial to any potential shipper or any class of potential shippers.

APP will process all similar Open Season requests for transportation capacity in the same manner and within the same time period. APP's methodology for awarding transportation capacity, *see* pp. 12-13 *supra*, does not give undue preference to any potential shipper, whether affiliated or not affiliated with the Project sponsors, in matters relating to the sale or purchase of transportation services including, but not limited to, price, curtailment, scheduling, priority, or any other terms and conditions of service offered during the Open Season.

The only distinction between shipper classes that is drawn in the Open Season Notice relates to Foundation Shippers that make capacity commitments equal to or exceeding 200,000

MMBtu/day in aggregate. As described above, Exhibit B of the Precedent Agreement stipulates that such Foundation Shippers will be subject to a more stringent creditworthiness standard than non-Foundation Shippers, which is necessary to finance an investment of this magnitude. In addition, under the terms of the Precedent Agreement, Foundation Shippers will be provided certain rights or benefits, including (1) the right to elect the same negotiated rate terms, in their entirety, including duration and capacity, as offered to and accepted by any other shipper, prior to the commencement of service; (2) the right to sell to TC Alaska a pro rata portion of the initial line fill requirements at a mutually agreed price; and (3) a one-time termination right exercisable within 30 days after receiving notice from APP that TC Alaska has accepted the final FERC certificate of public convenience and necessity. Foundation Shippers exercising this termination right will be required to reimburse the APP Parties for Project development costs, as specified in more detail in the Precedent Agreement. Given that Foundation Shippers will be taking on a role that is essential to the initial financing and ongoing financial viability of the Project, they are distinct from other shippers and are not similarly situated. They thus cannot claim that they are the subjects of undue discrimination. Nor can others claim that the Foundation Shippers are receiving an undue preference.[13]

One of the specific issues addressed by the Commission in Order No. 2005 relates to gas treatment service and gas quality specifications. *See* Order No. 2005A, PP 84, 87. Consistent with the Commission's order, APP is offering a separate rate for transportation service unbundled from the rate for the optional gas treatment service. Furthermore, APP is not requiring bidders to bid on both services and will not evaluate bids based on whether bidders

[13] *See Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224 at PP 76, 81 (2009); *Midcontinent Express Pipeline LLC,* 124 FERC ¶ 61,089 at P 82 (2008); *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272 at P 78 (2006).

requested both services. Nor will APP reject an otherwise qualified bidder that states that it will deliver gas to the pipeline facilities that meets the required gas quality specifications.

E. The Applicant and Related Companies Have Complied with Applicable Independent Functioning Requirements and Standards of Conduct

In the regulations adopted in Order No. 2005, the Commission required that each prospective applicant conducting an open season for an Alaska natural gas transportation project "must function independent of the other divisions of the prospective applicant as well as the prospective applicant's Marketing and Energy affiliates." 18 C.F.R. § 157.35 (c). The Commission also directed the prospective applicant to comply with certain specified standards of conduct. *Id*., § 157.35 (d). Each of these requirements was derived from the Commission's previous Order No. 2004, and each incorporated by reference then-existing regulations that the Commission had adopted in Order No. 2004. *See* Order No. 2005, P 74.

Because the regulations adopted in Order No. 2004 have now been overturned by judicial action[14] and replaced by the Standards of Conduct promulgated in Order No. 717,[15] it is doubtful whether the Order No. 2004-based requirements adopted in Order No. 2005 remain in effect. Some of the regulation sections incorporated by reference in Order No. 2005 no longer exist in the Code of Federal Regulations (*e.g.,* 18 C.F.R. §§ 358.4(e)(3), (4), (5) and (6)), and no section has the same content as the regulations that were in place in 2005. Moreover, the Commission's own website relating to Alaska Natural Gas Transportation Projects links to Order No. 717 as providing the applicable Standards of Conduct. *See* http://www.ferc.gov/industries/gas/indus-act/angtp.asp.

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[14] *See National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006).

[15] *See Standards of Conduct for Transmission Providers*, 125 FERC ¶ 61,064 (2008) ("Order No. 717"), *on rehearing*, 129 FERC ¶ 61,043 (2009) ("Order No. 717A"), 129 FERC ¶ 61,123 (2009) ("Order No. 717B").

The Standards of Conduct adopted in Order No. 717 differ from those adopted in Order No. 2004 in a number of fundamental respects. Most importantly, Order No. 717 eliminated the "energy affiliates" concept in its entirety. Order No. 717, PP 3, 12. Order No. 717 thus applies only when pipelines "conduct transmission transactions with an affiliate that engages in marketing functions," meaning that there is no specified requirement of independence between a pipeline and its production affiliates. *Id.*, PP 20, 26. In addition, Order No. 717 replaced the corporate separation approach with the employee function approach, which requires only that a pipeline's "transmission function" employees function independently of the pipeline's "marketing function" employees. *Id.*, PP 9, 12; *see* 18 C.F.R. § 358.5 (a). In this regard, "marketing functions" expressly do not include "sales of natural gas solely from a seller's own production." *Id.*, § 358.3 (c)(iii); *see* Order No. 717A, P 55.[16]

Interpreted consistently with Order No. 717, therefore, the independent functioning regulations of Order No. 2005 have no impact on TransCanada's Open Season conduct because no TransCanada affiliate is engaged in the sales or marketing of Alaska natural gas. Nor do the independent functioning regulations require separation of APP from ExxonMobil's production or marketing affiliates because the energy affiliates concept has been eliminated and the only Alaska natural gas that ExxonMobil will be marketing is from its own production.

Although the APP Parties believe that the Order No. 2004-based requirements no longer have any legal force and that the Order No. 717-based requirements are by their terms not applicable to the APP Open Season, APP has taken a conservative approach to its organization and structure to assure that APP remains independent. Thus, although TransCanada's

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[16] As the Commission noted, it "has not found evidence of undue preference that was exclusively a result of sales of natural gas solely from a seller's own production or its own gathering or processing facilities." Order No. 717A, P 57 n. 119.

organization and operations are outside the scope of the Commission's concerns, TransCanada personnel continue to be subject to existing codes of conduct which create independence between the TransCanada personnel providing services to APP and TransCanada personnel in non-regulated units. Moreover, as described below, APP has been separated on a corporate basis from ExxonMobil's Alaska production and marketing units and APP has put in place standards of conduct. These steps assure a fair open season process in compliance with the Commission's regulations.

1. TransCanada

The purpose of the independent functioning requirement is to "minimize the risk that an affiliate of a project applicant would have an advantage over non-affiliates in obtaining capacity through the open season." Order No. 2005, P 74. As to the applicant TC Alaska, this risk does not exist. TC Alaska was created solely to build an Alaska natural gas pipeline and has no other business operations. Neither TC Alaska nor TransCanada has any affiliates that are involved in the production of natural gas in Alaska. Nor does TC Alaska or TransCanada have any marketing affiliates that are involved in the sale or marketing of natural gas from Alaska.

Moreover, TransCanada employees providing services to APP are already effectively separated from TransCanada's non-regulated marketing affiliates. TransCanada is comprised of many affiliated companies, some regulated and some not, and is subject to inter-affiliate codes of conduct, as well as FERC Standards of Conduct under Order No. 717. Such codes of conduct are in place to safeguard against improper sharing of information, personnel, or resources. TransCanada's existing regulatory compliance program includes comprehensive training on the FERC Standards of Conduct issued under Order No. 717. Such training includes in-depth information on the no-conduit, independent functioning, non-discrimination and transparency rules. Individuals assigned to or supporting APP are required to complete such training.

In addition, TransCanada has implemented safeguards to assure that non-public APP information is not disclosed to ExxonMobil personnel involved in the production of natural gas in the State of Alaska or the marketing or sales of natual gas from the State of Alaska. TransCanada personnel who provide services to APP or who may receive non-public information regarding APP as part of their job function are instructed that ExxonMobil production and marketing personnel are to be considered in the same category as TransCanada non-regulated personnel and that, in connection with an Open Season, non-public APP information may not be disclosed to ExxonMobil production or marketing personnel, either directly or through a conduit, unless permitted by FERC regulations in connection with a specific request for transportation service.

2. ExxonMobil

The APP Parties recognize that ExxonMobil's participation in and support of the Project distinguishes this project from one in which only TransCanada would be involved. ExxonMobil, therefore, has established an organizational structure and implemented non-disclosure and other requirements that ensure that ExxonMobil personnel providing services to APP will function independently from those ExxonMobil entities engaged in the marketing and sales of natural gas from Alaska or in the production of natural gas in Alaska.

a. Structural Separation

ExxonMobil has three affiliated organizational units that conduct business related to Alaska natural gas: ExxonMobil Production Company ("EMPC") Americas unit, ExxonMobil Gas and Power Marketing Company ("EMGPM") Americas unit, and ExxonMobil Development Company ("EMDC") Arctic unit. To assure the independence of APP from the ExxonMobil organizational units involved in the production of natural gas in the State of Alaska and the marketing or sales of natural gas from the State of Alaska (including the EMDC Arctic unit's activities related to Point Thomson field development or Prudhoe Bay Unit support/oversight), ExxonMobil has established within EMDC a separate organizational unit to manage APP on behalf of the Project sponsors. This organizational unit is dedicated exclusively to APP and performs no other business function. Except for shared employees providing general corporate/business support or performing non-commercially sensitive activities, all ExxonMobil personnel with active involvement in the Project have been assigned to the APP organizational unit. Within the APP organizational unit, there is an identified Commercial Team that is responsible for Open Season activities.

b. Standards of Conduct

To supplement and reinforce the structural separation of the APP organizational unit, three firewall domains have been established: (1) inside the APP Firewall, (2) inside the Production/Marketing Firewall, and (3) outside the firewalls.

Personnel are designated to be inside the APP Firewall if they (1) work full-time on the APP team; (2) have active involvement in developing or modifying parameters and details related to the APP Open Season offering or the commercial basis of the Project (*e.g.*, cost and schedule projections, financing, tolling parameters, tariff terms and conditions, economics); or (3) perform an advocacy role for APP. All personnel with responsibility for conducting the APP Open Season are inside the APP Firewall. Personnel are designated as being inside the Production/Marketing Firewall if they (1) work full time in the EMPC Americas unit, in the EMGPM Americas unit, or on EMDC Arctic unit activities related to Point Thomson field development;[17] (2) have active involvement in or actively support, work activities related to

[17] The responsibility for the development of ExxonMobil's interests in the Point Thomson area, as contrasted with the ultimate production and marketing of gas from those fields for which EMPC and EMGPM are responsible, is within an organizational unit of EMDC that is entirely

Alaska gas production or the North American gas market (including EMDC Arctic unit activities related to Prudhoe Bay support/oversight); (3) have active involvement in developing or modifying parameters and details related to the commercial basis of the Point Thomson field development (*e.g.*, reserves and production profiles, project cost and schedule projections, economics); or (4) perform an advocacy function in relation to any of the foregoing.

All personnel designated to be inside one of the firewalls are subject to the following standards of conduct:

- All personnel designated to be inside the APP Firewall are prohibited from engaging in or performing any work activities relating to the production of natural gas in the State of Alaska or the marketing of natural gas from the State of Alaska.

- All personnel designated to be inside the Production/Marketing Firewall are prohibited from engaging in or performing any work activities related to conducting the APP Open Season or implementing APP.

- All communication and exchange of non-public information between the personnel designated to be inside the APP Firewall and the personnel of those organizational units inside the Production/Marketing Firewall are restricted, and are permitted only in limited circumstances consistent with an arm's length third-party business relationship and with prior approval of the respective unit's management.

- To the extent that APP makes non-public information available to personnel inside the Production/Marketing Firewall or obtains non-public information from personnel inside the Production/Marketing Firewall prior to the issuance of the Open Season Notice, that information will be included in the Notice or made available in the Open Season data rooms.

- All personnel designated to be within either firewall are prohibited from using anyone as a conduit for the conveyance of non-public information between the separated units.

The APP Open Season will be conducted by the APP Commercial Team, an identified APP working group that is responsible for commercial activities, including review of the Open Season bids and the allocation and award of capacity. The APP Commercial Team is inside the

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separate from the APP organization from the vice-president level down. These EMDC units are further separated by the applicable firewalls.

APP Firewall and, as such, is subject to the aforementioned standards of conduct applicable to ExxonMobil personnel inside the APP Firewall. In addition, during the conduct of the Open Season, the Commercial Team is to observe the following standards of conduct:

- Confidential shipper information received as part of the Open Season process is to be maintained in confidence and is not to be disclosed to personnel inside the Production/Marketing Firewall or shared with other potential shippers, unless authorized in writing by the shipper providing the information or required by law or regulation.
- Non-public APP information may not be disclosed to personnel inside the Production/Marketing Firewall except to the extent it relates solely to a specific request for transportation service on behalf of an ExxonMobil unit as a potential shipper.[18]
- If non-public APP information that does not relate solely to a specific request for transportation service on behalf of an ExxonMobil unit as a potential shipper is disclosed to personnel inside the Production/Marketing Firewall, that information will be made available to all other potential shippers.

The Offices of the Presidents and above, and employees providing general corporate/business support, or working in non-commercially sensitive areas (*e.g.*, technical managers/advisors and other subject matter experts), are considered to be outside of both firewalls and can be shared employees that provide advice or service to APP or those organizational units inside the Production/Marketing Firewall. Shared resources must comply with the communications and information sharing restrictions applicable to the unit they are supporting (*e.g.*, a person supporting APP must comply with Order No. 2005 and the related

[18] Once the Open Season commences, the Commercial Team expects to receive inquiries about the Open Season offering from potential shippers, including an ExxonMobil affiliate, and expects to engage in negotiations with potential shippers regarding the terms and conditions of the offering. As explained above, APP does not believe that these discussions will be subject to the Order No. 717 non-disclosure requirements because the ExxonMobil affiliate will be seeking capacity for the transportation of ExxonMobil's own production and thus will not be engaged in a marketing function. However, even assuming the Order No. 717 regulations were applicable, APP understands that such discussions, including discussions with affiliates, are permitted and that the information exchanged in these discussions need not be disclosed so long as the discussions relate to specific requests for service. *See* 18 C.F.R. § 358.7 (b).

standards of conduct). To maintain effective functional separation between APP and those organizational units inside the Production/Marketing Firewall, such shared personnel are provided Order No. 2005 compliance training and are required to abide by the following Firewall Related Behaviors:

- Personnel with access to non-public information may not act as a conduit for the conveyance of non-public information between the separated units.
- Personnel with access to non-public information may not use the non-public information received from one separated unit to influence the decision of another separated unit.
- Decisions concerning the Project made by personnel outside the firewalls shall be made on an objective basis in the best interests of APP (not ExxonMobil's general interest).

c. Access Restrictions

Physical access to the office space housing the APP organizational unit (including file rooms) is restricted and controlled by card key security. All ExxonMobil personnel designated to be inside the Production/Marketing Firewall are prohibited from receiving card key access to the APP offices. Access may be granted to certain ExxonMobil personnel designated to be outside the firewalls on a case-by-case basis to meet a specific business need, provided they have received appropriate compliance training. Additional procedures are in place that require a periodic review of the card key access to the APP offices.

APP has implemented controls, which utilize passwords or other information technology security measures, to restrict access to all electronic information systems (*e.g.*, e-mail, LAN systems, hardware or software) containing non-public APP information. Within the APP itself, access to confidential shipper information received only as part of any Open Season is further restricted to the APP Commercial Team. All ExxonMobil personnel designated to be inside the Production/Marketing firewall are prohibited from having access to APP electronic information systems, and vice-versa. Access to APP electronic information systems may be granted to certain ExxonMobil personnel designated to be outside the firewalls on a case-by-case basis to meet a specific business need, provided they have received appropriate compliance training. Additional procedures are in place that require a periodic review of the access to APP electronic information systems.

3. Implementation Procedures

APP has also implemented procedures to assure compliance with the standards of conduct – *i.e.*, training, posting of written compliance procedures, and designation of a Chief Compliance Officer.

In conjunction with the public APP announcement in June 2009, written Order No. 2005 compliance guidelines were provided to those ExxonMobil employees who were likely to be interfacing with APP or to become privy to non-public APP information. APP has since prepared written Compliance Procedures that have been distributed to all ExxonMobil personnel designated to be inside the APP Firewall, other EMDC personnel (officers, directors, supervisory employees, and any other employees) considered to be outside the firewalls who are likely to interface with APP or to become privy to non-public APP information, and TransCanada personnel assigned to or supporting the Project. The APP Chief Compliance Officer is coordinating through an established regulatory compliance network the distribution of these Compliance Procedures to the ExxonMobil personnel assigned to or supporting those organizational units designated to be inside the Production/Marketing Firewall. The dissemination of the Compliance Procedures, and any revisions to them, are made via an e-mail message that also contains an electronic link to the APP website where these Compliance Procedures have been posted.

Training on Order No. 2005 compliance and the related standards of conduct has been provided and will be provided on an annual basis to all ExxonMobil personnel designated to be inside the APP Firewall and to other EMDC personnel (officers, directors, supervisory employees, and any other employees) considered to be outside the firewalls who are likely to become privy to non-public APP information. The APP Chief Compliance Officer is coordinating through an established regulatory compliance network the delivery of similar Order No. 2005 compliance training to the ExxonMobil personnel involved in or supporting the work activities related to the production of natural gas in the State of Alaska or the marketing or sales of natural gas from the State of Alaska for those organizational units designated to be inside the Production/Marketing Firewall. TransCanada personnel assigned to or supporting the Project are required to complete annual training that includes training regarding the Commission's standards of conduct set forth in Order No. 717. All personnel receiving training are required to provide a written or electronic acknowledgement confirming that they have completed the training.

All personnel newly participating in APP, on behalf of either ExxonMobil or TransCanada, will receive appropriate compliance instructions as part of the APP Induction Manual (employee orientation package).

Finally, as noted above, APP has designated a Chief Compliance Officer who is the contact for all Order No. 2005 compliance issues and is responsible for implementing the Compliance Procedures.

V. CONCLUSION

For the reasons stated herein, TC Alaska's Open Season Plan should be approved.

Respectfully submitted,

_*/s/ Eugene R. Elrod*_____

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Counsel for TransCanada Alaska Company LLC and Alaska Pipeline Project

Date: January 29, 2010

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TransCanada Alaska Company LLC	)))	**Docket No. PF09-11-001**

OPEN SEASON PLAN DOCUMENTS
SUBMITTED IN CONNECTION WITH
REQUEST FOR COMMISSION APPROVAL OF DETAILED PLAN FOR
CONDUCTING AN OPEN SEASON

VOLUME I OF III
(**includes Open Season Notice and Precedent Agreement**)

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Counsel for TransCanada Alaska Company LLC and Alaska Pipeline Project

Date: January 29, 2010

OPEN SEASON PLAN DOCUMENTS (submitted separately in three volumes)

Volume I

Proposed Open Season Notice with:

Appendix A: Proposed Precedent Agreement

Exhibit A: Bid Forms for the Alaska-Canada Pipeline and Valdez Pipeline

Exhibit B: Creditworthiness

Exhibit C: Additional Shipper Conditions Precedent

Exhibit D: Illustrative Annual Negotiated Rate Calculation

Volume II

Appendix B: In-State Needs Study required by 18 C.F.R. § 157.34 (b)

Exhibit A: In-State Gas Demand Study Submission Letter

Exhibit B: In-State Gas Demand Study Approval Letter

Volume III

Appendix C: Information required by 18 C.F. R. §157.34 (c)

Item 1: Pipeline Routes

Item 2: Project Design and Capacities

Item 3: Operating Pressures

Item 4: Delivery Pressures

Item 5: In-Service Date

Item 6: Transportation and Treating Rates

Item 7: Cost of Service

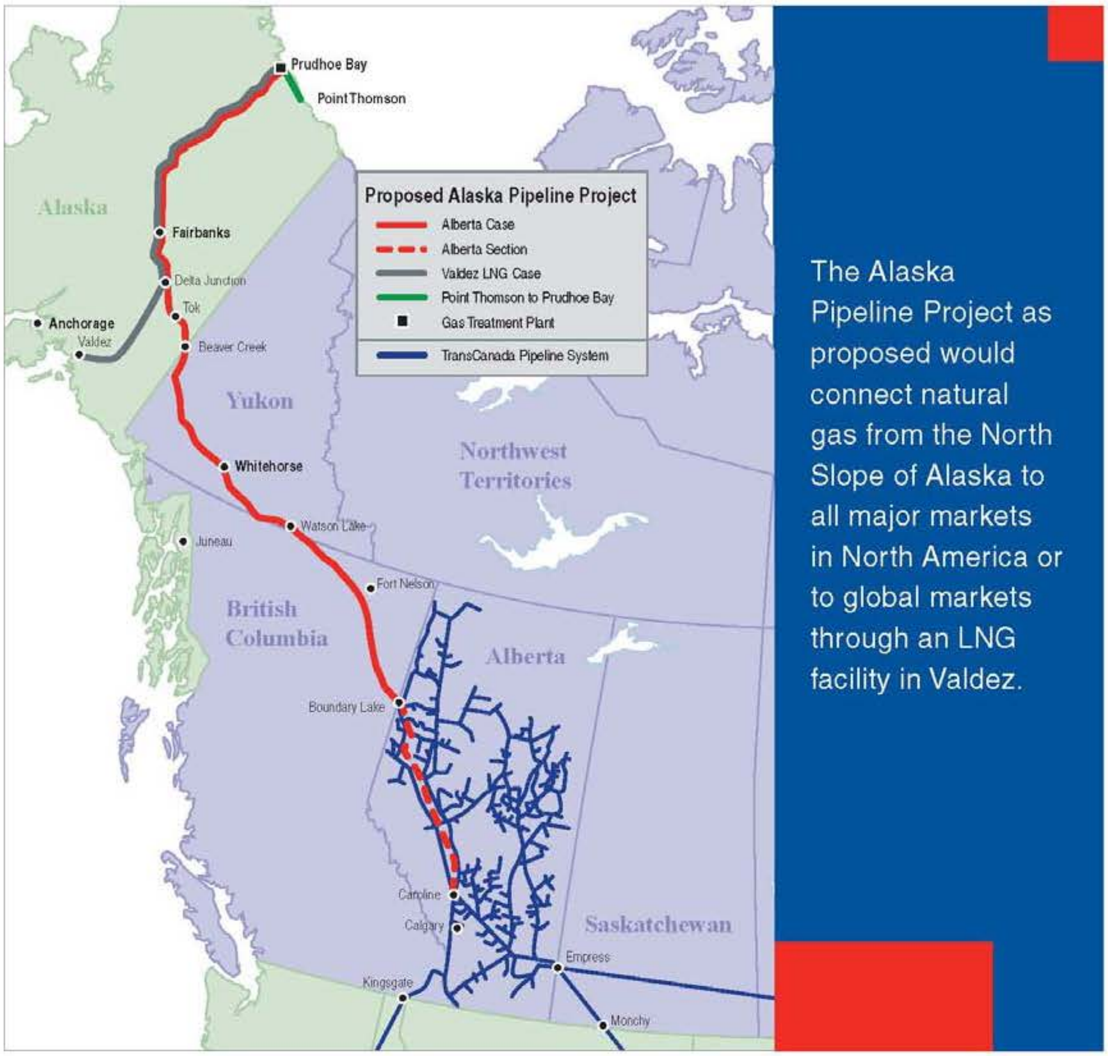
Item 8: In-State Transportation Rates

Item 9: Negotiated and Other Rates

Exhibit L: Definitions

Pre-Approval Form of
APP Open Season Notice

ALASKA PipelineProject



TransCanada ExxonMobil

Open Season Notice
April 30, 2010 – July 30, 2010

THE ALASKA PIPELINE PROJECT
OPEN SEASON NOTICE
FOR NEW INTERSTATE NATURAL GAS PIPELINE CAPACITY

Notice

TransCanada Alaska Company LLC ("TC Alaska") will conduct a binding Open Season for the U.S. portion of a new interstate natural gas pipeline system, beginning at 8:00 a.m. CDT on Friday April 30, 2010 and ending on Friday, July 30, 2010 at 5:00 p.m. CDT.

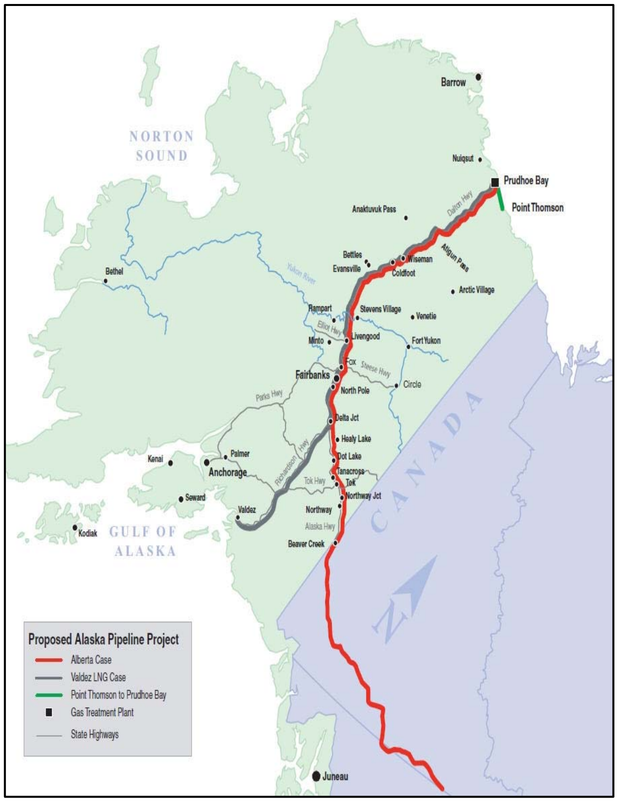
This Open Season is being held to solicit the submission and execution of binding Precedent Agreements (the form of which is attached hereto as Appendix A) for firm interstate natural gas transportation service and optional firm gas treatment service provided by TC Alaska's Alaska Pipeline Project ("APP" or "Project"). This Open Season is being conducted in accordance with the Federal Energy Regulatory Commission ("FERC") Regulations governing Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. §157.30 - §157.38, and will provide a non-discriminatory means of awarding capacity to bidders, provided APP receives bids that conform to its requirements and APP decides to proceed with the Project, pursuant to the terms of this Open Season. In accordance with 18 C.F.R. §157.34(b) and §157.34(c), attached hereto are the State of Alaska endorsed *In-State Needs Study* (Appendix B) and the 21 informational elements specified by FERC to be provided in the Open Season Notice (Appendix C).

Background

The Alaska Pipeline Project is a world-class undertaking in all of its aspects. Once completed, the Project will allow for transportation of natural gas from Alaska's North Slope to markets in Alaska, Canada and the lower 48 States or to global markets via an alternative liquefied natural gas ("LNG") project. The North Slope of Alaska holds approximately 35 trillion cubic feet ("Tcf") of currently proven natural gas reserves, and it is estimated that another 100 to 200 Tcf ultimately could be discovered.

The Project is being jointly advanced on behalf of TC Alaska by affiliates of TransCanada and ExxonMobil (the "APP Parties"). The APP Parties and their respective affiliates (generally TransCanada and ExxonMobil) bring substantial financial strength to the Project and are uniquely situated to efficiently and effectively advance the Project's development. TransCanada has extensive North American pipeline construction experience, particularly in cold weather environments, and operates pipeline networks across Canada and in the U.S. TransCanada also holds the certificates and right-of-way in the Yukon Territory under the Northern Pipeline Act, and has proven expertise in efficiently advancing pipeline projects through the regulatory process, construction and operation. ExxonMobil has proven global mega-project management experience and a long history of Arctic project successes and technological innovations. ExxonMobil has repeatedly demonstrated its ability to deliver world-class projects on time and within budget, and has proven expertise in innovative gas treatment, pipeline and compression technologies.

Project Description



APP proposes to design, permit and construct a new natural gas pipeline system, subject to regulation by the FERC, beginning near Point Thomson and extending through Alaska over one of two alternative routes.

One route would extend from Point Thomson through points near Prudhoe Bay, Fairbanks, and Delta Junction and then to the Alaska-Canada border ("Alaska-Canada Pipeline"), where the pipeline would interconnect to a new pipeline that APP plans to design, permit and construct ("Canadian Pipeline").

The proposed Canadian Pipeline would extend to an interconnection point with the Alberta Hub or other existing off-take capacity at or near the British Columbia/Alberta border, providing the capability of transporting natural gas to North American markets, including the contiguous United States. The Open Season described in this Notice is being conducted as part of a broader open season process under which APP is also separately soliciting shipper bids for capacity on the Canadian Pipeline.

An alternative pipeline route would extend from the outlet of the Point Thomson plant through points near Prudhoe Bay, Fairbanks, Delta Junction and then to an interconnection point with a third-party LNG terminal near Valdez, Alaska ("Valdez Pipeline"). From Valdez, LNG cargoes could potentially access markets around the globe.

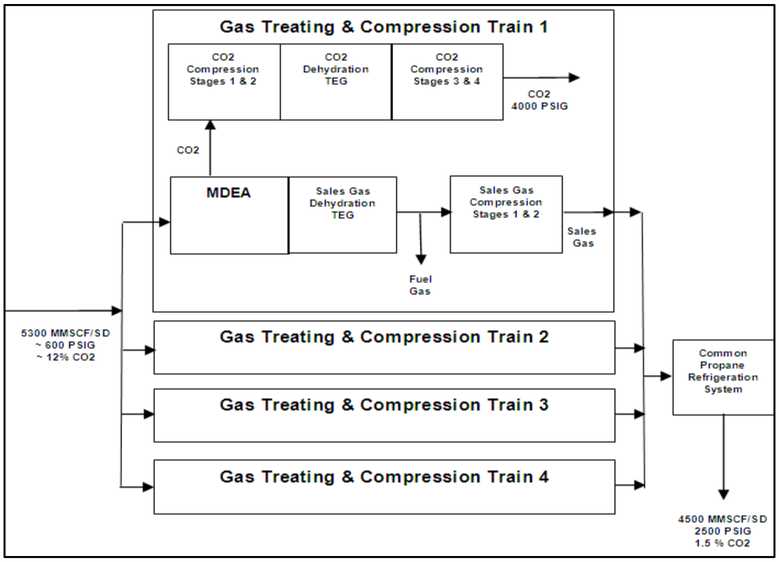
In either the Alaska-Canada Pipeline or the Valdez Pipeline alternative, a minimum of five delivery points will be made available in Alaska on a firm or interruptible basis to all shippers.

- The gas transmission pipeline segment between the outlet of the Point Thomson plant and the GTP (defined below) consists of a single 32-inch pipeline, a distance of approximately 58 miles, with no compression. The base-case capacity of this segment has been set at 1.1 Bcf/d (expandable with compression) with an operating pressure of approximately 1030 psi at the Point Thomson receipt point.

- The Alaska-Canada Pipeline gas transmission segment between the GTP and the Canadian border consists of a single 48-inch pipeline, a distance of approximately 734 miles, and six compressor stations. The base-case capacity of this segment has been set at 4.5 Bcf/d (expandable to 5.9 Bcf/d with additional compression) with an operating pressure of approximately 2500 psi along the entire route of this segment.

- The Valdez Pipeline gas transmission segment between the GTP and the LNG terminal facilities near Valdez consists of a single 48-inch pipeline, a distance of approximately 803 miles, and two compressor stations. The base-case capacity of this segment has been set at 3.0 Bcf/d (expandable with additional compression) with an operating pressure of approximately 900 psi at the Valdez LNG delivery point.

APP proposes to design, permit and construct a new gas treatment plant ("GTP") as an integral component of the APP's facilities and also subject to FERC regulation, located near Prudhoe Bay and operating in conjunction with either the Alaska-Canada Pipeline or the Valdez Pipeline. Shippers on APP's gas transmission pipeline will not be required to have their gas treated at the GTP, but shippers will be required to meet the gas quality specifications in TC Alaska's FERC Gas Tariff.



- The current GTP design for the Alaska-Canada Pipeline alternative is to treat approximately 5.3 Bcf/d of inlet gas, distributed to four trains, and deliver approximately 4.5 Bcf/d of pipeline quality gas with a CO_2 limit between 1.5% and 2%, remove approximately 0.6 Bcf/d of acid gas, and consume approximately 0.2 Bcf/d of fuel gas.

- The current GTP design for the Valdez Pipeline alternative is to treat approximately 3.6 Bcf/d of inlet gas, distributed to three trains, and deliver approximately 3.0 Bcf/d of pipeline quality gas with a CO_2 limit of ≤50 ppm, remove 0.44 Bcf/d of acid gas, and consume approximately 0.17 Bcf/d of fuel gas.

- The GTP will be designed for an inlet pressure of 600 psi and can be expanded to treat additional gas.

- The GTP's operation will be phased in.

- Shipper will be responsible for disposition of acid gas removed and returned to shipper. APP is willing to consider providing to shippers an acid gas disposal service.

The Alaska-Canada Pipeline and the Valdez Pipeline are alternative proposals. Depending on customer interest as evidenced in the Open Season, APP will proceed with either the Alaska-Canada Pipeline or the Valdez Pipeline, but not both.

Cost Range & Projected Timing

The APP Parties have undertaken an extensive effort to update cost and schedule estimates for the Project. These updated estimates conform to Association for the Advancement of Cost Engineering International ("AACEI") Class IV standards.

The overall cost estimate range in 2009 U.S. dollars is from $32 billion to $41 billion for the combined Alaska-Canada Pipeline and Canadian Pipeline and from $20 billion to $26 billion for the Valdez Pipeline. The estimated in-service date for both options is 2020 for initial gas and 2021 for full gas. It is normal practice to quote a range of cost estimates at this early stage of Project development to reflect inherent uncertainties and risks. APP is presenting to potential customers a credible estimate that can be used for their assessments and decisions.

As further described in the Precedent Agreement, a shipper executing a Precedent Agreement will bear a portion of project development costs in certain circumstances in which the shipper breaches the Agreement or exercises certain rights not to enter a firm transportation service agreement, or in which the APP Parties determine not to proceed with the Project.

Rates & Fuel

Recourse rates and negotiated rates are being offered in this Open Season. The principles for calculating the negotiated rates are shown in Exhibit A to the Precedent Agreement. Estimated ranges for negotiated and recourse rates and fuel percentages for firm gas transportation and firm gas treatment services are shown in Table 1 attached to this Open Season Notice. A shipper will be required to provide its proportionate share of actual Fuel and Lost and Unaccounted for Gas ("Fuel") at the receipt point. The amount of Fuel will be calculated based on the transmission path of the gas from the receipt point to the ultimate delivery point either in Alaska or Canada.

Based on the cost range set forth above, the estimated rate range for a 25-year negotiated rate from Prudhoe Bay to Alberta is $3.02 - $3.89 per MMBtu in nominal U.S. dollars or $2.43 - $3.13 per MMBtu in 2009 U.S. dollars and from Prudhoe Bay to Valdez is $2.76 - $3.59 per MMBtu in nominal U.S. dollars or $2.22 - $2.89 per MMBtu in 2009 U.S. dollars. These rate ranges include the cost of treating gas at the GTP.

Foundation Shippers

Shippers that make commitments to use capacity of at least 200,000 MMBtu/day on either the Alaska-Canada Pipeline or the Valdez Pipeline will be considered Foundation Shippers. Bids from multiple affiliates will be aggregated in determining whether a bidder will be considered a Foundation Shipper.

Due to the requirements to finance a project of this magnitude, Foundation Shippers will be subject to a more stringent creditworthiness standard as stated in Exhibit B of the Precedent Agreement.

Under the terms of the Precedent Agreement, Foundation Shippers will be provided certain rights including:

- The right to elect the same negotiated rate principles, in their entirety, as offered to and accepted by any other shipper, prior to the commencement of service;

- The right to sell to TC Alaska a pro rata portion of the initial line fill requirements at a mutually agreed price; and

- A one-time termination right exercisable within 30 days after receiving notice from APP that TC Alaska has accepted the final FERC certificate of public convenience and necessity. Foundation Shippers exercising this termination right will be required to reimburse the APP Parties for Project development costs, as specified in more detail in the Precedent Agreement.

Creditworthiness Standard

Shippers will be required to meet the creditworthiness standard as stipulated in Exhibit B to the Precedent Agreement.

Acceptable Bid Requirements

An acceptable bid for this Open Season shall consist of an executed Precedent Agreement for either or both of the Alaska-Canada Pipeline or the Valdez Pipeline in the form included in Appendix A to this Open Season Notice. Parties interested in contracting for firm capacity, regardless of which route is selected, must complete Exhibit A to the Precedent Agreement. At a minimum, bidders must provide the following information on Exhibit A to the Precedent Agreement:

- Maximum Daily Quantity ("MDQ") and optional Maximum Treatment Quantity ("MTQ"), exclusive of Fuel, by requested primary receipt and delivery points that bidders must indicate on Exhibit A to the Precedent Agreement.

- Whether the party intends to pay recourse rates or negotiated rates.

- Requested primary term of 20-25, 30 or 35 years for shippers selecting negotiated rates and 25 years for shippers selecting recourse rates (shippers selecting negotiated rates will also be entitled to a one-time, five-year extension of the initial service term).

To be considered a bona fide bid, the Precedent Agreement must be signed by an authorized representative of the bidding company. Each bidder must return the completed Precedent Agreement before the end of the Open Season to APP at the address specified below in the Precedent Agreement Submittal section of this Open Season Notice.

APP reserves the right to reject, on a not unduly discriminatory basis, any bid that does not conform to these requirements or that modifies the substantive terms set forth in the Precedent Agreement.

The following additional guidance should be followed by parties submitting bids:

- The negotiated rate principles in the Precedent Agreement available through this Open Season will be valid through the entire initial term and the contract renewal term of any firm transportation service agreement resulting from this Open Season.

- The recourse rates will be subject to the maximum applicable rates established in TC Alaska's FERC Gas Tariff, as may be modified from time-to-time.

- In addition to paying a recourse rate or a negotiated rate, shippers (i) will be charged a commodity or usage charge to cover costs which may vary with volumes actually shipped, and (ii) will be responsible for providing Fuel, subject to adjustment via an authorized Fuel tariff tracking mechanism.

- An Annual Charge Adjustment ("ACA"), a Change in Law/Tax/Regulation Surcharge, and any additional authorized surcharges that become generally applicable under TC Alaska's FERC Gas Tariff shall also be charged to shippers under both the recourse rates and the negotiated rates options.

- The Precedent Agreement contains two versions of Exhibit A, one reflecting the Project constructed with the Valdez Pipeline and the other reflecting the Project constructed with the Alaska-Canada Pipeline. Shippers should complete one or both versions of Exhibit A using the assumption that the particular pipeline option set forth in that version is the only line constructed.

- Shippers may propose additional points for the receipt of gas by the pipeline downstream of the GTP; provided that the gas conforms to the Project's quality specifications, and that the shipper is responsible for the cost of upstream facilities related to the delivery of gas to the APP pipeline.

Bidder Conditions Precedent

APP recognizes that bidders may desire to include certain conditions precedent ("CPs") to their bids that are outside the control of APP. Notwithstanding the bidders' execution of the Precedent Agreement during the Open Season, bidders will be allowed to negotiate CPs acceptable to the APP Parties and will have until December 31, 2010, to secure all necessary board approvals and internal authorizations necessary to undertake the obligations required by the Precedent Agreement. CPs that modify substantive terms in the Precedent Agreement may not be accepted.

Withdrawal of Bids

Bids received in this Open Season may be withdrawn prior to the conclusion of the Open Season upon written notification at the address specified below. Bidders may submit a bid to replace a withdrawn bid at any time prior to the close of the Open Season.

Route Selection

Shippers will be notified, as soon as reasonably practical following the completion of the Open Season, whether APP will proceed to seek to design, permit and construct the Alaska-Canada Pipeline and GTP, or will proceed to seek to design, permit and construct the Valdez Pipeline and GTP. APP will make this determination in its sole discretion, and is entitled to delay provision of this notification if it determines that commercial circumstances justify a later notification. Upon shippers' receipt of such notification, all terms of the Precedent Agreement are binding with respect to each shipper's elections on Exhibit A to the Precedent Agreement for service on the selected pipeline, and the shipper's service elections on Exhibit A to the Precedent Agreement with respect to the pipeline alternative that is not selected for development are thereafter without effect and are not enforceable by the shipper or by TC Alaska.

Award and Allocation of Capacity

The APP Parties intend to design the Project within certain economic and engineering design increments, to accommodate all capacity requests on a not unduly discriminatory basis from acceptable bids received during the Open Season. In the event qualifying bids from shippers for firm services received during the Open Season exceed the design capacity determined by APP, APP reserves the right to reduce the bidders' MDQs and MTQs indicated on Exhibit A to the Precedent Agreements pro rata, based solely on each bidder's proportion of the total quantity of firm transportation capacity and firm treatment capacity reflected in bids received by APP, without regard to whether a shipper would qualify as a Foundation Shipper, has selected recourse rates or negotiated rates, or has specified in-state or export deliveries. In the event that a bidder's transportation MDQ downstream of the GTP is reduced, as stated above, the bidder's MTQ will be reduced by a corresponding amount. In the event that a bidder's MTQ is reduced, as stated above, the bidder's transportation MDQ downstream of the GTP will be reduced by a corresponding amount.

Precedent Agreement

After awarding capacity and (i) receipt of winning bidders' sufficient written evidence of creditworthiness, as stipulated in Exhibit B to the Precedent Agreement, (ii) resolution of any outstanding commercial issues, and (iii) receipt of bidders' board approvals, TC Alaska will execute each binding Precedent Agreement previously submitted by a bidder and will return one copy to the bidder. If the amount of capacity awarded differs from the amount contained in the initial bid offer as a result of over-subscription, TC Alaska and the winning bidders will execute amended Precedent Agreements reflecting the final award of capacity. The Precedent Agreement will bind the bidder to execute a firm transportation service agreement ("FTSA") before Project construction commences, and will condition the provision of service on satisfaction or express waiver of the transporter Conditions Precedent stipulated in the Precedent Agreement.

Reservation of Rights

The APP Parties reserve the right, on a not unduly discriminatory basis, to reject any bid that does not meet the requirements for bids in this Open Season. Further, the APP Parties reserve the right to withdraw this solicitation of offers to subscribe for firm service on the pipeline system if the APP Parties determine, in their sole discretion, that providing service as requested in the bids received would render the proposed construction not economically feasible.

This Open Season filing and the Project as described herein, including the cost, schedule and expenditure estimates, is conditioned on the timely execution of Precedent Agreements and the timely satisfaction of the CPs outside the control of APP, in each case, in a form acceptable to APP.

Precedent Agreement Submittal

Interested bidders should submit two complete originals of Precedent Agreements by registered or certified mail, courier, or hand delivery at any time during the Open Season to:

Alaska Pipeline Project
Open Season Bid Submittal
Attention: Commercial Manager
16945 Northchase Drive
GP4 – 430
Houston, TX 77060

All material received will be time and date-stamped and opened at the conclusion of the Open Season.

Please direct any questions or requests you may have concerning this Open Season to:

Mr. Paul Pike, Senior Project Manager, (281) 654-4206, paul.j.pike@exxonmobil.com
Mr. Marty Heeg, Commercial Manager, (281) 654-6232, marty_heeg@transcanada.com
Mr. James Morse, Law Manager, (281) 654-3346, james.morse@exxonmobil.com

Additional Information

More detail regarding the Alaska Pipeline Project and this Open Season offering, in the form required by 18 C.F.R. § 157.34 (c), is provided in Appendix C hereto. In addition, attached as Exhibit I to Appendix C is an indicative FERC Gas Tariff. Such indicative tariff is subject to further revision and FERC approval as part of TC Alaska's application to FERC for a certificate of public convenience and necessity.

Additional information regarding this Open Season may be obtained from the APP website at www.thealaskapipelineproject.com, or by visiting an APP data room during the Open Season at the locations listed below:

- Houston, Texas – Main data room containing all required project information in electronic format or hard copy.

- Anchorage, Alaska – Adjunct data room containing all required information available in electronic format.

- Whitehorse, Yukon – Adjunct data room containing all required information available in electronic format.

- Calgary, Alberta – Adjunct data room containing all required information available in electronic format.

Due to the commercially and competitively sensitive nature of the information, all information contained in the data rooms that is not in the public domain will be treated as confidential information. Any person wishing access to such confidential information will be required to sign a confidentiality undertaking in the form attached hereto as Appendix C, Exhibit G, and to comply with the data room procedures, attached hereto as Appendix C, Exhibit H. The data rooms will be set up as follows:

- All information in the public domain will be accessible through APP's website, www.thealaskapipelineproject.com, and available for review by anyone interested in accessing that data.

- Data contained in the physical data rooms will be classified into three levels of confidentiality.

    - The first level ("Tier 1") will contain confidential Project information, not in the public domain, but which is of relatively lower commercial and competitive risk to the Project. All interested stakeholders granted access to the data rooms will have access to Tier 1 data.

    - The second level ("Tier 2") will contain high risk, commercially sensitive, data, such as Project component cost projections, land access cost projections and the like. Such information will be made available only to potential shippers and regulatory agencies with Project oversight responsibilities.

    - In addition, certain information ("Tier 3") contained in the data rooms is subject to third party confidentiality restrictions. Anyone seeking access to Tier 3 data will need to secure a release from such third parties in order to view such Tier 3 data.

Disclaimer

These Open Season materials are provided for informational purposes to enable interested parties to express an interest in obtaining firm transportation service on the proposed facilities. However, the information contained herein, and information that is provided in response to questions or requests for information, establishes no contractual or other relationship between the APP Parties and any other party. Any contractual relationship resulting from this Open Season solicitation will be reflected in the Precedent Agreements.

Table 1

Cost/Rate Range & Fuel*

Alaska-Canada Pipeline

			Term (years)	Zone					Total Capex Range	Total PBU-Alberta (Z2+Z3+CDN)
				1 - Pt. Thomson	2 - GTP	3 - AK Section		Canada Section**		
						In-State	Export			
	Capex Range ($2009B)		-	0.4 - 0.6	9.8 - 12.8	9.8 - 12.8		11.6 - 15.2	32 - 41	-
Nominal - $/MMBtu	Negotiated Rate Range		20	0.19 - 0.25	1.23 - 1.58	0.67 - 0.89	0.94 - 1.24	1.04 - 1.34	-	3.22 - 4.16
			21	0.19 - 0.25	1.22 - 1.55	0.66 - 0.87	0.93 - 1.22	1.03 - 1.32	-	3.17 - 4.09
			22	0.19 - 0.25	1.20 - 1.53	0.65 - 0.86	0.91 - 1.20	1.01 - 1.30	-	3.12 - 4.03
			23	0.19 - 0.24	1.18 - 1.51	0.64 - 0.85	0.90 - 1.18	1.00 - 1.29	-	3.08 - 3.98
			24	0.18 - 0.24	1.17 - 1.49	0.64 - 0.84	0.89 - 1.17	0.99 - 1.27	-	3.05 - 3.94
			25	0.18 - 0.24	1.16 - 1.48	0.63 - 0.83	0.88 - 1.16	0.98 - 1.26	-	3.02 - 3.89
			30***	0.18 - 0.24	1.15 - 1.47	0.63 - 0.83	0.88 - 1.15	0.98 - 1.26	-	3.01 - 3.88
			35***	0.18 - 0.24	1.15 - 1.47	0.63 - 0.83	0.88 - 1.15	0.98 - 1.26	-	3.00 - 3.88
	Recourse Rate Range		25	0.28 - 0.37	1.89 - 2.46	0.96 - 1.27	1.35 - 1.78	1.26 - 1.65	-	4.50 - 5.88
$2009 - $/MMBtu	Negotiated Rate Range		25	0.15 - 0.19	0.93 - 1.19	0.51 - 0.67	0.71 - 0.93	0.79 - 1.01	-	2.43 - 3.13
	Recourse Rate Range		25	0.22 - 0.30	1.52 - 1.98	0.77 - 1.02	1.08 - 1.43	1.01 - 1.33	-	3.62 - 4.73
	Fuel		-	0.25%	4.50%	0.80%	1.00%	1.00%	-	6.50%

Valdez Pipeline

		Term (years)	Zone				Total Capex Range	Total PBU-Valdez (Z2+Z3)
			1 - Pt. Thomson	2 - GTP	3 - AK Section			
					In-State	Export		
	Capex Range ($2009B)	-	0.5 - 0.6	8.6 - 11.2	10.7 - 14.0		20 - 26	-
Nominal - $/MMBtu	Negotiated Rate Range	20	0.19 - 0.25	1.54 - 1.97	1.24 - 1.64	1.42 - 1.88	-	2.97 - 3.86
		21	0.19 - 0.25	1.52 - 1.94	1.22 - 1.62	1.40 - 1.85	-	2.92 - 3.79
		22	0.18 - 0.24	1.49 - 1.91	1.20 - 1.59	1.38 - 1.82	-	2.87 - 3.74
		23	0.18 - 0.24	1.47 - 1.89	1.18 - 1.57	1.36 - 1.80	-	2.83 - 3.68
		24	0.18 - 0.24	1.45 - 1.86	1.17 - 1.55	1.34 - 1.77	-	2.79 - 3.64
		25	0.18 - 0.23	1.44 - 1.84	1.15 - 1.53	1.32 - 1.75	-	2.76 - 3.59
		30***	0.18 - 0.23	1.43 - 1.83	1.15 - 1.53	1.32 - 1.75	-	2.75 - 3.58
		35***	0.18 - 0.23	1.42 - 1.83	1.15 - 1.53	1.32 - 1.75	-	2.74 - 3.58
	Recourse Rate Range	25	0.28 - 0.36	2.40 - 3.08	1.81 - 2.38	2.08 - 2.73	-	4.48 - 5.81
$2009 - $/MMBtu	Negotiated Rate Range	25	0.14 - 0.19	1.16 - 1.48	0.93 - 1.23	1.06 - 1.41	-	2.22 - 2.89
	Recourse Rate Range	25	0.22 - 0.29	1.93 - 2.48	1.46 - 1.91	1.67 - 2.19	-	3.60 - 4.67
	Fuel	-	0.25%	5.70%	0.40%	0.50%	-	6.20%

* Rate calculations based on full design volume in first year. Detail Rate Design Schedules for Nominal Rates for U.S. facilities included in Exhibits J and K. Numbers may not add due to rounding.

** Canada Section for information purpose only. Rates subject to the National Energy Board of Canada and will be split into four zones.

*** 80% Capex recovered in first 25 years and remaining 20% Capex recovered in remaining term of contract.

Appendix A

Pre-Approval Form of Precedent Agreement

PRECEDENT AGREEMENT
Between
TransCanada Alaska Company LLC
And

____

This Precedent Agreement ("PA" or "Agreement") for services is entered into on this _____ day of __________, 2010 by and between TransCanada Alaska Company LLC, a Delaware limited liability company ("Transporter"), and ______________________ ("Shipper"). Transporter and Shipper are each referred to herein individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, Transporter intends to design, engineer, permit, build, own, and operate a new natural gas pipeline, subject to regulation by the Federal Energy Regulatory Commission ("FERC"), beginning near Point Thomson, Alaska and extending through Alaska over one of two routes. One route would extend from the outlet of the Point Thomson plant through points near Prudhoe Bay, Alaska, Fairbanks, Alaska, and Delta Junction, Alaska and then to the U.S. (Alaska)-Canada border ("Alaska-Canada Pipeline"), where the pipeline would interconnect to a new pipeline that affiliates of Transporter, Foothills Pipe Lines (South Yukon) Ltd. and Foothills Pipe Lines (North B.C.) Ltd. ("Canadian Affiliates") plan to design, engineer, permit, build, own and operate and which extends from the U.S. (Alaska)-Canada border to an interconnection point with pipeline facilities constructed, owned, and operated by Foothills Pipe Lines (Alberta) Ltd. or other existing off-take capacity at or near the British Columbia/Alberta border ("Canadian Pipeline"), providing the capability of transporting natural gas to markets in North America, including to the United States;

WHEREAS, an alternative Transporter pipeline route would extend from the outlet of the Point Thomson plant through points near Prudhoe Bay, Alaska, Fairbanks, Alaska, Delta Junction, Alaska and then to an interconnection point with LNG liquefaction facilities (to be built by third parties) near Valdez, Alaska ("Valdez Pipeline");

WHEREAS, Transporter intends to design, engineer, permit, build, own and operate a new gas treatment plant ("GTP") as an integral component of Transporter's facilities and also subject to FERC regulation, located near Prudhoe Bay, Alaska, and operating in conjunction with either the Alaska-Canada Pipeline or the Valdez Pipeline (together, the GTP and the Alaska-Canada Pipeline or Valdez Pipeline comprise the United States portion of the Alaska Pipeline Project ("APP U.S. Facilities"));

WHEREAS, before Transporter applies for regulatory approvals and permits to construct, own and operate its facilities, Transporter seeks the execution of binding precedent agreements with prospective shippers for firm gas transportation service and optional firm gas treatment service commitments and other terms that support Transporter's decision to seek approval from FERC to design, engineer, permit, build, own, and operate its facilities;

WHEREAS, Transporter's binding open season of April 30, 2010 to July 30, 2010 ("Open Season") solicits requests for firm transportation services and optional firm gas treatment services provided in relation to the APP U.S. Facilities;

WHEREAS, the Parties desire to enter into a binding PA that: (i) sets forth the terms upon which Transporter will design, engineer, permit, build, own, and operate facilities to provide Shipper with Service (as defined below); (ii) sets forth the terms upon which the Parties will enter into a firm transportation service agreement (including firm gas treatment services if selected by Shipper) ("FTSA"); and (iii) sets forth the circumstances under which Shipper may be required to pay for a portion of the costs of developing the APP U.S. Facilities;

NOW, THEREFORE, in consideration of the understandings and mutual covenants herein contained and intending to be legally bound thereby, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

I. EFFECTIVE DATE AND TERM

This PA shall become effective as of the date stated above and shall remain in effect, subject to Shipper's or Transporter's exercise of rights pursuant to Section V, until the effective date of the FTSA between Shipper and Transporter; provided that nothing in this section shall be interpreted to limit the surviving obligations set forth in Section VIII(q), including Section V(c).

II. SERVICE SPECIFICATIONS

a. Services

Subject to the terms and conditions set forth herein, including without limitation the conditions set forth in Section IV, the terms of the FTSA, and any applicable terms and conditions of the Transporter's FERC approved gas tariff ("Tariff"), Shipper shall pay for, and the Transporter shall provide, the firm transportation service and firm gas treatment service, if any, described further in this Section II and indicated on Exhibit A of this PA. The options elected by Shipper on Exhibit A (together with the terms of this PA, including Exhibits A and B, the FTSA, and any applicable terms of the Tariff) shall constitute the service to which the Shipper is entitled (the "Service").

(1) The path of firm transportation service shall be determined by the primary receipt and delivery points for firm transportation service selected by the Shipper as indicated on Exhibit A.

(2) The GTP shall perform firm gas treatment services, which shall consist of extraction of acid gas (CO_2 and H_2S), dehydration and compression of both acid gas and gas delivered at the outlet of the GTP for downstream transportation, and refrigeration of sales gas delivered at the outlet of the GTP plant for downstream transportation on the APP U.S. Facilities. Acid gas extraction and the refrigeration, dehydration and compression of sales gas will allow Shipper to meet gas quality specifications applicable to the APP's U.S. Facilities downstream of the GTP. Transporter will return extracted acid gas to Shipper at the outlet of the GTP, and Shipper is responsible for disposal of that acid gas. Whether Shipper shall receive firm gas treatment services will be determined by Shipper's election indicated on Exhibit A.

b. Capacity

Shipper has selected on Exhibit A (i) its maximum daily transportation quantity ("MDQ") with respect to its elected firm transportation service and, if applicable, (ii) its maximum daily treatment quantity ("MTQ") with respect to its elected firm gas treatment service. Shipper's elected MDQ and MTQ are exclusive of fuel and lost and unaccounted for gas.

c. Term of Shipper's Service, Service Phase-In, and Renewal Rights

(1) Initial Service Term: Subject to the satisfaction or waiver of the conditions set forth in Section IV, Service under the FTSA shall commence on the date ("Commencement Date") which shall be ten days after Transporter provides Notice to the Shipper, pursuant to Section VIII(c), that Transporter is physically capable of and legally authorized to provide the Service. Shipper's Service will commence on Commencement Date and shall continue until the last day of the month following the expiration of the number of months corresponding to the term selected by the Shipper on Exhibit A ("Initial Service Term"), subject to continuation of Service as a result of Shipper's election of renewal rights as provided in Section II(c)(3) or as further agreed by the Parties. Beginning on the Commencement Date and continuing until the conclusion of the Initial Service Term and during any extension of that Initial Service Term pursuant to Section II(c)(3), Shipper must pay reservation charges for its firm gas transportation capacity and, if applicable, its firm gas treatment capacity as indicated on Exhibit A; provided that during the Phase-in Period, Shipper's reservation charges for firm gas treatment capacity will be based upon a billing determinant that reflects the reduced firm gas treatment capacity provided by Transporter to Shipper.

(2) Phase-In Period: Following the Commencement Date, Shipper's MTQ shall be phased in, commencing at less than the certificated treating capacity of the GTP and increasing during that period until the GTP operates at certificated treating capacity ("Phase-in Period"). Except for Section 36.1 and the 30-day period in Section 36.2, Transporter shall follow the procedures set forth in Section 36 of the General Terms and Conditions of the indicative tariff included in Transporter's January 29, 2010 FERC filing with respect to the Phase-in Period. Firm gas treatment service will be provided at the MTQ elected by Shipper on Exhibit A at the conclusion of the Phase-In Period but will be provided to Shipper at less than Shipper's MTQ during the Phase-In Period. The Initial Service Term selected by Shipper as indicated on Exhibit A includes the Phase-In Period.

(3) Renewal Rights: If Shipper elects negotiated rates on Exhibit A, Shipper will have a one-time right to extend its Initial Service Term for a five year period at the MDQ (and, if applicable, MTQ) selected by Shipper on Exhibit A for the Initial Service Term. If Shipper elects to exercise this right, it must provide Notice to that effect to Transporter, consistent with Section VIII(c), at least 36 months prior to the conclusion of Shipper's Initial Service Term.

(4) Foundation Shippers: Shipper is a Foundation Shipper if Shipper and any Person associated with Shipper (directly or through Affiliates) has been awarded an MDQ equal to or greater than 200,000 MMBtu/day. All gas shipped by a shipper in which the State of Alaska has an economic interest, as the result of its exercise of sovereign powers or otherwise, is gas shipped by a Person

associated with Shipper for purposes of this subsection. “Person” means any natural person, Entity, estate, labor union, or government authority or component and includes persons, corporations, partnerships, Affiliates of any person and related components of any governmental entity; “Entity” means any foreign or domestic general partnership, limited partnership, limited liability company, corporation, joint enterprise or venture, joint stock company, business or statutory trust, employee benefit plan, cooperative, association, or other legal entity; “Affiliate” means, in relation to the specified Person, a Person which (a) directly or indirectly, through one or more intermediaries or otherwise, controls the specified Person; (b) is directly or indirectly controlled by the specified Person; or (c) is directly or indirectly under common control by a Person that directly or indirectly controls the specified Person; where “control” means (a) the right to exercise votes attaching to more than 50 percent of the voting stock of the entity in question or (b) the power to direct or cause the direction of the management or policies of the specified Person, whether through the ownership of securities, by contract, or otherwise. Transporter shall determine whether gas is associated with a Person in its sole discretion, and Shipper shall provide information requested by Transporter that may be of assistance in making that determination.

d. <u>Interruption of Service</u>

Shipper’s obligation to pay reservation charges continues during any period of Interruption of firm transportation service or firm gas treatment service.

(1) During any such period of Interruption, or any non-Interruption reduction in system capabilities (including periodically reduced levels of Service associated with the planned GTP turnaround (“GTP Turnaround”)), firm transportation and firm treatment of Shipper’s gas will be reduced on a pro rata basis (based on Shipper’s MDQ as a percentage of total firm gas transportation commitments, and MTQ as a percentage of total firm gas treatment commitments).

(2) Transporter shall provide Deferred Firm Transportation Service to Shipper in an amount equal to the quantity of gas subject to a reduction of Service as a result of an Interruption. For purposes of this Section II(d), Deferred Firm Transportation Service means a firm gas transportation service and, if applicable, a firm gas treatment service provided by Transporter (subject to the terms and conditions of the FTSA and any applicable terms of the Tariff) utilizing all transportation or gas treatment capacity, if any, that is available once Transporter has satisfied Shipper’s and other shippers’ MDQ and, if applicable, MTQ as indicated on Exhibit A, and shall be offered on a pro rata basis to all firm transportation and firm gas treatment shippers eligible to receive such service. Shipper may receive Deferred Firm Transportation Service only after utilizing its MDQ capacity and, if applicable, MTQ capacity.

(3) Deferred Firm Transportation Service shall be available to Shipper, when capacity is available and Shipper is eligible to receive such service due to a prior Interruption of firm service, at any time during Shipper’s Initial Service Term and during any extension or renewal of that Initial Service Term. Such Deferred Firm Transportation Service shall have priority over authorized overrun service

("AOS"), interruptible transportation ("IT") service, and park-and-loan ("PAL") service.

(4) Interruption, for purpose of this Section II(d), means an interruption, in whole or part, of Transporter's provision of firm gas transportation service or firm gas treatment service to Shipper due to limitations on the APP U.S. Facilities system operation, including for reasons of a Force Majeure Event, and does not include (i) any failure to provide Service attributable to the actions of Shipper (including the tender of gas at levels less than Shipper's MDQ or MTQ), (ii) anticipated levels of reduced Service associated with the Phase-In Period, and (iii) any reduction of Service due to GTP Turnaround.

e. Gas Quality

Gas provided by Shipper to Transporter must meet the gas quality and pressure specifications set forth in the Tariff for the receipt point where gas is tendered by Shipper to Transporter.

f. Reverse Open Season

In the event Transporter, after establishing an initial design capacity based on Precedent Agreements entered as a result of the Open Season, receives indications of interest for new capacity which cannot be satisfied by that initially established or certificated capacity, Transporter shall, prior to expanding such capacity, conduct a reverse open season pursuant to which Shipper shall have the right to offer to reduce all or a portion of Shipper's MDQ (and, if applicable, MTQ) up to an amount sufficient to satisfy the requests for new capacity. In the event other shippers, together with Shipper, offer capacity reductions in an amount that exceeds the requests for new capacity, capacity reductions for existing shippers, including Shipper, shall be adjusted on a pro rata basis. In the event aggregate offers to reduce capacity are less than requests for new capacity, and the difference cannot be provided by reasonable capital expenditures associated with facilities expansion, Transporter shall have the right to deny all or a portion of Shipper's requested reduction in capacity in the reverse open season. Any reduction of capacity pursuant to a reverse open season shall be subject to the shippers seeking new capacity meeting all applicable Transporter requirements, including creditworthiness. In no event shall Transporter be obligated to accept an offer to reduce capacity if such reduction, after taking into account the commercial arrangement with shippers seeking new capacity, results in a decrease of Transporter's revenues or is otherwise inconsistent with Transporter's economic interests.

g. Line Fill

If Shipper is a Foundation Shipper, Shipper shall have the right to sell to Transporter a pro rata portion of Transporter's initial line fill requirements (determined as a percentage of Shipper's MDQ compared to total committed firm gas transportation capacity) under terms and conditions mutually acceptable to Shipper and Transporter. Transporter shall secure any initial line pack not secured above on a commercially reasonable basis from Foundation Shippers or otherwise under a process to be defined by Transporter prior to Commencement Date.

III. ADDITIONAL OBLIGATIONS OF PARTIES

a. Prosecution and Completion of Project

(1) Subject to Sections IV and V, Transporter will use commercially reasonable efforts to:

(a) File with FERC an application for a certificate of public convenience and necessity ("CPCN") for the APP U.S. Facilities ("FERC Application") by approximately October 2012;

(b) Enter into interconnection agreements and operational balancing agreements with facilities designed to deliver gas to the APP U.S. Facilities receipt points and receive gas at delivery points in Alaska from the APP U.S. Facilities and with downstream facilities interconnected with the APP U.S. Facilities (the Canadian Pipeline or the third party LNG liquefaction facilities located near Valdez);

(c) Construct the APP U.S. Facilities in a commercially reasonable manner, including efforts to plan and develop the APP U.S. Facilities, design and implement start-up sequencing, seek financing, and enter into interconnection agreements, all taking into account interests of shippers as well as Transporter among other considerations and subject to Force Majeure Events and other events that delay the construction of the APP U.S. Facilities;

(d) Provide to Shipper, on (i) December 1, 2010, (ii) filing the FERC Application, and (iii) acceptance of the Final FERC CPCN, updated information regarding costs incurred related to development of APP U.S. Facilities and cost projections, through the Commencement Date, of development and construction costs related to the APP U.S. Facilities; and

(e) Work with shippers, producers, and other interconnecting parties to ensure a coordinated process leading to Commencement Date through a defined notification process.

(2) For purposes of Section III(a)(1), "commercially reasonable" shall be determined in light of the level of capacity commitments entered by shippers following the Open Season and the conditions attached to their commitments.

b. Execution of Firm Transportation Service Agreement

(1) Unless Shipper's obligation to enter into an FTSA has been terminated in accordance with Section V, Shipper shall execute an FTSA that reflects the terms of this PA within 30 days after Transporter provides Notice to Shipper, in accordance with Section VIII(c), that FERC has issued a CPCN for the APP U.S. Facilities and that Transporter has accepted such certificate in accordance with 18 C.F.R. Section 157.20(a) ("Final FERC CPCN"). That Notice shall also include the FTSA that reflects the terms of this PA. Unless Transporter's obligation to enter an FTSA has been terminated in accordance with Section V,

once Shipper has executed the FTSA as provided in this Section III(b), Transporter shall execute the FTSA executed by Shipper within 60 days after Transporter provides Notice to Shipper, in accordance with Section VIII(c), that Transporter intends to file a request with FERC for a notice to proceed with construction.

(2) The FTSA will preserve and include, among other provisions, the following:

(a) The levels of MDQ and MTQ and the Initial Service Term as set forth in Exhibit A,

(b) Shipper's agreement to the Phase-In Period service levels and related obligations set forth in Section II(c),

(c) The obligations set forth in Section II(d), including the obligation to continue to pay reservation charges and Transporter's obligation to provide Deferred Firm Transportation Service,

(d) For Shippers electing negotiated rates, the renewal rights set forth in Section II(c)(3),

(e) Shipper's obligations under Section III(c) and the creditworthiness provisions in Exhibit B,

(f) Shipper's obligation under Sections III(d)(2)-(4) and Section V(c)(1),

(g) The provisions of Section VII,

(h) Transporter's and Shipper's agreement to comply with the provisions of Sections VIII(a), (b), (c), (l), (o), (p), and (s), and,

(i) Any other unexpired provisions of this PA that are to be carried forward into the FTSA.

c. <u>Creditworthiness Requirements</u>

During the term of this PA and the term of the FTSA, Shipper shall establish and maintain its creditworthiness in accordance with the standards and according to the terms and conditions set forth in Exhibit B and, when requested by Transporter, shall promptly provide evidence to Transporter, sufficient to Transporter in its sole discretion, of Shipper's continuing compliance with this requirement, and shall provide annual audited financial statements and other information requested by Transporter.

d. <u>Cooperation</u>

(1) Each Party agrees to execute and deliver such other and additional instruments and documents and do such other acts and enter such additional agreements as may be reasonably requested by the other Party to effectuate the terms and provisions of this PA.

(2) Shipper shall support any application by Transporter for FERC approval of the executed FTSA as a non-conforming service agreement.

(3) To the extent Transporter's efforts are not inconsistent with Transporter's obligations to Shipper, this PA or the FTSA, Shipper shall cooperate with, and not oppose or protest, the efforts of Transporter to obtain any regulatory or governmental approvals Transporter deems necessary or desirable to design, engineer,, permit, build, own, or operate Transporter's facilities, in whole or in part, or otherwise to provide the Service, including in relation to Transporter's filing of the Tariff and recourse rates at FERC and through provision of any information that is reasonably requested by Transporter or by any governmental or regulatory body in connection with such applications; provided that Shipper may challenge Transporter's recourse rates and Tariff filing before the FERC so long as Shipper does not contest the provisions set forth in this PA or the FTSA.

(4) Shipper shall cooperate with Transporter in arranging financing commitments, including by incorporating in the FTSA terms customarily required by lenders, by entering into customary direct agreements with lenders, and by otherwise assisting Transporter in arranging financing commitments.

e. Gas Volumes and Takeaway Capacity

If Shipper has elected on Exhibit A to deliver gas to the Alaska-Canada border and as long as this PA remains in effect with respect to such deliveries, Shipper shall enter into and continue to abide by precedent agreements with Canadian Affiliates governing the transportation of such gas on the Canadian Pipeline. Shipper shall provide evidence to Transporter, sufficient to Transporter in its sole discretion and no later than six months after receiving Notice from Transporter that Transporter has accepted a Final FERC CPCN, that Shipper has secured (i) rights to natural gas available for shipment on the APP U.S. Facilities in quantities sufficient for Shipper to substantially use the shipping commitment as set forth in Exhibit A, (ii) in the case of the Alaska-Canada Pipeline, capacity on facilities interconnected upstream and downstream with the APP U.S. Facilities sufficient to transport the firm capacity commitment as set forth in Exhibit A, and (iii) in the case of the Valdez Pipeline, capacity on facilities interconnected upstream with the APP U.S. Facilities sufficient to transport the firm capacity commitment as set forth in Exhibit A and rights to services sufficient to provide the liquefaction, shipping, and regasification of gas subject to such election.

Shipper, if it is a Foundation Shipper, is not required to provide such evidence unless required by potential lenders.

f. Shipper Regulatory and Internal Approvals

Shipper will diligently seek to secure all internal approvals (including approval from Shipper's board of directors or equivalent ultimate management authority) and all government approvals, including certificates, permits, orders, licenses and authorizations from the U.S., Canada and other nations, necessary (i) to construct and operate facilities for the delivery of gas to receipt points on the APP U.S. Facilities, (ii) to enable Shipper, or others designated by Shipper, to export Shipper's gas from Alaska, import Shipper's gas into other states or nations, and otherwise to have Shipper's gas delivered to facilities interconnected with the APP U.S. Facilities, and (iii) where necessary as determined in Transporter's sole discretion, to have Shipper's gas delivered to its ultimate destination.

IV. CONDITIONS PRECEDENT

a. Transporter Conditions Precedent

Notwithstanding the Parties' execution of this PA, Transporter's obligations established by Sections II and III, including obligations to enter an FTSA, to construct and operate the APP U.S. Facilities, and to provide Service (pursuant to Sections II(a), II(c), III(a) and III(b)) are subject to the satisfaction or express waiver (in the sole discretion of Transporter) of the following conditions precedent:

(1) Certificates and Rights of Way: Transporter shall have (i) received and accepted the Final FERC CPCN authorizing the APP U.S. Facilities; (ii) obtained the rights-of-way and construction permits, easements, rights of access, waivers, authorizations, and other approvals necessary to construct, own and operate its facilities and provide Service to the Shipper; and (iii) received notice from the operators of downstream facilities to be interconnected with the APP U.S. Facilities (Canadian Affiliates, with respect to the Canadian Pipeline, or the third party operator(s) of the LNG facility at Valdez ("LNG Plant Operators")) that the operators have secured financing sufficient to construct those interconnected facilities and have received all government and other approvals necessary to construct, own, and operate those interconnected facilities, including approvals for the associated export and shipment of gas; with all authorizations and approvals listed in (i)-(iii) in form and substance satisfactory to Transporter in its sole discretion.

(2) Financial Commitments: Transporter has received financing commitments, in form and substance satisfactory to Transporter in its sole discretion, sufficient to support construction and operation of the APP U.S. Facilities.

(3) Corporate Approvals: Transporter shall have (i) obtained all corporate authorizations necessary for development, construction, and operation of the APP U.S. Facilities and to provide Service, including authorization from the Board of Transporter, and (ii) received notice that the operators of downstream facilities interconnected with the APP U.S. Facilities (Canadian Affiliates or LNG Plant Operators) have obtained all corporate authorizations necessary for their development, construction, and operation of the interconnected facilities.

(4) Shipper Performance Under PA and Related Precedent Agreements

(i) Transporter shall have received evidence (acceptable to Transporter in its sole discretion) of (i) Shipper's compliance with the terms of this PA, including its continuous compliance since the effective date of this PA with the creditworthiness provisions of Section III(c) and Exhibit B and its execution of an FTSA in accordance with Section III(b); (ii) Shipper's entry into and compliance with precedent agreements entered with the operators of facilities interconnected with the APP U.S. Facilities

(Canadian Affiliates or LNG Plant Operators); and (iii) Shipper's entrance into and compliance with firm contracts sufficient to ensure the delivery of Shipper's gas to facilities interconnected with the APP U.S. Facilities and, where Transporter determines it necessary, to its ultimate destination. If Shipper is a Foundation Shipper, Transporter is not entitled to rely upon sub-clause (iii) of this section with respect to failure by Shipper to provide such evidence unless such evidence is required by potential lenders.

(ii) Transporter shall have received evidence (satisfactory to Transporter in its sole discretion) that Shipper has satisfied or has waived its conditions precedent for each of the agreements identified in Section IV(a)(4)(i) and is in compliance with each of such agreements. Transporter shall also have received evidence, by December 31, 2010, that Shipper has received all corporate authorizations and internal approvals set forth in Section IV(b)(1).

(5) Shippers' Regulatory Approvals: Transporter shall have received evidence (acceptable to Transporter in its sole discretion) that Shipper, and a sufficient number of other shippers necessary in Transporter's assessment in its sole discretion to support proceeding with construction of the APP U.S. Facilities, have met all statutory and regulatory requirements, and secured all certificates, permits, licenses, orders, and authorizations, required to ship, export, and deliver natural gas to be transported on the APP U.S. Facilities (including those approvals set forth in Section III(f)).

(6) Capacity Commitments: Transporter determines, in its sole discretion, that the capacity commitments of Shipper and other shippers, reflected in FTSAs executed by Shipper and shippers (in accordance with Section III(b)), are sufficient to proceed with construction of the APP U.S. Facilities.

b. Shipper Condition Precedents

(1) Notwithstanding the Parties' execution of this PA, Shipper's obligations to make payments for Services, to enter an FTSA, and to make payments pursuant to Section V(c) are subject to Shipper's having secured, by December 31, 2010, all necessary board approvals and internal authorizations necessary to make such obligations to pay binding upon Shipper.

(2) Exhibit C sets forth any further conditions precedent agreed between the Parties.

(3) Shipper shall by December 31, 2010 notify Transporter of the satisfaction, waiver, or failure of the condition set forth in Section IV(b)(1) and shall notify Transporter of the satisfaction, waiver, or failure of conditions set forth in Exhibit C by the dates indicated in that Exhibit C.

V. TERMINATION

a. <u>Termination by Transporter.</u>

(1) Subject to Section VIII(q), Transporter may terminate its obligations under this PA (including its obligations under Sections III(a) and (b) to enter an FTSA and to proceed to develop and construct the APP U.S. Facilities, and under Sections II(a) and (c) to provide Service), effective upon provision of Notice to Shipper in accordance with Section VIII(c), in the event that:

(i) Any of the conditions set forth in Section IV(a) is not satisfied or waived by the conclusion of six months following Transporter's acceptance of a Final FERC CPCN for the APP U.S. Facilities or a final decision by FERC not to issue a CPCN for the APP U.S. Facilities; provided that, Transporter may pursuant to this Section V(a) terminate its obligations at any time prior to the conclusion of that period if Shipper's actions or other circumstances ensure that a condition set forth in Section IV(a) cannot be satisfied; or

(ii) A petition is filed, by or against Shipper, Shipper's ultimate parent company, or any intermediate company holding a direct or indirect ownership interest in Shipper, or by or against any guarantor of Shipper's obligations hereunder, under any chapter of the bankruptcy code of the United States or any other nation.

(2) Transporter may exercise its rights pursuant to Section V(a)(1) at any time prior to the execution of a binding FTSA. Any termination pursuant to Section V(a)(1) shall specify the condition set forth in Section IV(a) that has not been or cannot be satisfied.

b. <u>Termination of Certain Obligations by Shipper.</u>

(1) Subject to Section VIII(q), Shipper may, before December 31, 2010, terminate this PA, effective upon written Notice provided to Transporter in accordance with Section VIII(c), in the event that Shipper has not before then obtained all requisite management or board approvals set forth in Section IV(b).

(2) Subject to Section V(c) and Section VIII(q), Shipper, if it is a Foundation Shipper, may, within 30 days after receiving Notice from Transporter that Transporter has accepted a Final FERC CPCN, terminate its obligations to enter an FTSA established by Section III(b), to pay for Services established by Sections II(a) and II(c)-(d), and to undertake additional actions established by Sections III(c)-(f). Termination of certain obligations pursuant to this Section V(b)(2) is effective upon Transporter's receipt of Notice provided in accordance with Section VIII(c).

c. <u>Effect of Termination.</u>

(1) Except as expressly stated in this PA and notwithstanding the specification of certain obligations set forth in Sections V(c)(2)-(6), the termination of this PA or any particular obligations hereunder shall not relieve any Party from any right,

liability or other obligation, or any remedy or limitation of remedies, which has accrued or been incurred prior to the date of, or as a result of, such termination.

(2) Subject to Section V(c)(5), in the event that Transporter terminates provisions of this PA pursuant to Section V(a) (other than termination resulting from Shipper's failure to execute the FTSA reflecting the terms of this PA or other Shipper breach of this PA), Shipper shall owe and pay to Transporter a sum equal to Development Costs; provided that such costs shall not be owed or paid if Transporter's termination arises from Shipper's failure to secure board and other authorizations prior to December 31, 2010, and Shipper promptly notifies Transporter of such failure, as provided in Section IV(b)(2).

(3) In the event that Shipper terminates portions of this PA pursuant to Section V(b)(2), and Transporter determines to proceed with construction of the APP U.S. Facilities (and so notifies Shipper in accordance with Section VIII(c)), then Shipper shall owe and pay to Transporter a sum equal to Initial Development Costs and Development Costs.

(4) In the event that Shipper terminates portions of this PA pursuant to Section V(b)(2), and Transporter determines not to proceed with the construction of the APP U.S. Facilities (and so notifies Shipper in accordance with Section VIII(c)), then Shipper shall owe and pay to Transporter a sum equal to Project Disruption Costs.

(5) Shipper shall pay to Transporter Initial Development Costs and Development Costs (or, if Transporter does not proceed to construct the APP U.S. Facilities, Project Disruption Costs) in the event that Transporter terminates provisions of this PA because Shipper fails to sign an FTSA as required by Section III(b) or otherwise breaches this PA; nothing in this Section V(c) shall limit Transporter's right to payment or damages in excess of Initial Development Costs and Development Costs (or, if applicable, Project Disruption Costs) from Shipper, including payments for Service, in the event Shipper fails to sign an FTSA as required by Section III(b) or otherwise breaches this PA.

(6) For purposes of this Section V(c):

(i) Development Costs mean Shipper's pro rata share (determined as a ratio, the numerator of which is the firm transportation capacity secured by Shipper as indicated on Exhibit A and the denominator of which is the firm transportation capacity secured by all shippers as of or after January 1, 2011) of all expenditures and costs incurred by Transporter and its Sponsoring Parties related to the development of the APP U.S. Facilities between the conclusion of Transporter's Open Season and the Notice of termination provided by Transporter or, if applicable, by Shipper pursuant to Section V(b)(2) ("Post-Open Season Development Period"). Such costs include costs associated with preparing and filing regulatory applications, including the application to FERC for a CPCN, and costs incurred during the Post-Open Season Development Period even if required to be paid thereafter; provided that, if Transporter proceeds with the construction of the APP U.S. Facilities, Development Costs do not include costs associated with construction of the APP U.S. Facilities and paid by Transporter after the conclusion of the Post-Open Season Development Period. Notwithstanding the foregoing, in the event that Transporter terminates provisions of this PA pursuant to Section V(a) (other than termination resulting from Shipper's failure to execute the FTSA reflecting the terms of this PA or other breach of this PA), Development Costs shall exclude any amounts Transporter has received from the State of Alaska as reimbursement of costs pursuant to AS 43.90.110(a)(1).

(ii) Initial Development Costs mean Shipper's pro rata share (determined as a ratio, the numerator of which is the firm transportation capacity secured by Shipper as indicated on Exhibit A and the denominator of which is the firm transportation capacity secured by all shippers as of or after January 1, 2011) of the portion of $150 million equal to the percentage of the cost of the APP U.S. Facilities as compared to the total cost of the APP U.S. Facilities and the Canadian Pipeline.

(iii) Project Disruption Costs mean Shipper's pro rata share (determined as a ratio, the numerator of which is Shipper's firm transportation capacity as indicated on Exhibit A and the denominator of which is the firm transportation capacity secured by all shippers that exercised their rights to terminate pursuant to Section V(b)(2) or failed to enter an FTSA with Transporter as required by Section III(b)) of all expenditures made, and costs and obligations incurred, by Transporter and its Sponsoring Parties related to the development of the APP U.S. Facilities. Such costs are made up of Initial Development Costs and Development Costs.

(iv) Sponsoring Parties means TransCanada Corporation and its Affiliates and Exxon Mobil Corporation and its Affiliates, as well as any other parties that may become Sponsoring Parties during the term of this PA. Transporter shall provide Notice to Shipper of the addition of any new Sponsoring Parties. For purposes of this Section, Affiliate shall have the meaning specified in Section II(c)(4).

VI. REPRESENTATIONS AND WARRANTIES

a. Each Party represents and warrants to each other as follows:

(1) Organization: Such Party is duly organized, validly existing, and in good standing under the laws of the jurisdiction of its organization, and has all requisite power and authority to own, lease, and operate its assets and to carry on its businesses as they are now being conducted.

(2) Authorization: Such Party has all requisite power and authority to enter into this PA, to perform its obligations hereunder, and to consummate the transactions contemplated hereby. The execution, delivery, and performance by such Party of this PA and the consummation by such Party of the transactions contemplated by this PA have been duly authorized by all necessary corporate action or other action (as applicable) on the part of such Party. This PA has been duly executed

and delivered by such Party and, assuming the due authorization, execution, and delivery hereof by each of the other Parties, constitutes a legal, valid, and binding obligation of such Party, enforceable against such Party in accordance with its terms.

(3) No Violation: The execution and delivery by such Party of this PA, the consummation of the transactions contemplated by this PA, and the performance of the obligations of such Party hereunder will not conflict with, or result in any violation of or default under, any provision of any governing instrument applicable to such Party, or any agreement or other instrument to which such Party is a party or by which such Party or any of its assets is bound, or any governmental requirement or governmental approval applicable to such Party or its assets; provided that nothing in this sentence shall limit Shipper's ability to bid in an open season for or enter contracts related to the provision of gas transportation services by another Alaskan natural gas pipeline system. The execution, delivery, and performance by such Party of this PA does not require any governmental approval to be secured by such Party (other than government approvals associated with the development of the APP U.S. Facilities or the shipment of gas on the APP U.S. Facilities, or otherwise indicated in this PA).

b. Shipper represents and warrants to Transporter that there are no Third Party Claims or Proceedings pending against Shipper or its Affiliates or, to the knowledge of Shipper, threatened against Shipper or its Affiliates involving the transactions contemplated by this PA, other than those Notified to Transporter. Terms used in this Section VI(b) have the following meanings:

(1) Third Party Claim or Proceeding means any threatened, pending, or completed action, claim, controversy, filing, complaint, application, suit, arbitration, alternative dispute resolution procedure, investigation, inquiry, rulemaking or other proceeding (including all permitting processes conducted by any regulatory agency or body) by or against any Third Party arising out of or relating in any way to the obligations or undertakings reflected in this Agreement.

(2) Third Party means any person other than the Parties or any Affiliate of them.

VII. DISPUTE RESOLUTION

Any disputes, controversies, or claims between the Parties arising out of or relating to this PA or the breach thereof (a "Dispute") shall be resolved by means of the following procedure. Transporter and Shipper agree that the dispute resolution procedure described in this Section VII shall apply to any dispute during the term of the FTSA concerning negotiated rates, including disputes concerning the rate principles set forth in Section IV of Exhibit A, and shall not apply to any controversy wherein the FERC has exclusive jurisdiction.

a. Notification.

A Party who desires to submit a Dispute for resolution shall commence the dispute resolution process by providing Notice of the Dispute ("Notice of Dispute") to the other Parties. The Notice of Dispute shall contain a reasonably detailed description of the alleged Dispute and the facts and law the Party believes support the same, the relief requested, and shall request negotiations among executives of the Parties with authority to settle the Dispute. The submission of a Notice of Dispute shall toll any applicable statutes of limitation pending the conclusion or abandonment of dispute resolution proceedings under this Section VII.

b. Negotiations.

The Parties shall seek to resolve the Dispute by negotiation between executives who have authority to negotiate a settlement of the Dispute on behalf of each Party in Dispute. Within 30 Days after the date of the receipt of the Notice of Dispute, the executives representing each of the Parties in Dispute shall meet in person at a mutually acceptable time and place in an attempt to resolve the Dispute. If an executive intends to be accompanied at the meeting by an attorney, such executive shall give the other Party Notice of such intention at least three Business Days in advance, and the executive(s) representing the other Party may also be accompanied at the meeting by an attorney. Notwithstanding the above, any Party in Dispute may initiate arbitration proceedings pursuant to Section VII(c) at any time after 60 Days from the date of receipt of the Notice of Dispute.

c. Arbitration.

Any Dispute not finally resolved by negotiation between executives as set forth in Section VII(b) shall be exclusively and definitively resolved through final and binding arbitration, except as otherwise set forth herein or otherwise agreed by the Parties.

(1) Rules: Disputes shall be resolved by arbitration in accordance with the Rules for Non-Administered Arbitration of International Disputes of the International Institute for Conflict Prevention and Resolution ("CPR Rules") as in effect on the date of commencement of the arbitration, as modified in these arbitration procedures.

(2) Commencement of Arbitration: An arbitration shall be commenced in the manner set forth in the CPR Rules except as otherwise provided hereafter.

(3) Number of Arbitrators: The arbitration shall be conducted by three arbitrators.

(4) Method of Appointment of the Arbitrators.

(i) The claimant Party shall appoint one arbitrator in the Notice of arbitration and the respondent Party shall appoint one arbitrator within 30 Days after receiving the Notice of arbitration and give Notice of that appointment to the claimant; provided, that no Party in Dispute shall appoint an arbitrator who, by reason of residence or otherwise, has an interest in matters subject to dispute or who cannot remain at all times independent and impartial. If a Party in Dispute fails to appoint its Party-appointed arbitrator within the foregoing deadlines, the CPR shall appoint such arbitrator if requested to do so by a Party in Dispute.

(ii) The two arbitrators appointed in accordance with this Section VII(c)(4) shall appoint a third arbitrator, who shall act as the presiding arbitrator. If the two arbitrators cannot reach an agreement on the presiding arbitrator within 30 Days of the appointment of the second arbitrator, the CPR shall appoint the presiding arbitrator in accordance with the CPR Rules.

(5) Place of Arbitration: Unless otherwise agreed by all Parties in Dispute, the place of arbitration shall be Houston, Texas.

(6) Language: The arbitration proceedings shall be conducted in the English language.

(7) Entry of Judgment: The award of the arbitral tribunal ("Award") shall be in writing and shall be final and binding upon the Parties. Judgment on the Award may be entered and enforced by any court of competent jurisdiction and the Parties agree to submit to the personal jurisdiction of any such court.

(8) Notice: All Notices required for any arbitration proceeding shall be deemed properly given if sent in accordance with Section VIII(c).

(9) Qualifications and Conduct of the Arbitrators: All arbitrators shall be and remain at all times independent and impartial, and no arbitrator shall have any ex parte communications concerning the arbitration or the Dispute with any of the Parties in Dispute, other than communications appropriate under Rule 7.4 of the CPR Rules to determine an arbitrator's willingness and availability to serve or concerning the selection of the presiding arbitrator, where applicable.

(10) Interim Measures: The Parties in Dispute may seek interim measures as provided in Rules 13 and 14 of the CPR Rules. Any such measures granted by the arbitral tribunal may be immediately enforced by court order. Hearings on requests to the arbitral tribunal for interim measures may be held in person, by telephone, by video conference or by other means that permit the Parties in Dispute to present evidence and arguments.

(11) Costs and Fees of Arbitration: The arbitral tribunal is authorized to allocate the costs of the tribunal, including fees for the arbitrators and hearing room and transcription expenses, between or among the Parties to the Dispute in such proportions as the tribunal shall determine. Each Party in Dispute shall bear its own attorney's and expert witness fees, its expenses and the expenses of its witnesses, unless otherwise directed by the tribunal.

(12) Award: The arbitral Award shall be made and payable in U.S. Dollars.

(13) Consequential Losses: The Parties waive their rights to claim or recover, and the arbitral tribunal shall have no authority to award, any Consequential Losses, which for purposes of this PA means, as to any Person, any damage, cost, expense, or liability (including pass-through claims for indemnification or contribution owed to another Person under a contract, governmental requirement, or other obligation), or loss of any other nature of that Person that is caused (directly or indirectly) by any of the following arising out of, relating to, or connected with this PA or work carried out (or failed to be carried out) in relation to it: loss or deferment of income or profits; loss of use of any asset; loss of business or reputation; loss of business opportunity; loss of labor or management

productivity; increases in wage, salary, or other cost of labor cost; or indirect damages or losses, costs, expenses, or liabilities, whether or not similar to the foregoing; in addition, Consequential Loss includes any exemplary, punitive, special, or treble damages.

(14) Waiver of Challenge to Decision or Award: To the extent permitted by law, the Parties waive any right to challenge any arbitral decision or Award, or to oppose enforcement of any such decision or Award, except on the limited grounds for modification or non-enforcement provided by the CPR Rules or any applicable arbitration statute or treaty.

(15) Governing Law: The tribunal will apply the substantive law of the State of New York to the merits of the case, except that the tribunal will not apply any choice of law rules that would call for the application of the law of any other jurisdiction.

d. Confidentiality.

All negotiations and arbitration proceedings (including a settlement resulting from negotiation or an Award, documents exchanged or produced during an arbitration proceeding, and memorials, briefs, or other documents prepared for the arbitration) are confidential and may not be disclosed by the Parties in Dispute, their respective employees, officers, directors, counsel, consultants, and expert witnesses, except to the extent necessary to enforce this Section VII or any Award, to enforce other rights of a Party, or as required by law; provided, however, that breach of this confidentiality provision shall not void any settlement or Award.

VIII. MISCELLANEOUS

a. Limitation of Actions:

The period for seeking an Award, remedial order, or relief for any claim arising in connection with this PA is six years from the date the claim first arises.

b. Force Majeure.

(1) The requirement to perform obligations set forth in Sections II(a), II(c), II(d), and III(a) of this PA are subject to any delay or other effect attributable to the occurrence and continuation of any Force Majeure Event.

(2) Force Majeure Event means any acts of God, strikes, lockouts or other labor disputes or industrial disturbances, terrorist acts or acts of a public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, other storms, floods, washouts or other act of nature, civil disturbances, explosions, breakage, accident or repairs to machinery or lines of pipe, freezing or cratering of pipe, inability to obtain or unavoidable delay in obtaining pipe, materials or other equipment, acts or binding orders of any court or other governmental authority whether or not having jurisdiction, and any other cause, whether similar or dissimilar to any above enumerated, not reasonably within the control of the Party claiming relief from liability and which

such Party was or would have been unable to prevent by the exercise of due diligence. Failure to prevent or settle any strike or strikes or any dispute leading to a lockout shall not be considered to be matter within the control of the Party claiming relief. A Force Majeure Event affecting the performance by either Shipper or Transporter of any of its obligations under this Agreement shall not relieve the Party seeking relief from liability in respect of any period when the continuance of its inability to perform such obligations is due to its failure to use reasonable efforts to remedy the situation in a reasonable manner and with reasonable dispatch, nor shall a Force Majeure Event, regardless of the circumstances thereof, affect in any way the obligations of Transporter or Shipper to make payments under this Agreement or the FTSA (and a Force Majeure Event shall not include Shipper's inability to meet its obligation to pay for reasons related to the unavailability of reserves or any Interruption or other impairment of the operation of APP U.S. Facilities or facilities upstream or downstream of the APP U.S. Facilities, including impairment due to circumstances beyond Shipper's control). The Party claiming relief from liability by reason of a Force Majeure Event shall give prompt Notice to the other of the occurrence and cessation of such Force Majeure Event.

c. Notices.

(1) Whenever this Agreement requires or permits any notice to be given to any Party or any other Person, that notice must be in writing and must be delivered in person or by courier, facsimile, or mail (a "Notice"). A Notice under this PA will be deemed given when the Person to which it is addressed receives it; provided, however, that a facsimile which is transmitted after the normal business hours of the recipient will be deemed given on the next Business Day unless the recipient has in fact acknowledged its earlier receipt. All Notices to a Party must, if not delivered in person, be sent to the address for that Party which Section VIII(c)(2) specifies or at such other address as that Party has specified by Notice to the other Parties. Oral communication does not constitute Notice for purposes of this Agreement, and e-mail addresses and telephone numbers for the Parties are listed below as a matter of convenience only.

(2) This Section VIII(c)(2) includes initial contact information for each Party. A Party may change its contact information from time to time by Notice to the other Parties.

Transporter: TransCanada Alaska Company LLC
Attention: Commercial Manager
16945 Northchase Drive
GP4 – 430
Houston, TX 77060
Facsimile: (281) 654-5800
Phone: (281) 654-6232
E-mail: marty_heeg@transcanada.com

Shipper: ______________________________

[Address]

Attention:

(3) Whenever any Notice is required to be given under the provisions of this Agreement, a waiver thereof in writing signed by the Person or Persons entitled to receive that Notice will be equal to the giving of that Notice.

d. Severability.

If any provision of this PA is invalid, illegal, or unenforceable, that provision shall, to the extent possible, be modified in such manner as to be valid, legal, and enforceable while most nearly retaining the Parties' intent as expressed herein, and if such a modification is not possible, that provision shall be severed from this PA. In either case, the validity, legality, and enforceability of the remaining provisions of this PA are not in any way affected or impaired. The Parties shall endeavor to replace that severed provision with a new provision agreeable to the Parties that is valid and enforceable and places the Parties in substantially the same economic, business, and legal position in which they would have been if the original provision had been valid and enforceable.

e. Binding Effect.

This PA binds, and inures to the benefit of, the Parties and their respective successors and permitted assignees.

f. Government Requirements.

This PA and the rights and obligations of the Parties under this PA are subject to all valid and applicable governmental requirements, except choice of law or conflict-of-laws rule or principle under Section VIII(r).

g. Waiver.

No waiver by a Party of any breach by another Party in the performance of any provision, condition, or requirement of this PA is deemed to be a waiver of, or in any manner a release of such Party from, performance of any other provision, condition, or requirement. No waiver is deemed to be a waiver of, or in any manner a release of such other Party from future performance of the same provision, condition, or requirement; nor shall any delay or omission of a Party to exercise any right hereunder in any manner impair the exercise of any such right or any like right accruing to it thereafter. Any waiver of any provision, condition, or requirement of this PA is valid only if it is in writing and signed by the Party against whom it is sought to be enforced.

h. Amendment.

The Parties may not modify, amend or supplement this PA except by the Parties' written agreement.

i. Further Assurances.

Each Party agrees to use all reasonable commercial efforts to take, or to cause to be taken, all actions, and to do, or to cause to be done, all things reasonably necessary or appropriate under applicable governmental requirements to consummate the actions this PA contemplates.

j. Exhibits.

Exhibits A-D are incorporated herein and made a part of this PA.

k. Entire Agreement.

This PA constitutes the entire agreement of the Parties relating to their relationship under this PA. All prior negotiations and all provisions and concepts contained in all prior agreements between the Parties on matters contained in this PA are expressly superseded by this PA. The Parties expressly waive any reliance on representations or course of dealings made prior to the execution of this PA regarding the subject of this PA.

l. Remedies.

No Party shall be liable to any other Party under this PA, pursuant to Section VII or otherwise, for any Consequential Losses.

m. Third Party Beneficiaries.

No provision of this PA affords any right to, is for the benefit of, or is enforceable by, any creditor of any of the Parties, and no provision of this PA confers, or is to be construed, deemed or interpreted as conferring, on any Person other than the Parties, any rights or remedies hereunder, except as this PA otherwise expressly provides; provided that, the corresponding provision of the FTSA addressing third party beneficiaries shall provide for third party creditors to benefit from and enforce the provisions of the FTSA.

n. Counterparts.

This PA may be executed in two or more counterparts, all of which will be considered one and the same agreement and will become effective when two or more counterparts have been signed by each of the Parties named on the original signature pages hereof and delivered to the other Parties, it being understood that the Parties need not sign the same counterpart.

o. Assignment.

(1) Shipper may permanently assign its rights and obligations, in whole or in part, under this PA or FTSA, either before or after the Commencement Date, only if:

(i) Transporter has provided Shipper with written consent, which consent shall not be unreasonably withheld;

(ii) The assignee satisfies and adheres to the creditworthiness requirements set out in Section III(c) and Exhibit B, to Transporter's satisfaction in its sole discretion; if Shipper is a Foundation Shipper, the assignee must also satisfy and adhere to the creditworthiness requirements applicable to a Foundation Shipper; and

(iii) The assignee has entered into a PA or FTSA if required by and in a form satisfactory to Transporter.

(2) Shipper shall remain liable for payment related to unassigned capacity in the event Shipper assigns less than all of its capacity. In the event Shipper effects an assignment of all capacity for the balance of the FTSA term in accord with the conditions of Section VIII(o)(1), Shipper shall thereafter not be liable for payment in relation to the assigned capacity.

(3) If Shipper is a Foundation Shipper and assigns a part of its rights and obligations under this PA or FTSA (or reduces MDQ pursuant to Section II(f)) such that Shipper's remaining MDQ is less than 200,000 MMBtu/day, Shipper shall retain all rights and obligations set out in this PA or FTSA related particularly to a Foundation Shipper and, subject to Section VIII(o)(1)(ii), no such distinct rights or obligations shall transfer to the assignee.

p. Confidentiality.

This PA and the terms set forth herein are (except insofar as certain terms are in the public domain and as such are not subject to this provision) confidential and the Parties agree not to disclose such terms other than as otherwise set forth in this PA and as required by applicable laws, regulations or in connection with any requirement or request of a regulatory authority having jurisdiction over a Party or the subject matter hereof (including the State of Alaska). The Parties acknowledge that Transporter may file information with FERC or Canadian or Alaskan regulatory authorities in a public manner disclosing the content of this PA as necessary or desirable to support its FERC application or in furtherance of other FERC, Canadian, or Alaskan proceedings (or appeals thereof) and furthermore the Transporter may disclose the Shipper's name as a shipper and may disclose aggregate committed volumes of all shippers, by term. In addition, the Parties acknowledge that, unless otherwise restricted by applicable law or regulations, each Party may disclose the terms hereof to each of their and their respective Affiliates' officers, employees, agents, potential lenders and lenders, and other advisors that have a *bona fide* need to know such information and to potential assignees of their interests under the PA that have agreed to use this information only for the purposes intended herein and who agree to keep such information confidential; provided further, that the disclosing party shall be responsible for any such breach of these confidentiality provisions by the parties to which it disclosed such information. To the extent which any content of this PA shall be disclosed by FERC to the public in connection with Transporter's FERC Application, or by the officials of the State of Alaska or Canada (or its subdivisions), such disclosure shall constitute a permanent waiver by the Parties to claims of confidentiality under this Section VIII(p) with respect to the content so disclosed.

q. Surviving Terms.

Unless expressly terminated by an executed FTSA, the following provisions of this PA shall survive any termination or purported termination of this PA or certain obligations of this PA: Section III(c) and Exhibit B; Section V(c); Section VII; and Section VIII (including Section VIII(p) and Section VIII(l)); provided, that Section VII, Section VIII (including Section VIII(p) and Section VIII(l)), and Section V(c)(1) shall survive Shipper's proper exercise of its rights provided by Section V(b)(1), within the time there provided.

r. Governing Law.

This PA and disputes arising in relation to it are governed by the law of the State of New York, excluding such law (including conflicts of law or choice of law rules, principles, or statutes) that might result in the application of law other than the law of the State of New York.

s. Indemnification.

The FTSA between the Parties shall include the following provisions:

(1) Except as provided in Section VIII(s)(3), the Party that is the titleholder to gas lost or the source of harm to the other Party or to third parties shall bear responsibility for such loss or harm and shall hold harmless and indemnify the non-titleholding Party against any claim, liability, loss or damage whatsoever suffered by the non-titleholding Party or by any third party;

(2) Except as provided in Section VIII(s)(3), no Party shall pursue a claim for liability, loss, or damage against the other Party for harm to that Party and its facilities caused by acts of third parties or by acts of nature or for the cost of repair of damage to such facilities caused by such acts;

(3) Each Party shall bear responsibility for all its own tortious acts or tortious omissions connected in any way with the FTSA or the provision or acceptance of Service and causing damage or injuries of any kind to the other Party or to any third party. The tortfeasor Party shall hold harmless and indemnify the other Party against any claim, liability, loss or damage whatsoever suffered by that Party or by any third party;

(4) Except as provided in Section VIII(s)(3), Transporter shall have no liability in damages to Shipper in respect of failure for any reason whatsoever to accept receipt of, receive or deliver gas pursuant to the provisions of the FTSA (or any applicable provisions of the Tariff), and Shipper shall, notwithstanding any failure, for any reason whatsoever, to accept receipt of, receive, or deliver gas, make payment to Transporter in the amounts, in the manner, and at the times provided in the FTSA (and any applicable provisions of the Tariff);

(5) In no case addressed by this Section VIII(s) shall one Party be required to make payments to the other Party for Consequential Losses suffered by that other Party; and

(6) Nothing in this Section VIII(s) shall alter the implementation or applicability of the rate principles in Exhibit A or Transporter's ability to recover such costs in its recourse rates.

t. Interpretation.

(1) Capitalized terms have the meanings specified in this PA or, where no meaning is specified in this PA, the meanings specified in the Tariff.

(2) The words “Section” and “Exhibit” refer to sections and exhibits of this PA unless this PA specifies otherwise.

(3) This Agreement uses the words “herein,” “hereof,” and “hereunder” and words of similar import to refer to this PA as a whole and not to any provision of this PA.

(4) Whenever the context so requires, the singular number includes the plural and vice versa, and a reference to one gender includes the other genders.

(5) The word “including” (and, with correlative meaning, the word “include”) means including, without limiting the generality of any description preceding that word. The words “shall” and “will” are used interchangeably in the mandatory and imperative sense. The word “may” means is authorized or permitted to, while “may not” means is not authorized or permitted to. The word “knowledge” (and, with correlative meaning, the word “known”) means actual knowledge of a fact, rather than constructive knowledge of a fact.

(6) The word “Day” means one of Monday through Sunday of each week including legal holidays.

(7) A reference to a governmental requirement includes any amendment to it, and a reference to a particular provision of a governmental requirement includes any corresponding provisions in a succeeding governmental requirement.

(8) A reference to a governmental official, agency, board, bureau, commission, department, or other instrumentality thereof continues to apply regardless of any changes in name or title, and applies to the successor official, agency, board, bureau, commission, department, or other instrumentality thereof to which the referenced responsibilities or functions may be transferred. Reference to a government official includes the official’s designee.

(9) This PA uses the language the Parties have chosen to express their mutual intent. The language used in this PA shall not be construed more strictly against any Party.

(10) This PA includes captions to sections, and subsections of, and exhibits to this PA for convenience of reference only, and these captions shall not be used in the construction or the interpretation of this PA.

(11) Where this PA provides for a determination by Transporter, such a determination shall be made in Transporter’s sole discretion unless otherwise indicated in this PA.

Accepted and agreed to as of the date hereof:

TransCanada Alaska Company LLC

Signature: _________________

Printed Name: _________________

Title: __________________

_______________________ **(Shipper)**

Signature: _________________

Printed Name: _________________

Title: __________________

The above company representative is a duly authorized agent of the company and has the authority to bind the company.

Appendix A

Exhibit A
Bid Forms for the Alaska-Canada Pipeline and Valdez Pipeline

EXHIBIT A

to PRECEDENT AGREEMENT

(Alaska-Canada Pipeline)

Indicate your firm capacity commitment for firm transportation service and firm gas treatment service applicable to the Alaska-Canada Pipeline.

For purposes of selecting primary receipt and primary delivery points for firm gas transportation service and, if selected, firm gas treatment service, the following zones apply:

Zone 1: Comprising Transporter's facilities from the Point Thomson plant outlet to the inlet of the GTP, with a receipt point at Point Thomson and delivery points at or near the inlet of the GTP (permitting further delivery to the GTP or to Shipper for gas treatment using a gas treatment plant other than the GTP, for further transport in either case on Transporter's facilities in Zone 3).

Zone 2: Comprising the GTP, providing firm gas treatment service, with a receipt point at the GTP inlet and no separate delivery point. Gas delivered to the GTP will continue to Zone 3 of Transporter's facilities.

Zone 3: Comprising the pipeline downstream of the outlet of the GTP and proceeding to the Alaska-Canada border, with a receipt point or points downstream of the GTP and delivery points at any of five points within Alaska as indicated in the Open Season description and at the Alaska-Canada border for further transport on the Canadian Pipeline.

I. FIRM TRANSPORTATION AND (OPTIONAL) GAS TREATMENT SERVICE

Zone 1:

Receipt Points

Point Thomson Plant Outlet ____________ MMBtu/day MDQ

________________________ ____________ MMBtu/day MDQ
Specify Other

Delivery Points

GTP Inlet ____________ MMBtu/day MDQ

________________________ ____________ MMBtu/day MDQ
Specify Other*

*Shipper is obligated to treat gas at non-GTP facility and redeliver such treated gas to Transporter's facility in Zone 3

Zone 2:

GTP Inlet/Outlet ____________ MMBtu/day MTQ

Zone 3:

Receipt Points

GTP ____________ MMBtu/day MDQ

_______________________ ____________ MMBtu/day MDQ
Specify Other

Delivery Points

Alaska: Livengood ____________ MMBtu/day MDQ

Alaska: Fairbanks ____________ MMBtu/day MDQ

Alaska: Parks Highway ____________ MMBtu/day MDQ

Alaska: Delta Junction ____________ MMBtu/day MDQ

Alaska: Tok ____________ MMBtu/day MDQ

Alaska-Canada Border ____________ MMBtu/day MDQ

_______________________ ____________ MMBtu/day MDQ
Specify Other

Note: Indicated amounts exclude fuel used by Transporter or lost and unaccounted for during the provision of Services, which must be separately provided by Shipper. Shipper to provide its in-kind fuel and lost and unaccounted for gas ("Fuel") at the Receipt Point(s) where Shipper's gas first enters into Transporter's facilities ("Point of Origin"). Fuel will be aggregated based on the nominated path of the gas from the Point of Origin to the ultimate Delivery Point off of Transporter's or Canadian Affiliate's system.

II. RATE OPTION: FIRM TRANSPORTATION SERVICE AND (OPTIONAL) GAS TREATMENT SERVICE.

( ) Recourse Rate

( ) Negotiated Rate

III. INITIAL SERVICE TERM: FIRM TRANSPORTATION SERVICE AND (OPTIONAL) GAS TREATMENT SERVICE.

( ) 20-25, 30 or 35 Years________(specify) (available only if “Negotiated Rate” is selected)

( ) 25 Years (if “Recourse Rate” is selected)

IV. NEGOTIATED RATE PRINCIPLES

Shippers electing negotiated rates agree to pay such rates without regard to any action or determination of the FERC with respect to recourse rates. The Parties acknowledge and agree that negotiated rates will be computed and paid in accordance with the negotiated rate principles and process set forth below and further agree that any disputes concerning negotiated rates shall not be resolved by FERC but will instead be decided by the dispute resolution provisions of Section VII of this PA or, following execution of the FTSA, comparable provisions of Transporter’s FERC Tariff.

Negotiated rates shall be based upon, and the Parties intend that they will recover, Transporter’s costs as identified in items 1-12 below. The Parties agree that negotiated rates shall be recalculated annually in order to assure that Transporter’s rates recover all costs of providing service. The Parties further agree to utilize the following process to revise negotiated rates. On each November 1st following at least 15 months after the Commencement Date, Transporter shall circulate schedules and work papers to all Shippers electing negotiated rates which identify (i) Transporter’s cost of service and normalized billing determinants for the twelve months ending the preceding August 31st determined in accordance with the negotiated rate principles set forth below, and (ii) Transporter’s revenues collected during such twelve month period, net of any credits or applicable adjustments during such period. Transporter shall also identify revised negotiated rates to be effective beginning January 1st of the following year which shall be based upon the cost of service and normalized billing determinants identified above, adjusted for any difference (positive or negative) between costs and revenues, net of any credits or applicable adjustments, during the twelve month period identified in (i) above. Adjustments in normalized billing determinants shall be made separately by Zone if necessary to recognize different levels of service or service interruption by Zone.

Transporter and all Shippers electing negotiated rates shall meet to discuss the cost of service, billing determinants, schedules, work papers and proposed negotiated rates. Transporter will then file at FERC such negotiated rates, or such other rates which Transporter agrees to file, no later than December 31st and request that the negotiated rates be made effective January 1st. In the event Shipper objects to Transporter’s filed negotiated rates, the matter shall be subject to the Dispute Resolution provisions of Transporter’s Tariff. If the award of the arbitral Tribunal determines that Shipper’s negotiated rates should be lower than the rates in effect for any applicable period, Transporter shall refund the difference between such lower rates and the rates charged.

Negotiated firm transportation reservation rates will be stated on an MMBtu (thermal) basis to provide for recovery by the Transporter of all fixed costs of providing firm transportation service. Shipper will also pay a commodity or usage charge for MMBtus actually transported, and provide volumes for Fuel. The negotiated firm reservation rate for gas treatment services will be calculated and stated on an MMBtu basis to provide for recovery by Transporter of all fixed costs of providing firm gas treatment services at Transporter’s GTP. Shippers will also pay commodity charges per MMBtu and provide volumes for Fuel, as applicable, for gas treatment services.

The major elements in determining the cost of service and the methodology for the rate design of negotiated rates, are set forth below. Exhibit D sets forth an illustrative rate calculation.

1. Upon the approval of the final costs by FERC, the target capital structure will be 75% debt and 25% equity. The final capital structure used for setting the negotiated rates shall be equal to Transporter's actual capital structure, provided that the capital structure utilized in determining negotiated rates shall include no less than 25% equity and be subject to A.S. 43.90.130(10), as amended from time to time. For expansions and maintenance capital the capital structure for rate making purposes shall be 70% debt and 30% equity.

2. The actual weighted average cost of Transporter's debt calculated using an interest rate equal to the weighted average of the interest rate(s) on such debt. Any payments made to secure or reduce the cost of debt financing will be added to rate base. Changes in the actual weighted average cost of Transporter's debt will be reflected in negotiated rates for the Initial Service Term and any extension of the initial term of the FTSA.

3. Rate of return on equity will be 12% on an after-tax basis.

4. Income taxes will be calculated on a normalized basis, utilizing the federal and state corporate income tax rates for the Initial Service Term and any extension of the initial term of the FTSA. Changes in the federal and state corporate income tax rates will be reflected in the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

5. For the Initial Service Term and any extension of that term, depreciation on transmission and gas treatment plant used for purposes of deriving rates will be calculated annually. An FTSA with an Initial Service Term of 20 to 25 years will recover 80% of the Shipper's proportional share of capital costs approved by FERC for Recourse Rates, and AFUDC and property tax paid during construction ("Approved Capital Costs"), during the Initial Service Term, with Shipper's proportional share equal to Shipper's MDQ divided by aggregate MDQs as of the Commencement Date. Such Shipper's proportional share of the remaining 20% shall be recovered in an additional period of five years following the Initial Service Term, with Shipper's proportional share equal to Shipper's MDQ divided by aggregate MDQs as of the last month in the Initial Service Term. An FTSA with an Initial Service Term exceeding 25 years shall recover 80% of Shipper's proportional share of such costs in the first 25 years and the remaining 20% shall be recovered in an additional period of not less than five years, with Shipper's proportional share based on Shipper's MDQ divided by aggregate MDQs as of the last month in the Initial Service Term.

6. Rates will include a reasonable estimate of negative salvage costs to fund the net costs of abandoning the APP U.S. Facilities and restoring the affected properties at the end of the system's service life. Changes in the negative salvage costs will be reflected in the revenue requirement of the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

7. The rate base will include, among other things, (i) debt service reserve, (ii) cost of line pack, inventory, and spare parts, (iii) payments made to secure or reduce the cost of debt financing, (iv) working capital up to one-eighth of annual operating expenses, (v) prepayments, and (vi) Approved Capital Costs utilizing the weighted average cost of debt in principle No. 2 and the 12% return on equity, and be reduced by the cumulative depreciation and cost reimbursement received pursuant to the Alaska Gasline Inducement Act.

8. The negotiated reservation rates will be calculated based upon billing determinants equal to the sum of all firm contracted capacities under non-defaulting service agreements, normalized for any billing determinants attributable to in-state rates designed on a distance basis and adjusted for any reductions associated with service disruptions or changes in Shippers' MDQ or MTQ, for both the Initial Service Term and any extension of that term.

9. During the Initial Service Term and any extension of that term,

   (a) Shipper shall continue to pay full reservation charges during any period of reduction of firm transportation service or firm gas treatment service, including an Interruption; provided that, reservation charges during a GTP Turnaround or Phase-In Period will be charged with respect to a reduced capacity for firm gas treatment and firm gas transportation services;

   (b) There will be a commodity or usage charge which will recover costs which vary with volumes actually shipped (the commodity charge is estimated to be minimal);

   (c) Fuel will be recovered on the basis of actual quantities of fuel consumed or utilized in operations and fuel lost and unaccounted for;

   (d) Rates will reflect changes in Transporter's taxes (other than income taxes), fees assessed by any governmental entity, and all other operating costs;

   (e) In addition to changes reflected elsewhere in these rate principles, negotiated rates will reflect changes in (i) billing determinants reflecting contracted capacities and (ii) rate base;

   (f) Transporter will credit to Shipper and other shippers that have secured firm transportation service, on a pro rata basis according to firm transportation shippers' MDQ, 75 percent of the revenue received by Transporter for the provision of AOS service, IT service, and PAL service.

10. Negotiated rates shall be adjusted to ensure that they are not inconsistent with A.S. 43.90.130(7)(A)-(D), as amended from time to time.

11. A Foundation Shipper shall be entitled to elect the same negotiated rate principles, in their entirety, as offered prior to the Commencement Date and accepted by any other shipper.

12. Negotiated rate shippers shall pay the recourse rate for AOS and any other non FT-1 service.

EXHIBIT A

to PRECEDENT AGREEMENT

(Valdez Pipeline)

Indicate your firm capacity commitment for firm transportation service and firm gas treatment service applicable to the Valdez Pipeline.

For purposes of selecting primary receipt and primary delivery points for firm gas transportation service and, if selected, firm gas treatment service, the following zones apply:

> **Zone 1**: Comprising Transporter’s facilities from the Point Thomson plant outlet to the inlet of the GTP, with a receipt point at Point Thomson and delivery points at or near the inlet of the GTP (permitting further delivery to the GTP or to Shipper for gas treatment using a gas treatment plant other than the GTP, for further transport in either case on Transporter’s facilities in Zone 3).
>
> **Zone 2**: Comprising the GTP, providing firm gas treatment service, with a receipt point at the GTP inlet and no separate delivery point. Gas delivered to the GTP will continue to Zone 3 of Transporter’s facilities.
>
> **Zone 3**: Comprising the pipeline downstream of the outlet of the GTP and proceeding to near Valdez, with a receipt point or points downstream of the GTP and delivery points at any of five points within Alaska as indicated in the Open Season description and at the LNG liquefaction facility at Valdez.

I. FIRM TRANSPORTATION AND (OPTIONAL) GAS TREATMENT SERVICE

Zone 1:

<u>Receipt Points</u>

Point Thomson Plant Outlet ____________ MMBtu/day MDQ

________________________ ____________ MMBtu/day MDQ
Specify Other

<u>Delivery Points</u>

GTP Inlet ____________ MMBtu/day MDQ

________________________ ____________ MMBtu/day MDQ
Specify Other*

*Shipper is obligated to treat gas at non-GTP facility and redeliver such treated gas to Transporter's facility in Zone 3

Zone 2:

GTP Inlet/Outlet ____________ MMBtu/day MDQ

Zone 3:

Receipt Points

GTP ____________ MMBtu/day MTQ

_______________________ ____________ MMBtu/day MDQ
Specify Other

Delivery Points

Alaska: Livengood ____________ MMBtu/day MDQ

Alaska: Fairbanks ____________ MMBtu/day MDQ

Alaska: Parks Highway ____________ MMBtu/day MDQ

Alaska: Delta Junction ____________ MMBtu/day MDQ

Alaska: Glennallen ____________ MMBtu/day MDQ

Alaska: Valdez ____________ MMBtu/day MDQ

Valdez LNG Facility ____________ MMBtu/day MDQ

_______________________ ____________ MMBtu/day MDQ
Specify Other

Note: Indicated amounts exclude fuel used by Transporter or lost and unaccounted for during the provision of Services, which must be separately provided by Shipper. Shipper to provide its in-kind fuel and lost and unaccounted for gas ("Fuel") at the Receipt Point(s) where Shipper's gas first enters into Transporter's facilities ("Point of Origin"). Fuel will be aggregated based on the nominated path of the gas from the Point of Origin to the ultimate Delivery Point off of Transporter's or Canadian Affiliate's system.

II. RATE OPTION: FIRM TRANSPORTATION SERVICE AND (OPTIONAL) GAS TREATMENT SERVICE.

( ) Recourse Rate.

( ) Negotiated Rate.

III. INITIAL SERVICE TERM: FIRM TRANSPORTATION SERVICE AND (OPTIONAL) GAS TREATMENT SERVICE.

( ) 20-25, 30 or 35 Years________(specify) (available only if "Negotiated Rate" is selected)

( ) 25 Years (if "Recourse Rate" is selected)

IV. NEGOTIATED RATE PRINCIPLES

Shippers electing negotiated rates agree to pay such rates without regard to any action or determination of the FERC with respect to recourse rates. The Parties acknowledge and agree that negotiated rates will be computed and paid in accordance with the negotiated rate principles and process set forth below and further agree that any disputes concerning negotiated rates shall not be resolved by FERC but will instead be decided by the dispute resolution provisions of Section VII of this PA or, following execution of the FTSA, comparable provisions of Transporter's FERC Tariff.

Negotiated rates shall be based upon, and the Parties intend that they will recover, Transporter's costs as identified in items 1-12 below. The Parties agree that negotiated rates shall be recalculated annually in order to assure that Transporter's rates recover all costs of providing service. The Parties further agree to utilize the following process to revise negotiated rates. On each November 1st following at least 15 months after the Commencement Date, Transporter shall circulate schedules and work papers to all Shippers electing negotiated rates which identify (i) Transporter's cost of service and normalized billing determinants for the twelve months ending the preceding August 31st determined in accordance with the negotiated rate principles set forth below, and (ii) Transporter's revenues collected during such twelve month period, net of any credits or applicable adjustments during such period. Transporter shall also identify revised negotiated rates to be effective beginning January 1st of the following year which shall be based upon the cost of service and normalized billing determinants identified above, adjusted for any difference (positive or negative) between costs and revenues, net of any credits or applicable adjustments, during the twelve month period identified in (i) above. Adjustments in normalized billing determinants shall be made separately by Zone if necessary to recognize different levels of service or service interruption by Zone.

Transporter and all Shippers electing negotiated rates shall meet to discuss the cost of service, billing determinants, schedules, work papers and proposed negotiated rates. Transporter will then file at FERC such negotiated rates, or such other rates which Transporter agrees to file, no later than December 31st and request that the negotiated rates be made effective January 1st. In the event Shipper objects to Transporter's filed negotiated rates, the matter shall be subject to the Dispute Resolution provisions of Transporter's Tariff. If the award of the arbitral Tribunal determines that Shipper's negotiated rates should be lower than the rates in effect for any applicable period, Transporter shall refund the difference between such lower rates and the rates charged.

Negotiated firm transportation reservation rates will be stated on an MMBtu (thermal) basis to provide for recovery by the Transporter of all fixed costs of providing firm transportation service. Shipper will also pay a commodity or usage charge for MMBtus actually transported, and provide volumes for Fuel. The negotiated firm reservation rate for gas treatment services will be calculated and stated on an MMBtu basis to provide for recovery by Transporter of all fixed costs of providing firm gas treatment services at Transporter's GTP. Shippers will also pay commodity charges per MMBtu and provide volumes for Fuel, as applicable, for gas treatment services.

The major elements in determining the cost of service and the methodology for the rate design of negotiated rates, are set forth below. Exhibit D sets forth an illustrative rate calculation.

1. Upon the approval of the final costs by FERC, the target capital structure will be 75% debt and 25% equity. The final capital structure used for setting the negotiated rates

shall be equal to Transporter's actual capital structure, provided that the capital structure utilized in determining negotiated rates shall include no less than 25% equity and be subject to A.S. 43.90.130(10), as amended from time to time. For expansions and maintenance capital the capital structure for rate making purposes shall be 70% debt and 30% equity.

2. The actual weighted average cost of Transporter's debt calculated using an interest rate equal to the weighted average of the interest rate(s) on such debt. Any payments made to secure or reduce the cost of debt financing will be added to rate base. Changes in the actual weighted average cost of Transporter's debt will be reflected in negotiated rates for the Initial Service Term and any extension of the initial term of the FTSA.

3. Rate of return on equity will be 12% on an after-tax basis.

4. Income taxes will be calculated on a normalized basis, utilizing the federal and state corporate income tax rates for the Initial Service Term and any extension of the initial term of the FTSA. Changes in the federal and state corporate income tax rates will be reflected in the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

5. For the Initial Service Term and any extension of that term, depreciation on transmission and gas treatment plant used for purposes of deriving rates will be calculated annually. An FTSA with an Initial Service Term of 20 to 25 years will recover 80% of the Shipper's proportional share of capital costs approved by FERC for Recourse Rates, and AFUDC and property tax paid during construction ("Approved Capital Costs"), during the Initial Service Term, with Shipper's proportional share equal to Shipper's MDQ divided by aggregate MDQs as of the Commencement Date. Such Shipper's proportional share of the remaining 20% shall be recovered in an additional period of five years following the Initial Service Term, with Shipper's proportional share equal to Shipper's MDQ divided by aggregate MDQs as of the last month in the Initial Service Term. An FTSA with an Initial Service Term exceeding 25 years shall recover 80% of Shipper's proportional share of such costs in the first 25 years and the remaining 20% shall be recovered in an additional period of not less than five years, with Shipper's proportional share based on Shipper's MDQ divided by aggregate MDQs as of the last month in the Initial Service Term.

6. Rates will include a reasonable estimate of negative salvage costs to fund the net costs of abandoning the APP U.S. Facilities and restoring the affected properties at the end of the system's service life. Changes in the negative salvage costs will be reflected in the revenue requirement of the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

7. The rate base will include, among other things, (i) debt service reserve, (ii) cost of line pack, inventory, and spare parts, (iii) payments made to secure or reduce the cost of debt financing, (iv) working capital up to one-eighth of annual operating expenses, (v) prepayments, and (vi) Approved Capital Costs utilizing the weighted average cost of debt in principle No. 2 and the 12% return on equity, and be reduced by the cumulative depreciation and cost reimbursement received pursuant to the Alaska Gasline Inducement Act.

8. The negotiated reservation rates will be calculated based upon billing determinants equal to the sum of all firm contracted capacities under non-defaulting service agreements, normalized for any billing determinants attributable to in-state rates designed on a distance basis and adjusted for any reductions associated with service disruptions or changes in Shippers' MDQ or MTQ, for both the Initial Service Term and any extension of that term.

9. During the Initial Service Term and any extension of that term,

   (a) Shipper shall continue to pay full reservation charges during any period of reduction of firm transportation service or firm gas treatment service, including an Interruption; provided that, reservation charges during a GTP Turnaround or Phase-In Period will be charged with respect to a reduced capacity for firm gas treatment and firm gas transportation services;

   (b) There will be a commodity or usage charge which will recover costs which vary with volumes actually shipped (the commodity charge is estimated to be minimal);

   (c) Fuel will be recovered on the basis of actual quantities of fuel consumed or utilized in operations and fuel lost and unaccounted for;

   (d) Rates will reflect changes in Transporter's taxes (other than income taxes), fees assessed by any governmental entity, and all other operating costs;

   (e) In addition to changes reflected elsewhere in these rate principles, negotiated rates will reflect changes in (i) billing determinants reflecting contracted capacities and (ii) rate base;

   (f) Transporter will credit to Shipper and other shippers that have secured firm transportation service, on a pro rata basis according to firm transportation shippers' MDQ, 75 percent of the revenue received by Transporter for the provision of AOS service, IT service, and PAL service.

10. Negotiated rates shall be adjusted to ensure that they are not inconsistent with A.S. 43.90.130(7)(A)-(D), as amended from time to time.

11. A Foundation Shipper shall be entitled to elect the same negotiated rate principles, in their entirety, as offered prior to the Commencement Date and accepted by any other shipper.

12. Negotiated rate shippers shall pay the recourse rate for AOS and any other non FT-1 service.

<u>Appendix A</u>

Exhibit B
Creditworthiness

EXHIBIT B

to PRECEDENT AGREEMENT:

CREDITWORTHINESS

The following creditworthiness standards apply for purposes of this PA, including Section III(c), Section IV(a)(4), and Section V(a) of this PA, and for evaluating requests for provision of service. These creditworthiness standards shall continue to apply to Shipper (or assignees) through the FTSA and during the Initial Service Term and any extension of that term. Transporter shall not be required to continue to perform its obligations under this PA or an FTSA, or to commence or continue Service, on behalf of any Shipper that fails to establish and maintain creditworthiness. Transporter shall determine Shipper's creditworthiness, at any time in its sole discretion, in accordance with the following:

1. Creditworthiness Standard

(a) Subject to Transporter's analysis of factors set forth below in Subsection 2, Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment in its sole discretion, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 1(b) or 1(d), as applicable. Nothing herein shall limit Transporter's ability to undertake further analysis of the factors set forth in Subsection 2 in evaluating and making a determination regarding Shipper's creditworthiness. If Shipper is the State of Alaska, is guaranteed by the State of Alaska, or otherwise is supported by the full faith and credit of the State of Alaska, Shipper is deemed to have satisfied the Tangible Net Worth requirement set forth in this Section 1(a); provided that Shipper still must satisfy the requirements of Section 1(b) or 1(d), as applicable.

Shipper's "Capital Cost Share" is its pro rata share (determined based on the aggregate of firm transportation capacity commitments indicated by Shipper on all of its Exhibit As compared to shippers' total firm transportation capacity commitments, excluding any firm transportation capacity commitments secured by a shipper that fails to secure board and internal approvals, as indicated in Section V(b)(1)) of the capital costs (net of cumulative depreciation collected and cost reimbursement received under AGIA by Transporter), AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's facilities.

(b) Foundation Shipper will be deemed creditworthy if its long-term unenhanced senior unsecured debt securities are rated at least A- by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least A3 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and it meets the provisions of Section 1(a) above. If Foundation Shipper's rating has a negative outlook or is on creditwatch for downgrade, Foundation Shipper's rating will be reduced by one rating level. If Foundation Shipper is rated by both S&P and Moody's, only the lower rating will be taken into account.

(c) If Shipper is not a Foundation Shipper, it will be deemed creditworthy if its long-term unenhanced senior unsecured debt securities are rated at least BBB by

S&P or at least Baa2 by Moody's, in each case with a stable or better outlook, and it meets the provisions of Section 1(a) above. If Shipper's rating has a negative outlook or is on creditwatch for downgrade, Shipper's rating will be reduced by one rating level. If Shipper is rated by both S&P and Moody's, only the lower rating will be taken into account.

(d) "Tangible Net Worth," for purposes of this Section 1, means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations. Intangible assets include, but are not limited to, goodwill, patents, copyrights, and unamortized loan costs. Only actual tangible assets are included for purposes of assessing creditworthiness.

2. Determination of Creditworthiness

In evaluating Shipper's creditworthiness, Transporter may consider, in addition to the factors set forth in Section 1, the following additional information and factors:

(a) Opinions, outlooks, watch alerts, and rating actions of S&P and Moody's and other credit reporting agencies;

(b) The pro forma effect on Shipper's debt rating of execution by Shipper of the FTSA;

(c) Financial statements and reports;

(d) Whether a petition is filed by or against Shipper, any of its affiliates, or any guarantor of Shipper's obligations hereunder, under any chapter of the bankruptcy code of the United States or under legislation of a similar nature of any other nation;

(e) Whether Shipper is subject to any lawsuits or outstanding judgments which could materially impair its ability to remain solvent;

(f) The nature of Shipper's business and the effect on that business of general economic conditions and economic conditions specific to it, including Shipper's ability to recover the costs of Transporter's services through filings with regulatory agencies or otherwise to pass on such costs to its customers;

(g) Whether Shipper has or has had any delinquent balances outstanding for services provided previously by Transporter and whether Shipper is paying and has paid its account balances according to the terms established in its agreement(s) (excluding amounts as to which there is a good faith dispute);

(h) Any other information, including any information provided by Shipper or requested by Transporter, that is relevant to Shipper's creditworthiness.

3. As indicated further in Section VIII(o) of this PA, the creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) of this PA or to any permanent release, in whole or part, pursuant to an FTSA.

4. Failure to Satisfy Creditworthiness – Alternatives

If Shipper fails or ceases to satisfy the creditworthiness standard or criteria as described above, in order to obtain or continue service Shipper must provide and maintain one or more of the following credit alternatives, in lieu of the creditworthiness standard requirements outlined in Section 1:

(a) Guaranty: Shipper may provide a guaranty that is sufficient to cover its contractual obligations to the Transporter in a form satisfactory to Transporter in its sole discretion, from a guarantor which meets the creditworthiness standard or criteria described above; or

(b) Collateral:

(i) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in its sole discretion in an amount no greater than Shipper’s contractual obligations to Transporter. If Shipper does not, at least twenty (20) business days prior to the conclusion of the letter of credit’s term, provide the Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Paragraph 4, acceptable to Transporter in its sole discretion, Transporter shall be entitled to draw upon the full value of the letter of credit;

(ii) Shipper may provide a cash security deposit acceptable to Transporter in its sole discretion in an amount no greater than Shipper’s contractual obligations to Transporter; or

(iii) Shipper may provide any other security or collateral acceptable to Transporter in Transporter’s sole discretion.

(c) Upon termination in whole or part of this PA, if not superseded by an executed FTSA, or upon termination of an executed FTSA, any guarantee or collateral provided by Shipper shall first be applied to meet any obligation of Shipper to Transporter, and any remaining balance shall thereafter be returned to Shipper.

5. Ongoing Creditworthiness Review

Transporter shall have the right to review a Shipper's creditworthiness and the continued acceptability of any credit alternative provided on an ongoing basis, and Shipper shall provide, within ten (10) business days upon Transporter's request, any requested information in order to determine the continuing creditworthiness of Shipper and acceptability of any credit alternative provided. If Shipper or credit alternative provider is not subject to regulation by the Securities and Exchange Commission, Shipper shall notify Transporter in writing within ten (10) business days of the details of any material adverse change in its or its credit alternative provider’s business, properties, conditions, or results of operations (financial or otherwise). If Shipper does not provide such information or notification within ten (10) business days of Transporter's request or occurrence of material adverse change, the Transporter may deem that it cannot determine the Shipper’s or its guarantor’s Tangible Net Worth, and the Transporter may set the Shipper’s or its guarantor’s Tangible Net Worth to zero.

6. Notification of Failure to Meet Creditworthiness

Upon notification by Transporter, in accordance with PA Section VIII(c), that Shipper no longer meets Transporter's creditworthiness standard or criteria, Shipper must within five (5) business days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Exhibit B.

(a) If Shipper fails to provide one of the credit alternatives within this time period prior to the Commencement Date, Transporter has the right to suspend its performance under this PA and any FTSA or terminate this PA and any FTSA pursuant to Section V, with Shipper to pay the amounts indicated in Section V(c) (or corresponding provision of the FTSA). Transporter may, after terminating this PA or any FTSA, resell capacity previously secured by Shipper. Nothing in this Subsection limits other remedies, including actions for damages, that Transporter may seek against Shipper.

(b) If Shipper fails to provide one of the credit alternatives within this time period following the Commencement Date, Transporter may provide Notice to Shipper of its intention to suspend service in five (5) business days, provided however, that any such suspension shall not relieve Shipper from any obligation to pay any further rates, charges or other amounts payable to Transporter under the Tariff. If Shipper does not provide one of the credit alternatives within five (5) business days of suspension of its service, Transporter may initiate termination of service proceedings with the Commission and provide such Notice to Shipper and any replacement shipper(s).

(c) If Shipper at any time fails to provide one of the credit alternatives at the time Transporter initiates termination of service proceedings, Transporter shall immediately be entitled to collect, and Shipper shall be immediately obligated to pay, all amounts due to Transporter from Shipper during the full term of this PA and an FTSA (or, if no executed FTSA exists, the amounts that would be due under the FTSA Shipper is obligated to enter pursuant to Section III(b)); these rights shall be in addition to other rights of and remedies available to Transporter, including those set forth in this Section 6(a) and 6(b) to Exhibit B and in Section V(c).

(d) If Shipper has multiple agreements with Transporter and defaults on one agreement, Transporter may deem a default by Shipper on that one agreement as a loss of creditworthiness on any other agreement(s) Shipper has with Transporter.

(e) If a petition is filed, by or against Shipper, any of its affiliates, or any guarantor of Shipper's obligations hereunder, under any chapter of the bankruptcy code of the United States or under legislation of a similar nature of any other nation, Transporter reserves the right to suspend and terminate service as described in Section 6. Transporter also may exercise any other remedy available to it hereunder, at law or in equity.

<u>Appendix A</u>

Exhibit C
Additional Shipper Conditions Precedent

<u>EXHIBIT C</u>

to PRECEDENT AGREEMENT:

ADDITIONAL SHIPPER CONDITIONS PRECEDENT

Appendix A

Exhibit D
Illustrative Annual Negotiated Rate Calculation

EXHIBIT D

to PRECEDENT AGREEMENT:

ILLUSTRATIVE ANNUAL NEGOTIATED RESERVATION (20- 25 Year Term) RATE CALCULATION[1/]

Negotiated Rate = Revenue Requirement / Billing Determinants

Revenue Requirement = Cost of Equity + Cost of Debt + Income Tax + OPEX + Negative Salvage + Depreciation + Other Taxes

Billing Determinants = projected annual contracted firm transportation capacity (adjusted for prior year projected / actual difference)

Cost of Equity = Rate Base x Equity Percentage x 12%

Cost of Debt = Rate Base x Debt Percentage x Debt WAC

Income Tax = Cost of Equity x Income Tax Rate / (1 – Income Tax Rate)

Income Tax Rate = composite Federal and State income tax rates

OPEX = projected annual operating and administrative / general expenses (adjusted for prior year projected / actual difference)

Negative Salvage = projected abandonment cost amortized over contract life (adjusted for inflation)

Depreciation = (Gross Plant + AFUDC + Property Tax paid during construction) x 80%, levelized over term of contract (20 – 25 years)

Gross Plant = original cost of the pipeline and facilities

Other Taxes = projected annual ad valorem and other non-income taxes (adjusted for prior year projected / actual difference)

Rate Base = Capital cost as approved by FERC, working capital, AFUDC and property tax paid during construction, net of accumulated depreciation, accumulated deferred income taxes and AGIA payments received

Allowance for Funds Used during Construction (AFUDC) = sum of interest during construction (IDC) and return on equity during construction (EDC) calculated on an annual basis

IDC = Capital Costs Incurred x 70% (targeted) x Debt WAC

EDC = Capital Costs Incurred x 30% (targeted) x 12%

[1] Exhibit D is provided for illustration purposes only.

Equity Percentage = actual capital structure (target 25%) and, for maintenance and expansion, 30%

Debt Percentage = actual capital structure (target 75%) and, for maintenance and expansion, 70%

Return on Equity (RoE) = 12% after tax

Debt WAC = an interest rate equal to the weighted average cost of the interest rate(s) on Transporter's debt

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
TransCanada Alaska Company LLC	**)**	**Docket No. PF09-11-001**
	)	

OPEN SEASON PLAN DOCUMENTS
SUBMITTED IN CONNECTION WITH
REQUEST FOR COMMISSION APPROVAL OF DETAILED PLAN FOR
CONDUCTING AN OPEN SEASON

VOLUME II OF III
(**includes In-State Needs Study**)

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Date: January 29, 2010

OPEN SEASON PLAN DOCUMENTS (submitted separately in three volumes)

Volume I

Proposed Open Season Notice with:

Appendix A: Proposed Precedent Agreement

Exhibit A: Bid Forms for the Alaska-Canada Pipeline and Valdez Pipeline

Exhibit B: Creditworthiness

Exhibit C: Additional Shipper Conditions Precedent

Exhibit D: Illustrative Annual Negotiated Rate Calculation

Volume II

Appendix B: In-State Needs Study required by 18 C.F.R. § 157.34 (b)

Exhibit A: In-State Gas Demand Study Submission Letter

Exhibit B: In-State Gas Demand Study Approval Letter

Volume III

Appendix C: Information required by 18 C.F. R. §157.34 (c)

Item 1: Pipeline Routes

Item 2: Project Design and Capacities

Item 3: Operating Pressures

Item 4: Delivery Pressures

Item 5: In-Service Date

Item 6: Transportation and Treating Rates

Item 7: Cost of Service

Item 8: In-State Transportation Rates

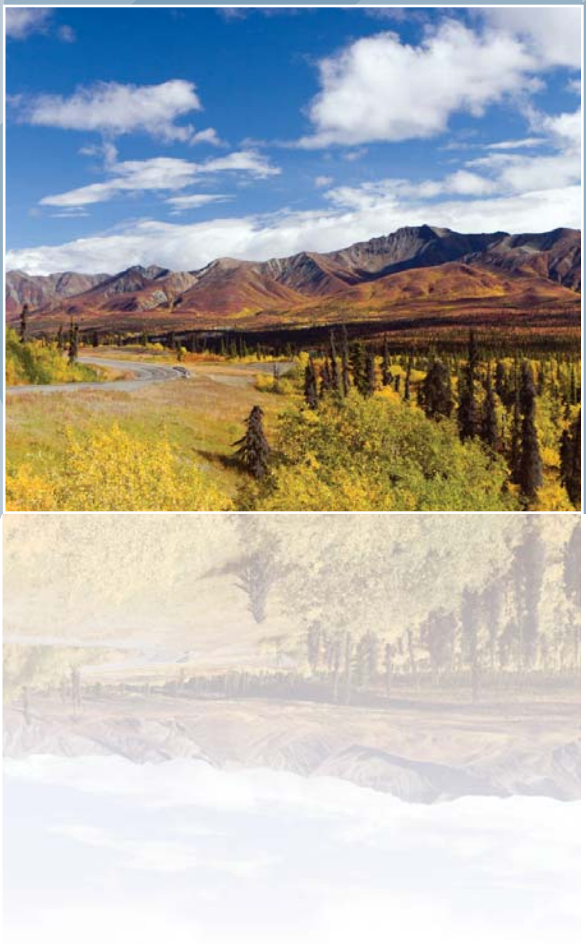
Item 9: Negotiated and Other Rates

Exhibit L: Definitions

Appendix B

In-State Needs Study

In-State Gas Demand Study
Volume I: Report



Prepared for

TransCanada Alaska Company, LLC

January 2010

Northern Economics

Wisdom • Trust • Relevance • Innovation

In association with

- Institute of Social and Economic Research, University of Alaska
- Science Applications International Corporation

In-State Gas Demand Study

Prepared for

TransCanada Alaska Company, LLC

January 2010

Prepared by

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Organization	Contact Person/s
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Anchorage Municipal Light & Power	James Posey
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Abbreviations

2009$	U.S. Dollars, in real 2009 dollars
ADNR	Alaska Department of Natural Resources
AEA	Alaska Energy Authority
AECO	Alberta Energy Company, Alberta gas hub
AHFC	Alaska Housing Finance Corporation
ANGDA	Alaska Natural Gas Development Authority
ANGPA	Alaska Natural Gas Pipeline Act
ANRTL	Alaska Natural Resources to Liquids, LLC
APT	Alaska Power and Telephone
ASRC	Arctic Slope Regional Corporation
AVEC	Alaska Village Electric Cooperative
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Bpd	Barrels per day
BTU	British thermal units
CEA	Chugach Electric Association
CIRI	Cook Inlet Regional Inc.
CMAI	Chemical Market Associates, Inc.
CVEA	Copper Valley Electric Association
DOG	Alaska Division of Oil and Gas
DSM	Demand side management
EIA	Energy Information Authority
FERC	Federal Energy Regulatory Commission
FNG	Fairbanks Natural Gas, LLC
GTL	Gas to liquids
GVEA	Golden Valley Electric Association
HEA	Homer Electric Association
ISER	Institute of Social and Economic Research
kWh	Kilowatt-hour
LNG	Liquefied Natural Gas
Mcf	Thousand cubic feet
MEA	Matanuska Electric Association

ML&P	Anchorage Municipal Light and Power
MMBtu	Million British thermal units
MMcfd	Million cubic feet per day
MMTPA	million metric tons per annum
MW	megawatt
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratories
NPV	Net present value
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
REGA	Railbelt Energy Generation Authority
RIRP	Regional Integrated Resource Plan
SAIC	Science Applications International Corporation
SES	Seward Electric System
SLP	City of Seward Light and Power
TAPS	TransAlaska Pipeline System

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Executive Summary

This *In-State Gas Demand Study* projects the potential demand from Alaska residents and industries for natural gas and propane that would be available with construction of a natural gas pipeline to commercialize North Slope gas. The purpose of the study is to meet the requirements of §157.34(b) of the FERC open season regulations for Alaska natural gas transportation projects. This study facilitates identification of at least five off-take or delivery points and potential delivery volumes at various locations along the pipeline. The study is also intended to allow the initial design of in-state delivery tariffs, which would help potential pipeline customers plan for the initial open season.

Study Scope and Approach

Potential demand is presented for two different future timeframes: (1) the Year 1 to 5 timeframe, which captures the demand in the first five years of operation of the gas pipeline; and (2) the Year 10 to 15 timeframe, which captures potential demand of various economic development projects or prospects that are expected to take a longer time to develop.

The study considers the two pipeline route configurations proposed by TransCanada: 1) the ***Alberta Line*** – from the North Slope of Alaska to Alberta, Canada following the Alaska-Canada highway, and 2) the ***Valdez LNG Line*** – from the North Slope to Valdez, Alaska, terminating at a liquefied natural gas (LNG) facility and marine terminal[1].

The study evaluates potential future demand for natural gas and propane for industrial uses, electric power generation, and heating demand from the residential and commercial sector, including the military. Stakeholder interviews were valuable in developing assumptions used in the demand projection models for each of the sectors. Industrial and electric power demand analyses were based on an assessment of several different future scenarios. Analysis of the industrial scenarios was based on an evaluation of the economic viability of various potential industrial prospects. Electric power scenarios were based on four future power generation scenarios currently being considered for the Railbelt[2] region. Residential and commercial sector heating demand analysis involved looking at increasing penetration rates as well as expansion of service areas, primarily in the areas with existing piped natural gas distribution systems.

The study employed a probabilistic approach to estimating natural gas demand. Projecting future demand that may occur 10 or more years into the future is challenging due to the considerable uncertainties that exist, particularly regarding future industrial and power demand. Furthermore, the possibility of future increases in Alaskan gas production from Cook Inlet or the Interior, and the rates of fuel-switching add further complexities to projections of in-state demand for North Slope gas. The probability analysis considered these high levels of uncertainty that exist about the energy situation in Alaska[3]. The results of the probability analysis are summarized according to the three most probable industrial demand cases; these are presented in Table ES-1.

[1] The economics and natural gas demand of the new Valdez LNG facility with an associated marine terminal, were not analyzed in this study. Based on information provided by TransCanada, the Valdez LNG facility is assumed to require 3.0 Bcf of natural gas per day.

[2] For this study, the Railbelt is defined as the service areas of the six Railbelt electric utilities including Chugach Electric Association, City of Seward Light and Power, Golden Valley Electric Association, Homer Electric Association, Matanuska Electric Association, and Municipal Light and Power. The service areas of ENSTAR Natural Gas Company and Fairbanks Natural Gas are within the service area boundaries of these electric utilities.

[3] More detailed discussion of the probability analysis and associated assumptions for the different sectors is provided in the main body of the report.

Major Findings

Historically, Alaskan demand for natural gas has been greater for gas-intensive industries than for all other sectors combined (i.e., power, residential, commercial, and other industrial). Hence, the future demand for natural gas in the state of Alaska is substantially affected by the future of Alaskan gas-intensive industries.

Table ES-1 summarizes the results of the probability analysis; it shows results for three demand scenarios categorized as "No Industry", "Current Industry", and "Growth Industry". Recognizing that no in-state gas-intensive industrial load is very certain in the future, the No Industry case represents in-state demand without a large industrial load. The Current Industry case represents a continuation of current trends, with a facility representative of the demand required by the Nikiski LNG terminal operating at full capacity. Finally, the Growth Industry case represents a scenario in which a facility representative of the demand of the existing LNG facility will expand to double its current capacity, but no greenfield projects will be built in years 1 to 5 of pipeline operations. Greenfield (or new) industrial projects are not assumed to be built at the same time as the pipeline because the joint demand for labor and materials could significantly increase the capital costs for a new facility, causing it to be uneconomic. Furthermore, unless owners of the greenfield industrial projects are to secure gas supply and commit to pipeline capacity in the early open seasons, it is unlikely that they would have sufficient gas to support the greenfield projects in the initial years of pipeline operation. In years 10 to 15, greenfield projects with reasonably likely economic feasibility are included under the Growth Industry case.

Table ES-1 also shows the percent chance that each case will occur. The No Industry case is more likely in the first years of pipeline operation than in later years. Under the Alberta project, the Current Industry case is the most likely of the assessed scenarios.

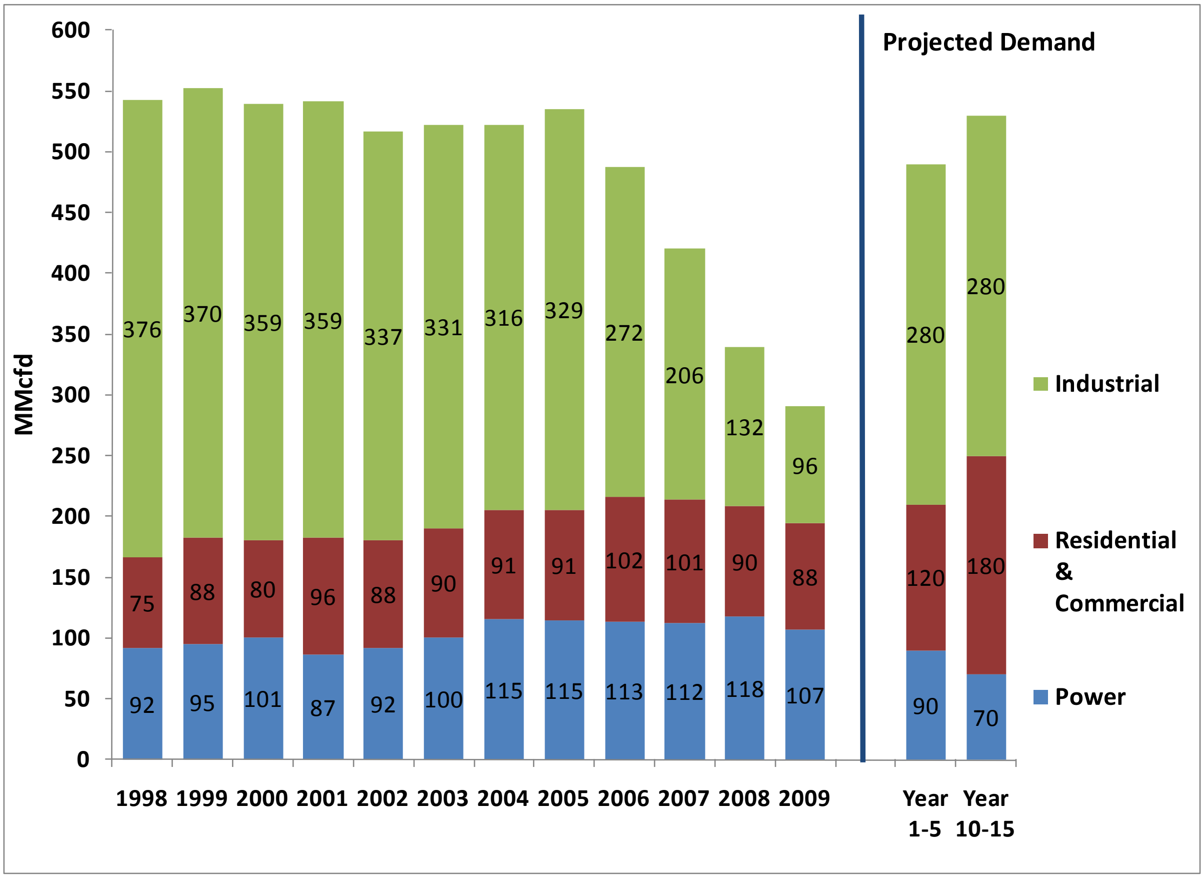
Table ES-1. Total In-State Natural Gas Demand Estimates for Three Scenarios, Alberta Project (MMcfd)

	Year 1 to 5 of Pipeline Operation			Year 10 to 15 of Pipeline Operation		
Demand Scenarios	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level
Alberta Project						
No Industry	260	29	71	290	14	86
Current Industry	490	38	26	520	18	65
Growth Industry	740	12	3	1,120	6	2

Source: Northern Economics, Inc. and SAIC, Inc., 2009.
Note: MMcfd is million cubic feet per day.

Figure ES-1 shows historic consumption of natural gas and the projected demand by sector. The projected demand totals are those depicted by the Current Industry case for the Alberta Project for the first five years of pipeline operations. Since 2006, the Agrium ammonia-urea plant has ceased operation and the LNG plant owned by ConocoPhillips and Marathon has reduced LNG production. The export license for the plant expires in 2011; consequently, the projected gas-intensive industrial demand shown in Figure ES-1 is uncertain.

Figure ES-1. Historic and Projected Total Annual Average Daily Demand for Natural Gas, Current Industry Case for the Alberta Project

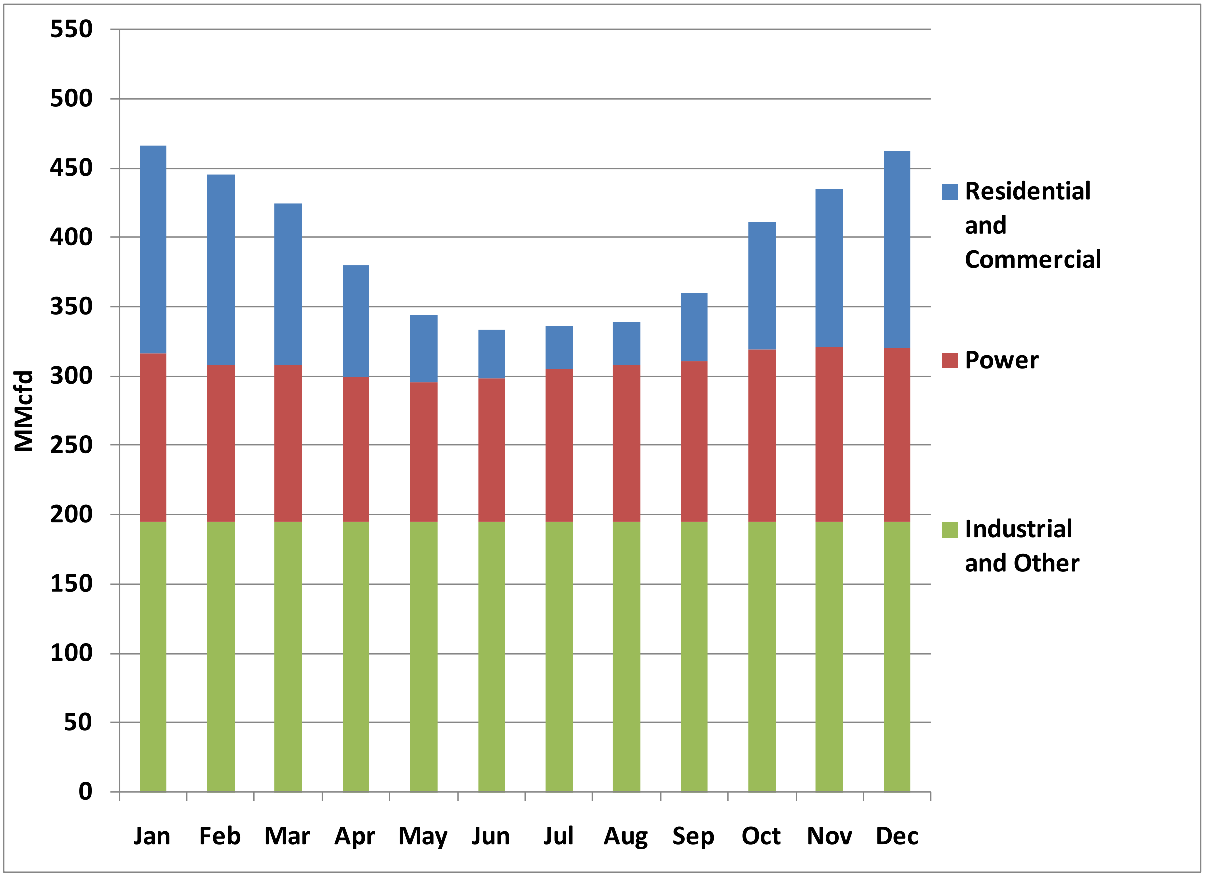


Source: Historical data are from the Division of Oil and Gas, Alaska Department of Natural Resources. Projected demand in Year 1 to 5 and Year 10 to 15 of pipeline operations are based on the results of this study.

Notes: Historical values for industrial sector include gas consumption for the LNG facility, the Ammonia-Urea plant from 1998 to 2007, and for other small operations such as for military bases in Anchorage, the GTL facility, Tesoro refinery, the small liquefaction facility that transports LNG to Fairbanks Natural Gas, etc. Gas consumed in field/lease operations is not included in the values shown above. The sum of the projected values for Year 10-15 in this figure does not match the total Current Industry case demand in Table ES-1 due to rounding.

Figure ES-2 presents the average monthly demand during a calendar year. The monthly average daily demand varies by about 130 million cubic feet per day (MMcfd) over the year. Demand from the industrial sector helps to moderate seasonal variation in the residential, commercial and power sectors, which can experience demand as low as 138 MMcfd in the summer and as high as 271 MMcfd in the winter. The industrial sector curtails its demand if needed in the winter.

Figure ES-2. Typical Total Average Daily Demand for Natural Gas by Month



Source: Data on historical natural gas usage are based on information provided by the Alaska Department of Natural Resources, for the years 1998 to 2009.

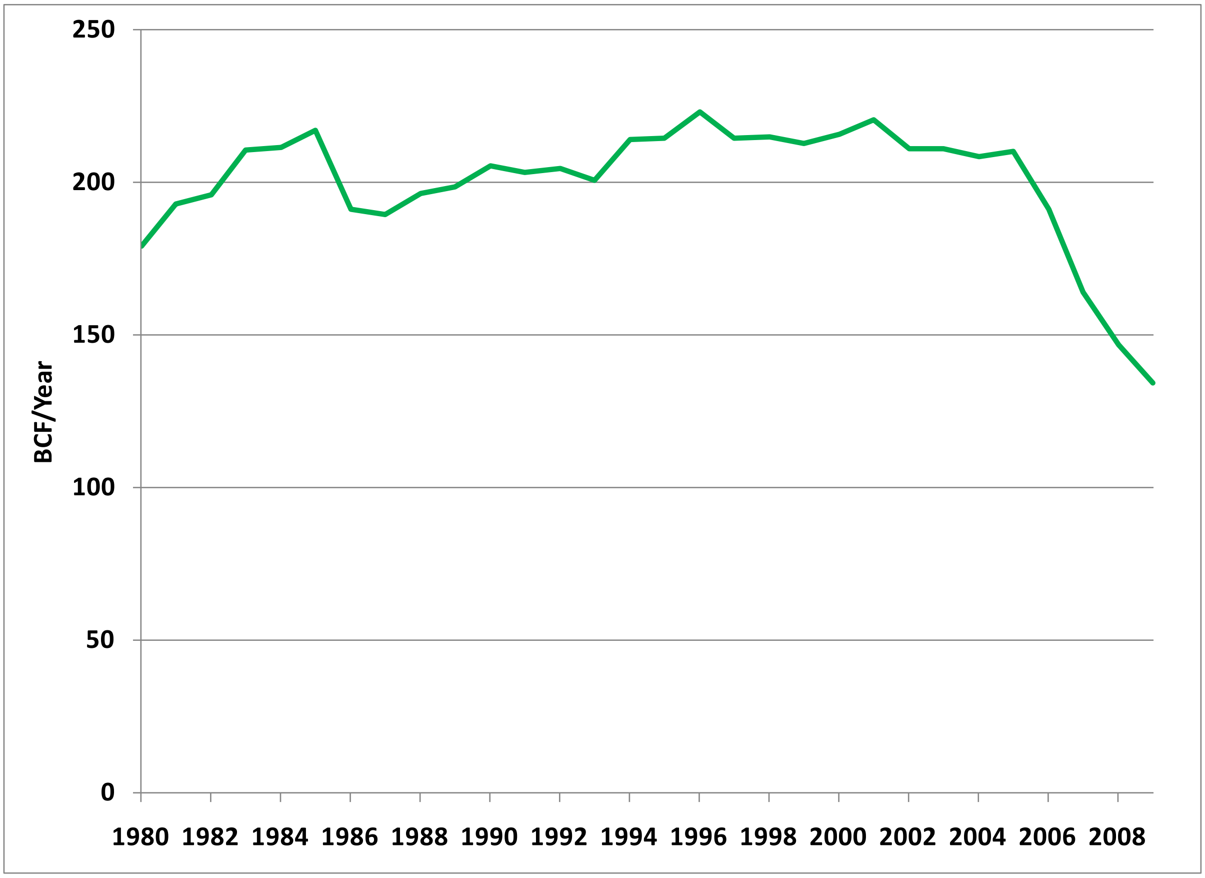
Note: Industrial demand above excludes historical gas volumes used for field operations and for fertilizer production at the Agrium plant.

This study assumes that in the interim years before the proposed pipeline becomes operational, measures to address the natural gas deliverability problems in Southcentral Alaska will be put in place. These measures could be in the form of building new underground gas storage facilities and promoting demand side management such as entering into agreement with industrial gas users on demand curtailment during peak winter season when total demand exceeds supply. It is anticipated that an additional option will be available for managing seasonal swing once the TransCanada Alaska pipeline is in service. Typically, pipelines can deliver more gas during the winter when ambient temperature is lower due to an increase in the compressor efficiency. This enhancement in performance is approximately 5 percent of the nominal design capacity of the pipeline; hence, this pipeline feature can be a flexible tool for in-state gas shippers to meet their winter load demand by contracting short-term firm transportation services during the peak load periods. The development of incremental gas storage facilities, implementation of load shedding demand side management and availability of incremental pipeline capacity during winter allow in-state gas shippers to contract capacity on the pipeline based upon their annual average volumes instead of winter peak demand volumes. For the purpose of calculating an indicative in-state delivery tariff, the projected annual average daily demand for North Slope gas will be used.

Cook Inlet Supply

Figure ES-3 shows historic Cook Inlet natural gas production from 1998 to 2009. Although production has been declining since 2001, the Cook Inlet basin is anticipated to continue production well into the future.

Figure ES-3. Total Historic Cook Inlet Natural Gas Production



Source: Alaska Department of Natural Resources, Division of Oil and Gas.

The Alaska Department of Natural Resources, Division of Oil and Gas (DOG) recently issued a report that evaluated the remaining Cook Inlet natural gas reserves. Table ES-2 presents the DOG estimates for Cook Inlet natural gas volumes. The more conservative estimates are based on engineering analyses using decline curve and material balance techniques. According to DOG, the geologic analysis for the four major fields in Cook Inlet is strong enough to classify these volumes as reserves that have the potential, if developed, to meet the local demand well into and possibly beyond the next decade. Furthermore, there are potential exploration targets throughout the basin that could provide additional gas resources, though there is less certainty for this geologic estimate compared to the gas reserves engineering estimate.

Table ES-2. Remaining Cook Inlet Natural Gas Volumes by Type of Reserves and Resources

Location/Type of Reserve	Derivation of Estimate	Volume
All Fields		**(Bcf)**
Proved, developed, producing	Decline Curve Analysis (DCA)	863
Probable	Material Balance (MB)-DCA (1,142-863)	279
Four Fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River)		
High-confidence pay intervals	Geologic PAY (GP)-MB for 4 fields (1,213-860)	353
Lower-confidence pay intervals	GP+50%-risked Potential Pay-GP (1,856-1,213)	643
Total Estimated Reserves		**2,138**
All Fields		
Higher risk contingent resources	Exploration Leads, Basin-wide	300
Total Estimated Reserves and Resources		**2,438**

Source: Values shown in the table are from, Hartz, J.D., et al, 2009. Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves. Alaska Department of Natural Resources.

The Cook Inlet basin produces enough gas to meet annual average demand. However, supplying the required volumes during spikes in demand on very cold days in the winter is challenging for the current system. Currently, wells are being drilled and storage facilities are being developed, which indicates that investment is being made to address the deliverability issue. The DOG report notes that "infill drilling, perforating undeveloped sands, and targeting marginal reservoirs are effective ways to add reserves to replace production." However, all these costs will need to be absorbed into a market that requires relatively small volumes, which will likely place upward pressure on gas prices.

DOG assumes that "either a significant amount of gas is found by explorers to meet industrial use in the future, or that export of gas out of the basin will stop at the end of the current license period" (2011) for the LNG plant. DOG further assumes that no new demand will occur until reserves are developed to satisfy the market, which requires that sufficient risk-capital be available to explore and develop the higher risk contingent and prospective gas resources.

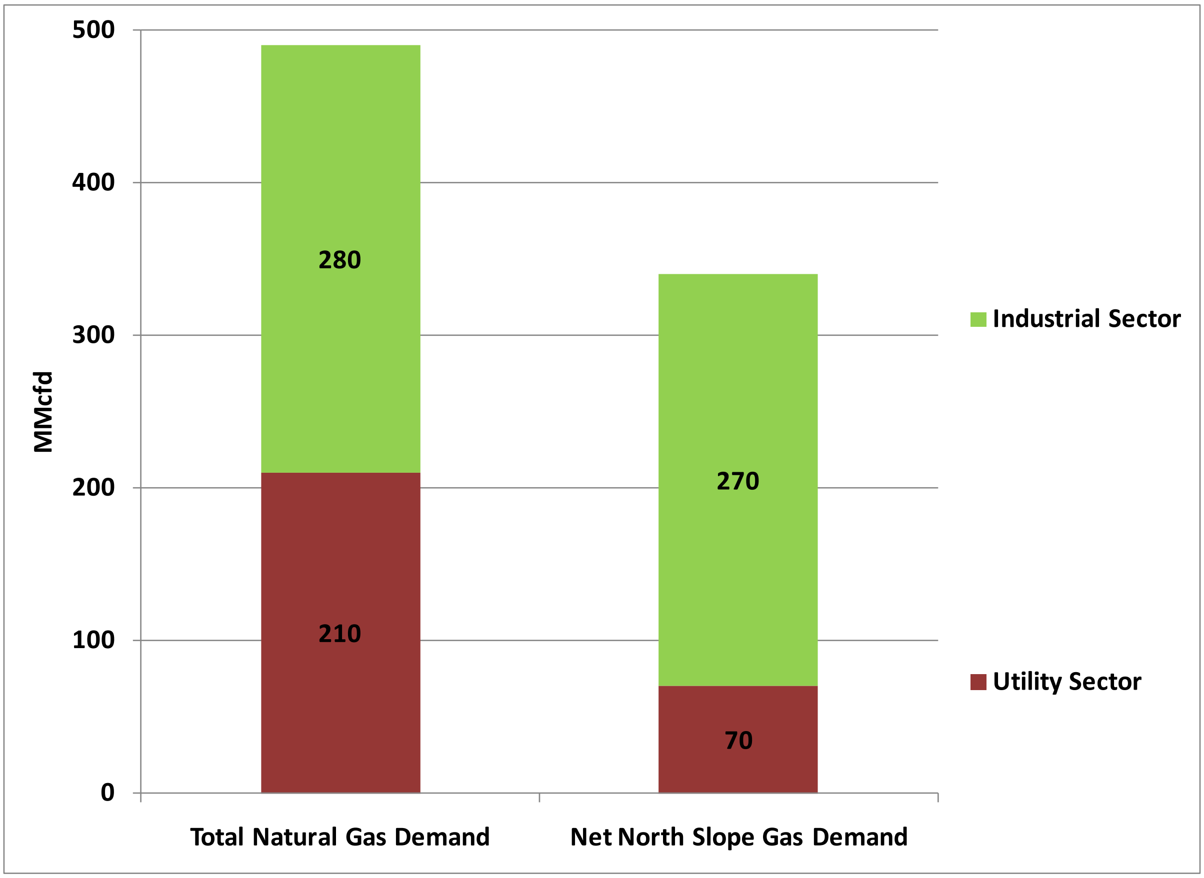
After the proposed spur line to Southcentral Alaska is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence on natural gas with increased demand side management and energy efficiency, increased use of renewable energy sources, and expanded transmission systems. However, even with such diversification and new facilities, natural gas remains a major energy source for the Railbelt, even 50 years into the future. Given this long time frame, utilities would seek to diversify their supplies of natural gas and would consider gas from the North Slope, coal bed methane, landfill gas, underground coal gasification, and other sources. The utilities have indicated that Cook Inlet sources would remain as a very large percentage of their natural gas supplies even if North Slope gas is less expensive.

Net In-State Demand for North Slope Gas

Discussions with several Southcentral utilities indicated that they might look to source 5 to 50 percent of their total gas demand from the North Slope. These percent estimates, when aggregated, suggest an average daily utility demand of about 40 MMcfd of North Slope Gas in the Southern Railbelt region in Years 1 to 5. In addition, gas-intensive industrial demand in the Southern Railbelt region for the current industry case is assumed to be met solely by North Slope gas. Therefore, the total demand in the Southern Railbelt region that will be supplied by North Slope gas is projected to be about 270 MMcfd for the Alberta route.

The total net demand for North Slope gas including the projected utility and industrial sector demand in the Northern Railbelt region and Livengood is projected to be about 340 MMcfd in Years 1 to 5 after pipeline operations begin (as shown in Figure ES- 4).

Figure ES- 4. Total Natural Gas Demand versus Total North Slope Natural Gas Demand, Current Industry Case, Year 1 to 5 of Pipeline Operations, Alberta Project



Source: Northern Economics, Inc., and SAIC, Inc., 2009.

The Valdez Project

Not counting demand from a new Valdez LNG facility, the Valdez route is estimated to have a higher gas demand than the Alberta route for the three demand scenarios presented above. This is due to the additional industrial demands in the Valdez area with the availability of natural gas. For the first five years of pipeline operations, the projected demand for the No Industry case, Current Industry case, and Growth Industry case, are 270, 500, and 750 MMcfd respectively; and the percent chance of these scenarios happening are 61 percent, 30 percent, and 9 percent respectively.

The total net demand for North Slope gas for the Valdez Project under the Current Industry case is projected to be about 350 MMcfd in Years 1 to 5 of pipeline operations.

Potential Propane Demand

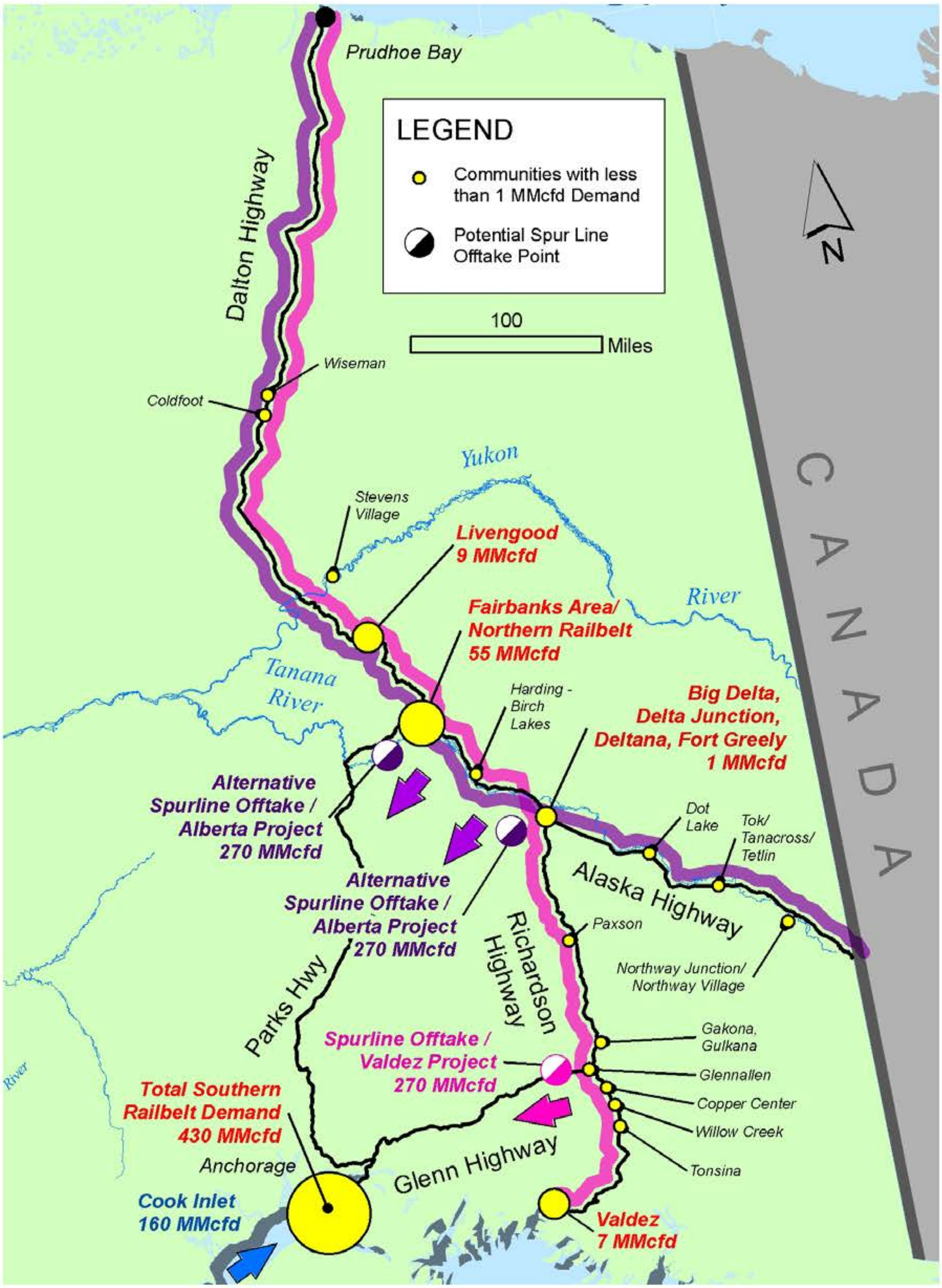
The natural gas stream in the main gas pipeline will contain large volumes of propane and other natural gas liquids; energy needs outside of the Railbelt could be supplied with propane. It is anticipated that the propane will be less expensive than distillate fuels on an energy-equivalent basis in many areas of the state, and there is keen interest in reducing the cost of energy, particularly in rural Alaska. In the initial years there is a 48 percent chance that the propane demand will be about 3,500 bpd. Ten years later there is a 67 percent chance that demand could increase to about 35,000 bpd as the propane infrastructure is built around the state. This study anticipates that propane extraction facilities would be built in the Fairbanks area and in Cook Inlet or Valdez, depending on the route. A comparison of the potential tariffs for a small propane extraction plant and trucking costs indicate that it would be less expensive to truck propane from Fairbanks to communities in the pipeline corridor and on the road system than to pay the tariff for a small plant.

A proposed propane extraction plant at Prudhoe Bay could have lower transportation costs to Arctic and western Alaska and supply propane to those regions. A Prudhoe Bay plant that may be built in the near term could facilitate a faster conversion to propane in the Fairbanks area and along the road system, thus potentially increasing propane demand in the initial years.

Potential Off-Take Points and Volumes

Figure ES-5 shows the potential total energy demand (as natural gas equivalent volumes) along the pipeline corridor. This figure shows the demand by community, as well as for potential spur line off-take points at Delta Junction or Glennallen, assuming a Richardson Highway or Glenn Highway spur line is built. If a Parks Highway spur is built instead of a Richardson Highway or Glenn Highway spur, similar demand would exist at a Parks Highway off-take location. The spur line off-take volume represents the current industry case for the Southern Railbelt region.

Figure ES-5. Potential Net Demand along the Pipeline Corridor, Current Industry Case, Year 1 to 5 of Pipeline Operations



Source: Alaska Map Co. based on the results of this study, 2009.

Table ES-3 shows the most likely off-take points based on the analysis conducted for this report. A proposed gold mine at Livengood is a likely candidate for a delivery point, and one or more off-take points may be required in the Fairbanks area, and another one to provide for a Parks highway spur line to Southcentral Alaska, or for future growth along the Parks Highway. The communities in the Delta Junction area plus Fort Greely are a likely location for an off-take point, which could be on the main gas pipeline or on a proposed spur line that would generally parallel the Richardson and Glenn highways to the Cook Inlet region. The communities in the vicinity of Tok may not have sufficient demand at present to justify an off-take point, but there is the potential for future mineral development and associated demand in the region around Tok. Glennallen and Valdez would be obvious off-take points for a line to Valdez since Glennallen would be the location of a spur line to Southcentral Alaska, and Valdez has community demand plus demand from the Alyeska marine terminal.

Table ES-3. Potential Off-Take Locations along the Alberta Line and the Valdez Line

	Route	
Location	**Alberta**	**Valdez**
Livengood	1	1
Fairbanks	1-2	1-2
Parks Highway spur	1	1
Delta Junction area/ Richardson Highway spur	1	1
Tok	1	NA
Glennallen	NA	1
Valdez	NA	1
Total	**5-6**	**6-7**

Source: Northern Economics, Inc.

At this time, ten years prior to the planned commencement of the TransCanada Alaska pipeline operation, the pro forma in-state gas tariff for the upcoming open season will be an estimate based on the demand net of Cook Inlet supply as noted in this study. The actual tariff for the pipeline will be highly dependent on the actual contracted volume of the pipeline, which will be determined in the initial open season and subsequent open seasons.

1 Introduction

In 2004, Congress passed the Alaska Natural Gas Pipeline Act of 2004 (ANGPA). Section 103 (g) of ANGPA requires a "study of in-State needs, including tie-in points along the Alaska natural gas transportation project for in-State access." In regulations implementing the ANGPA, the U.S Federal Energy Regulatory Commission (FERC) requires an applicant for a FERC Certificate of Public Convenience and Necessity to "conduct or adopt a study of gas consumption needs and prospective points of delivery within the State of Alaska" (18 CFR §157.34(b)). The regulations require that the study's estimate of the pipeline capacity that will be used in-state be included in an applicant's open season proposal.

In 2007, the State of Alaska adopted the Alaska Gasline Inducement Act (AGIA.) This statute provides for issuing a State License to a gas line project proponent that meets specified state criteria for the gas line. The statute further provides that the AGIA Licensee has access to particular inducements provided by the State of Alaska.

In 2008, TransCanada Alaska Company LLC (TransCanada) applied for and was awarded the State AGIA License for TransCanada's described gas line project. This project would transport approximately four and a half billion cubic feet of natural gas per day from Alaska to points within Alaska or to Alberta, Canada.

As the AGIA Licensee, TransCanada is advancing this project and has scheduled an open season for its proposed pipeline project in 2010. In March 2009, TransCanada issued a Request for Proposals for the Alaska in-state gas needs study in order to satisfy the FERC and ANGPA requirements. In May 2009, a contract to complete the study was awarded to the consultant team of Northern Economics, Inc., Science Applications International Corporation (SAIC), and the Institute for Social and Economic Research at the University of Alaska, Anchorage (ISER).

1.1 Purpose

The purpose of the study is to meet the requirements of §157.34(b) of the FERC open season regulations for Alaska natural gas transportation projects. This study will determine natural gas requirements for in-state use and in particular determine potential demand at locations along the pipeline to facilitate the identification of at least five off-take or delivery points.

The location of the potential off-take points and the potential volumes at each location would enable the initial design of in-state delivery tariffs. The initial in-state delivery tariffs would help potential pipeline customers plan for the initial open season. Final tariffs would be established after pipeline customers make transportation commitments during the open season and pipeline design is completed for the committed volumes.

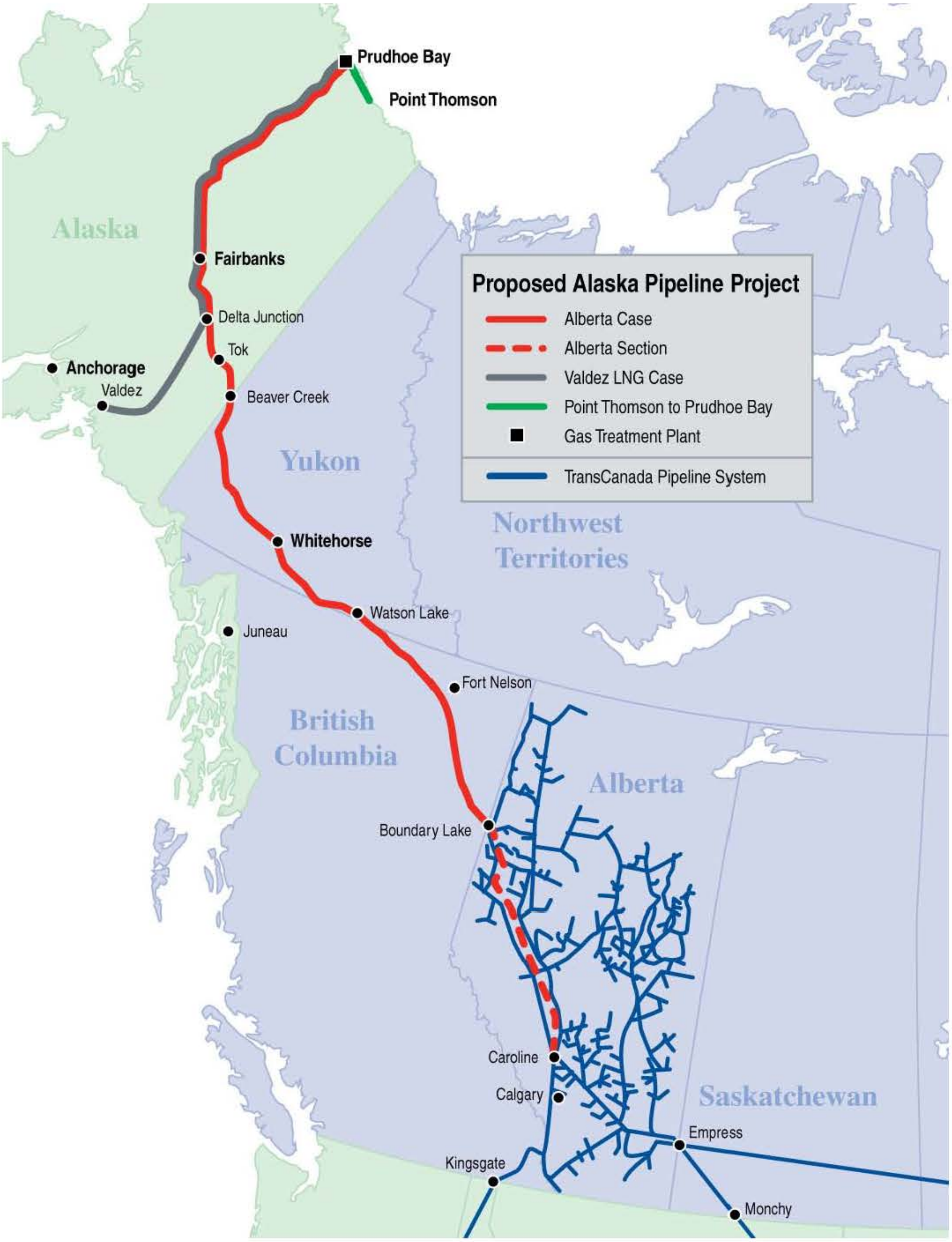
1.2 Study Scope

The study considers the two pipeline routes proposed by TransCanada (shown in Figure 1): (1) the *Alberta Line*—from the North Slope of Alaska to Alberta, Canada following the Dalton and Alaska-Canada highways, and (2) the *Valdez Line*—from the North Slope to Valdez, Alaska, delivering to a liquefied natural gas facility and marine terminal. The Valdez LNG facility is not considered part of this in-state demand study; hence these volumes are not included in the study's demand projections.

This in-state gas demand study takes into consideration the following:

1. Continued growth of existing gas demand from residential, commercial, and electricity generation primarily due to population growth;
2. Potential demand for fuel switching from distillate fuels and coal to natural gas and propane;
3. Incremental demand from potential new or expanded industries and power generation in Alaska as a result of the availability of North Slope natural gas;
4. With a pipeline that would transport natural gas from the North Slope to outside markets, natural gas prices in Alaska will reflect North American market prices adjusted for transportation costs between various markets.

Figure 1. Proposed Alaska Pipeline Project Routes: Alberta Case and Valdez LNG Case



Source: TransCanada, 2009.

1.3 Overview of Research Approach

The demand projections in this study were determined based on information gathered from previous studies, stakeholder interviews, expert opinions, and various secondary data sources.

The stakeholder interview process was a key element in obtaining information on potential demand for natural gas and in identifying future scenarios, economic development prospects, and general economic growth in Alaska. Valuable insights on the approach and data to be used for the analysis were also gained in the process.

The following is a list of the 30 organizations/entities contacted for this study:

1. Electric and gas utilities:
   - Alaska Village Electric Cooperative (AVEC)
   - Anchorage Municipal Light & Power (ML&P)
   - Chugach Electric Association (CEA)
   - Matanuska Electric Association (MEA)
   - ENSTAR Natural Gas
   - Fairbanks Natural Gas, LLC (FNG)
   - Golden Valley Electric Cooperative (GVEA)
   - Copper Valley Electric Cooperative (CVEA)
   - Homer Electric Association (HEA)
   - Alaska Power and Telephone (APT)
   - City of Seward Light and Power Division
2. State Agencies:
   - Alaska Energy Authority (AEA)
   - Alaska Department of Natural Resources (ADNR)
   - Alaska Natural Gas Development Authority (ANGDA)
   - Alaska Housing Finance Corporation
3. Native Corporations:
   - Cook Inlet Regional Inc. (CIRI)
   - Doyon, Ltd.
   - Village Corporations of the Upper Tanana
   - Arctic Slope Regional Corporation
4. Industry:
   - Agrium
   - Nikiski LNG facility owners: ConocoPhillips and Marathon Oil
   - Donlin Creek, LLC (Donlin Creek mine)

- International Tower Hill Mines (Livengood prospect)
- PetroStar
- Alyeska Pipeline Service Company

5. Other entities:
   - Fairbanks Economic Development Corporation
   - Doyon utilities (power plant operator at military bases)
   - Alaska Natural Resources to Liquids, LLC (Alaska GTL project proponent)
   - Black and Veatch (Regional Integrated Resource Plan (RIRP) consultants and author of the Railbelt Energy Generation Authority (REGA) study)

The potential in-state demand for natural gas was determined for two different future timeframes: (1) the Year 1 to 5 timeframe, which captures the demand in the first five years of operations of the gas pipeline; and (2) the Year 10 to 15 timeframe, which captures potential demand of various economic development projects or prospects that are expected to take a longer time to develop after the pipeline comes on line.

To address the high degree of uncertainty regarding potential future outcomes, a probability-based analysis using *@RISK*, a probability analysis software program, was conducted. The *@RISK* analysis allows the uncertainty present in the future demand estimates to be explicitly incorporated in the analysis, and generate results that show possible outcomes given the range of uncertainty. The model uses Monte Carlo simulation to do the risk analysis.

Given the variability in possible outcomes (demand estimates) resulting from various assumptions used in the probability analysis, the results of the study are summarized by presenting three probable demand scenarios representing the following: i) No Large Industry case; ii) Current Industry case; and iii) a Growth Industry case, for each of the 2 future timeframes (see Section 9: Integration for more details).

Communities and industries with large demand in proximity to the main gas pipeline project or a spur line, or with existing piped distribution networks are anticipated to use natural gas from these projects. Communities or industries with smaller demand or at some distance from the main gas pipeline or a spur line could convert from distillate fuels to propane if propane is more cost-effective than distillate fuels. Potential demand for natural gas and for propane are analyzed separately and presented in separate sections in the report.

The analysis for natural gas and propane include the following major consumer sectors:

1. Residential and commercial sector (demand for space heating, water heating, and cooking);
2. Electric power sector (demand for generation of electricity); and
3. Industrial sector (both demand for heating and power generation, and for feedstock gas).

Projected in-state demand is also presented by region. This allows potential demand to be summarized on a regional basis to facilitate determination of potential delivery volumes at various areas along the pipeline. While demand for natural gas consumption is anticipated to be concentrated in the Southcentral (Southern Railbelt) and the Fairbanks (Northern Railbelt) regions, potential demand for propane could be identified in locations outside of the Railbelt region. As shown in Figure 2, nine Alaska regions are defined for this study.

The Boroughs and Census Areas that comprise the Regions are:

- Northern Railbelt region (the Fairbanks North Star Borough and the Denali Borough)
- Southern Railbelt (sometimes referred to as Southcentral Alaska; includes Municipality of Anchorage, Matanuska-Susitna Borough, and the Kenai Peninsula Borough)
- Southeast Fairbanks
- Valdez-Cordova (includes Valdez and Cordova)
- Southeast (includes Skagway-Hoonah Angoon, Yakutat, Haines, Juneau, Sitka, Wrangell-Petersburg, Prince of Wales-Outer, Ketchikan)
- Northwest Arctic (includes North Slope Borough, Northwest Arctic Borough, and Nome)
- Southwest (includes Dillingham, Lake and Peninsula, Bristol Bay Borough, Aleutians East, Aleutians West, and Kodiak)
- Yukon-Kuskokwin (includes Wade Hampton and Bethel)
- Yukon-Kuyukok.

Figure 2. Regions for In-State Gas Demand Analysis

Source: Alaska Map Company, 2009.

Finally, it should be noted that this study assumes that in the interim years before the proposed pipeline becomes operational, measures to address the natural gas deliverability problems in Southcentral Alaska will be put in place. These measures could be in the form of building new underground gas storage facilities and promoting demand side management such as entering into agreement with industrial gas users on demand curtailment during peak winter season when total demand exceeds supply. It is anticipated that an additional option will be available for managing seasonal swing once the TransCanada Alaska pipeline is in-service. Typically, pipelines can deliver more gas during the winter when ambient temperature is lower due to an increase in the compressor efficiency. This enhancement in performance is approximately five percent of the nominal design capacity of the pipeline; hence, this feature can be a flexible tool for in-state gas shippers to meet their winter load demand by contracting short-term firm transportation services during the peak load periods. The development of incremental gas storage facilities, implementation of load shedding demand side management and availability of incremental pipeline capacity during winter allow in-state gas shippers to contract capacity on the pipeline based upon their annual average volumes instead of winter peak demand volumes. For the purpose of calculating an indicative in-state delivery tariff, the projected annual average daily demand for North Slope gas will be used.

More detailed descriptions of assumptions and methodology are presented in each of the sector demand analysis sections of the report.

1.4 Organization of the Report

This report is organized into 12 sections and 6 technical appendices.

Section 1 is this introduction that includes the purpose, study scope, approach, and the organization of the report.

Section 2 provides context on the evolving energy picture in Alaska and the uncertainties regarding the future that may affect in-state natural gas consumption.

Section 3 discusses the statewide economic and demographic projection. The outputs of the projection were used in estimating potential demand in the sector analyses.

Section 4 discusses the potential residential and commercial sector demand for natural gas; including model assumptions and approach.

Section 5 discusses the potential power sector demand for natural gas in the Railbelt region considering four alternative future energy scenarios.

Section 6 discusses the potential industrial sector demand for natural gas for two types of industries: 1) industries that use natural gas for feedstock; and 2) industries that use natural gas to generate power and process heat.

Section 7 presents the potential demand for natural gas by the military.

Section 8 presents potential demand for propane across the state by sector—residential and commercial, power, and industrial sector.

Section 9 presents a summary of the Alaska Department of Natural Resources' report on remaining Cook Inlet Gas Reserves.

Section 10 is an integration of all the sector demand results for natural gas. This section ties together all the components of in-state demand including the net effect of the availability of Cook Inlet supplies on potential pipeline delivery volumes. This section summarizes the demand estimates generated by the probability analyses under the Alberta and the Valdez line projects in the two future timeframes under consideration.

Section 11 presents the potential community demand along the pipeline corridors.

Section 12 lists all the references used in the report.

The technical appendices include the following:

Appendix A: MAP Model Methodology, Assumptions, and Projection Summary

Appendix B: Summary Tables: Table 1: Estimated Demand Ranges by Sector and Table 2: Projected Annual Average Daily Propane Demand by Sector, in Two Future Time Frames for the Alberta Route (in Barrels per day).

Appendix C: Power Sector Demand Analysis

Appendix D: Alaskan Propane Extraction Facilities Cost Estimates for 0.5, 65, and 300 MMcfd Plants

Appendix E: Fuel Price Forecasts

Appendix F: Industrial Product Price Forecasts

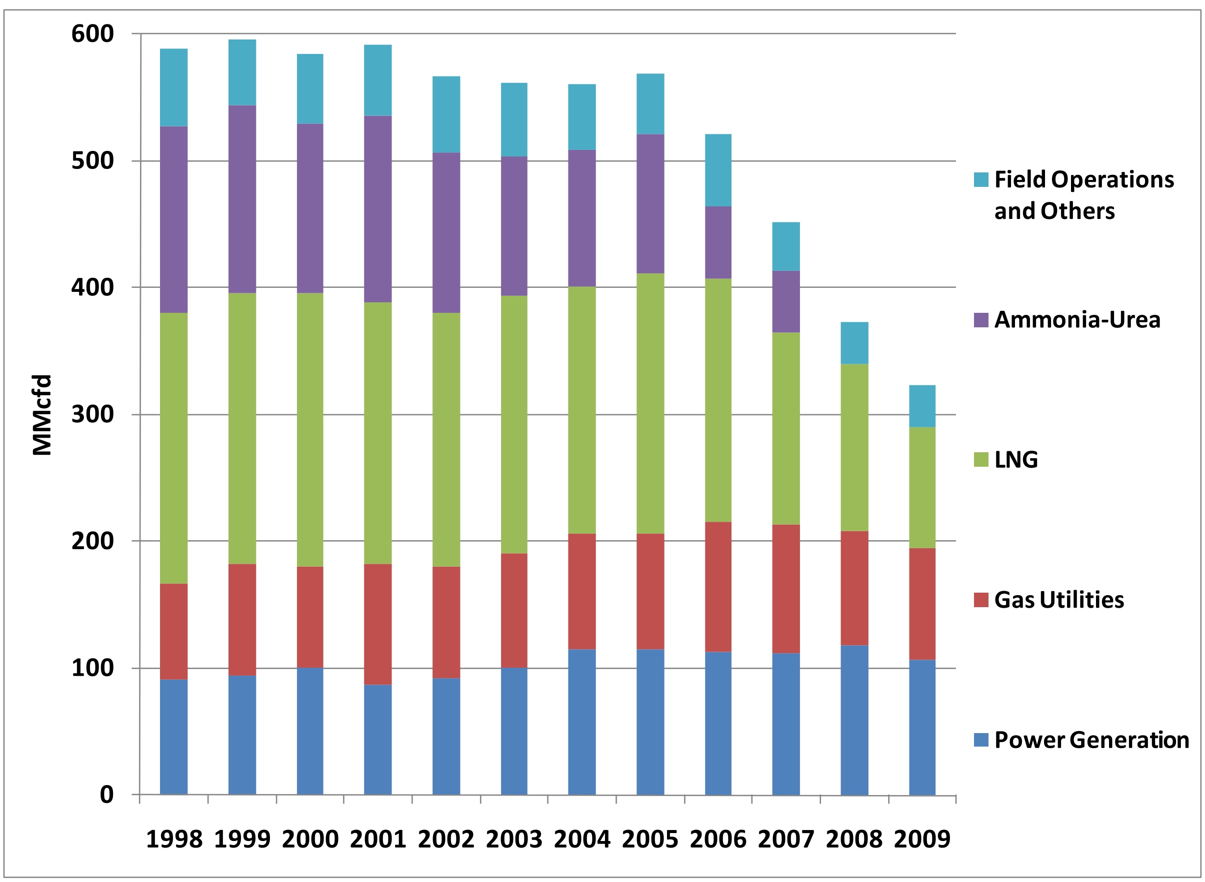
2 The Evolving Energy Picture in Alaska

This section provides context on the evolving energy picture in Alaska, and highlights uncertainties about the future that may affect Alaska's demand for natural gas when the proposed pipeline comes on line.

It is common knowledge that the petroleum industry has long been the most important natural resource sector in Alaska. The industry dominates the private sector economy in terms of gross state product—if it disappeared overnight, a third of the jobs for Alaskans would also disappear (Goldsmith, 2008). Perhaps what is less known is that natural gas, not oil, generates the energy for electricity and heating in the majority of Alaska homes and businesses. This is because Alaska's population is concentrated in the Southcentral region where there is an established natural gas-based power and heating infrastructure. Currently, natural gas is used to generate 54 percent of the electricity consumed in Alaska (Alaska Energy Authority, 2009).

Natural gas is currently produced at Cook Inlet and the North Slope. The historical gas consumption in Southcentral Alaska by sector, as reported by the Alaska Department of Natural Resources, is shown in Figure 3. The graph shows the significant decrease in industrial consumption over the years (from 2001 to 2009).

Figure 3. Historical Natural Gas Consumption of Cook Inlet Gas by Sector



Source: Alaska Department of Natural Resources, Division of Oil and Gas.

Cook Inlet gas is consumed by residential, commercial, power generation, and industrial users in the Southcentral and Interior regions. The Interior consumption occurs due to the availability of an electrical transmission line from the Cook Inlet region to Fairbanks, and to the transportation of natural gas in the form of LNG from Cook Inlet to Fairbanks. Most North Slope gas produced in association with oil operations is re-injected for field maintenance; a small portion is used for oil field equipment, operations, and pipelines (including the first four TransAlaska Pipeline System (TAPS) pump stations), and also for local sales to North Slope utilities. Compared to total Cook Inlet gas production however, the North Slope lease and field operations (not including re-injected gas) use approximately 50 percent more gas than has been historically produced from Cook Inlet on an annual basis (Alaska Department of Revenue 2006). Because of the lack of infrastructure to transport North Slope gas to markets beyond the North Slope region, Cook Inlet gas has been the sole source of natural gas for in-state uses outside the North Slope.

Historically, the largest uses of Cook Inlet gas have been LNG export from the plant owned jointly by ConocoPhillips Alaska, Inc. and Marathon Oil Corporation, and ammonia-urea fertilizer production at the plant owned by Agrium, Inc. Natural gas consumption by these two facilities, accounted for about 57 percent of total Cook Inlet gas consumption for the period 1997 to 2006, while gas consumed for power generation and space heating has accounted for 33 percent of total Cook Inlet gas consumption (ADNR, DOG 2007). Generally, natural gas consumed for power generation and space heating has increased in step with steady growth in residential and commercial demand.

Annual Cook Inlet gas consumption averaged over the period 1998 through 2007 was 204 Bcf. After 2007, there was a drop in consumption due to the shutdown of the Agrium facility[4]; annual consumption since then has averaged only 127 Bcf/yr.

Southcentral Alaska had a surplus of relatively inexpensive natural gas resources for decades, but that era has ended with declining production from older fields (Alaska Department of Revenue 2006). Industrial gas users that depend on low-cost base-load gas have been confronted with the implications. As noted above, the Agrium ammonia-urea plant closed in 2007.

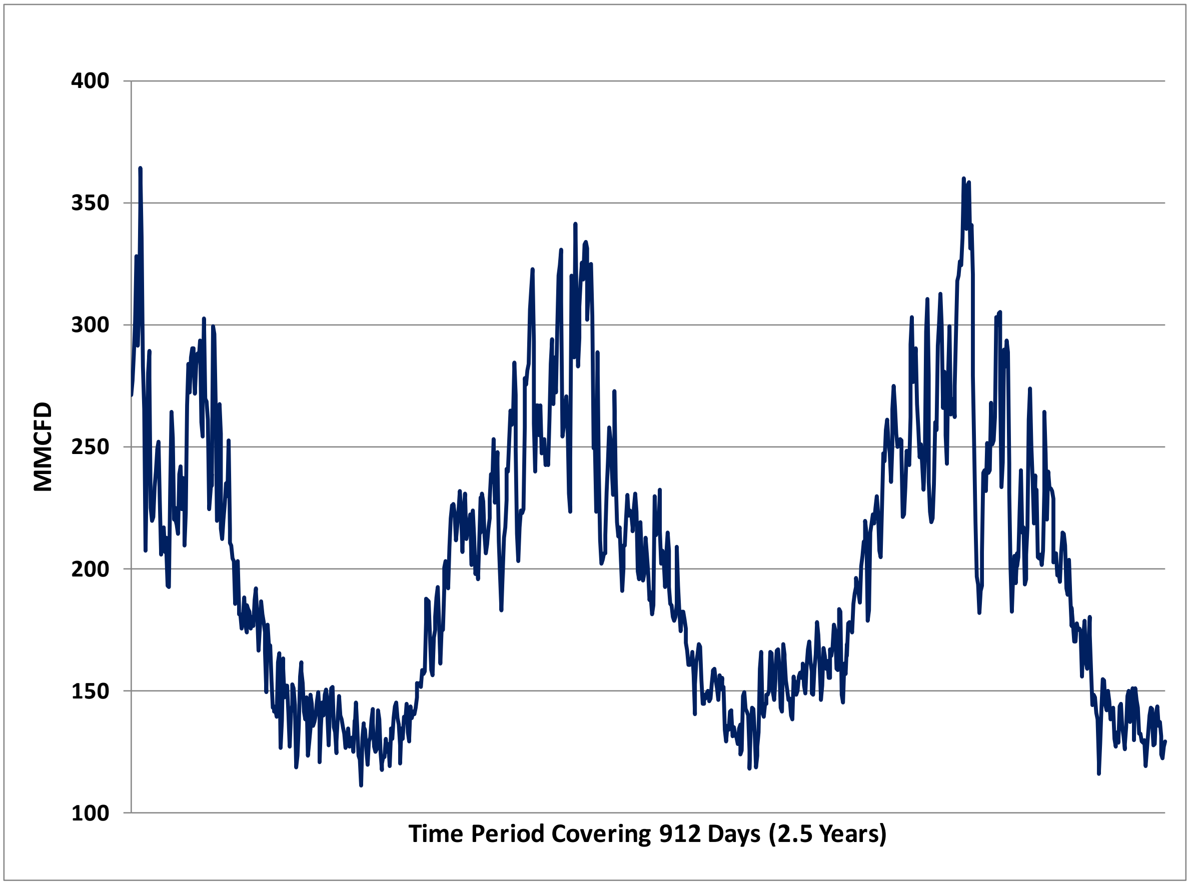
The future of the ConocoPhillips-Marathon LNG plant is uncertain beyond 2011, when its LNG export permit expires. The facility owners could apply for an extension on their permit, but a condition to the U.S. Department of Energy's approval of an export permit extension requires a showing that the permit extension is consistent with the 'public interest.' One public interest criteria considered is whether adequate natural gas supplies exist to meet both proposed exports as well as local needs during the proposed export term.

Figure 4 shows seasonal fluctuations in demand for Cook Inlet gas for combined electric power generation and residential and commercial heating – the primary sectors with seasonal demand fluctuations. As one would expect, demand is highest in winter, when the need for heat and electricity is greatest. Over the course of a typical year, daily gas demand for heating and electricity ranges from around 120 MMcfd in the summer, to 360 MMcfd in the winter – a roughly 3-fold increase.

Figure 5 illustrates the typical total average daily demand for natural gas, including industrial sector demand by month; the average monthly demand over a typical year vary by as much as 130 MMcfd.

[4] In 2007, gas price and supply issues forced the closure of the Agrium plant.

Figure 4. Historical Daily Gas Usage for Power and Heating in Southcentral Alaska



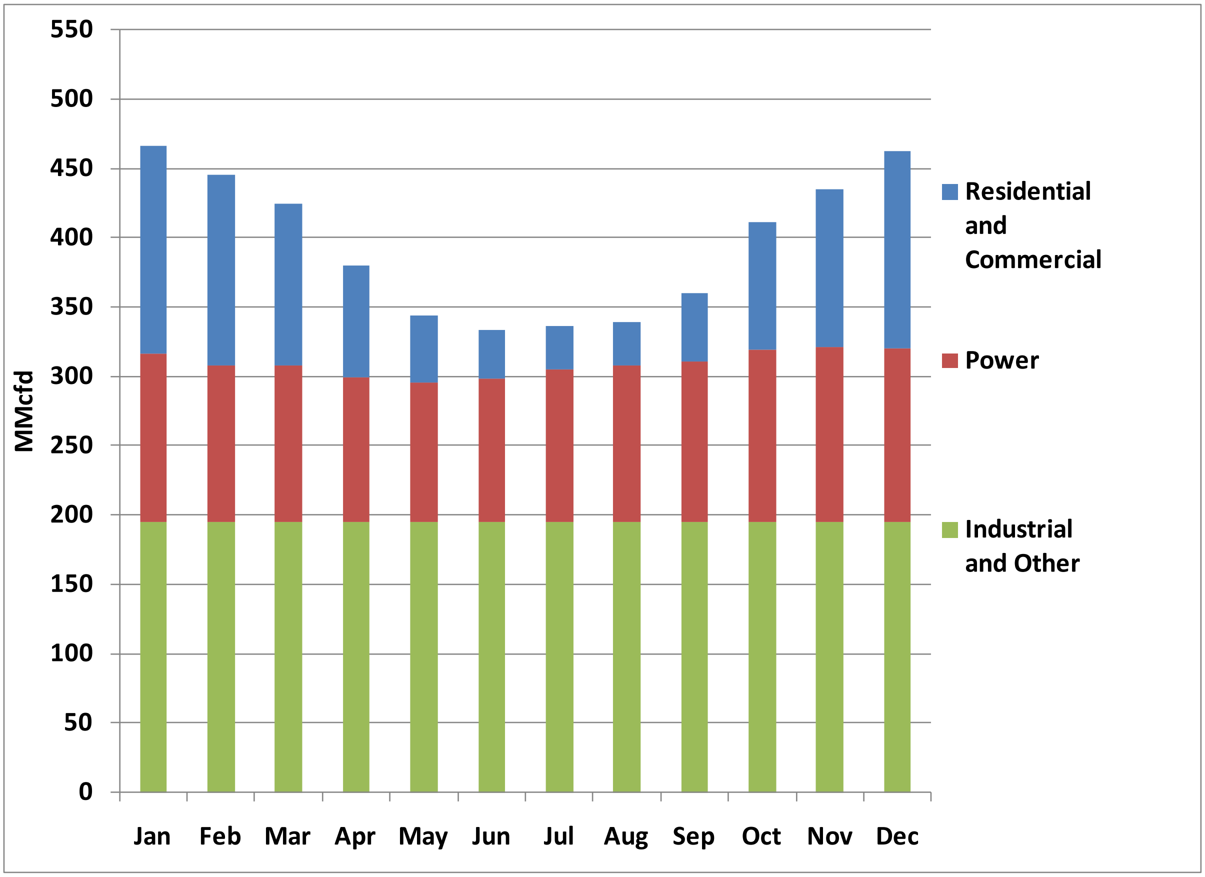
Source: Alaska Department of Natural Resources, (2009)

Cook Inlet gas production is better able to approach or meet Southcentral demand on an annual basis than on a seasonal basis due to high swings in seasonal demand and limited field delivery rates. Seasonal swings can be accommodated through gas additions to storage during low-demand periods, and withdrawals from storage during high-demand periods.

Cook Inlet gas production could be increased through reserves growth in the existing fields, and/or timely exploration success and development of new fields. If increased production from Cook Inlet is not sufficient and exploration in other basins is not successful, alternative solutions include various combinations of increased storage, demand reduction strategies, an in-state gas pipeline from the North Slope to Southcentral Alaska, LNG imports, increased power generation from renewable sources such as solar, wind, geothermal, and tidal, and coal gasification; especially in the interim before North Slope gas may become available.

Overall, Southcentral Alaska is facing a deliverability problem during periods of peak demand, and a potential gas supply shortfall could become more costly and difficult to manage before a mainline and a spur line are in place. The remedy is to encourage more development and exploration, provide adequate storage for seasonal peaking, and begin the process of developing options to supplement Cook Inlet gas.

Figure 5. Typical Total Average Daily Demand for Natural Gas by Month



Source: Data on historical natural gas usage are based on information provided by the Alaska Department of Natural Resources, for the years 1998 to 2009.

Note: Industrial demand above excludes historical gas volumes used for field operations and for fertilizer production at the Agrium plant.

In the Fairbanks region, the current market for natural gas has been limited due to similar supply constraints. Most residential and commercial customers in this region use heating oil for space heating and domestic hot water. Market expansion of natural gas will require expansion of existing infrastructure. There are also several ongoing exploration efforts near Nenana and in the Yukon Flats that could potentially serve the region in the long-term if discoveries are made. In addition, recent developments suggest that there is a possibility that Fairbanks may have access to North Slope gas in the form of LNG before the pipeline comes on line if the proposed LNG project in the North Slope that is being pursued by the Alaska Gasline Port Authority is developed. In the near future however, expansion of the natural gas distribution system would continue to be affected by the availability of natural gas supplies from Cook Inlet.

A Regional Integrated Resource Plan (RIRP) has been developed to identify and evaluate the best resource mix to ensure that least-cost options for electricity are developed in the Railbelt region. The RIRP considered a portfolio of energy options for Railbelt power generation in the future, including large hydropower dams; renewable energy sources such as geothermal, wind, tidal, and solar; and demand side management. However, natural gas remains a major energy source in the Railbelt even 50 years into the future.

Although most Alaskan homes and businesses are powered and heated by natural gas, there are many areas of Alaska where natural gas is currently unavailable due to the significant cost of gas exploration and development, or because transportation from areas of large known accumulations to areas where it can be utilized for heat and power by a smaller population base is costly (Alaska Energy Authority 2009). Over 150 communities in rural Alaska depend on diesel fuel for electric generation and home heating. Most of these communities are geographically isolated and have populations less than 1,000. They have no access to a power grid, and must import diesel fuel to operate a local electric generator (Colt et al. 2003). Costs are high due to the expense of moving fuel to rural Alaska and the small scale of operations.

These electric generators have been increasingly expensive to operate as fuel costs increase. As the operation costs of village electric generators have escalated, the price of electricity has also increased. A recent study indicated low-income households in remote rural Alaska may be paying 47 percent of their income on home energy use, compared to less than five percent for the average Alaska household (Haley et al. 2008). High energy prices combined with high unemployment rates, limited local economies, and local governments struggling to provide basic services have presented rural communities and households in the Interior and elsewhere in Alaska with challenging circumstances (Grewe and Caldwell 2008).

In some rural Alaska communities alternative energy technologies, such as wind turbines, offset some of their dependence on diesel fuel to produce electricity. Due to the high price of diesel, Alaska is fast becoming a testing ground for such technologies (Milkowski 2009). About 24 percent of the state's power already comes from renewable energy—mostly hydropower from Southeast Alaska. Moreover, recent advances in diesel engine efficiency, automated generator controls, heat recovery, and continuous operations and maintenance techniques have made possible diesel fuel efficiency improvements of more than 50 percent in some rural community powerhouses (Alaska Energy Authority 2009).

All of these energy related issues are evolving and the approach used by industry and government to address these issues is going to be determined in the next several years. This study attempts to incorporate these uncertainties in the different sector demand analyses. Assumptions and approaches in dealing with these uncertainties are explained in succeeding sections.

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3 Statewide Economic and Demographic Projection

Regional estimates of residential and commercial sector demand for natural gas in the Northern and Southern Railbelt and propane demand in the rest of the state are determined using the projected number of households in each region. These regional household projections were derived from a statewide economic and demographic projection conducted by ISER using the MAP projection model. (See Appendix A for a description of the model structure).

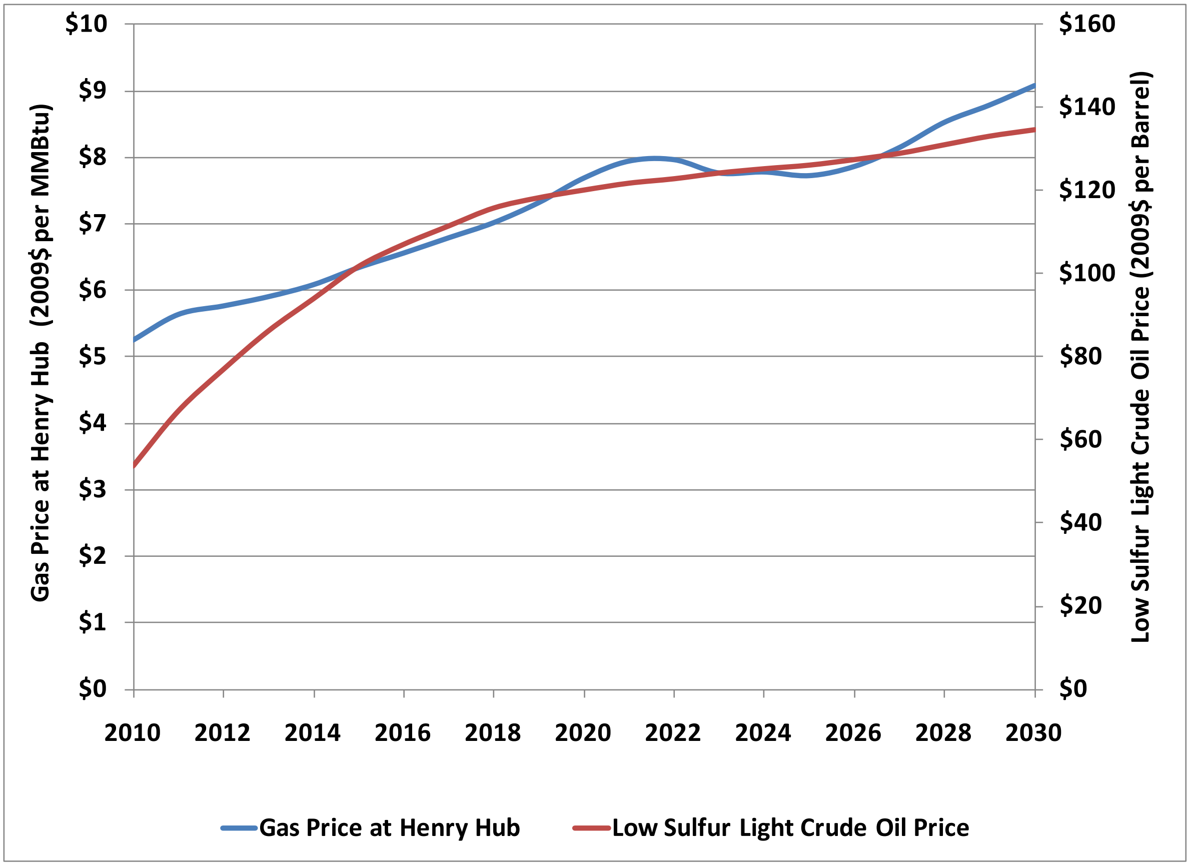
The economic and demographic model projects an average annual growth in wage and salary jobs between 2010 and 2030 of 1.3 percent based on a large number of assumptions contained in an *Economic Development Scenario* (See Appendix A). The highlights of that *Scenario* are as follows:

- World oil price gradually increases over time and averages about $100 (2009 $) over the period 2010-2030 (see Figure 6; based on Annual Energy Outlook, EIA, 2009)
- Cumulative onshore oil production from the Central North Slope over the period 2010-2030 is 4.1 billion barrels
- Natural gas price (Henry Hub) gradually increases over time and averages $6.60 (2009 $) over the period 2010-2030 (see Figure 6, based on Annual Energy Outlook, EIA, 2009)
- A gas pipeline is constructed and becomes operational in 2019 with a capacity of 4.5 Bcf/day
- OCS oil production from the Beaufort Sea begins 2021
- Donlin Creek Mine begins production in 2014
- Pebble Mine begins production in 2024
- Active duty military force level trends slowly downward from its current high level
- Annual growth in tourist visitors resumes in 2011, but from a lower base
- Growth in federal spending falls below the historical trend
- US recession slows the Alaska economy in 2009 and 2010 with growth resuming in 2011

Figure 6 shows the oil and gas price forecast used in the model.

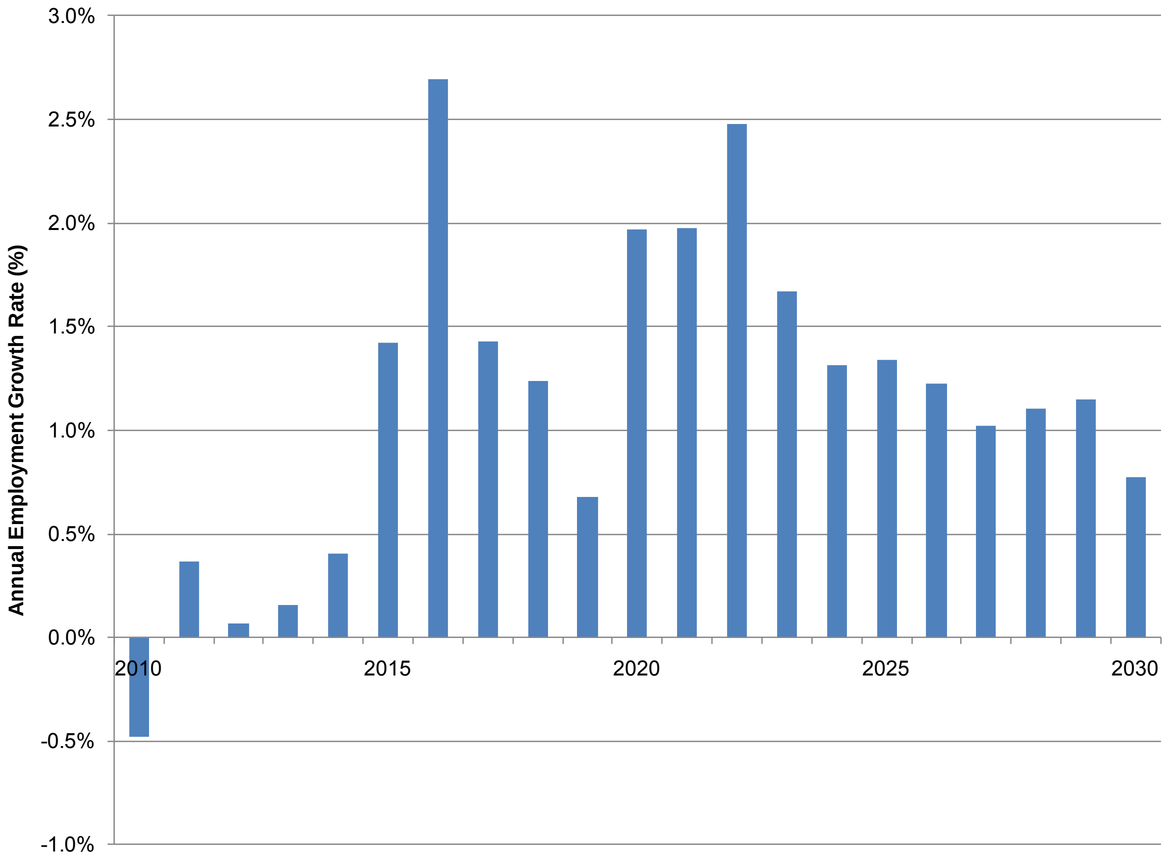
These assumptions result in a pattern of employment growth that begins with a slow recovery from the current recession (see Figure 7). This slow recovery is followed by an acceleration of growth associated primarily with construction of the gas pipeline. There is then a slowdown followed in the next decade by renewed growth driven by OCS development. Revenues from oil and gas production are sufficient to allow state spending to continue to increase, and this also contributes to employment growth (See Appendix A for more detailed state projection results).

Figure 6. Natural Gas and Oil Price Forecasts, 2009$



Source: SAIC, Inc. estimates. See Appendix E for details.

Figure 7. Projected Alaska Annual Growth Rate of Jobs



Source: ISER, 2009.

Statewide population growth is determined by the growth in employment. When job growth is rapid, the increase in the demand for labor results in net immigration to Alaska and this adds to the growth attributable to natural increase (births minus deaths).

Projecting the number of households in each region of the state depends on the share of jobs within each region and the historical relationship between jobs and population. The regional household projections show an increase in each region of the state, although growth is somewhat concentrated in the Railbelt regions (See Table 1 and Table 2).

Table 1. Alaska Households by Region

Region	Year 2010	2019	2030
Southern Railbelt	155,330	176,340	216,360
Municipality of Anchorage	*106,020*	*118,390*	*145,960*
Matanuska-Susitna	*29,300*	*35,840*	*44,400*
Kenai Peninsula	*20,010*	*22,110*	*26,010*
Northern Railbelt	37,100	39,910	45,930
Fairbanks North Star	*36,380*	*39,060*	*44,880*
Denali	*720*	*850*	*1,050*
Northwest-Arctic	6,880	7,640	8,800
Southeast Fairbanks	2,430	2,660	3,120
Southeast	27,330	30,860	37,450
Southwest	8,450	8,950	9,670
Valdez-Cordova	3,730	4,130	4,750
Yukon – Koyukuk	2,070	2,260	2,550
Yukon – Kuskokwim	6,550	7,210	8,220
Total Households	249,870	279,960	336,850

Source: ISER, 2009.

Table 2. Alaska Households: Annual Growth Rates by Region (%)

Region	Timeframe and Growth Rate 2010-2019	2019-2030
Southern Railbelt	1.40	1.90
Municipality of Anchorage	*2.30*	*2.00*
Matanuska-Susitna	*1.20*	*1.90*
Kenai Peninsula	*1.10*	*1.50*
Northern Railbelt	0.80	1.30
Fairbanks North Star Borough	*0.80*	*1.30*
Denali	*1.80*	*2.00*
Northwest-Arctic	1.20	1.30
Southeast Fairbanks	1.00	1.50
Southeast	1.40	1.80
Southwest	0.60	0.70
Valdez-Cordova	1.10	1.30
Yukon – Koyukuk	1.00	1.10
Yukon – Kuskokwim	1.10	1.20
Average Growth Rate	1.30	1.70

Source: ISER, 2009.

4 Potential Residential and Commercial Sector Demand for Natural Gas

This section presents the historical and projected residential and commercial sector demand for natural gas in Alaska. The projected residential and commercial sector demand covers the demand in communities that are in proximity to the proposed natural gas pipeline with a large population base or with a significant commercial demand that are anticipated to have their energy needs met by a piped natural gas distribution network. The energy requirements of smaller communities and those located some distance from the main gas pipeline (or a spur line) on the other hand, are anticipated to be supplied by propane; and the projected in-state demand for propane is presented in a separate section (see Section 8).

Generally, residential consumption refers to natural gas used in private dwellings (including apartments) for heating, air conditioning, cooking, water heating, and other household uses, while commercial consumption refers to gas used by non-manufacturing establishments or agencies primarily engaged in the sale of goods and services. The commercial sector typically includes establishments such as hotels, restaurants, wholesale and retail stores, and other service enterprises, as well as local, state, and federal agencies engaged in non-manufacturing activities.

Historically, residential and commercial consumption of natural gas in Alaska was limited to the Railbelt region and Barrow, a community of about 4,500 residents on the North Slope that has access to a nearby gas field. More recently, the community of Nuiqsut has obtained gas supplies from the Alpine Field on the North Slope. Natural gas consumption in Barrow and Nuiqsut, however, will not directly be affected by the availability of natural gas through the proposed main gas pipeline; the demand analysis presented in this section therefore, does not include potential future demand in Barrow or Nuiqsut.

Natural gas consumption in the Railbelt region is concentrated in two major areas: 1) Southcentral Alaska which encompasses the greater Anchorage area, including the Matanuska-Susitna Borough and the Kenai Peninsula; and 2) Fairbanks. These two areas have natural gas piped distribution systems that are served by two separate local distribution companies—ENSTAR and Fairbanks Natural Gas (FNG), respectively. Both Southcentral and Fairbanks areas are supplied with gas coming from Cook Inlet production.

To be consistent with the Alaska regions as defined in the study scope in Section 1.2, the Southcentral region will be referred to as the Southern Railbelt and the Fairbanks area will be part of the Northern Railbelt region. Heating demand outside of the Fairbanks area in the Northern Railbelt region is assumed to be met with propane and is discussed in Section 8.

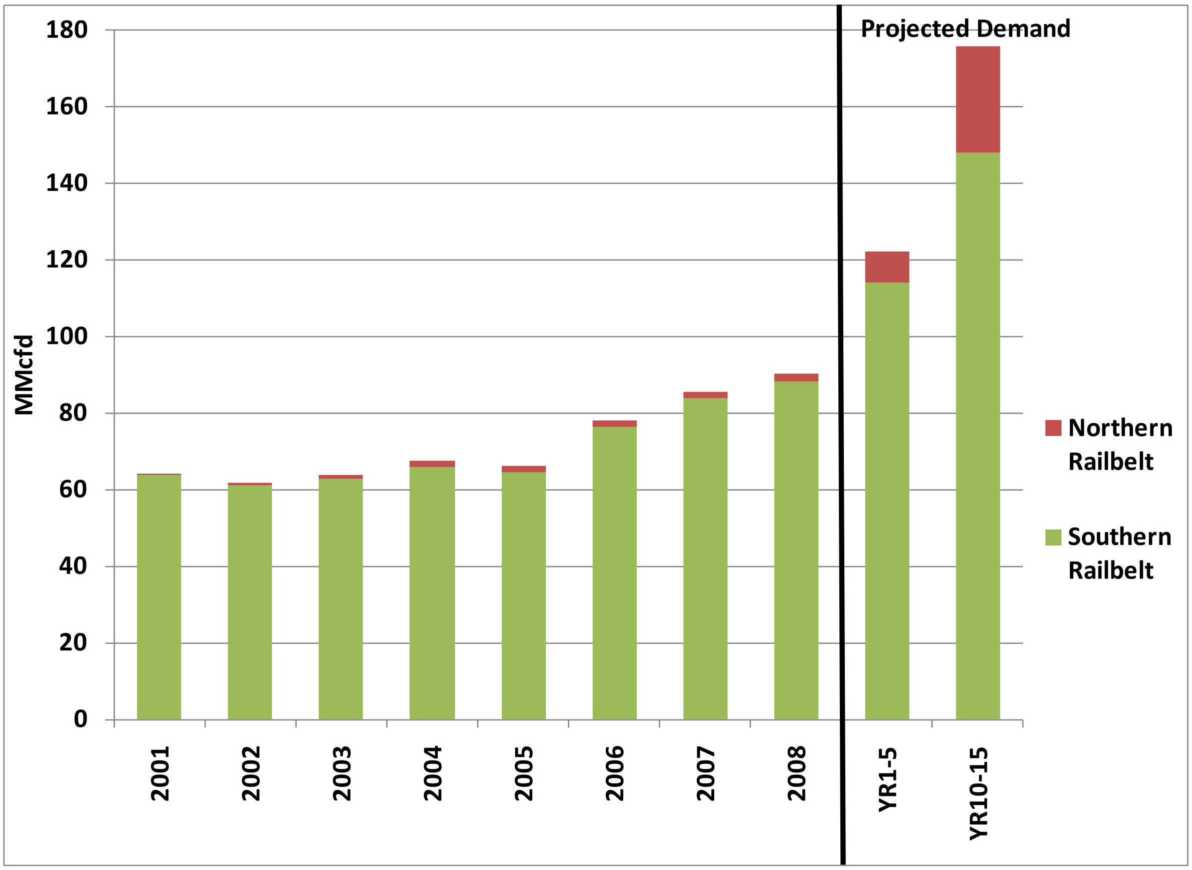
Figure 8 summarizes the findings of this section. Figure 8 shows the historical and the estimated natural gas consumption by region in the two future timeframes under consideration: Year 1 to 5 and Year 10 to 15 of pipeline operations. As shown in the figure, residential and commercial sector demand for natural gas is estimated to increase from the current consumption of about 90 MMcfd to about 122 MMCfd and 175 MMCfd[5] in the Year 1 to 5 and Year 10 to 15 timeframe, respectively.

As evident in Figure 8, the Southern Railbelt region accounts for a majority of the residential and commercial sector natural gas consumption. The Southern Railbelt region has in fact the highest concentration of population within the State; with an estimated 155,000 households (see Table 1 in Section 3). Currently, about 78 percent of the residential market in the Southern Railbelt region is

[5] These projected demand volumes represent the mean estimate resulting from the probability analysis.

served with natural gas. In contrast, in the Northern Railbelt region, particularly the Fairbanks North Star Borough, less than 2 percent of the residential market (with an estimated 35,400 households) is supplied with natural gas for their heating requirements. A majority of the homes in this region use oil for space heating.

Figure 8. Historical and Projected Annual Average Daily Residential and Commercial Sector Demand for Natural Gas



Source: Data from 2001 to 2007 are from the Energy Information Administration, 2008 data are from ENSTAR and the Interior Issues Council report, and demand projections in the two future timeframes are estimated based on this study's analysis.

The following sections provide more detail on the current and projected residential and commercial sector demand for natural gas in the Northern and Southern Railbelt regions.

4.1 Current Demand Estimates

In 2008, total consumption of natural gas by residential and commercial customers in Alaska was about 33 billion cubic feet (Bcf), an increase of about two Bcf from the previous year[6]. As noted in the

[6] The 2008 natural gas consumption by residential and commercial customers is the sum of ENSTAR and FNG natural gas sales in 2008. Data are from ENSTAR and the Interior Issues Council report entitled *In-State Gas Pipeline Supply Option Studies* (February 5, 2009).

previous section, the Southern Railbelt accounted for most of this residential and commercial gas consumption.

The subsequent sections describe in more detail the current residential and commercial sector market in the state. The discussion is focused on the Southcentral region and in Fairbanks, the only two areas of the state with a piped natural gas distribution system. Again, to conform with the classification of regions as defined in Section 1.2, the discussion is broken out into the Southern Railbelt and Northern Railbelt regions.

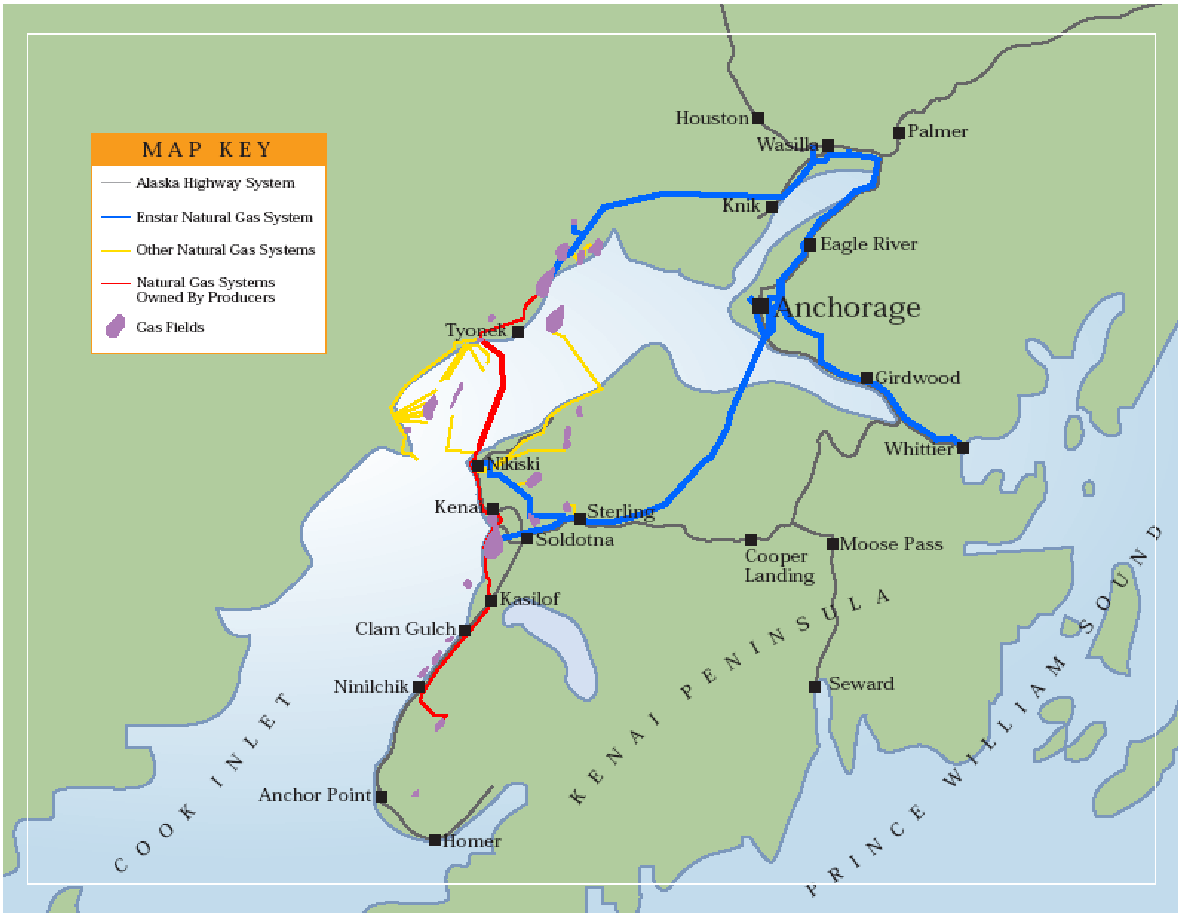
4.1.1 Southern Railbelt Region

ENSTAR is the local distribution company serving the Southern Railbelt region. The company was established in 1961. Today, ENSTAR has over 3,200 miles of distribution and transmission mains, with 129,000 customers, and is serving an estimated 348,800 Southcentral Alaska residents (ENSTAR, 2009).

Figure 9 is a map of the gas distribution system in Southcentral Alaska. The blue line represents the major gas transmission pipelines in the ENSTAR natural gas system. ENSTAR currently has gas supply contracts with Cook Inlet producers; however, sources of future gas supplies (beyond 2011) are still uncertain.

ENSTAR has more than 116,000 residential and about 13,000 commercial accounts. In 2005, penetration in the residential market was already about 75 percent. In 2007, ENSTAR added another 1,757 customers.

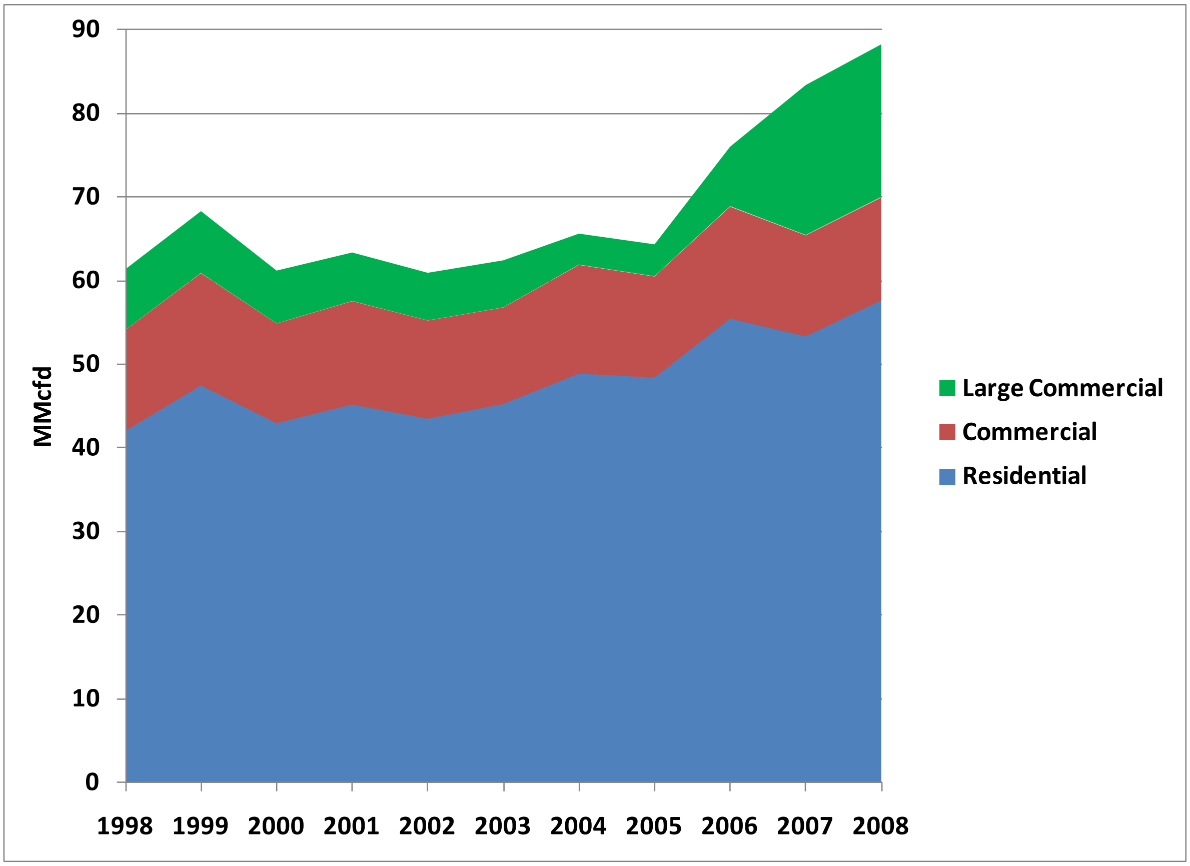
Figure 9. Southcentral, Alaska Gas Distribution System



Source: ENSTAR Natural Gas Company presentation to the Commonwealth North Energy Action Committee, May 22, 2009.

Annual average daily natural gas consumption data for ENSTAR in the past 10 years are shown in Figure 10. Residential sector demand has increased from about 61 MMcfd in 1998 to 88 MMcfd in 2008; a 37 percent increase in demand. Natural gas consumption by small to medium commercial customers has been relatively steady, fluctuating from a low of about 12 MMcfd in 2003 to a high of 13 MMcfd in 1999 and 2006. Average annual daily consumption by the large commercial customers on the other hand has increased significantly in recent years from 7 MMcfd in 2006 to 18 MMcfd in 2008.

Figure 10. Annual Average Daily Residential and Commercial Sector Gas Consumption, ENSTAR Service Area 1998 to 2008 (MMcfd)



Source: ENSTAR, 2009.

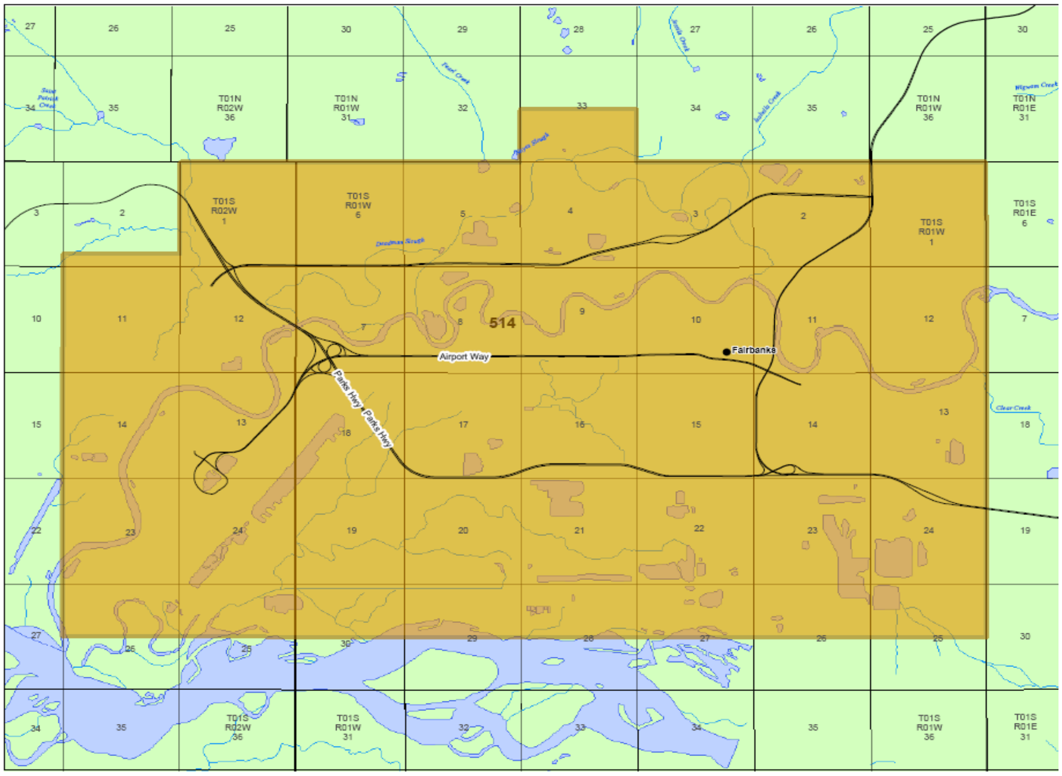
4.1.2 Northern Railbelt Region (Fairbanks North Star Borough)

Fairbanks Natural Gas (FNG) is the local distribution company serving Fairbanks. FNG began natural gas service to the area in 1998 by transporting LNG from a liquefaction plant at Point McKenzie to Fairbanks, a distance of approximately 300 miles. Currently, LNG is trucked in specialized tanker trailers to its two LNG storage and regasification facilities. On average, about three 800 Mcf truckloads per day are transported.

Unlike the ENSTAR service area, penetration into the residential market has been relatively slow since 1998, primarily because FNG does not have ready access to natural gas and also because of the added expense of trucking LNG. As noted in a previous study, in 2005, only 2 percent of the roughly 11,500 housing units in Fairbanks were using natural gas. The majority of the houses use heating oil for space heating. On the other hand, natural gas penetration in the commercial sector is close to 50 percent of the estimated 1,277 commercial units. The conversion rate in the commercial sector has been faster than the residential sector because higher fuel use per commercial customer makes recovery of conversion costs faster (RDS LLC, 2006).

Figure 11 shows FNG's service area. The distribution system has 65 miles of pipe (IIC, 2009). FNG is presently supply-constrained and is not expanding their service area or taking new customers within the area served by their existing distribution system. They have a large transmission backbone to their present system and could readily expand if gas were available. Commercial customers account for 90 percent of the total volume of gas sales. Average annual consumption of residential customers is 190 Mcf (Dan Britton, personal communication, 2009).

Figure 11. Fairbanks Natural Gas Service Area



Source: Regulatory Commission of Alaska, 2009 (http://rca.alaska.gov/RCAWeb/Certificate/CertificateDetails.aspx?id=14aed247-df8f-4dc6-8b2a-325acf1cb3c7)

In 2008, total residential sector demand was 63,515 Mcf, accounting for 7 percent of FNG's total gas sales that year. In contrast, commercial customers accounted for 73 percent of total gas sales, with a combined 624,169 Mcf of natural gas usage for small and large commercial customers. Residential sector demand increased by 13 percent from the previous year. Likewise, demand from small commercial customers and large commercial customers increased by 16 percent and 18 percent, respectively, from 2007 numbers.

In addition, FNG serves the hospital, the University, and the CIRI Talkeetna Lodge (located in Talkeetna, Alaska which is not within the Fairbanks North Star Borough). These three customers accounted for 20 percent of FNG's gas sales in 2008. As shown in Table 3, there was a significant increase in gas sales to the University from 2007 to 2008.

Table 3 also shows natural gas consumption by FNG customers in terms of annual average daily consumption (expressed in MMcfd).

Table 3. FNG Natural Gas Sales by Type of Customer, 2007 and 2008 (in Mcf per year and MMcfd)

	2007		2008	
Customers	**MCF/Yr**	**MMcfd**	**MCF/Yr**	**MMcfd**
Residential Customers	56,286	0.15	63,515	0.17
Small Commercial Customers	373,322	1.02	431,998	1.18
Large Commercial Customers	162,397	0.44	192,171	0.53
Hospital	104,452	0.29	107,892	0.30
University of Alaska Fairbanks	10,967	0.03	50,549	0.14
CIRI Talkeetna Lodge	11,998	0.03	13,410	0.04
Total:	719,422	1.97	859,535	2.35

Source: Interior Issues Council, *In-State Gas Pipeline Supply Options*, February 5, 2009.

4.2 Future Demand Estimates

New residential and commercial natural gas customers in Alaska are expected from increased market penetration in existing ENSTAR and Fairbanks Natural Gas demand service areas, as well as an expansion of these service areas. The potential future demand is presented in two future timeframes: Year 1 to 5 and Year 10 to 15 of pipeline operations. The following sections discuss the assumptions, approach, and results of the demand analysis.

4.2.1 Assumptions and Approach

Residential and commercial sector demand estimates for the Year 1 to 5 timeframe are based on market studies conducted by ENSTAR, the Interior Issues Council (IIC), and Fairbanks Natural Gas for the Southcentral and Fairbanks regions. Demand projections for the Year 10 to 15 timeframe are based on projected growth in population and employment in the region; estimated using the MAP model as described in Section 3 and Appendix A.

To account for potential variability in the critical assumptions used in the demand projections, a probability analysis was conducted to generate a range of potential demand estimates given different levels of probability. The "uncertainty" variables that were varied and tested in the probability analysis include the following:

- Percent growth in number of households
- Percent growth in employment
- Load per residential customer
- Load per medium and large commercial customer
- Residential and commercial market penetration rates
- Start year of build-out rate in the Fairbanks region
- Annual build-out rate
- Annual rate of growth in Southcentral (Southern Railbelt region) natural gas demand

The projections for the Fairbanks Northstar Borough region are based on a build out schedule as envisioned by FNG. Personal communication with Mr. Dan Britton, president of FNG, indicated that the company does not expect to start their build out until after the proposed mainline construction has been completed (Britton, 2009). However, recent developments suggest that there is a possibility that FNG could receive natural gas in the form of LNG (trucked from the North Slope to Fairbanks) even before the main gas pipeline comes on line. On September 29, 2009, the Alaska Gasline Port Authority announced that it has executed a letter of intent to buy FNG and develop a North Slope liquefaction plant that would allow liquefied natural gas to be trucked to Fairbanks (Petroleum News, 2009). To account for this possibility the demand analysis considered different start years for the build out in Fairbanks with 2013 being the earliest start year and 2019 as the latest start year. The base assumption is that the build out start year is in 2017. The demand projection assumes a fairly modest build out rate of 12.5 percent. By Year 10 to 15 of pipeline operations however, it is assumed that the build out will have been completed and therefore the demand projection reflects the maximum projected load as determined by the build out plan plus additional load from natural population and household growth.

To estimate growth in number of commercial customers, employment projections from the MAP model were used as a proxy measure. The U.S. Census Bureau *County Business Patterns* provides data on the total number of establishments, total number of paid employees, and the number of establishments by firm size (i.e. 1 to 4 employees, 5 to 9 employees, etc.). This information was used to determine the potential number of establishments or commercial customers that would be considered small, medium, and large. The average natural gas consumption by type of customer was used to project future demand.

The projections for the Southcentral Region are based on the load forecast developed by ENSTAR. As noted in the previous demand analysis, the ENSTAR projections provide reliable estimates of demand given the already high rate of natural gas penetration in the Southcentral region and the company's history in tracking current accounts and forecasting future accounts (RDS LLC, 2006). ENSTAR's load forecast covered the years 2009 to 2018. The forecast assumed normal temperatures resulting in 9,911 heating degree days annually. A traditional time series trend was used to project demand further into 2030. This time series approach extrapolates the underlying trend in natural gas usage over time period for the residential and commercial sector. To account for potential variation in this growth trend, the annual rate of growth was varied from a low of 1.5 percent to a high of 3.25 percent.

4.2.2 Projected Natural Gas Demand by Region

The residential and commercial sector demand projections for the Northern Railbelt and the Southern Railbelt regions are presented in this section. As noted above, for the Alberta Line, potential natural gas demand is identified only for the Railbelt region (both Northern and Southern Railbelt). These regions directly correspond to potential future load for FNG and ENSTAR, the two local gas distribution companies operating in the Railbelt region. The Valdez Line would add the City of Valdez to areas served with natural gas. This demand is also presented in this section.

4.2.2.1 Northern Railbelt Region

Table 4 shows the mean projected demand generated by the probability analysis of the demand in the Northern Railbelt region for the two future timeframes. While the Denali Borough is part of the Northern Railbelt region, the potential demand for natural gas presented below reflects future demand for a portion of the Fairbanks North Star Borough only; this is the portion which has a reasonably foreseeable chance of being part of the build out plan for the region's piped natural gas distribution system. The remainder of the Fairbanks North Star Borough and all of the Denali Borough are addressed in the Propane Analysis (Section 8).

The combined residential and commercial sector demand in the Year 1 to 5 timeframe is expected to be about 8 MMcfd, and in the Year 10 to 15 timeframe, the demand is expected to be about 28 MMcfd. The later timeframe potential demand reflects potential load after planned build out has been completed by FNG with an additional load resulting from natural population growth.

Table 4. Projected Annual Average Daily Residential and Commercial Sector Demand in the Northern Railbelt Region, in Two Future Timeframes (in MMcfd)

Type	Year 1 to 5 of Pipeline Operations	Year 10 to 15 of Pipeline Operations
Residential	4.04	18.43
Commercial	4.22	9.32
Total:	8.26	27.75

Source: Northern Economics estimates, 2009.

4.2.2.2 Southern Railbelt Region

Table 5 shows the mean projected demand generated by the probability analysis of demand for the Southern Railbelt; which corresponds to the current ENSTAR service area plus modest expansion of the service area in the future. The results show the range of possible outcomes given the variability in the rate of growth in residential and commercial customers in the region.

In the Year 1 to 5 timeframe, potential demand in this region is expected to be about 114 MMcfd. In the Year 10 to 15 timeframe, potential demand in this region is expected to be about 148 MMcfd.

Table 5. Projected Annual Average Daily Residential and Commercial Sector Demand in the Southern Railbelt Region, in Two Future Timeframes (in MMcfd)

Type	Year 1 to 5 of Pipeline Operations	Year 10 to 15 of Pipeline Operations
Residential	74.69	96.78
Commercial	39.55	51.24
Total:	114.24	148.02

Source: Northern Economics estimates, 2009.

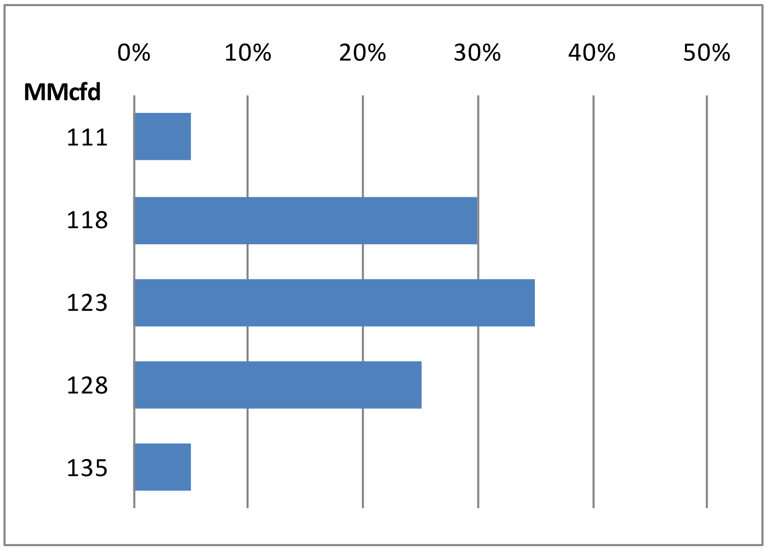
4.2.2.3 Valdez-Cordova Region

The discussion of potential demand in the sections above so far considers the Alberta Line configuration--the main pipeline from the North Slope of Alaska to Alberta, Canada. Considering the Valdez Line route—a main pipeline from the North Slope to Valdez, it is anticipated that the City of Valdez would switch from heating oil to natural gas based space heating systems if the terminus of the main gas pipeline is located in their vicinity. The estimated residential and commercial sector demand (mean values) in this region is 0.96 MMcfd for the Year 1 to 5 timeframe and 1.10 MMcfd for the Year 10 to 15 timeframe.

4.2.2.4 Probability Analysis of Total Projected Natural Gas Demand for the Residential and Commercial Sector

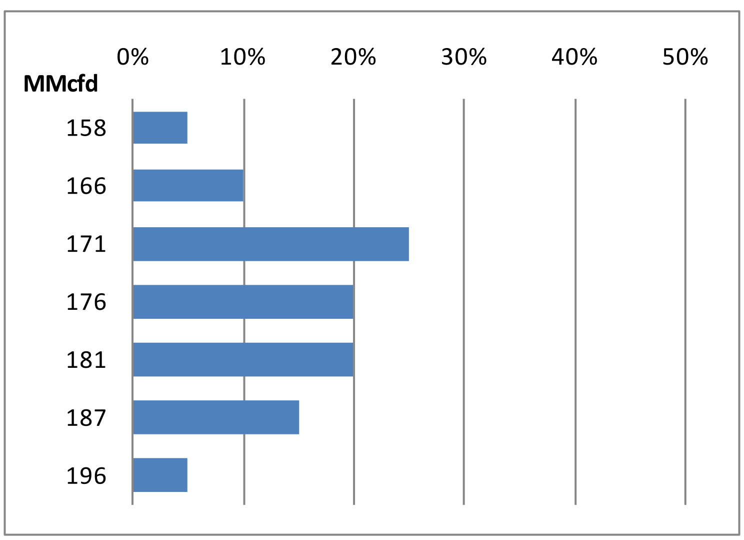
Figure 12 and Figure 13 provide a different perspective (probabilistic analysis) on the estimated demand for residential and commercial sector in the state for the Alberta Line during the two time periods. Both figures show the percent probability that demand will fall within one of the demand categories shown on the vertical axis. The most likely outcome in Figure 12 is about 123 MMcfd (which is the sum of demand shown in Table 4 and Table 5) while there is a 30 percent chance that demand could exceed that estimate. The results of the probability analysis for the Valdez Line are very similar; hence, are not shown below.

Figure 12. Chances of Residential and Commercial Sector Demand, Alberta Line, Year 1 to 5



Source: Northern Economics, Inc., 2009.

Figure 13. Chances of Residential and Commercial Sector Demand, Alberta Route, Year 10 to 15



Source: Northern Economics, Inc., 2009

5 Potential Power Sector Demand for Natural Gas

5.1 Current Demand Estimates

This assessment is limited to the interconnected portion of the electric power grid called the Railbelt, encompassing Fairbanks, the Denali Borough, the greater Anchorage area (including the Matanuska-Susitna Borough) and the Kenai Peninsula. The Alaska Energy Policy Task Force Report defined the Railbelt as: "the power-sharing area between Interior Alaska, from Fairbanks, and Southcentral, to Homer, connected by roads, generating facilities and transmission lines, which include the Alaska Intertie and the Bradley Lake Hydro Project." (Alaska Energy Policy Task Force, 2004). The interconnected electric system for Southcentral Alaska (the Railbelt System) consists of six electric utilities in Fairbanks, the greater Anchorage area and the Kenai Peninsula. Table 6 lists the main generation areas and the corresponding electric utilities. Detailed background information for each utility is provided in Appendix C, Section 2.

Table 6. Generation Areas and Utilities in the Railbelt System

Generation Area	Utilities
Greater Anchorage	Municipal Light & Power (ML&P)
	Chugach Electric Association (CEA)
	Matanuska Electric Association (MEA)
Kenai	Seward Electric System (SES)
	Homer Electric Association (HEA)
Fairbanks-Healy	Golden Valley Electric Association (GVEA)

The current assessment of the Railbelt power sector builds upon a previous 2008 study sponsored by the Alaska Energy Authority (AEA). The study, performed by Black and Veatch, evaluated the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA), whose purpose is to manage and dispatch electric power on the Railbelt grid (Black and Veatch, 2008). In order to evaluate the value of REGA, detailed capacity and dispatch modeling of the region's existing electric power system was performed, with the model making economic decisions to select those technology and fuel options that minimize long-term costs for customers. This analysis was based upon the following:

- Application of a power cost model to perform a least-cost resource systems optimization to develop optimal portfolios of resources for each of four alternative scenarios.
- Cost and performance characteristics of the region's existing generation and transmission assets, as described in Appendix C, Section 2.
- Cost and performance characteristics of various resources that could be added to the region's resource portfolio, as briefly described in Appendix C, Section 3.

To maintain consistency, the current study did not perform independent utility systems modeling, but builds upon the outcomes of the REGA Study utility capacity and dispatch modeling results. The REGA outcomes were adjusted based on new information gathered for this project (see Appendix C, Section 3.5)

This study estimates that the current total Railbelt installed capacity is 1,246 MW based on the B&V study data and updated utility information provided through key informant interviews (see Table 7).

Table 7. Railbelt Installed Capacity (MW)

Utility	Thermal Plants: Existing Capacity	Hydroelectric Plant Capacity			Total
		Bradley Lake	Eklutna Lake	Cooper Lake	
MEA	0	12.4	6.7	0	19.1
HEA	39	10.8	0	0	49.8
CEA	504	27.4	12	20	563.4
GVEA	275	15.2	0	0	290.2
ML&P	278	23.3	21.3	0	322.6
SES	0	0.9	0	0	0.9
Total	**1,096**	**90**	**40**	**20**	**1,246**

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study- Final Report," September 12, 2008 and SAIC.

The current Railbelt utility electricity supply to satisfy demand is listed in Table 8, as well as the electricity supplied by natural gas-based generators. As shown, 79 percent of current generation is supplied by natural gas.

Table 8. Current Aggregate Railbelt Utility Electricity Supply to Satisfy Demand

Total Railbelt Electricity Supply (MW-Hours)	Total Railbelt Electricity Supply From Natural Gas (MW-Hours)	Total Railbelt Electricity Supply From Natural Gas (%)
5,246,000	4,120,000	79

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

Table 9 provides the current associated aggregate Railbelt power sector natural gas consumption data. While the table indicates that the Fairbanks region does not consume natural gas, there is an intertie between the utilities in the southern portion of the Railbelt and Golden Valley Electric that is generally used to transmit electricity from the natural gas-fired plants in Southcentral Alaska to GVEA since the gas-fired electricity is less expensive than the fuels available to GVEA.

Table 9. Current Aggregate Railbelt Utility Natural Gas Consumption

Total Railbelt Natural Gas Consumption (BBtu/Year)	Total Railbelt Natural Gas Consumption (Bcf/Year)	Total Railbelt Natural Gas Consumption - Fairbanks Region (Bcf/Year)	Total Railbelt Natural Gas Consumption - South-Central Region (Bcf/Year)
42,255	41.67	0	41.67

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

5.2 Future Demand Estimates

Based on the AEA/B&V study methodology, future natural gas consumption estimates have been developed for four "Evaluation Scenarios" that are considered alternative energy futures for the Railbelt region. These are defined as follows:

- **Natural Gas Scenario:** Assumes that all of the future generation resources will be natural gas-fired facilities, continuing the region's dependence upon natural gas.
- **Mixed Resource Portfolio Scenario:** Assumes that a combination of large hydroelectric, renewables, demand side management (DSM)/energy efficiency programs, coal, and natural gas resources is added over the next 30 years to meet the future needs of the region.
- **Large Hydro/ Renewables/ DSM/ Energy Efficiency Scenario:** Assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and DSM and energy efficiency programs.
- **Coal Scenario:** Assumes the addition of coal plants to meet the future needs of the region.

Discussions were held with James Strandberg of AEA and Kevin Harper, the B&V project manager for the Regional Integrated Resource Plan (RIRP) study, the follow-on study to the REGA study, to assess the probability of occurrence of these scenarios. Table 10 presents the consensus from them regarding the probability of each scenario in the two subject timeframes. The probability of the natural gas scenario is higher in the Year 1 to 5 than the Year 10 to 15 timeframe because gas is considered a "bridge fuel" until other alternatives can be brought onboard.

Table 10. Assumed Probabilities of Occurrence for Alternative Energy Scenarios

	Future Timeframes	
	Year 1 to 5	Year 10 to 15
Scenario	(%)	
Natural Gas	45	20
Mixed	25	60
Large hydro	20	15
Coal	10	5

Source: James Strandberg of AEA and Kevin Harper, the B&V project manager for the RIRP study

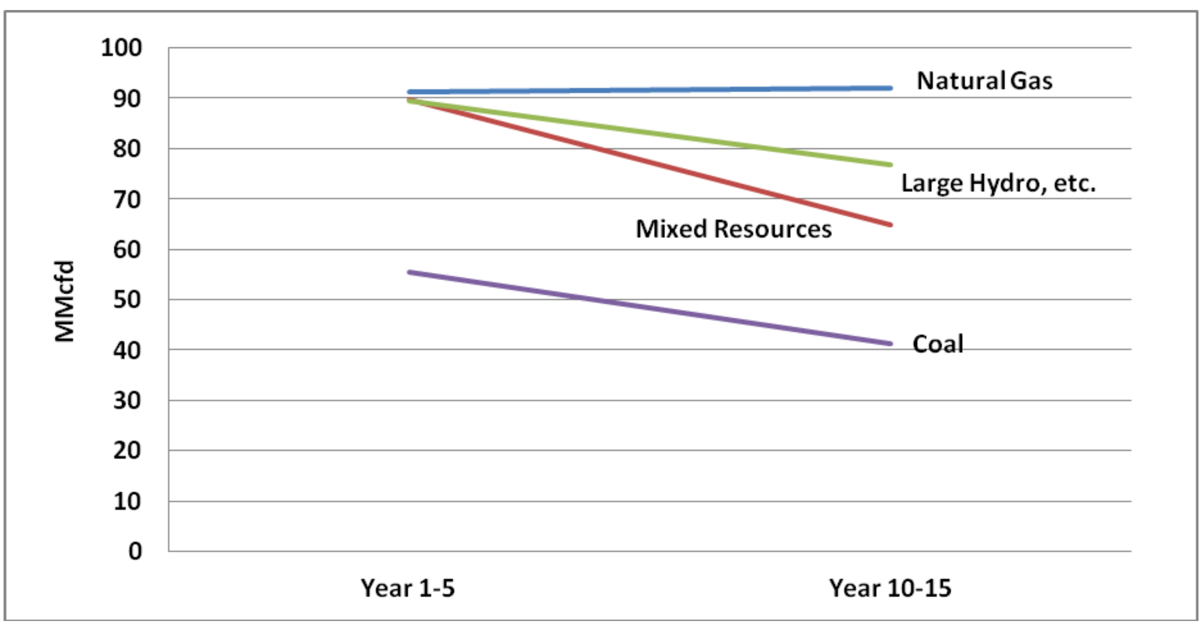
Table 11 provides the projection of average daily future natural gas demand in the two future timeframes for the Fairbanks area and the Southcentral area of the Railbelt and the total Railbelt power sector under these four scenarios. Figure 14 and Figure 15 display the projected change in total power sector natural gas demand used in these scenarios for the two pipeline projects, respectively. It should be noted that AEA and B&V have completed a Regional Integrated Resource Plan (RIRP) as follow-on to the REGA study (on which the current study is based). Scenarios are defined differently in REGA and RIRP; hence, demand estimates in RIRP and in the current study will differ.

Table 11. Projected Future Natural Gas Demand for the Railbelt Electric Power Utilities in MMcfd

Geographic Location	Year 1 to 5	Year 10 to 15
Large Hydro / Renewables / DSM / Energy Efficiency Scenario		
Northern Railbelt (Fairbanks, North Pole)	19.7	26.0
Southern Railbelt (Southcentral)	76.7	57.2
Total:	**96.5**	**82.8**
Natural Gas Scenario		
Northern Railbelt (Fairbanks, North Pole)	22.2	29.0
Southern Railbelt (Southcentral)	76.3	70.3
Total:	**98.5**	**99.3**
Coal Scenario		
Northern Railbelt (Fairbanks, North Pole)	12.8	15.8
Southern Railbelt (Southcentral)	47.2	28.8
Total:	**60.0**	**44.6**
Mixed Resource Scenario		
Northern Railbelt (Fairbanks, North Pole)	19.2	14.7
Southern Railbelt (Southcentral)	77.6	55.4
Total:	**96.8**	**70.1**

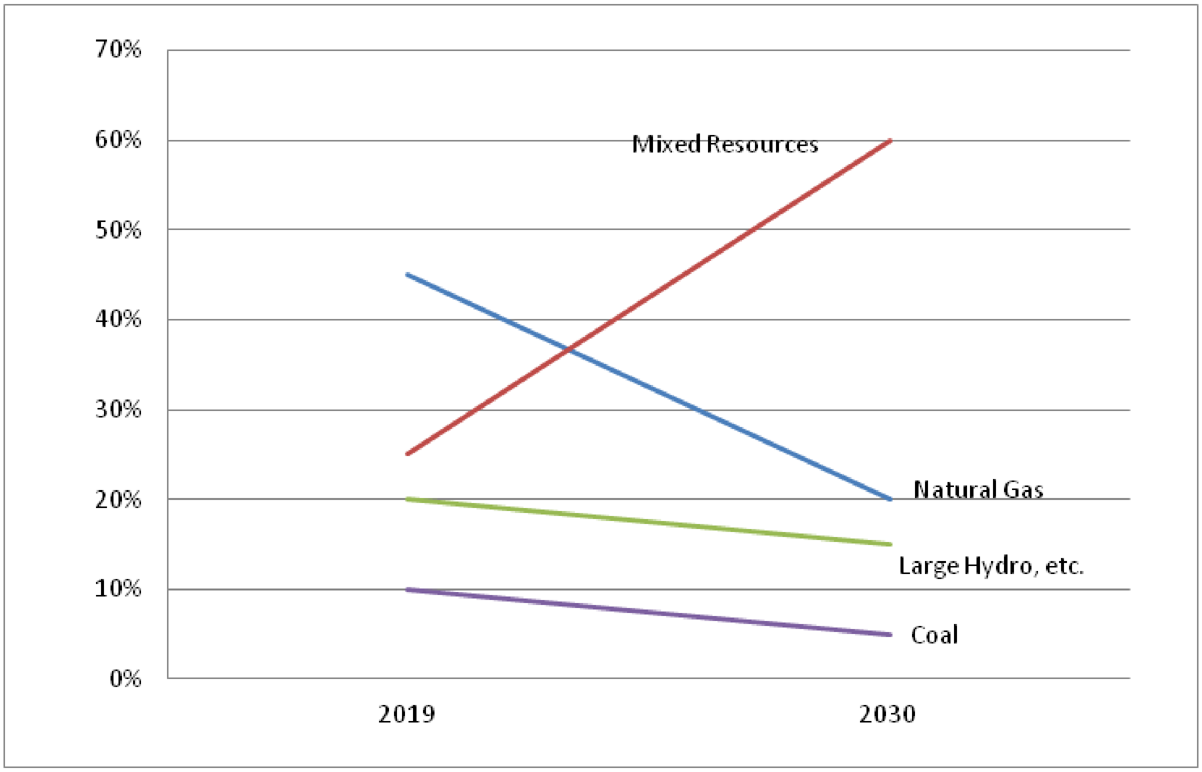
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study- Final Report," September 12, 2008 and SAIC.

Figure 14. Change in Total Power Sector Natural Gas Demand under Four Scenarios in MMcfd



Source: SAIC, Inc., 2009.

Figure 15. Change in Percent Chance of Occurrence for Power Sector Scenarios



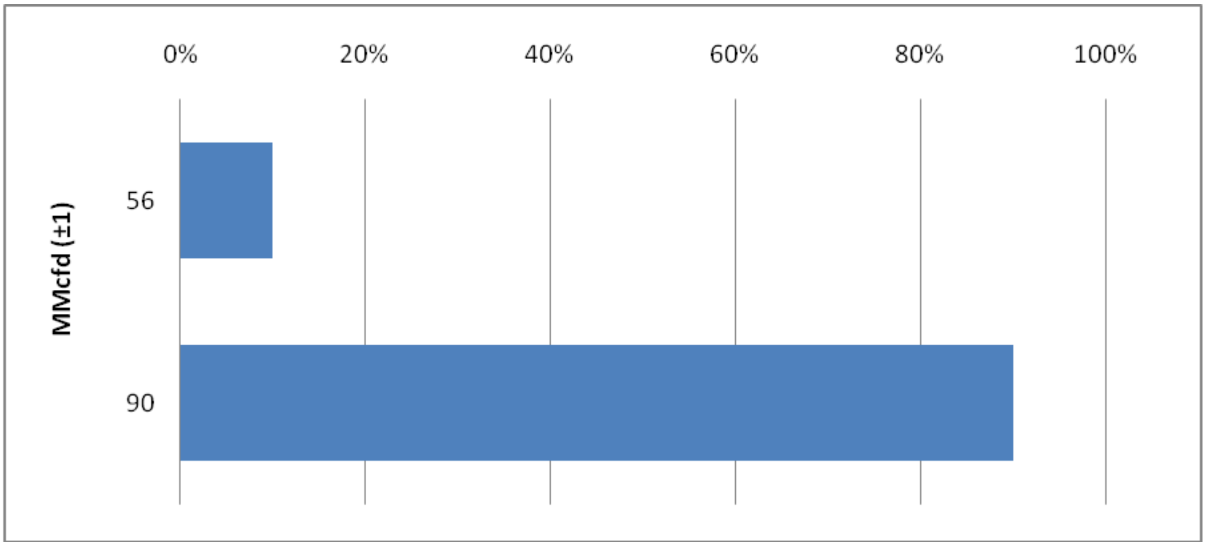
Source: SAIC, Inc., 2009.

As seen Figure 14, the highest natural gas demand occurs under the natural gas scenario, while lowest demand occurs under the coal scenario. For all scenarios other than the natural gas scenario, the shift in power sector energy sources continues over time, thus differences between the scenarios are greater in 2030 than in 2019.

For the probabilistic analysis of natural gas demand from the Railbelt power sector, natural gas demand from each sub-region was modeled as a discrete distribution of demand as reported in Table 11, with the associated probabilities as reported in Table 10. This allows the range of possible Railbelt power demand to be reflected in overall demand estimates. Figure 15 shows the percent chance of the different power sector scenarios over time.

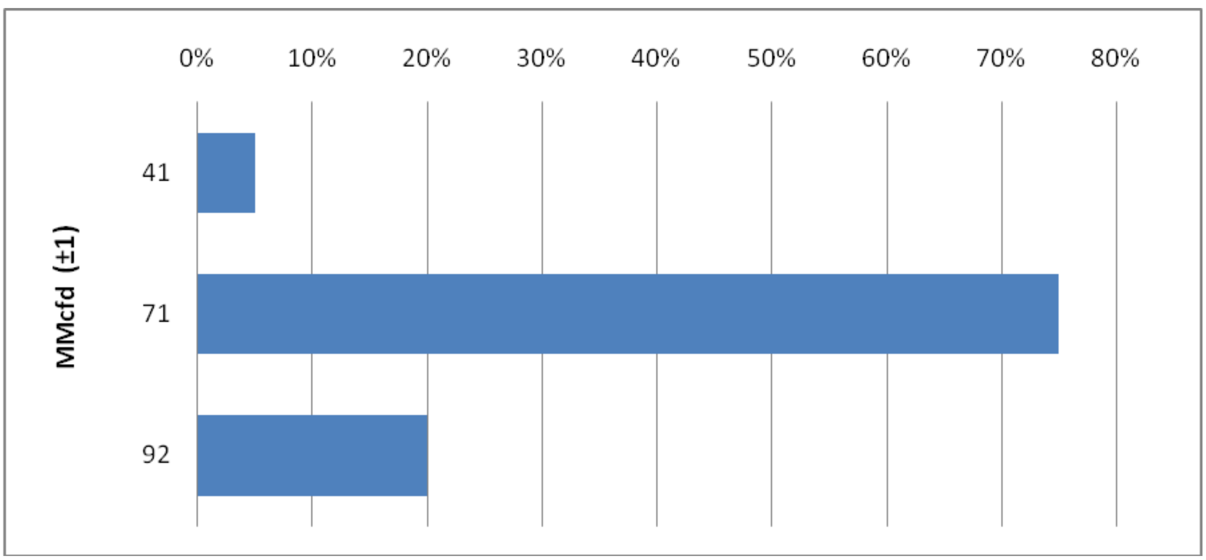
Figure 16 and Figure 17 show the chance of occurrence that demand will approximate the volumes shown on the vertical axis. For example, in the first five years of operation, there is about a 90 percent chance that demand will be about 90 MMcfd, and a 10 percent chance that demand will be about 56 MMcfd. In the later years of the project power demand would have about a 70 percent chance of requiring 71 MMcfd and a 20 percent chance of requiring 92 MMcfd. The reduction is due to the anticipated transition from a large reliance on natural gas as the primary fuel for electric power generation to a more balanced portfolio of generation fuels.

Figure 16. Chances of Power Demand, Year 1 to 5



Source: SAIC, Inc., 2009.

Figure 17. Chances of Power Demand, Year 10 to 15



Source: SAIC, Inc., 2009.

6 Potential Industrial Sector Demand for Natural Gas

Industrial demand comprises two basic types of gas use: use as a fuel for heating and electricity, and use as a feedstock to create products. Natural gas is just one of several alternatives that can meet industrial fuel needs. In contrast, feedstock demand for natural gas can often be met only with natural gas. Furthermore, industries that use natural gas for feedstock typically need much larger amounts of gas than industries with only fuel needs, and thus are referred to as gas-intensive industries. Gas-intensive industries provide anchor customers for a gas pipeline because their continuous need for large volumes of gas enables them to sign long-term contracts for large deliveries. These contracts provide financial stability for gas pipeline owners, and allow other gas customers to benefit from the economies of scale that may be achieved with the construction of a larger pipeline.

The large amount of gas needed by gas-intensive industries typically causes them to be very sensitive to gas price in order for their products to compete on the world market. Alaska's ability to attract and maintain gas-intensive industries largely depends on the ability to provide long-term gas supply agreements that are indexed to relatively low gas prices.

In recent years, there has been a decline in Alaskan gas-intensive industries along with declines in Cook Inlet gas production. However, historically, gas-intensive industrial demand for natural gas has exceeded the combined demand of all other sectors in Alaska (i.e., power, residential, commercial, and other industrial). Hence, the future demand for natural gas in the state of Alaska is substantially affected by the future of Alaskan gas-intensive industries.

The following sections address current Alaskan industrial demand for natural gas, and possible future demand based on the ability of North Slope gas to provide an economically feasible source of natural gas for gas-intensive industries.

6.1 Current Demand Estimates

There is currently only one operating source of gas-intensive industry demand in Alaska—the ConocoPhillips/Marathon LNG terminal, located in Nikiski on the Kenai Peninsula (Southern Railbelt). When not under curtailment, the LNG terminal consumes up to 230 MMcfd. Under the current export license for this facility (i.e., from April 1, 2009 to March 31, 2011), it is limited to about 49 Bcf/year (Petroleum News, June 8, 2008), which is equivalent to an annual average of 134 MMcfd.

Consumption of natural gas by other industries that are not gas-intensive also currently occurs only in the Southern Railbelt region. This demand is from the Tesoro Refinery located in Nikiski on the Kenai Peninsula. Tesoro processes crude oil from the Kenai Peninsula and Cook Inlet oil fields, and supplements it with purchases from the North Slope (via Valdez) and imported crude. The Tesoro refinery has a rated crude oil capacity of 72,000 barrels per day (bpd), and on average, operates at roughly 65,000 bpd. The refinery's maximum natural gas demand is 18 MMcfd, with typical consumption rates of 11 MMcfd (Hansen et al., 2005).

6.2 Future Demand Estimates

Future industrial demand for natural gas will be substantially determined by whether or not the price of gas in Alaska results in economic feasibility for gas-intensive industries. Given the 2011 expiration of the export license for the LNG terminal and uncertainty in license renewal, there is currently no highly likely gas-intensive industrial demand in Alaska for the first 15 years of pipeline operation. While further development of Cook Inlet fields may provide natural gas to meet future industrial demand, for the purposes of this analysis, gas prices are based on the assumption that essentially all industrial natural gas demand will be met by North Slope gas transported through the TransCanada Alaska pipeline and a spur line with Cook Inlet production meeting electric and gas utility demand.

Growth in natural gas demand for the residential and commercial sectors generally occurs with the addition of many small increments. In contrast, growth in demand from gas-intensive industries generally occurs in substantial steps because these industries typically need to operate at near-full capacity to be economically viable. Thus, projections of large industrial demand are developed through the analysis of several potential gas-intensive industrial projects.

Potential gas-intensive industries were assessed with a net present value (NPV) analysis. This analysis incorporates feedstock and product prices, capital expenses, operational and maintenance (O&M) cost, salvage price, and the time value of money. Appendix F provides more detail regarding the industrial product price forecasts used in the analysis.

The following assumptions were used in the NPV analyses:

- 20-year project-life
- after-tax discount rate of 15 percent
- Federal tax rate of 35 percent
- State tax rate of 4.5 percent

Projects with favorable economics have an NPV that is equal to or higher than zero—these are the projects that are more likely to be developed. Use of NPV to determine the likelihood of project implementation is a significant simplification for the purposes of this study. It should be recognized that final investment decisions are based on many other factors that are not included in an NPV analysis, such as corporate strategic planning; geopolitical distribution of assets; local development incentives and acceptance; risk, profit, and other criteria compared to other investment options, etc.

The natural gas price forecast was developed with the National Energy Modeling System (NEMS), using inputs similar to those used by the EIA in the Annual Energy Outlook, adjusted to reflect commencement of pipeline operations in 2019. Further details of the natural gas price forecasts applied in this report are available in Appendix E.

The probability distributions for capital expenses, feed prices, and product prices were modeled as distributions characterized by the estimated most-likely value, and lowest and highest expected values. Feed and product prices were correlated, with correlation coefficients determined from their historical relationships.

Each project-specific analysis resulted in a series of NPV values representing NPV results under the various possible capital costs, and feed and product prices. The proportion of the simulations that result in a positive NPV corresponds to the chances of the project being economically feasible, and hence being developed with the associated natural gas demand.

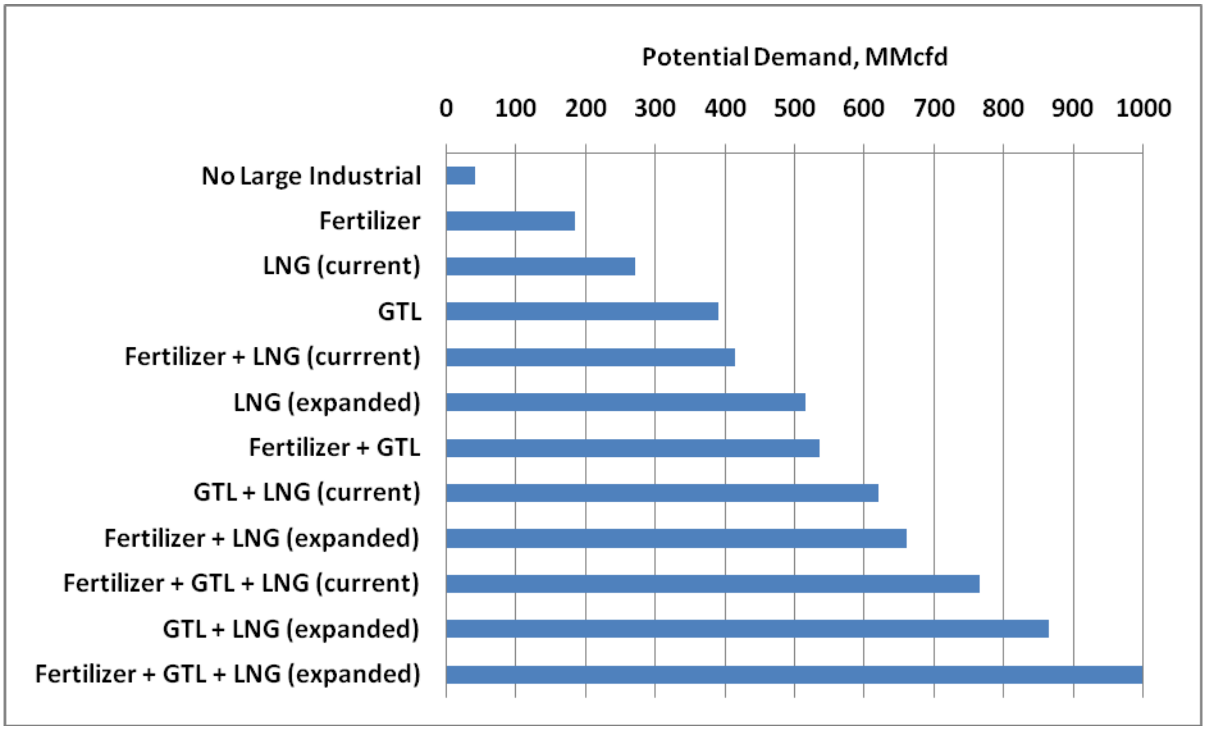
The example projects analyzed and their associated natural gas demand are as follows:

- Continuation of the Nikiski LNG export terminal operating at the current capacity, with a demand for 230 MMcfd.
- Expansion of the Nikiski LNG export terminal operating at roughly twice the current capacity, with a demand for 475 MMcfd.
- Re-start of the Agrium fertilizer plant operating at the historic capacity, with a demand of approximately 145 MMcfd.

- Greenfield development of a Gas-to-Liquids (GTL) complex with a capacity of 38,000 bpd, representing a demand of approximately 350 MMcfd.

Demand for all of the possible combinations of modeled industrial projects is shown in Figure 18.

Figure 18. Natural Gas Demand from All Possible Combinations of Modeled Large Industrial Projects



Source: SAIC, Inc., 2009

The focus of this analysis is on dry gas; hence, potential gas-intensive industry demand for natural gas liquids (i.e., ethane, butane, propane) was only assessed at a cursory level. Under the Alberta pipeline scenario, assuming industry development near a port (i.e., Anchorage) for easy access to world markets, the amount of NGLs in a 1,000 MMcfd spur line would be insufficient for a world-class petrochemical complex. In particular, new petrochemical complexes typically require at least 75,000 bpd ethane, and a 1,000 MMcfd spur line carrying gas with a composition as in the "Rich Gas Case" composition (as published in the AGIA Request for Applications) could only provide about 42,000 bpd.[7] However, under the Valdez pipeline scenario, 3,000 MMcfd of North Slope gas would be transported to Valdez. This would contain a sufficient volume of ethane to support a world-class petrochemical complex under the "Lean Gas Case" (as published in the AGIA Request for Applications).

[7] A recent white paper commissioned by the Anchorage Economic Development Corporation and ANGDA and conducted by Chemical Market Associates, Inc. (CMAI, 2009) indicates that Alaska could offer an opportunity for Pacific Rim chemical companies to diversify their sources of supply and develop new facilities in Cook Inlet that would use feedstock from the North Slope of Alaska. A straddle plant on the main pipeline could extract liquids for an enriched gas stream in the spur line, providing sufficient natural gas liquids (NGLs) for an Alaskan petrochemical complex. NGL demand from new projects would likely have to compete with currently operational NGL demand sites in Alberta with expected surplus capacity.

Each of the example gas-intensive industrial projects that use dry gas (i.e., fertilizer, LNG, and GTL) are further described in the sections below, followed by projected demand for other industries that are not considered as gas-intensive industries, and discussion of the total estimated demand for the industrial sector.

6.2.1 Fertilizer

Agrium U.S., Inc. has a world class ammonia and urea production facility in Nikiski on the Kenai Peninsula in the Southern Railbelt region. At full capacity, the plant produces 1.25 million gross tonnes of anhydrous ammonia and 1 million tonnes of urea annually, which it has previously sold to world markets and domestic customers. In 2007, increases in natural gas prices associated with reduced natural gas production caused Agrium to curtail its Kenai operations. Production ceased altogether in late 2007 (Petroleum News, January 20, 2008 and March 8, 2009). Agrium is reportedly seeking buyers for the Nikiski plant, and concurrently continuing efforts to identify future feedstock sources.

The Agrium Kenai plant is not in operation at this time. The company has removed all chemicals and catalysts, removed exchanger bundles, and undertaken other closure activities. Assuming the plant is not dismantled, the facility would require refurbishments prior to operation in 2019. These refurbishments are to eliminate the need for additional major capital improvements/expenditures during the 20-year operating life. Capital costs for refurbishment are based on the 2006 study prepared for the National Energy Technology Laboratory, *Alaska Natural Gas Needs and Market Assessment* (RDS LLC, 2006), adjusted to mid-$2009. The adjusted estimate of $257 million was modeled as the "most-likely" capital costs, with low costs estimated as 38 percent less, and high costs estimated as 75 percent more.

The price forecast for ammonia is based on the historical relationship of ammonia prices to natural gas. The correlation between these prices was modeled as 0.9, based on historical correlations of annual average prices. The price forecast for natural gas was developed as described above (Section 2.2).

Table 12 summarizes key assumptions and results of the probabilistic NPV analysis of a resumption of operations at the Agrium fertilizer production facility.

Table 12. Fertilizer Industrial Analysis: Assumptions and Results

Static Assumptions			
Capacity	1.25 MMTPA Ammonia 1.16 MMTPA Urea		
Natural Gas Demand, MMcfd	145		
Annual O&M *(excluding gas)*	$69 million		
Probability Distribution Parameters			
	Low	**Mid**	**High**
Capital, $ millions *(Depreciable cost basis)*	$160	$257	$450
Alberta Pipeline, Gas Price, $/Mcf	$5.11	$7.57	$10.46
Valdez Pipeline, Gas Price, $/Mcf	$7.66	$8.71	$10.05
Ammonia, $/MT	$320	$370	$417
Results: Probability NPV ≥ 0			
Alberta Pipeline		0.22	
Valdez Pipeline		<0.01	

Source: SAIC, Inc., 2009
Note: MMTPA is million metric tons per annum.

As shown in Table 12, low, mid, and high estimates were applied for capital costs, gas prices under both pipeline scenarios, and ammonia prices on the global market. Net present value was calculated for the given size of the fertilizer plant, and the cost and price ranges shown. Under the Alberta pipeline scenario, the NPV exceeded zero 22 percent of the time, indicating a probability of 0.22 that this project will be economically feasible. Under the Valdez pipeline scenario, higher gas prices reduced the probability of economic feasibility to less than 0.01 (i.e., less than a one percent chance that this project will be realized).

6.2.1.1 LNG

This analysis models LNG scenarios for projects in Nikiski, which may occur with the main pipeline terminating in either Alberta or Valdez. Under the Valdez pipeline scenario, it is assumed that the proposed Valdez LNG facility will reserve pipeline capacity prior to any decision to terminate the main pipeline in Valdez. Hence, the feasibility of an LNG terminal in Valdez will have already been favorably assessed by the project investors.

Nikiski currently has one operating LNG liquefaction terminal, with capacity of 1.5 MMTPA. This represents a 230 MMcfd demand for natural gas, including gas consumed in processing. The Nikiski terminal is 40 years old, and is relatively small by contemporary standards. Many new world class LNG facilities have capacities of 730 MMcfd to 3.0 Bcfd (5 to 20 MMTPA).

The Nikiski LNG terminal is operated by ConocoPhillips, which has 70 percent ownership. Marathon has the remaining 30 percent interest, and is responsible for operation of the specialized LNG carriers that transport the LNG to Japan. Until the recent curtailment of the LNG terminal operations, there were two specialized LNG carriers with reinforced hulls for navigation in ice-covered waters. The carriers both had capacities of 88,000 cubic meters—a mid-size carrier, but the maximum size that can currently be accommodated at the Nikiski terminal. One of these carriers has since been sold.

Capital costs for the two LNG scenarios considered in this analysis are based on the 2006 ANGDA report conducted by Stone & Webster titled, *Commercial Future of the Kenai LNG Plant*. It was concluded in the 2006 ANDGA report that the remaining useful life of the Kenai plant was on the order of 6 years without significant investment to modernize key elements, specifically, replacement of the aging combustion turbines. Hence, plant operation much beyond the 2011 export license expiration will require significant capital investment.

In addition to continued operation of the current LNG capacity, the ANDGA report also includes estimates for an expansion of the facility to 3.0 MMTPA. This includes new pre-treatment and liquefaction systems, a full-containment LNG storage tank to meet current standards, and expansion of utility and support facilities. All costs taken from the 2006 ANDGA report were adjusted to mid-$2009. The adjusted capital cost estimates of $355 million and $1.85 billion for current and expanded capacity, respectively, were modeled as the "most-likely" capital costs, with low costs estimated as 38 percent less, and high costs estimated as 75 percent more.

For this analysis, it is assumed that LNG will be sold in the Japanese market. Japanese and Korean LNG prices are typically higher than those in the United States and Europe. The differentials are due to the formulae for calculating the LNG price: in the U.S. and Europe, the LNG price is typically linked to the pre-burner price of alternative fuels (heating oil, heavy fuel oil, coal, etc.) while in Japan and Korea, LNG prices are typically linked to the price of crude oil. East Asian buyers also pay higher rates due to an "Asian Premium," which is attributed to the lack of indigenous sources of natural gas supply and the security-conscious, long-term nature of most East Asian energy contracts. In energy equivalent terms, the Asian Premium on LNG has been found to be greater than the Asian Premium on crude oil. While analysts speculate that the magnitude of the difference in Asian LNG prices compared to the rest of the world will not be sustained indefinitely, there are no clear trends indicating near or mid-term changes in the status quo. Indeed, recent 20-year LNG contract values suggest at least some LNG sold to Asia will maintain the recent Asian Premium through 2029. Thus, the current pricing formulae are assumed in this analysis for long term (e.g., 20-year) contracts that would be negotiated within the next decade.

The exact pricing formulae in LNG contracts are rarely disclosed, but it is widely known that current Japanese and Korean long term LNG contracts are linked to the "Japanese Crude Cocktail" (JCC) price, which is a weighted-average of all crude import prices reported by the Japanese Customs office. Hence, the LNG product prices used in this analysis are based on the historical relationship of Japanese LNG prices to the JCC, and the JCC historical relationship to the price of crude oil in the U.S. The modeled correlation between LNG product prices and natural gas is 0.8, based on historical correlations of annual average prices.

The price forecast for natural gas feed for the LNG terminal was developed as described above (Section 2.2). Table 13, below, summarizes key assumptions and results of the probabilistic NPV analysis for continued operation of the Nikiski LNG terminal at both current capacity, and with expansion to double the current capacity.

Table 13. LNG Industrial Analysis: Assumptions and Results

	LNG Current Capacity			LNG Expanded		
Static Assumptions						
Capacity		1.5 MMTPA			3.0 MMTPA	
Natural Gas Demand, MMcfd		230			475	
Annual O&M *(excluding gas)*		$86 million			$222 million	
Probability Distribution Parameters						
	Low	**Mid**	**High**	**Low**	**Mid**	**High**
Capital, $ millions *(Depreciable cost basis)*	$286	$461	$806	$1,590	$2,565	$4,489
Alberta Pipeline, Gas Price, $/Mcf	$5.11	$7.57	$10.46	$5.11	$7.57	$10.46
Valdez Pipeline, Gas Price, $/Mcf	$7.66	$8.71	$10.05	$7.66	$8.71	$10.05
LNG (cif), $/MMBtu	$6.78	$12.06	$17.70	$6.78	$12.06	$17.70
Results: Probability NPV ≥ 0						
Alberta Pipeline		0.63			0.15	
Valdez Pipeline		0.39			0.09	

Source: SAIC, Inc., 2009.

As shown in Table 13, low, mid, and high estimates were applied for capital costs, gas prices under both pipeline scenarios, and LNG prices on the Asian market. Net present value was calculated for the given sizes of the LNG terminals, and the cost and price ranges shown. Under the Alberta pipeline project, the NPV exceeded zero 63 percent of the time, indicating a probability of 0.63 that this project will be economically feasible. Under the Valdez pipeline project, higher gas prices reduced the probability of economic feasibility to 0.39 (i.e., a 39 percent chance of project realization).

6.2.1.2 GTL

The conversion of natural gas to liquid (GTL) represents another way to monetize stranded natural gas, and for Alaskans, it could also represent an alternative source of liquid fuels. GTL technology uses the Fisher Tropsch (F-T) process to convert natural gas to longer chain, liquid hydrocarbons. The advantage of GTL-produced liquid fuels is that they are substantially cheaper to store and transport than gaseous fuels, and they contain virtually no sulfur, nitrogen, or metals, and thus burn cleanly.

Capital cost estimates for an Alaskan GTL complex are based on a review of past and expected future costs. While each of the several processes incorporated in the GTL process have been applied for decades independent of the GTL process, the best technical way to combine these processes and optimize each sub-process for the purposes of the overall GTL process is far from mature. New technological developments are in demonstration phases for several key GTL sub-processes, offering potential for substantial reductions in cost. Until greater technological maturity is achieved, GTL capital costs will likely remain quite variable and difficult to predict, making GTL investments particularly high-risk. However, between the present and the end of the timeframe considered in this analysis, i.e., beyond 2030, it is reasonable to assume that there will be movement towards a more mature GTL technology.

While there are perhaps a half-dozen GTL projects under consideration across the globe, there are currently only two full-scale operating GTL complexes that have been completed since 1990. These are Bintulu in Malaysia, with a capacity of 14,700 bpd brought on-line in 1993; and Oryx in Qatar, with a capacity of 34,000 bpd brought on-line in 2008. An additional two are under construction (Pearl in Qatar, 140,000 bpd, and Escravos in Nigeria, 33,000 bpd). Reported costs for these facilities are often provided as total project costs, rather than just costs associated with the GTL process. Non-GTL costs for projects such as Shell's Pearl include offshore platforms and gathering lines, which represent a significant portion of the project costs. In contrast, it is assumed that an Alaskan GTL complex would not have significant non-GTL costs because wells, gathering lines, and delivery systems are already in place.

At this time, economies of scale have yet to be realized for GTL; hence, prices are often discussed in terms of $ per billion barrels ($/bbl). Low-end estimates for GTL costs alone begin around $25,000/bbl, and are comparable to costs realized for the Oryx complex. High-end costs are in the range of $100,000/bbl and more, such as those reported for the Pearl complex, which has seen construction delays, and is currently scheduled for operation in 2012. While not specified in media reports, the high-end Pearl costs are suspected to include non-GTL, gas production costs. For the purposes of this analysis of a potential Alaskan GTL project, a mid-cost was estimated as $35,000/bbl and adjusted to Alaskan prices by a multiplier of 1.5 for construction in the Southern Railbelt, yielding $53,000/bbl. For construction in Valdez, a multiplier of 1.8 was used to compensate for the expected additional construction costs associated with the relatively small amount of available flat terrain in this area, yielding $63,000/bbl. Low and high costs were estimated as 38 percent less and 75 percent more. This cost range does not incorporate reasonably likely significant technological advances over the next 10 to 15 years, which may provide capital cost reductions in excess of 25 percent (Carolan et. al., 2002).

The modeled GTL complex was sized similarly to the recently completed Oryx GTL complex in Qatar. While a GTL complex could be constructed at North Slope, avoiding gas pipeline tariffs, it is assumed that the cost of pipeline gas transport to a port (for export), is lower than the cost of trucking liquid products to port.[8] Hence under the mainline to Alberta scenario, the GTL complex is assumed to be located in the Southern Railbelt. Under the mainline to Valdez scenario, it is located in Valdez, because over the life of the project, avoidance of the tariff associated with a spur line provides greater savings than the higher capital costs associated with construction in Valdez.

Transportation diesel fuel prices were forecast along with the Lower 48 natural gas prices developed with NEMS. An Asian premium was added based on the lowest annual premium paid in Japan on before-tax transportation diesel compared to Lower 48 before-tax transportation diesel from 1998 to 2008, as reported on the International Energy Association website. The lowest annual premium during this period was $0.11 per gallon, which is equivalent to $4.62 per barrel. The modeled correlation between diesel product prices and natural gas is 0.82, based on historical relationships.

The price forecast for natural gas feed for the GTL complex was developed as described above (Section 2.2). Table 14, below, summarizes key assumptions and results of the probabilistic NPV analysis of a Greenfield GTL complex.

[8] Trucking is assumed as the transport mode in order to avoid contamination of the GTL fuel with crude oil if the GTL were shipped in the TAPS line.

Table 14. GTL Industrial Analysis: Assumptions and Results

Static Assumptions			
Capacity	38,000 Bpd		
Natural Gas Demand, MMcfd	350		
Annual O&M *(excluding gas)*	$154 million		
Probability Distribution Parameters			
	Low	**Mid**	**High**
South Railbelt Capital, $ millions *(Depreciable cost basis)*	$1,701	$2,744	$4,803
Valdez Capital, $ millions *(Depreciable cost basis)*	$1,990	$3,210	$5,618
Alberta Pipeline, Gas Price, $/Mcf	$5.1	$7.57	$10.46
Valdez Pipeline, Gas Price, $/Mcf	$7.53	$7.71	$7.89
Diesel Fuel, $/bbl	$77	$145	$216
Results: Probability NPV ≥ 0			
Alberta Pipeline		0.52	
Valdez Pipeline		0.41	

Source: SAIC, Inc., 2009.

As shown in Table 14, low, mid, and high estimates were applied for capital costs, gas prices under both pipeline scenarios, and diesel prices on the Asian market. Net present value (NPV) was calculated for the given size the GTL complex, and the cost and price ranges shown. Under the Alberta pipeline project, the NPV exceeded zero 52 percent of the time, indicating a probability of 0.52 that this project will be economically feasible. Under the Valdez pipeline project, the range of forecast gas prices (i.e., the difference between low and high price estimates) is reduced because it is assumed that the GTL complex would be built in Valdez to avoid a spur line tariff and the substantial uncertainty associated with this tariff. Overall, the probability of GTL complex economic feasibility is lower under the Valdez pipeline scenario than the Alberta pipeline scenario (i.e., 0.41, representing a 41 percent chance of feasibility).

6.2.2 Other Industry

6.2.2.1 Refining

The future natural gas demand of the Tesoro refinery is assumed to be similar to the current demand of 11 MMcfd (as discussed above, in Section 2.2). Refineries in other regions of the state are expected to switch to use of natural gas to meet their process and space heating needs under pipeline scenarios that are likely to allow development of a gas distribution system in their local area.

Under both Alberta and Valdez pipeline scenarios, refineries in North Pole (Railbelt North) are expected to represent new demand for natural gas. These refineries, Flint Hills and Petro Star, process crude oil from the North Slope, with rated capacities of 220,000 and 12,000 bpd, respectively. Both facilities currently produce heat for their processing needs from crude. These facilities are considered very likely to switch to natural gas as it becomes available, with estimated demands of 12.3 MMcfd and 0.9 MMcfd for Flint Hills and Petro Star, respectively, as reported by the Interior Issues Council (2008), with Flint Hills demand further confirmed (Cook, 2009). This demand is based on the continuation of production at roughly 25 percent facility capacity. Total dry gas demand from refineries in Region 9 (Railbelt North) was projected as 13.2 MMcfd beginning shortly after commencement of pipeline operations.

Under the Valdez pipeline scenario, the Petro Star refinery in Valdez (Valdez-Cordova) is expected to represent new demand for natural gas. This crude oil refinery has a rated capacity of 48,000 bpd. The refinery provides fuel to a cogeneration unit operated by Copper Valley Electric Association (CVEA), which in turn provides heat for Petro Star's distillation tower and electricity for other refinery needs. Under the Valdez pipeline scenario, natural gas for CVEA is anticipated to be less expensive than fuel from the refinery, so CVEA will convert to using natural gas and so will the refinery. The demand from the Petro Star's Valdez refinery is estimated to be 2.6 MMcfd, based on a simplifying assumption of operations similar to the North Pole refineries.

6.2.2.2 Alyeska Terminal and Pump Stations

Under the Valdez pipeline scenario, additional industrial natural gas demand is likely as Alyeska switches its terminal operations in Valdez to natural gas; although Alyeska will need to conduct an economic analysis to confirm this conversion. Based on information from Alyeska (Robertson, 2009), the estimated demand for the terminal is estimated at approximately 2 MMcfd.

In the event that the mainline to Alberta is constructed, none of the Alyeska operations are expected to convert to dry gas, although the marine terminal in Valdez could convert to propane.

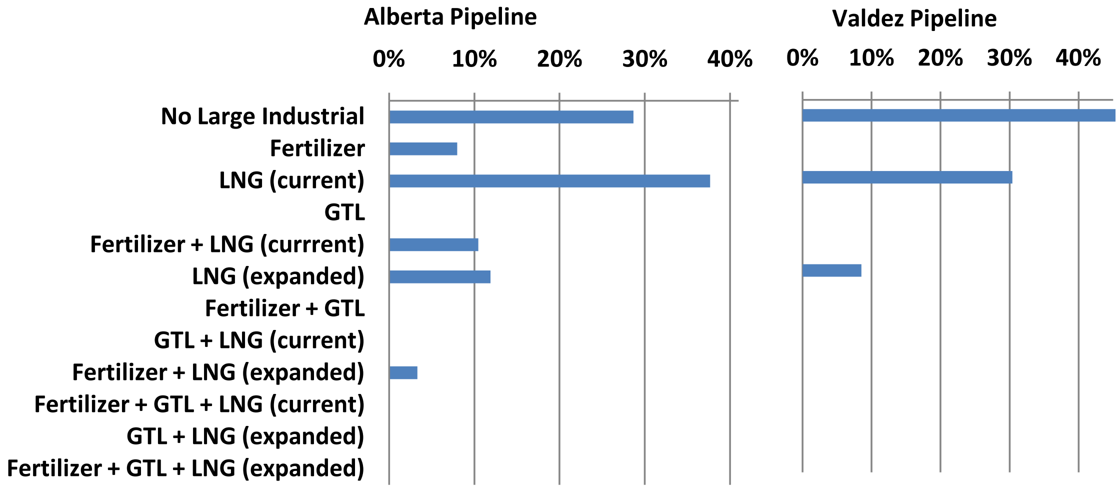
6.2.3 Total Industrial Demand for Natural Gas

Figure 20 shows the chances of large, gas-intensive industrial development based on the probability of economic feasibility (i.e., NPV > 0). For demand projections in this report, it is assumed that Greenfield development will not become operational until after the first several years of pipeline operation. Hence in projecting demand for the first 5 years of pipeline operation, industrial scenarios that include GTL are not considered.

Comparison of the chances of large industrial development for the two pipeline projects suggests that under the Valdez pipeline project, the overall chances of large industrial development (beyond the assumed LNG complex in Valdez) are reduced. This is indicated by the 36 percent chance of "no large industrial" (i.e., top bar) under the Valdez project versus the 14 percent chance of "no large industrial" under the Alberta project.

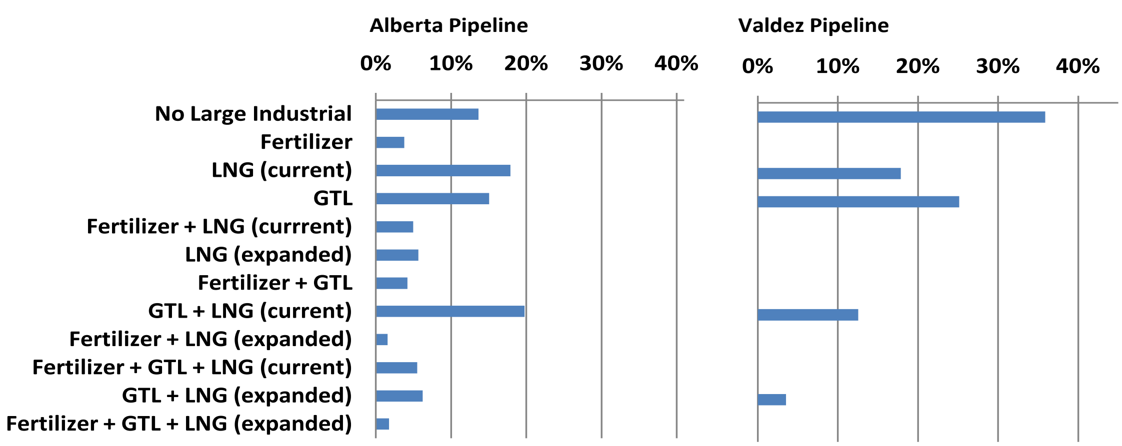
Furthermore, as indicated in Figure 20, the economic feasibility of the assessed fertilizer project (i.e., renovation of the Agrium plant in Nikiski) is relatively unlikely under the Alberta pipeline project, and has virtually no chance of realization under the higher Southern Railbelt gas prices of the Valdez pipeline project. The GTL is the only individual project assessed that has a greater chance of realization under the Valdez pipeline project. This is due to the assumption that under the Valdez pipeline project, GTL would be located in Valdez, thereby avoiding the spur line tariff.

Figure 19. Percent Chance of Development (i.e., NPV > 0) for Assessed Industrial Scenarios, Year 1 to 5



Source: SAIC, Inc., 2009

Figure 20. Percent Chance of Development (i.e., NPV > 0) for Assessed Industrial Scenarios, Year 10 to 15



Source: SAIC, Inc., 2009.

Finally, it should be noted that it is reasonably likely that none of the large gas-intensive industrial projects will be represented in the first open season, simply because these projects require significant investment, and given commencement of pipeline operations in 2019, these investment decisions do not need to be finalized for several more years (with the possible exception of Nikiski LNG terminal refurbishment). Most of the modeled industrial projects are of sufficient size that they could merit a pipeline expansion if and when a positive investment decision is made.

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7 Potential Military Demand for Natural Gas

Military bases in the Northern Railbelt could also potentially increase the demand for natural gas in the future. Doyon Utilities operates the power plant at Fort Wainwright and Fort Greeley. Fort Wainwright uses coal-fired boilers to provide steam for heating to the base, and also to generate electricity. Fort Greeley uses oil to heat the base and to provide standby power to the electricity that is provided by Golden Valley Electric Association. Eielson Air Force Base is also powered by a coal-fired power plant.

It was noted during the stakeholder interview that the military would be interested in converting from their existing coal-fired facilities if an analysis demonstrated that the gas fuel price and the conversion costs would provide a lower cost of energy for the bases. The military would also be interested for environmental reasons, such as reduced carbon emissions.

According to the Interior Issues Council report potential natural gas demand for Eielson Air Force Base and Fort Wainwright is 2,828,448 and 3,013,920 Mcf per year, respectively. This suggests a daily demand of approximately 16 MMcf.

The ENSTAR market study provided an estimate of the potential natural gas demand at Fort Greeley. According to the report, the daily demand would be approximately 0.9 MMcf.

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8 Potential Propane Demand

The proposed gas pipeline from the North Slope to Alberta or Valdez will transport a large quantity of natural gas liquids, including propane. Propane is presently used in most, if not all, Alaska communities. Its primary function at the household level is for cooking, followed by water heating, and, to a lesser extent, space heating.

This section provides information on current consumption of propane and the potential demand if all cooking, heating, and electrical generation needs currently supplied by distillate fuels in that portion of the state not anticipated to be served with natural gas (primarily the Fairbanks area and the ENSTAR service area) converted to propane. It should be noted that the volume of propane available for residential, commercial, power, and industrial consumption in Alaska would be a function of the volume of gas taken off the mainline, or in the case of a propane extraction facility in Cook Inlet, the volume of propane available would be a function of the throughput of the spur line to Southcentral Alaska. This section also describes key elements of a spreadsheet model that compares the cost of propane and distillate fuels in various regions around the state to determine if residents and businesses would convert to propane. The spreadsheet model incorporates a probability analysis to reflect the uncertainty about future prices and costs.

8.1 Current Demand Estimates

In a prior study of propane feasibility, PND (PND, Inc., 2005) estimated that propane demand in Alaska was approximately 15 million gallons per year (approximately 1,000 bpd). About half of this demand was met by production from the Tesoro refinery (500 bpd) and the balance was imported from Canada via barge/rail and truck. Data from the U.S. Energy Information Administration (EIA) for sales or consumption of propane in Alaska is seldom published to avoid disclosure of proprietary information. The last reported sales statistics are for 2005 and 2006, which indicated that approximately 31,000 and 32,000 gallons per day (740 to 760 bpd) were sold in those years. In the mid-1990s, sales were as high as 45,000 gallons per day (Energy Information Administration, 2009). Propane demand has likely increased since the PND estimate due to the higher cost of distillate fuels in comparison to propane, and commencement of operations at the Pogo gold mine which consumes one million gallons of propane each winter (Shaw, 2009).

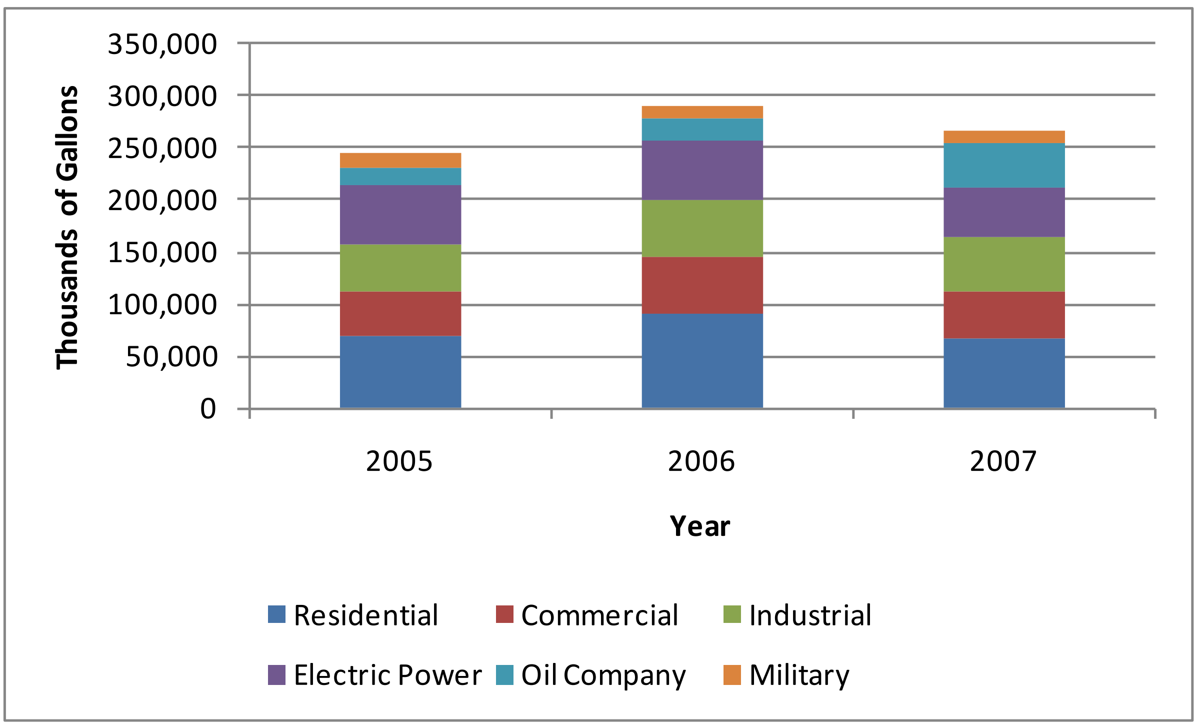
The EIA provides annual estimates of total distillate fuels by end use (Energy Information Administration, 2008). Total distillate consumption has ranged from about 565 million gallons in 2005 to 622 million in 2006 (See Table 15). Propane is not anticipated to replace distillates used in transportation. The potential volumes of distillates used for end uses other than transportation, ranges from about 246 million to 291 million gallons (See Figure 21). A portion of this consumption could be displaced by natural gas when the gas pipeline is operational, and a portion could be displaced by propane that would be extracted from the natural gas stream.

Table 15. Distillate Fuel Oil and Kerosene Sales in Alaska by End Use, 2005-2007 (thousands of gallons)

End Use	Year 2005	Year 2006	Year 2007
Residential	69,253	90,341	66,924
Commercial	42,239	55,447	44,937
Industrial	44,852	53,219	53,605
Electric Power	57,455	56,777	47,477
Oil Company	17,515	21,347	40,742
Military	14,401	13,786	12,390
Subtotal	245,715	290,917	266,075
Transportation	319,069	330,723	335,298
Total	**564,784**	**621,640**	**601,373**

Source: Energy Information Administration, 2008.

Figure 21. Distillate Fuel Oil and Kerosene Sales in Alaska by End Use, 2005-2007



Source: Energy Information Administration, 2008.

8.2 Future Energy Demand

As noted earlier, the Fairbanks area and most of the Cook Inlet region are expected to be served by a piped natural gas distribution system, with Fairbanks served by the main gas pipeline, and Cook Inlet served by a spur line connecting to an expanded ENSTAR distribution network. If the main gas line runs to Valdez, then it is anticipated that the City of Valdez would also be served by a piped natural gas distribution system. The remainder of the state is a potential market for propane extracted from the natural gas stream and trucked or barged to communities. Some communities with sufficient density of development could have piped natural gas distribution networks, but propane transported to the community would be the primary basis for the gas supply.

Future energy demand outside of the Fairbanks and Cook Inlet areas was estimated for residential and commercial, electric power, and industrial sectors. The following paragraphs describe the assumptions and approach used to estimate future energy demand.

8.2.1 Approach

The approach used to estimate the potential demand for propane outside of the areas served by natural gas-based distribution systems includes developing a basic spreadsheet model that estimates potential demand for energy in each region, and compares the projected price of distillate fuels with the anticipated price of propane calculated in the model to evaluate if residents and businesses would convert to using propane. The following subsections provide additional detail on the approach used for the propane-based residential and commercial sector, followed by electric power and industrial sectors.

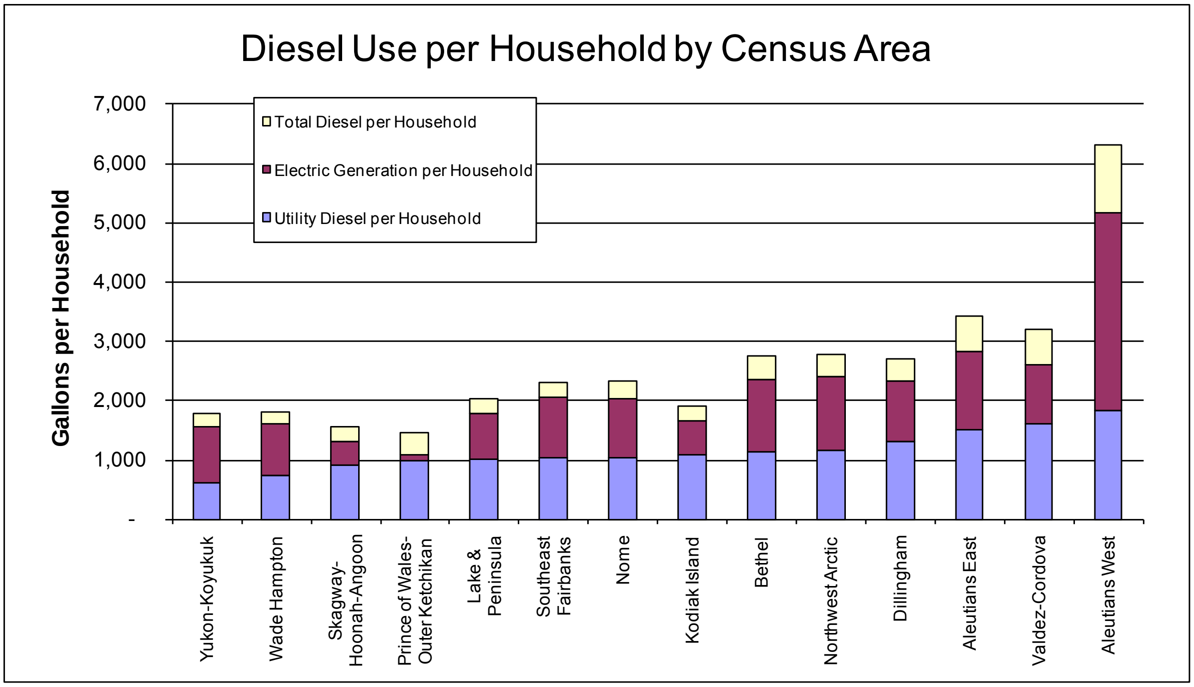
8.2.2 Residential and Commercial Demand

As noted earlier, the primary use of propane currently is for cooking with some used for water heating and a lesser amount for space heating. In contrast, residential and commercial demand for distillate fuel, excluding transportation fuel, is primarily a space heating load with additional consumption for cooking and heating water.

8.2.2.1 Current Energy Demand

ISER conducted a study in 2008 that surveyed fuel use in a number of Alaska communities (Institute of Social and Economic Research, University of Alaska Anchorage, 2008). The results of the survey were then aggregated at the census area level into average fuel use per household for transportation, electric generation, and utility (i.e., heating) fuel (See Figure 22).

Figure 22. Diesel Use per Household by Census Area, 2008



Source: Institute of Social and Economic Research, University of Alaska Anchorage, 2008.

It is anticipated that propane would not displace distillates used as transportation fuels so the estimates for heating and power generation represent the distillate volumes that might be replaced by propane. The estimates for utility diesel (primarily heating fuel) were reviewed and considered to be representative of the demand for heating fuel, given differences in heating degree days, per capita income, and other fuels (e.g., biomass) that could be used for heating among the census areas. Fuel use for community electricity generation was also reviewed and considered to be representative. Industries that generate their own power are modeled separately and included in the industrial demand (See Section 6.2.2). Per household estimates of distillate consumption for each region are presented in Table 16.

Table 16. Estimated Gallons of Distillate Use per Household in 2008

Region	Utility	Electricity	Total
Northwest-Arctic	1,109	1,119	2,228
Yukon – Koyukuk	605	951	1,556
Northern Railbelt	1,033	1,019	2,052
Southeast Fairbanks	1,033	1,019	2,052
Yukon - Kuskokwim	942	1,036	1,977
Southwest	1,270	1,580	2,850
Southern Railbelt	1,353	786	2,139
Valdez-Cordova	1,612	997	2,609
Southeast	947	256	1,202

Source: Calculated by Northern Economics from data contained in ISER, 2008.

Heating fuel consumption has been increasing in Alaska but the higher fuel prices that began in 2007 have resulted in a significant decrease in demand throughout the state, and particularly in those regions with lower household incomes. The crude oil forecast used in this analysis is based on the National Energy System Modeling System used by EIA and assumes increasing prices over time. The crude oil forecast is similar to the April 2009 forecast published by EIA (Energy Information Administration, 2009) with adjustments to account for differences in timing for the main gas pipeline to be in operation and a potential gas pipeline to Valdez. Higher prices have resulted in energy conservation and efforts to increase energy efficiency in appliances and facilities. It is anticipated that conservation and energy efficiency efforts will offset any potential increases associated with higher household incomes in the future so that average household consumption remains near these levels.

Change in the number of households is the other factor used in estimating residential and commercial heating demand; as the number of households in the community changes total consumption in the community is expected to change. As discussed earlier in this report, ISER prepared statewide forecasts of population, households, and employment for this study. The estimated number of households in each region for 2009 and the future years of interest are shown in Table 17.

Table 17. Estimated Number of Households by Region (in Thousands)

Region	Years		
	2009	2019	2030
Northwest-Arctic	6.819	7.64	8.802
Yukon – Koyukuk	2.05	2.264	2.554
Northern Railbelt	36.971	39.906	45.93
Southeast Fairbanks	2.419	2.66	3.12
Yukon – Kuskokwim	6.446	7.21	8.216
Southwest	8.343	8.95	9.675
Southern Railbelt	153.881	176.341	216.358
Valdez-Cordova	3.709	4.128	4.748
Southeast	27.163	30.865	37.446
Total	**247.801**	**279.964**	**336.849**

Source: Institute of Social and Economic Research, 2009.

Specific adjustments are made to the household numbers in the model as necessary to account for community-specific situations. For example, Barrow households were subtracted from the Northwest-Arctic region estimates since Barrow has a natural gas supply from nearby gas fields and would not need propane in any significant quantities. Many households in the Southern Railbelt and Northern Railbelt would also be served by gas and the number of households is reduced to account for this situation.

Multiplying the number of households that might use propane in each region by the heating fuel and electric generation fuel consumption estimates developed by ISER (Table 16) results in the following demand for distillate fuel in each region (See Table 18).

Table 18. Estimated Gallons of Distillate Fuels Required (Thousands of Gallons)

Region	2019		2030	
	Utility	Electricity	Utility	Electricity
Northwest-Arctic	7,032	7,098	8,102	8,177
Yukon – Koyukuk	1,369	2,153	1,545	2,429
Northern Railbelt	11,545	11,389	13,288	13,107
Southeast Fairbanks	2,748	2,711	3,224	3,180
Yukon – Kuskokwim	6,790	7,469	7,737	8,512
Southwest	11,373	14,142	12,295	15,287
Southern Railbelt	11,932	6,933	14,640	8,506
Valdez-Cordova	6,655	4,118	7,654	4,736
Southeast	29,219	7,897	35,449	9,581
Total	**88,664**	**63,910**	**103,932**	**73,516**

Source: Northern Economics, Inc., 2009

8.2.2.2 Potential Propane Demand

Propane has lower energy content per gallon than distillate fuels. A gallon of propane contains approximately 91,000 Btus while distillate fuels can range from approximately 135,000 to 140,000 Btus per gallon with various sources reporting different average values. Kerosene and Diesel No. 1 are at the lower end of the range and Diesel No. 2 is at the higher end of the range. The result of the lower energy content of propane is that additional volumes of propane are required to generate the same amount of energy for heating. Table 19 shows the estimated potential demand for propane in each region based on a conversion rate of 91,000 Btus for propane and 135,000 Btus for distillate fuels. This potential demand assumes that propane would replace all distillate fuels for use by the residential and commercial sectors in each region.

Table 19. Potential Residential and Commercial Demand for Propane (Thousands of Gallons)

Region	Years 1-5	Years 10-15
Northwest-Arctic	10,432	12,019
Yukon – Koyukuk	2,031	2,292
Northern Railbelt	17,128	19,712
Southeast Fairbanks	4,077	4,782
Yukon – Kuskokwim	10,073	11,479
Southwest	16,872	18,058
Southern Railbelt	17,701	21,718
Valdez-Cordova	9,872	11,355
Southeast	43,347	52,590
Total	131,534	154,185

Source: Northern Economics, Inc., 2009.

The future price of distillate fuels in each region is based on a spreadsheet model developed by ISER for the Alaska Energy Authority's alternative energy grant application program. The model, which provides price forecasts for individual communities, was adapted by Northern Economics to provide regional information and using NEMS model runs for crude oil price forecasts that are similar to the EIA April 2009 forecast rather than the 2008 EIA forecast in the ISER model. The resulting average price per gallon for distillate fuels in each region is presented in Table 20.

Table 20. Estimated Distillate Fuel Prices by Region, 2019 and 2030 (Dollars per Gallon)

Region	Year	
	2019	2030
Northwest-Arctic	$4.65	$5.05
Yukon-Koyukuk	$4.78	$5.19
Northern Railbelt	$4.55	$4.95
Southeast Fairbanks	$4.23	$4.62
Yukon-Kuskokwim	$4.83	$5.26
Southwest	$5.37	$5.86
Southern Railbelt	$4.13	$4.46
Valdez-Cordova	$4.43	$4.81
Southeast	$4.90	$5.38

Source: Adapted by Northern Economics from Institute of Social and Economic Research, 2008.

It is anticipated that once the main gas pipeline is operational, natural gas prices in Alaska will be linked to national prices for natural gas. The NEMS model projects future natural gas prices at Henry Hub, which is a major gas pipeline interconnect point in Louisiana. Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange. TransCanada has observed over the years that natural gas prices at a similar hub in Alberta (AECO) are about $0.75 per MMBtu less than natural gas prices at Henry Hub (Lee, 2009). Thus, the wellhead price of natural gas on the North Slope can be estimated by taking the Henry Hub price, subtracting the price differential between Henry Hub and AECO, and then subtracting the estimated mainline tariff of approximately $3.50± per MMBtu for the main gas pipeline from the North Slope to AECO and the gas treatment plant (TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd., 2007). At a hypothetical future price of $7.00 per MMBtu at Henry Hub, the wellhead value in Prudhoe Bay would be $7.50 - $0.75 - $3.50 = $3.25 per MMBtu.

Prices for propane are estimated in a spreadsheet model that is based on prior work to assess the feasibility of propane distribution to coastal communities in Alaska (PND, Inc., 2005). The model was updated to reflect current (2009) prices and also revised to estimate propane prices delivered to communities on major river systems and to communities on the road system. Delivery costs on river systems and truck delivery costs are based on work conducted for the Alaska Department of Transportation & Public Facilities(CH2M-Hill, Inc., 2003), updated with more recent Corps guidance on tow boat and barge costs (U.S. Army Corps of Engineers, Directorate of Civil Works, 2004), and updating the truck and towboat and barge cost information to 2009 dollars using the producer price index for Coastal and Intercoastal Towing Transportation (Bureau of Labor Statistics, 2009). The following bullets summarize the major features of this model.

The price of propane to a community in western Alaska consists of the following cost items:

- Wellhead value of natural gas on the North Slope expressed in energy content (MMBtu)

- Tariff on the main gas line to a spur line to Cook Inlet ($2.00± per Mcf) or Valdez $2.50± per MMBtu)
- Tariff on the spur line to Cook Inlet ($2.25± per MMBtu), if required
- Tariffs at a propane extraction plant, a product pipeline (Cook Inlet only), and a marine terminal (approximately $0.30± per gallon combined)
- Marine shipping costs via tug and barge delivery to representative communities in each region
- Offloading, storage, operations and maintenance, and refurbishment and repair costs of storage facilities in each representative community
- Taxes and distribution costs (if any).

The price of propane on an energy basis (MMBtu) was calculated for each region and compared with the projected price of distillate fuels on an energy basis. Adjustments were made for the combustion characteristics of propane which require about ten percent more fuel when used in a turbine or reciprocating engine (PND, Inc., 2005), and to account for the costs of converting from distillate fuels to propane. If the cost of propane was 90 percent or less of the cost of distillate fuels on an energy equivalent basis then the region was assumed to switch to propane.

Distribution to Southeast Alaska is assumed to be by barge from either Cook Inlet or Valdez. If a pipeline from Haines Junction to Haines was found to be commercially viable, propane distribution from Haines to other communities in Southeast Alaska might provide cost savings over shipping from Cook Inlet or Valdez. However, an off-take point at Haines Junction would be outside of Alaska and it is not evaluated in this report.

8.2.2.3 Probability Analysis

As discussed previously, a probability analysis was conducted to account for the uncertainty about the future of residential and commercial sector demand. Table 21 shows the variables that are incorporated in the probability modeling for propane use in the residential and commercial sector. The mid-point and high and low estimates are also shown. The electric power sector demand for propane uses these same variables. A brief discussion of these variables follows the table.

Table 21. Variables for Residential and Commercial Sector Probability Analysis

Variables	Years 1-5 Mid	Years 1-5 Low	Years 1-5 High	Years 10-15 Mid	Years 10-15 Low	Years 10-15 High
Crude price (2009$/barrel)	115.88	47.75	191.23	128.19	47.75	212.29
Gas Price at Henry Hub (2009$/MMBtu)	7.04	6.29	7.79	8.50	7.26	9.55
Mainline tariff to AECO (2009$/MMBtu)	2.62	1.96	3.27	2.62	1.96	3.27
Mainline tariff for in-state off-take (2009$/MMBtu)	1.49	1.12	1.87	1.49	1.12	1.87
Spurline tariff (2009$/MMBtu)	1.68	1.75	2.99	1.68	1.75	2.99
Capital cost range (% of initial estimate)	100%	62%	175%	100%	62%	175%
Propane market penetration rate						
Community (% per year convert to propane)	7%	5%	10%	7%	5%	10%
Households (thousands)						
Northwest-Arctic	6.34	6.18	6.50	7.31	7.13	7.49
Yukon-Koyukuk	2.26	2.21	2.32	2.55	2.49	2.62
Northern Railbelt	11.17	10.90	11.46	12.86	12.54	13.19
Southeast Fairbanks	2.66	2.59	2.73	3.12	3.04	3.20
Yukon-Kuskokwim	7.21	7.03	7.39	8.22	8.01	8.42
Southwest	8.95	8.73	9.18	9.68	9.44	9.92
Southern Railbelt	8.82	8.60	9.04	10.82	10.55	11.09
Valdez-Cordova	4.13	4.03	4.23	4.75	4.63	4.87
Southeast	30.87	30.10	31.65	37.45	36.52	38.39

Source: Northern Economics, Inc.

Note: Specific adjustments are made to the household numbers in the model as necessary to account for community-specific situations such as subtracting Barrow households from the Northwest-Arctic region estimates since Barrow has a natural gas supply from nearby gas fields and would not need propane in any significant quantities. Many households in the Southern Railbelt and Northern Railbelt would also be served by gas and the number of households is reduced to account for this situation.

The analysis varies the prices for crude oil and natural gas separately. The mid-point and the range of prices for natural gas are linked to the price of crude oil in NEMS but each commodity is varied independently in the probability analysis. Prices of crude oil and natural gas have historically been correlated on an energy equivalent basis, but recent natural gas prices have been much lower than crude oil prices, and EIA forecasts indicate that the historical relationship is not expected to return. This analysis also assumes that the potential price savings that might accrue with use of North Slope propane are passed on to consumers and not captured by intermediaries that could price North Slope propane just under the price of heating fuel.

The capital costs of the main gas pipeline and the spur line are still unknown and changes in the capital cost would affect the future tariffs and the cost of natural gas to the consumer. In addition, the volume of gas that may be transported by the spur line and the location of the spur line (Parks highway route or the Richardson/Glenn highway) are also unknown so the range of possible tariffs for the spur line is very large.

The capital cost estimates for building propane tank farms are also uncertain since large propane vessels are not fabricated in Alaska and the cost estimates are from Lower 48 vendors. It is anticipated that with a large demand in-state manufacturers would come forward and the capital cost location factor accounts for variations in the cost of manufacturing in Alaska compared to the Lower 48. The mid-point of 1.5 is the same as that estimated by GLE for the propane extraction plants (Gas Liquids Engineering Ltd., 2009).

GLE provided cost estimates for three different sizes of propane extraction facilities (See Appendix D). One facility of about 0.5 MMcfd which a small community (e.g., Tok and the surrounding area) might require, one of about 65 MMcfd, potentially the off-take volumes for the Fairbanks area, and 300 MMcfd which might be near the delivery volumes to the Cook Inlet area. A pro forma analysis of the potential tariffs for each plant indicate that the capital cost for the smallest plant are too large in comparison to the throughput and that it would be less expensive to truck propane from Fairbanks or another location rather than build a very small plant along the pipeline route.

To account for the cost of conversion to new heating appliances, prime movers for electricity generation, and other equipment the model assumes that the price of propane has to be 90 percent or less of the cost of distillate fuels on an energy equivalent basis. However, conversion to community-wide propane use could take some years to implement since a propane tank farm would need to be built and, based on the time span that the State and others have been involved in the current Bulk Fuel Tank Farm program, it is assumed that the rate of conversion will take a number of years. This conversion rate is incorporated in the probability analysis and limits the propane demand in the initial years.

The number of households is also subject to change with resultant affect on the heating and electric power demand. The mid-point is based on the MAP model output (Institute of Social and Economic Research, 2009) and the range is based on a plus or minus 0.25 percent change in the annual rate of growth calculated from the ISER projections.

The regional aggregation (e.g., the Yukon-Koyukuk census area would rank fifth in size behind Montana if it were a state) and the use of one community per region in general results in estimates for the region as if all demand was located at the selected community or communities. However, some communities would be located closer to the origin shipping point than the community used in the model which could make a difference in the cost of propane delivered to the community, and the estimate of potential demand. For example, Galena is used as the destination community for the Yukon-Koyukuk region and transportation costs to Tanana would be less than Galena. Conversely, demand in the Southeast Fairbanks census area assumes year-round truck access but the Taylor Highway is not maintained in the winter which would increase the storage costs for communities that are accessed by that road and potentially reduce demand in that region.

The costs of transportation and storage are important factors in determining the competitiveness of propane versus distillate fuels. A gallon of propane has about two-thirds of the energy content of a gallon of distillate fuels so to obtain the same amount of energy about 50 percent more gallons of propane must be transported to a community or industrial site. In addition, over 50 percent more storage must be built in a community since propane tanks are normally only filled to 80 percent of rated (water gallon) capacity compared to about 90 percent or greater for distillate fuel tanks. Moreover, the costs for propane tanks, since they are pressure vessels, could be about 60 percent higher than bulk fuel tanks in rural Alaska based on the differences in vendor prices in the lower 48 states for 30,000 gallon (water gallon) fuel tanks and propane tanks.

This analysis assumes there are no subsidies or grants for building propane tank farms or converting equipment and appliances to use propane although such grants are routinely provided for bulk fuel tank farms and diesel generating plants. If similar subsidies were available for propane facilities then the estimated propane demand would be larger.

At volumes higher than about 100 million gallons per year of propane additional propane extraction facilities or a straddle plant would be required on the main gas pipeline to Alberta. The additional tariff for this plant is based on capital cost estimates in the NETL report ((National Energy Technology laboratory, 2006) and updated by the producer price index for other pipeline transportation (Bureau of Labor Statistics, 2009) plus operating costs.

8.2.3 Electric Power Demand

The electric power demand described here is for communities that are not served by the six Railbelt utilities. With the exception of the Southeast region where a substantial amount of hydroelectric facilities are in place, most of this electricity demand is met by small utilities which generate local requirements with diesel-electric generators.

8.2.3.1 Potential Propane Demand

The approach to estimate electric generation demand for distillate fuels in communities not served by the six Railbelt utilities is identical to that described earlier for heating demand estimates. The current volume of fuel required for electric generation on a per household basis (Institute of Social and Economic Research, University of Alaska Anchorage, 2008) is assumed to remain constant and is multiplied by the projected number of households in 2019 and 2030 (See Table 17).

The total gallons of diesel fuel are then converted into Btus to establish the total energy demand required for electric generation in 2019 and 2030. Propane has certain combustion characteristics that result in propane providing about 10 percent less power than diesel fuel when used in turbines or reciprocating engines so additional propane will be needed to provide the required electricity output (PND, Inc., 2005) and an adjustment is made for that factor. The vast majority of the households in the Northern and Southern Railbelt regions would be served by natural gas-fired electric generation rather than propane so zero demand is shown for propane in those regions. Much of the electric generation in Southeast is generated by hydroelectric plants and it is anticipated that this generation would continue, if not expand. The potential demand shown in Table 22 would be the total propane requirements if all communities in each region were to switch 100 percent of their diesel generation to propane use.

Table 22. Potential Propane Demand for Electric Generation, 2019 and 2030 (Thousands of Gallons)

Region	Years 1-5	Years 10-15
Northwest-Arctic	13,952	16,074
Yukon – Koyukuk	3,514	3,964
Northern Railbelt	0	0
Southeast Fairbanks	4,423	5,188
Yukon – Kuskokwim	12,187	13,887
Southwest	23,073	24,942
Southern Railbelt	0	0
Valdez-Cordova	6,718	7,727
Southeast	12,884	15,631
Total	76,752	87,414

Source: Northern Economics, 2009.

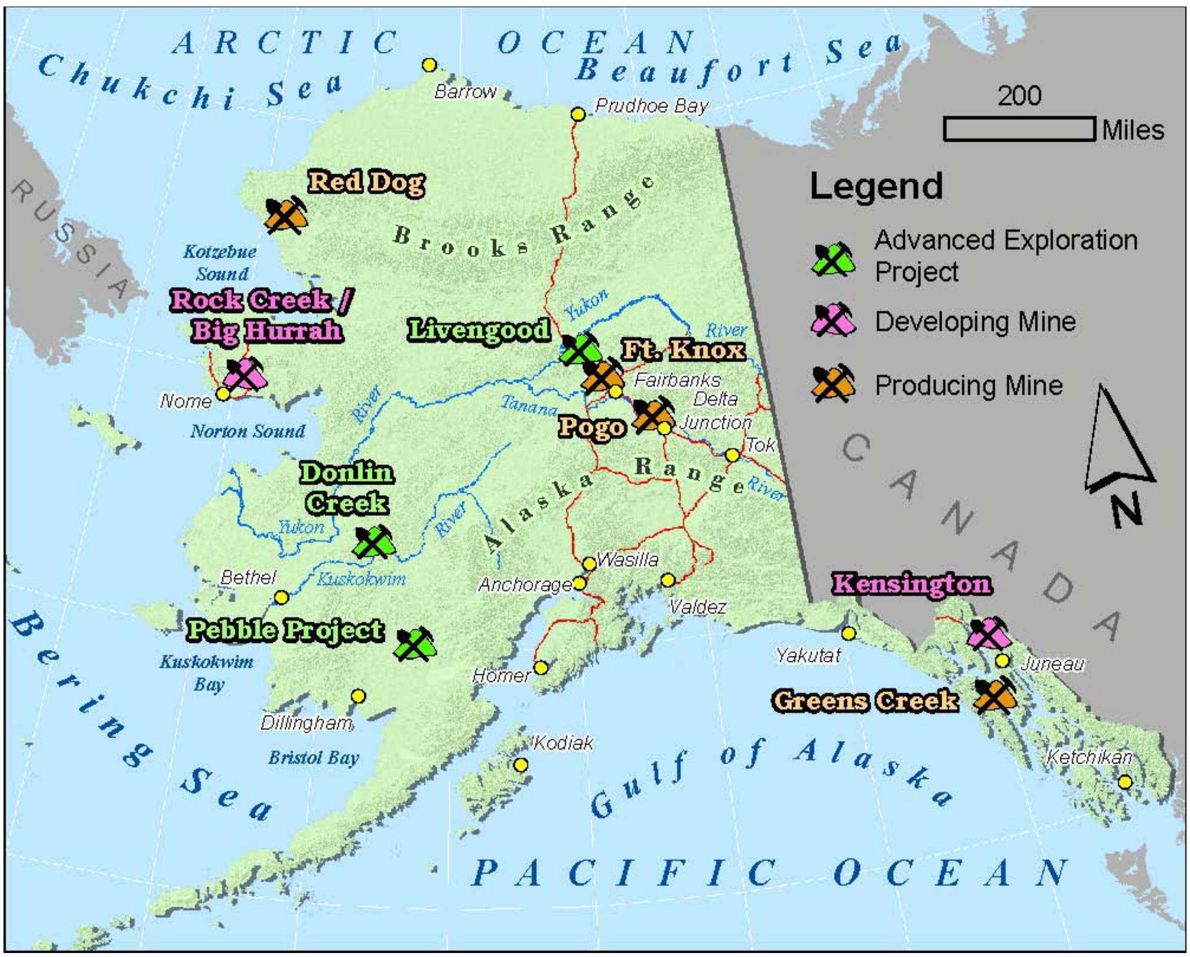
8.2.4 Industrial Demand

Demand by other, non-gas intensive industries is primarily for process and space heating, and for self-generation of electricity. The industrial demand estimated in this analysis incorporates statewide demand by the mining industry and the seafood processing industry, and potential propane demand by Alyeska Pipeline Service Company for pump stations and marine terminal operations.

8.2.4.1 Mining Industry

The mining industry demand reflects existing and anticipated demand at the major mines and exploration projects circled in Figure 23.

Figure 23. Existing and Potential Major Metal Mines in Alaska



Source: Alaska Map Company, 2009.

The Fort Knox mine and the Pogo mine are both served by Golden Valley Electric (GVEA) and it is not anticipated that they would generate their own power if natural gas became available since GVEA's cost of electricity would also decrease with the availability of natural gas. According to Shaw, the Pogo mine currently uses about one million gallons of propane each winter and this need would be expected to be met with propane extracted from the gas pipeline stream since it would be less expensive than propane transported from the Tesoro refinery on the Kenai Peninsula or imported from Canada.

The potential Livengood gold mine is expected to require 20 to 25 megawatts of power with peak demand occurring in the 2016 to 2018 period (Pontius, 2009). GVEA could potentially extend their transmission lines north to Livengood but since the potential demand from the Livengood project is not included in the Railbelt power demand estimates that were generated in 2008 (See Section 5 for additional detail), it is assumed that the Livengood project would commence operations with dual fuel generating systems and switch to propane or natural gas depending on the availability of each fuel. Future Livengood demand is captured in natural gas estimates.

Energy demand for the Red Dog, Greens Creek, and the Kensington Mine are held constant at the levels provided by Shaw (2009). Although one or more of these mines may close during the time period of this analysis it is anticipated that other, yet-to-be identified mines will open, or additional deposits will be found in the vicinity of the mines to enable them to continue operation.

The Donlin Creek and Pebble projects are advanced exploration projects. In developing assumptions for ISER's MAP model it was anticipated that the Donlin Creek mine would be online prior to the main pipeline and spur line being completed, and that the Pebble project would come online after the main pipeline and spur line are completed although the scale of the Pebble project and the resultant energy demand is uncertain.

8.2.4.2 Seafood Industry

The seafood industry analysis estimates the demand to meet process heat, space heat, and power generation by certain shore-based seafood processing plants. The Intent to Operate database maintained by the Alaska Department of Fish & Game (Alaska Department of Fish & Game, 2009) was the basis for identifying shore-based seafood processors throughout the state. The seafood processors were then placed into three categories to aid in estimating fuel consumption. The largest category (Industrial Scale) were identified by reviewing air quality permit databases to determine which seafood processors had significant power generation or other equipment that resulted in the need for an air quality permit (Alaska Department of Environmental Conservation, 2009). Seafood processors requiring such permits are very large processors operating year-round and processing significant volumes of product. A number of processors operating in Unalaska as well as other plants in communities such as Akutan and King Cove require such permits and had the highest average demand for distillate fuels by plant.

The second category (Large Scale) consisted of plants that required permits but did not operate year round, or those that operate year round and generate their own power but do not require air quality permits. This categorization was based on a review of the plants by Northern Economics staff with significant experience in the seafood industry. A similar professional review was conducted to estimate the number of small plants (Small Scale) operating seasonally that generate their own power but have emissions lower than permit thresholds, and those that operate year-round but obtain power from the local community and only require distillate for space heat in the winter and process heat when operating. No growth in seafood energy demand is projected for the future.

8.2.4.3 Total Distillate Demand for Mining and Seafood Industries

Table 23 shows the estimated distillate demand for the major metal mines and the seafood processing sector in Alaska for the years of interest. In the event that the mainline to Alberta is constructed, the crude oil marine terminal in Valdez could convert to propane. Demand at the Alyeska marine terminal is presented in the mining column in the Valdez-Cordova region.

Table 23. Estimated Distillate Demand by Mining and Seafood Processing Sectors by Region (Thousands of Gallons)

	Years 1-5			Years 10-15		
Region	Mining/ Alyeska	Seafood	Total	Mining/ Alyeska	Seafood	Total
Northwest-Arctic	16,141	100	16,241	16,141	100	16,241
Yukon – Koyukuk	0	0	0	0	0	0
Northern Railbelt	0	0	0	0	0	0
Southeast Fairbanks	674	0	674	674	0	674
Yukon - Kuskokwim	68,204	500	68,704	68,204	500	68,704
Southwest	68,560	10,700	79,260	68,560	10,700	79,260
Southern Railbelt	4,485	700	5,185	99,819	700	100,519
Valdez-Cordova	8,148	1,100	9,248	8,148	1,100	9,248
Southeast	24,136	2,800	26,936	24,136	2,800	26,936
Total	205,147	15,900	221,047	300,481	15,900	310,582

Source: Northern Economics, Inc., 2009.

8.2.4.4 Potential Propane Demand

The potential demand for propane (i.e., assuming all potential industrial consumers switch to propane) is estimated in a manner similar to that described for the electric power sector with adjustments for the combustion characteristics of propane (See Table 24).

Table 24. Potential Industrial Propane Demand (Thousands of Gallons)

	Years 1-5			Years 10-15		
Region	Mining/ Aleyska	Seafood	Total	Mining/ Alyeska	Seafood	Total
Northwest-Arctic	23,945	148	24,093	23,945	148	24,093
Yukon - Koyukuk	0	0	0	0	0	0
Northern Railbelt	0	0	0	0	0	0
Southeast Fairbanks	1,000	0	1,000	1,000	0	1,000
Yukon - Kuskokwim	101,182	742	101,924	101,182	742	101,924
Southwest	101,710	15,874	117,584	101,710	15,874	117,874
Southern Railbelt	6,654	1,038	7,692	148,083	1,038	149,121
Valdez-Cordova	10,456	1,632	12,088	10,456	1,632	12,088
Southeast	35,806	4,154	39,960	35,806	4,154	39,960
Total	280,751	23,588	304,339	422,180	23,588	445,768

Source: Northern Economics, Inc.

The difference in potential propane demand between the initial and later years is the proposed Pebble mine. This demand could possibly be met with gas-fired electrical generation in the Southern Railbelt with transmission lines to the mine site but this situation was not modeled in the 2008 REGA study so it is assumed that propane would be used so that this potential demand is included.

8.2.4.5 Probability Analysis

To estimate industrial demand for propane, two additional variables were added to the list of probability variables described for the propane residential and commercial sector. These variables are shown in Table 25.

Table 25. Probability Analysis Variables for Industrial Demand

Variables	Years 1-5 Mid	Years 1-5 Low	Years 1-5 High	Years 10-15 Mid	Years 10-15 Low	Years 10-15 High
Propane market penetration rate						
Industrial (% per year convert to propane)	20%	10%	25%			
Pebble mine potential load (MW)				200	100	250

Source: Northern Economics, Inc.

The industrial sector is anticipated to be more responsive to potential cost savings than the residential and commercial or the electric power sector in rural Alaska. The market penetration rate reflects that assumption with a mid-point of 20 percent per year (full conversion in five years), and a range from 10 percent to 25 percent. No values are shown for the later years since even the low range would result in 100 percent conversion by the tenth year.

The proposed Pebble mine could result in a significant demand for energy but it is assumed that the demand would occur after the main gas pipeline and the spur line are built. This assumption is consistent with ISER MAP model assumptions. The project is very early in the planning stage and estimates of power or energy demand are uncertain (Shaw, 2009). The potential power demand from Pebble is not modeled in the Alaska Railbelt Electrical Grid Authority Study done for the Alaska Energy Authority in 2008 (Black & Veatch, 2008) although there have been discussions between HEA and the Pebble mine sponsors. To ensure that this potential demand is included in the analysis it is assumed that propane would be used to generate power for the mine.

Information available for power demand at the Pebble mine suggests that the power load could be more than 200 MW (Shaw, 2009) but there is a limited amount of information on which to base the estimate at this stage in the project development. A mid-point of 200 MW is used with a range from 100 to 250 MW.

Table B-2 in Appendix B summarizes the maximum potential propane demand for residential and commercial, electric power, and industry in years 1-5 if propane were less expensive than distillate fuels in all regions. The following section provides propane demand estimates that account for the fact that propane may be more costly than distillate fuels in some regions due to the additional cost to transport and store larger volumes of propane.

8.3 Propane Demand Estimates

The following material provides propane demand estimates for the residential and commercial sector, the electric power sector, and the industrial sector, for the Alberta route and the Valdez route.

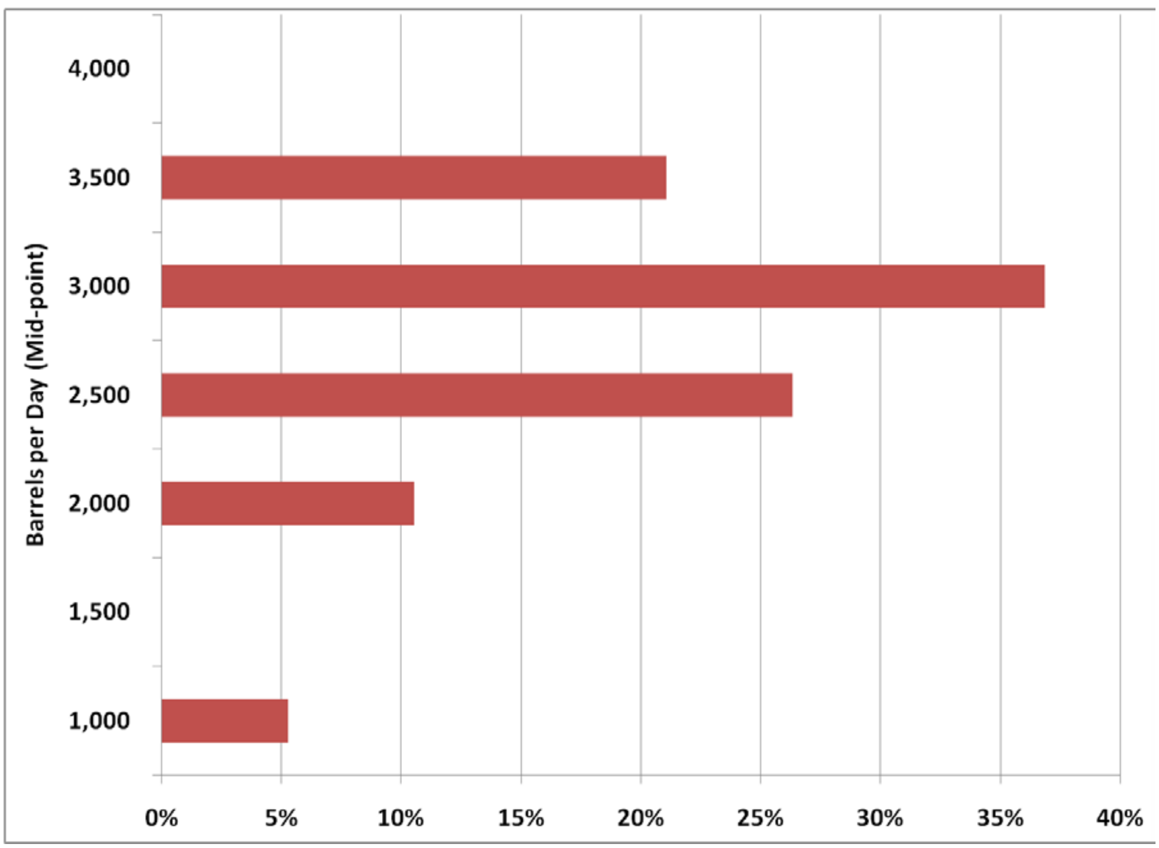
The results presented here anticipate that propane extraction facilities would be built in the Fairbanks area and in either Cook Inlet or Valdez, depending on the ultimate route. The capital cost for small propane extraction plants is very large compared to the throughput and a comparison of the potential tariff of such a plant with trucking costs indicate that it would be less expensive to truck propane from Fairbanks to small communities on the road system.

A propane extraction facility is proposed to be built at Prudhoe Bay with the propane sold into the Fairbanks area. Such a facility could facilitate an earlier conversion to propane in Fairbanks and communities along the road system and increase the demand in the earlier years of the pipeline project. The Prudhoe Bay facility could have lower transportation costs to parts of western and Arctic Alaska which could result in additional propane demand in those areas.

A competing project to provide LNG to Fairbanks has also been proposed. This LNG project would not have the same effect on propane conversion and since there is substantial uncertainty regarding which project might move forward we have not modeled future demand with a North Slope propane extraction facility.

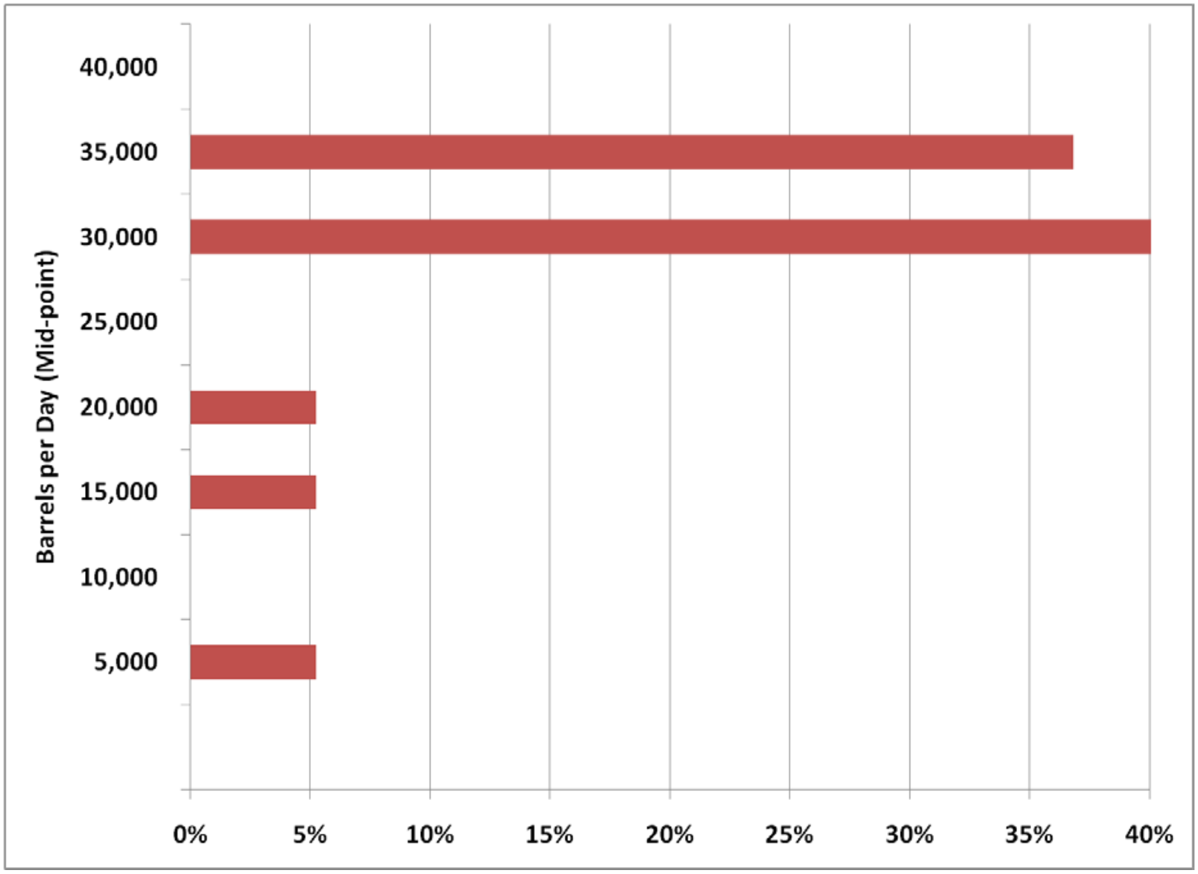
Figure 24 and Figure 25 show the percent probability that demand will fall within one of the demand categories shown on the vertical axis. For example, Figure 24 shows that there is a 37 percent chance that the actual demand will fall within 2,751 to 3,250 barrels of propane per day, and a 26 percent chance that demand will be within 2,251 to 2,750 bpd. In Years 10 to 15 the probability model indicates that there is a 40 percent chance that demand will fall within 27,501 to 32,500 bpd.

Figure 24. Chances of Propane Demand, Alberta Route, Years 1-5



Source: Northern Economics, Inc.

Figure 25. Chances of Propane Demand, Alberta Route, Years 10-15

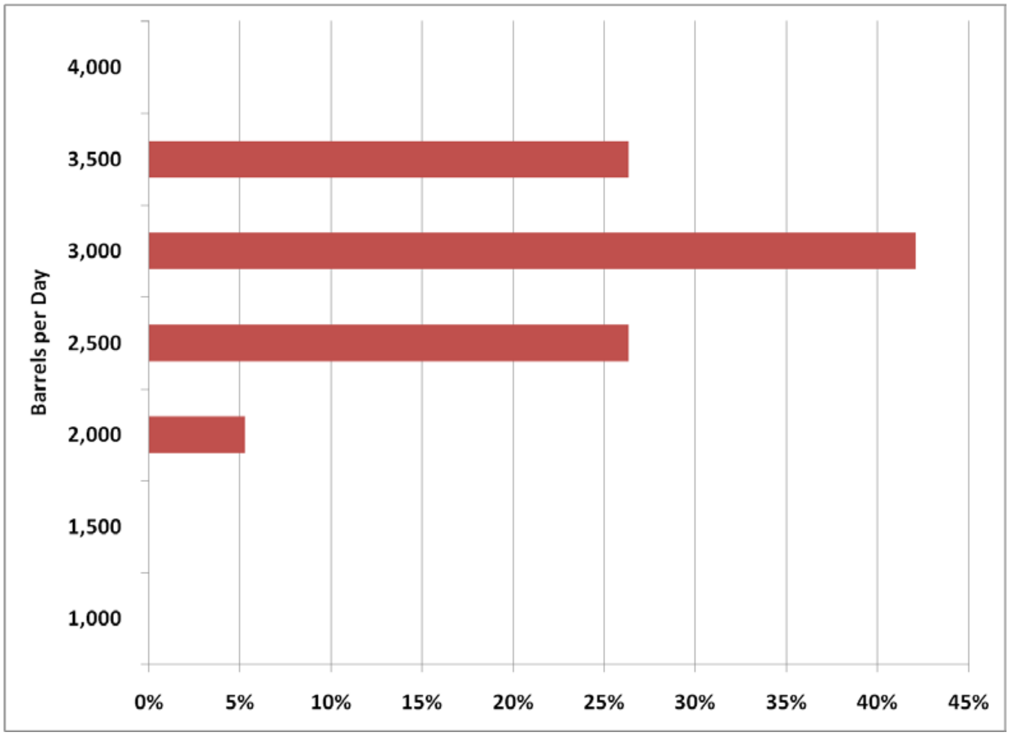


Source: Northern Economics, Inc.

The demand estimates presented in Figure 26 are similar to those shown earlier for the Alberta route, although the range is much narrower. The percent of total demand in Figure 27 vary from the Alberta route in that the range is much narrower and there is a higher probability of demand being greater than 22,500 bpd.

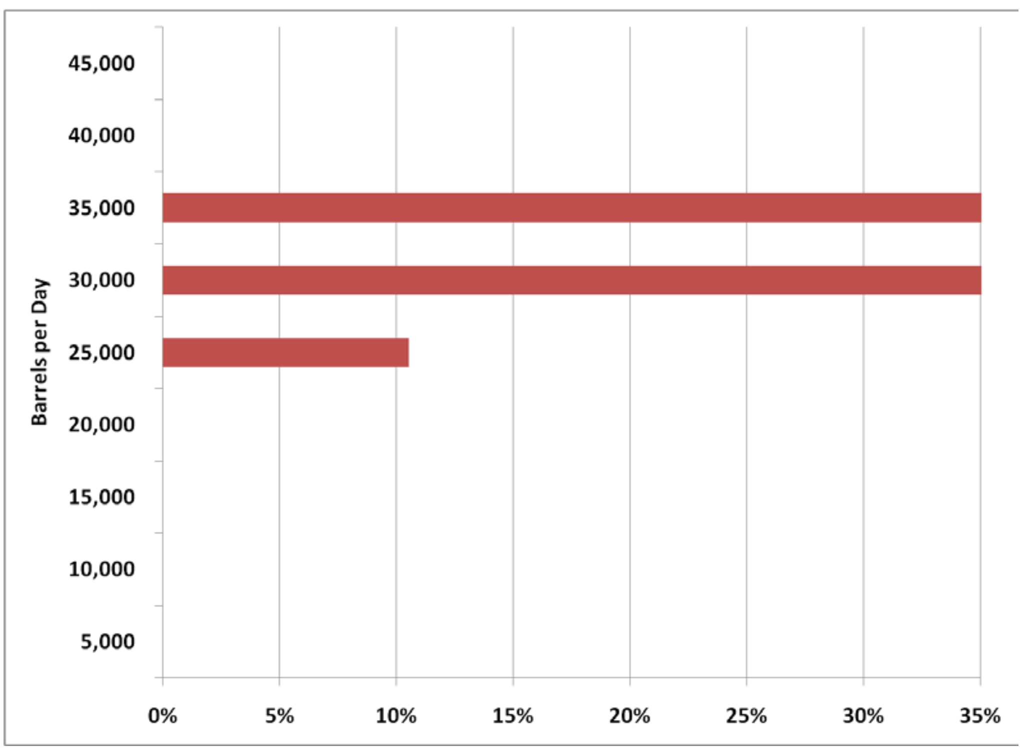
The propane composition of the North Slope gas could range from 1.7 to 3.6 percent per volume. A pipeline with 4.5Bcf per day of North Slope gas would be transporting about 21,000 to 47,000 bpd so the propane demand in years 1-5 could readily be met with the anticipated propane volumes. Demand in years 10-15 would exceed the propane volumes if the lean gas composition (1.7 percent) occurs but demand would be met with the rich gas composition. Much of the demand in the later years arises with potential demand from large mines that begin operations. Such operations may not have access to the volumes of propane they might desire and as a result would need to use distillate fuels.

Figure 26. Chances of Propane Demand, Valdez Route, Years 1-5



Source: Northern Economics, Inc.

Figure 27. Chances of Propane Demand, Valdez Route, Years 10-15



Source: Northern Economics, Inc., 2009.

Table 26 shows the projected demand generated by the probability analysis of demand for propane throughout the State of Alaska. The table results represent the mean (average) estimate for the analysis that developed the probability estimates presented in Figure 24 and Figure 25. The estimates show the growth in demand over time as people and firms convert to propane over time or as new industrial users emerge in the future. In the Year 1 to 5 timeframe for the Alberta Route, expected propane demand could be about 2,700 bpd with a range of about 500 bpd to 3,750 bpd (Figure 24). In the Year 10 to 15 timeframe expected propane demand is about 28,400 bpd with a range of about 5,000 to 37,000 bpd (Figure 25).

Table 26. Projected Annual Average Daily Propane Demand by Sector, in Two Future Time Frames for the Alberta Route (in Barrels per day)

Sector	Year 1 to 5 of Pipeline Operations	Year 10 to 15 of Pipeline Operations
Residential & Commercial	477	6,133
Electric Power	337	4,248
Industrial	2,484	22,326
Total	3,298	32,707

Source: Northern Economics, Inc.

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9 Cook Inlet Supply

The Alaska Department of Natural Resources, Division of Oil and Gas (DOG) recently issued a report that evaluated the remaining Cook Inlet natural gas reserves (Hartz, J.D., et al, 2009). As noted in the report, the issue of "whether the existing system of natural gas production and delivery in Cook Inlet can continue to meet the energy demands of south-central Alaska" depends on two separate sets of information. The first includes the geologic and engineering estimates of the gas remaining to be recovered from Cook Inlet fields, and the steps to access the gas. The second set deals with the complex commercial and infrastructure issues that affect the provision of gas to the end user. The DOG report only addresses the geologic and engineering issues regarding natural gas resources and reserves.

Table 27 presents the DOG estimates for natural gas volumes in Cook Inlet. The more conservative estimates are based on engineering analyses using decline curve and material balance techniques. According to DOG, the geologic analysis for the four major fields in Cook Inlet is strong enough to classify these volumes as reserves that have the potential, if developed, to meet the local demand well into and possibly beyond the next decade. Finally, there are potential exploration targets throughout the basin that could provide additional gas resources though there is less certainty for this estimate compared to the gas reserves estimate.

Table 27. Remaining Cook Inlet Natural Gas Volumes by Type of Reserves and Resources

Location/Type of Reserve	Derivation of Estimate	Volume
All Fields		**(Bcf)**
Proved, developed, producing	Decline Curve Analysis (DCA)	863
Probable	Material Balance (MB)-DCA (1,142-863)	279
Four Fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River)		
High-confidence pay intervals	Geologic PAY (GP)-MB for 4 fields (1,213-860)	353
Lower-confidence pay intervals	GP+50%-risked Potential Pay-GP (1,856-1,213)	643
Total Estimated Reserves		**2,138**
All Fields		
Higher risk contingent resources	Exploration Leads, Basin-wide	300
Total Estimated Reserves and Resources		**2,438**

Source: Values shown in the table are from, Hartz, J.D., et al, 2009. Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves. Alaska Department of Natural Resources.

DOG assumes that "either a significant amount of gas is found by explorers to meet industrial use, or that export of gas out of the basin will stop at the end of the current license period" (2011) for the LNG plant. DOG further assumes that no new demand will occur until reserves are developed to satisfy the market, which requires that sufficient risk-capital be available to explore and develop the higher risk contingent and prospective gas resources.

Figure 28 is a schematic production forecast from the DOG report that shows the incremental reserves identified by the various methods used in their analysis.

Figure 28. Schematic Cook Inlet Production Forecast,

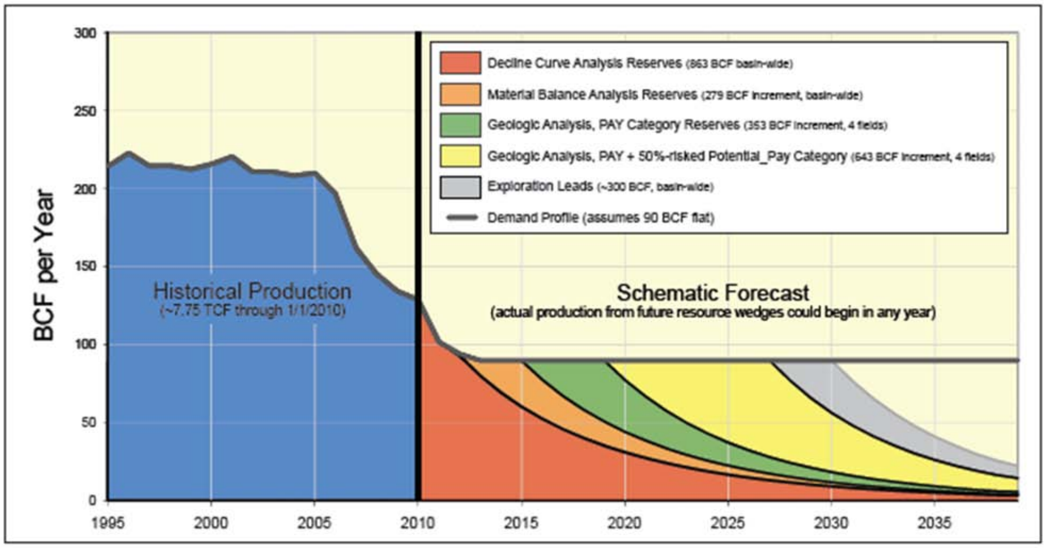

Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative estimation techniques. Successive wedges are introduced with progressively lower certainty regarding commerciality, volume, and timing of first production. Production from future resource wedges could begin in any year, resulting in a more complex forecast, and extending the production lifespan of previous wedges. On the other hand, we are unable to predict the commercial thresholds at which volumes from future wedges become economic to recover. Wedges show gas volume increments from basin-wide decline curve analyses (red), basin-wide material balance analyses (orange), deterministic geologic mapping of PAY (green), and 50 percent-risked Potential_Pay (yellow) in four large gas fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands). The last wedge (gray) is a more speculative estimate of aggregated gas volumes that may be recoverable from the exploration leads discussed in text. See text for additional discussion.

Source: Hartz, J.D., et al, 2009. Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves. Alaska Department of Natural Resources.

The DOG report states that "infill drilling, perforating undeveloped sands, and targeting marginal reservoirs are effective ways to add reserves to replace production." However, these costs will need to be absorbed into a market that requires relatively small volumes which will likely place upward pressure on gas prices.

As noted earlier in Section 2, Cook Inlet produces enough gas to meet annual average demand. However, supplying the required volumes during spikes in demand on very cold days in the winter is challenging for the current system. This indicates that it is difficult for producers to justify the investment to meet short-duration peak deliverability requirements when such projects must compete with other projects on a global basis. Wells are being drilled and storage facilities are being developed which indicates that investment is being made to address the issue but projects to address deliverability will continue to be marginal investments in many instances.

After the proposed spur line to Southcentral Alaska is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence on natural gas with increased demand side management and energy efficiency, increased use of renewable energy sources, and expanded transmission systems. However, even with such diversification and new facilities, natural gas remains a major energy source for the Railbelt, even 50 years into the future. Given this long time frame, utilities would seek to diversify their supplies of natural gas and would consider gas from the North Slope, coal bed methane, landfill gas, underground coal gasification, and other sources. The utilities have indicated that Cook Inlet sources would remain as a very large percentage of their natural gas supplies even if North Slope gas is less expensive.

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10 Integration

This section integrates the modeling results of the probability analyses for all the components of in-state natural gas demand. Sections 4, 5, and 6 discussed the preliminary probability analyses completed for the residential and commercial sector, electric power sector, and the industrial sector, respectively. Military demand (as discussed in Section 7) and the potential demand from the yet-to-be developed gold mine at Livengood in the Yukon-Koyukuk region (as noted in Section 8.2.4.1), were combined with Industrial demand. The outputs from these sector models were then integrated into a combined demand model to allow a simultaneous probability analysis of all the sectors using the variables specific to each probability model[9]. Appendix B provides a summary of the estimated demand ranges by sector for both the Alberta and the Valdez routes.

The first few sub-sections below discuss the demand scenarios for the Alberta and the Valdez projects, demand uncertainty, and a summary of the current industry scenario. Finally, the last section, provides a discussion of net North Slope gas demand.

10.1 Demand Scenarios

Historically, Alaskan demand for natural gas has been greater for gas-intensive industries than for all other sectors combined. As for the future, it is anticipated that the total in-state demand for natural gas would also be largely driven by the volume of natural gas requirements of future Alaska gas-intensive industries. There is great uncertainty, however, as to what industrial prospects will come to pass as North Slope gas becomes accessible through the gas pipeline.

The Industrial Sector analysis in Section 6 discussed several possible future demand scenarios. Three of these have been selected to define demand scenarios categorized as "no industry", "current industry", and "growth industry". Recognizing that no in-state gas-intensive industrial load is very certain, the No Industry case represents in-state demand without a gas-intensive industrial load. The Current Industry case represents a continuation of current trends, with a facility representative of the demand required by the Nikiski LNG terminal operating at full capacity. Finally, the Growth Industry case represents a scenario in which a facility with a demand similar to double the capacity of the existing LNG facility is built, but no greenfield projects will be built in years 1 to 5. Greenfield (or new) industrial projects are not assumed to be built at the same time as the pipeline because the joint demand for labor and materials could significantly increase the capital costs for a new facility, causing it to be uneconomic. Furthermore, unless owners of the greenfield industrial projects are to secure gas supply and commit to pipeline capacity in the early open seasons, it is unlikely that they would have sufficient gas to support the greenfield projects in the initial years of pipeline operation. In years 10 to 15, greenfield projects with reasonably likely economic feasibility are included under the Growth Industry case.

Table 28 and Table 29 summarize the total in-state demand for the three scenarios for both the Alberta Project and the Valdez Project. The tables also show the percent chance that each case will occur. The "no industry" case is more likely in the first years of pipeline operation than in later years.

Under the Alberta project, the "current industry" case is the most likely of the assessed scenarios. A summary of the current industry case for the Alberta Project is discussed in more detail in Section 10.3.

[9] In this situation, each model was subject to the same random number generation and the outputs would be consistent across all of the models. Simulations were run with 10,000 iterations and results have very little differences between subsequent runs (e.g., variances of less than 2 percent of the mean).

Not counting demand from a new Valdez LNG facility, the Valdez Project is estimated to have a higher gas demand than the Alberta Project for the three demand scenarios. This is due to the additional industrial demands in the Valdez area with the availability of natural gas. For the first five years of pipeline operations, the projected demand for the No Industry case, Current Industry case, and Growth Industry case, are 270, 500, and 750 MMcfd respectively; and the percent chance of these scenarios happening are 61 percent, 30 percent, and 9 percent respectively.

Table 28. Total In-State Natural Gas Demand Estimates for Three Scenarios, Alberta Project (MMcfd)

	Year 1 to 5 of Pipeline Operation			Year 10 to 15 of Pipeline Operation		
Demand Scenarios	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level
No Industry	260	29	71	290	14	86
Current Industry	490	38	26	520	18	65
Growth Industry	740	12	3	1,120	6	2

Source: Northern Economics, Inc. and SAIC, Inc., 2009.
Note: MMcfd is million cubic feet per day.

Table 29. Total In-State Natural Gas Demand Estimates for Three Scenarios, Valdez Project (MMcfd)

	Year 1 to 5 of Pipeline Operation			Year 10 to 15 of Pipeline Operation		
Demand Scenarios	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level
No Industry	270	61%	39%	300	36%	64%
Current Industry	500	30%	9%	530	18%	46%
Growth Industry	750	9%	<1%	1,130	4%	5%

Source: Northern Economics, Inc. and SAIC, Inc., 2009.
Note: MMcfd is million cubic feet per day.

10.2 Demand Uncertainty

The demand forecast is best expressed as a range due to uncertainty in the actual future demand. Furthermore, the demand forecast for each sector (residential/commercial, power, and industrial) has a different level of uncertainty. The amount of uncertainty is greatest for large industrial demand because as noted earlier, there is no certain gas-intensive industry in Alaska after 2011, when the Nikiski LNG terminal export license expires. Furthermore, a single large industrial project can have a demand that exceeds all the other sectors' in-state demand combined.

Figure 29, Figure 30, Figure 31, and Figure 32 show the range of likely in-state demand for natural gas by sector in the two future timeframes for the Alberta and the Valdez pipeline project, respectively. In these figures, certain demand is defined as demand that has at least a 90 percent chance of realization. Uncertain demand is potential demand that has a lower chance of realization. In Year 1 to 5, for the Alberta Project, 17 percent of the potential demand from the residential/commercial sector is uncertain, and roughly 30 percent of the potential demand from the power sector is uncertain. In contrast, 95 percent of industrial demand (i.e., all the gas-intensive industrial demand) is categorized as uncertain.

Figure 29. Projected Annual Average Daily Demand by Sector, Year 1 to5, Alberta Project

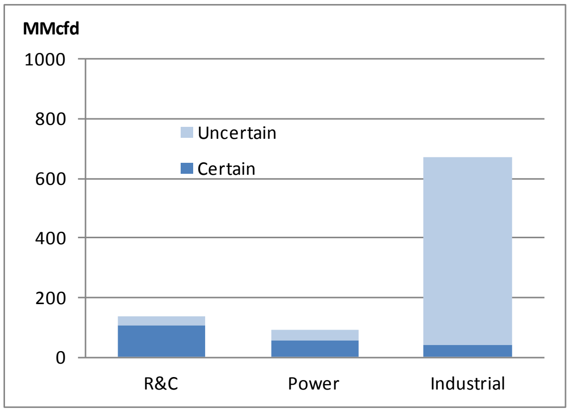
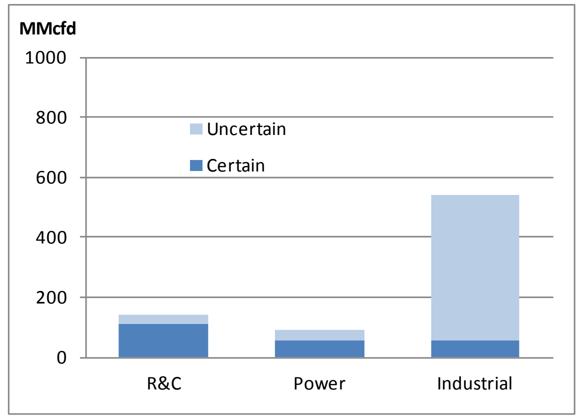


Figure 30. Projected Annual Average Daily Demand by Sector, Year 1 to5, Valdez Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

Figure 31. Projected Annual Average Daily Demand by Sector, Year 10 to15, Alberta Project

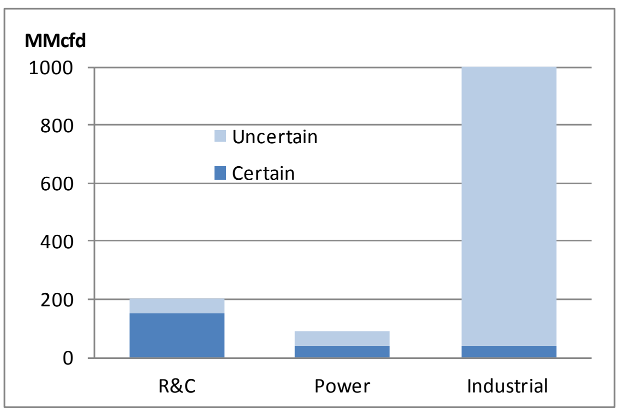
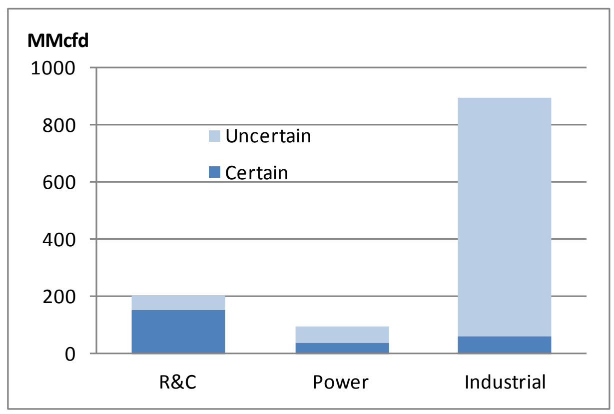


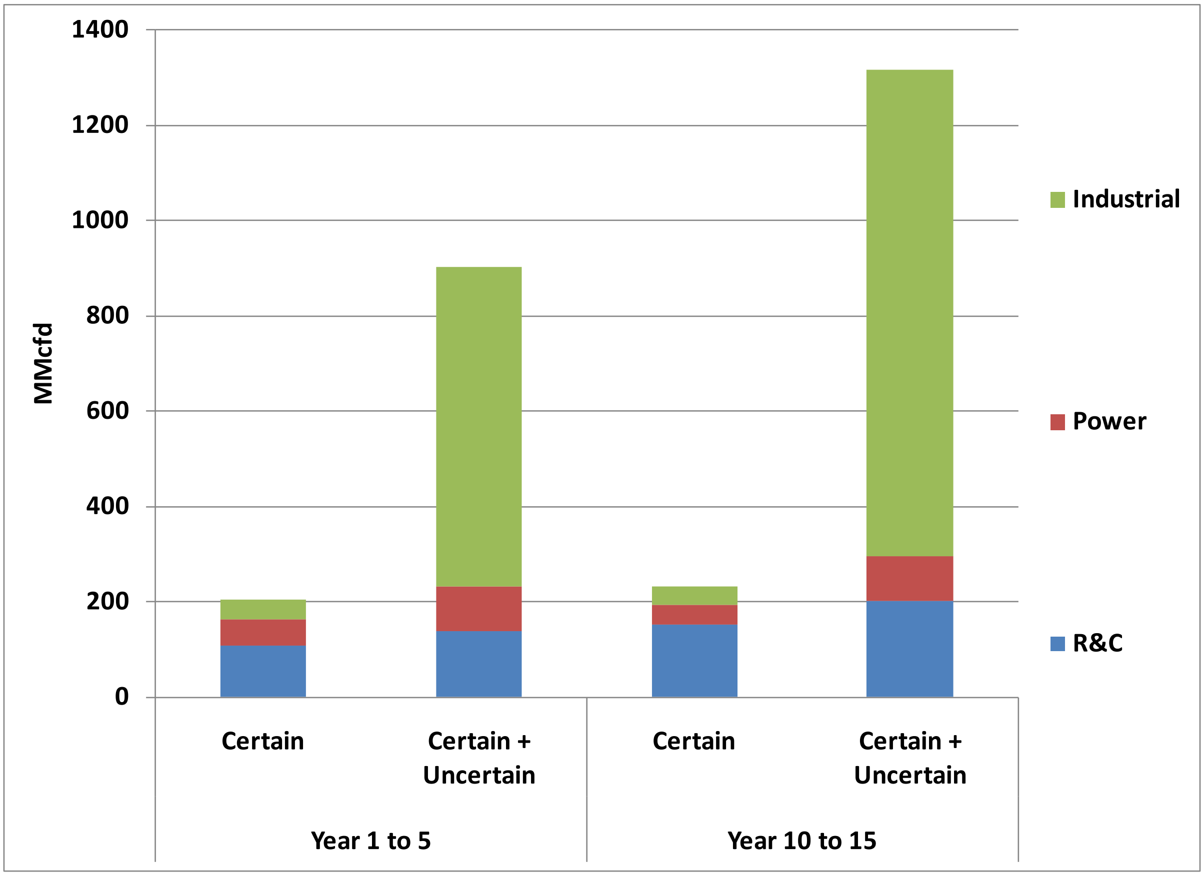
Figure 32. Projected Annual Average Daily Demand by Sector, Year 10 to15, Valdez Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

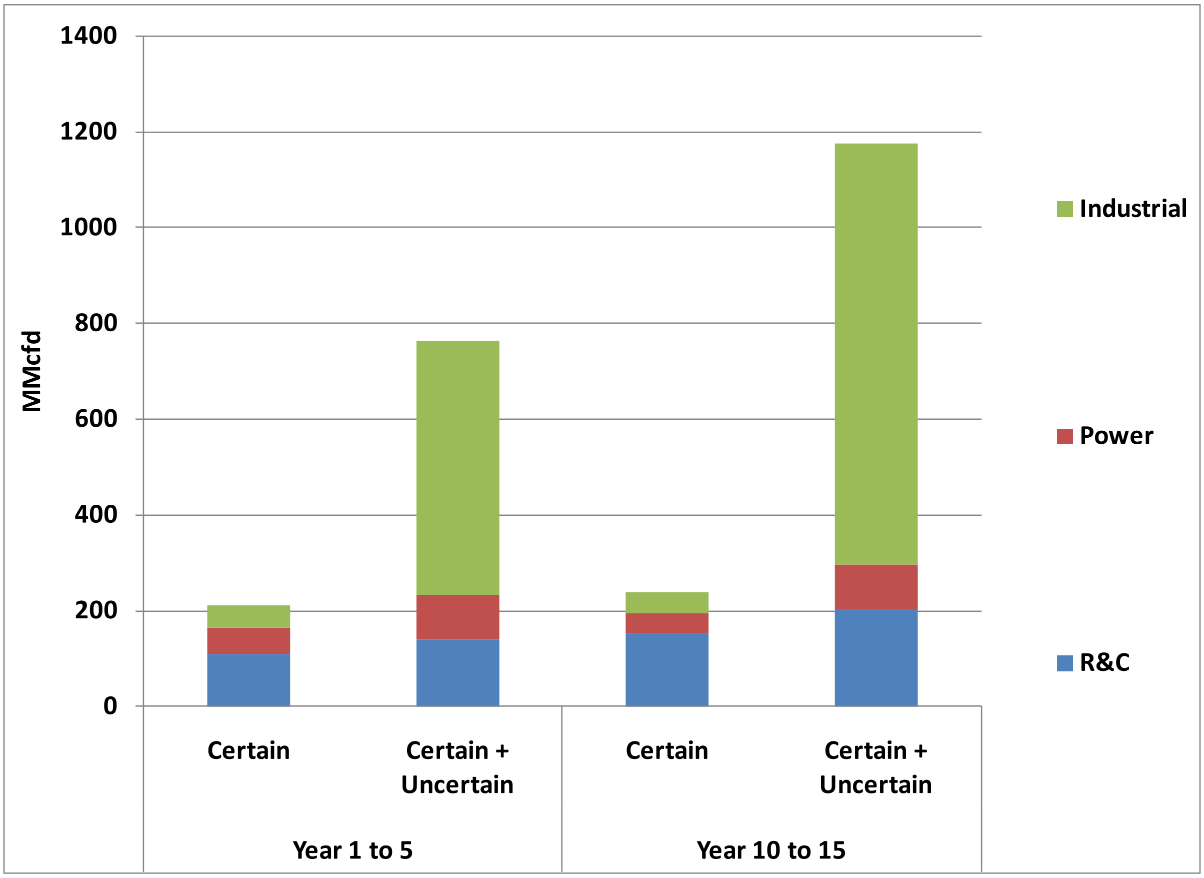
Figure 33 and Figure 34 present the range of certain and uncertain demand by sector in a different manner as the figures above, for both the Alberta and Valdez projects.

Figure 33. Projected Annual Average Daily Demand showing Certain and Uncertain Demand Range by Sector for Years 1 to 5 and Years 10 to 15, Alberta Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

Figure 34. Projected Annual Average Daily Demand showing Certain and Uncertain Demand Range by Sector for Years 1 to 5 and Years 10 to 15, Valdez Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

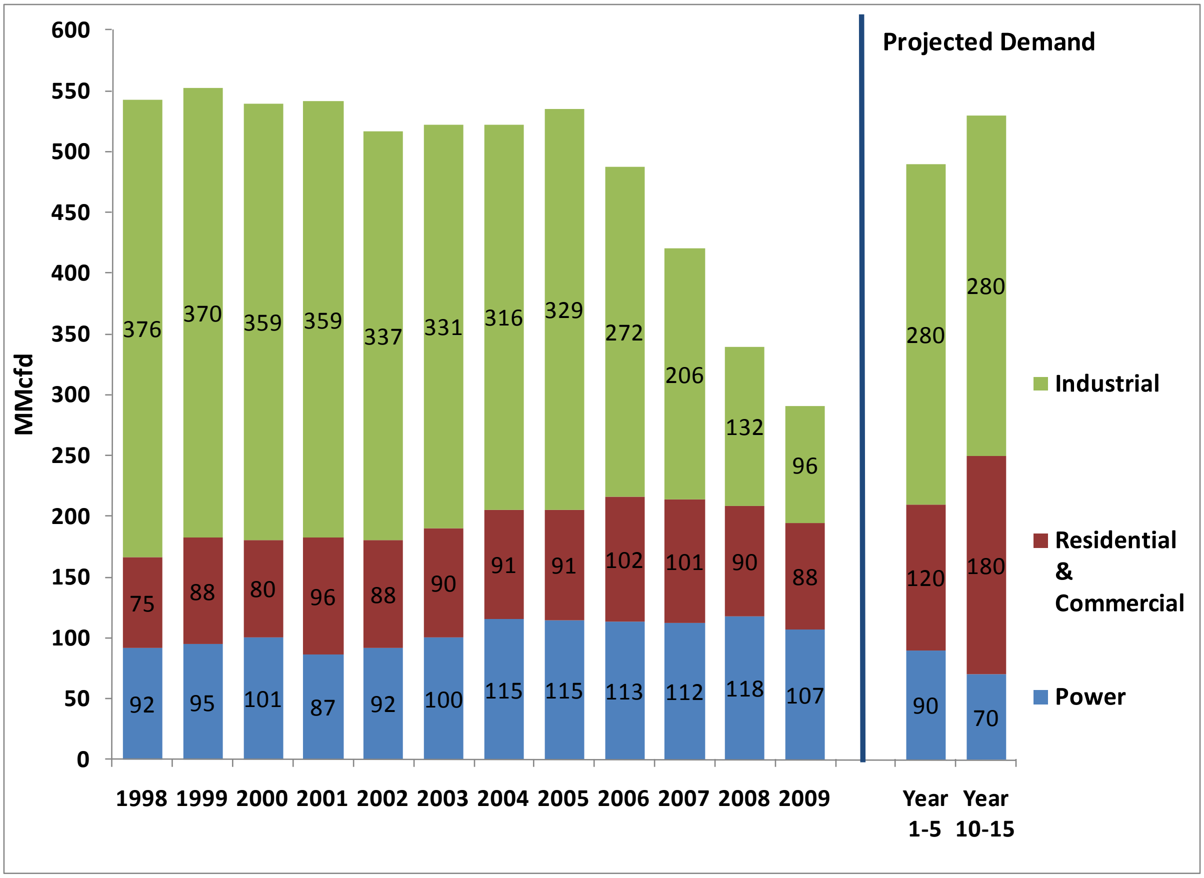
10.3 Summary of Projected Demand in the Current Industry Case

As described earlier, the current industry case represents a continuation of current trends with reasonable growth in demand in the power and residential and commercial sector, and one large gas-intensive industry—such as the existing LNG facility. Since this demand scenario has the greatest chance of occurrence among the three summary cases, the projected demand under the current industry case is used for analysis of potential off-take locations and volumes.

Figure 35 illustrates both the historic and the projected natural gas demand by sector. The projected demand totals represent the Current Industry Case for the Alberta Project for Year 1 to 5 and Year 10 to 15 of pipeline operations.

For the period 1998 to 2009, the total annual daily demand averaged about 480 million cubic feet. In the Current Industry scenario, this annual average daily demand is expected to stay at about the same level in the first five years of pipeline operations. While there is a projected increase in residential and commercial sector demand, the power sector and industrial sector demand are anticipated to decrease. Efficiency and demand side management programs implemented prior to pipeline operation are expected to decrease natural gas requirements for power generation. Projected industrial demand for the Current Industry scenario, assumes only one major gas-intensive industrial user. Demand is projected to increase to 520 MMcfd in the later years of pipeline operations due primarily to population growth.

Figure 35. Historic and Projected Total Annual Average Daily Demand for Natural Gas, Current Industry Scenario, Alberta Project



Source: Historical data are from the Division of Oil and Gas, Alaska Department of Natural Resources. Projected demand in Year 1 to 5 and Year 10 to 15 of pipeline operations are based on the results of this study.

Notes: Historical values for industrial sector include gas consumption for the LNG facility, the Ammonia-Urea plant from 1998 to 2007, and for other small operations such as for military bases in Anchorage, the GTL facility, Tesoro refinery, the small liquefaction facility that transports LNG to Fairbanks Natural Gas, etc. Gas consumed in field operations is not included in the values shown above. The sum of the projected values for Year 10-15 in this figure does not match the total Current Industry case demand in Table 28 due to rounding.

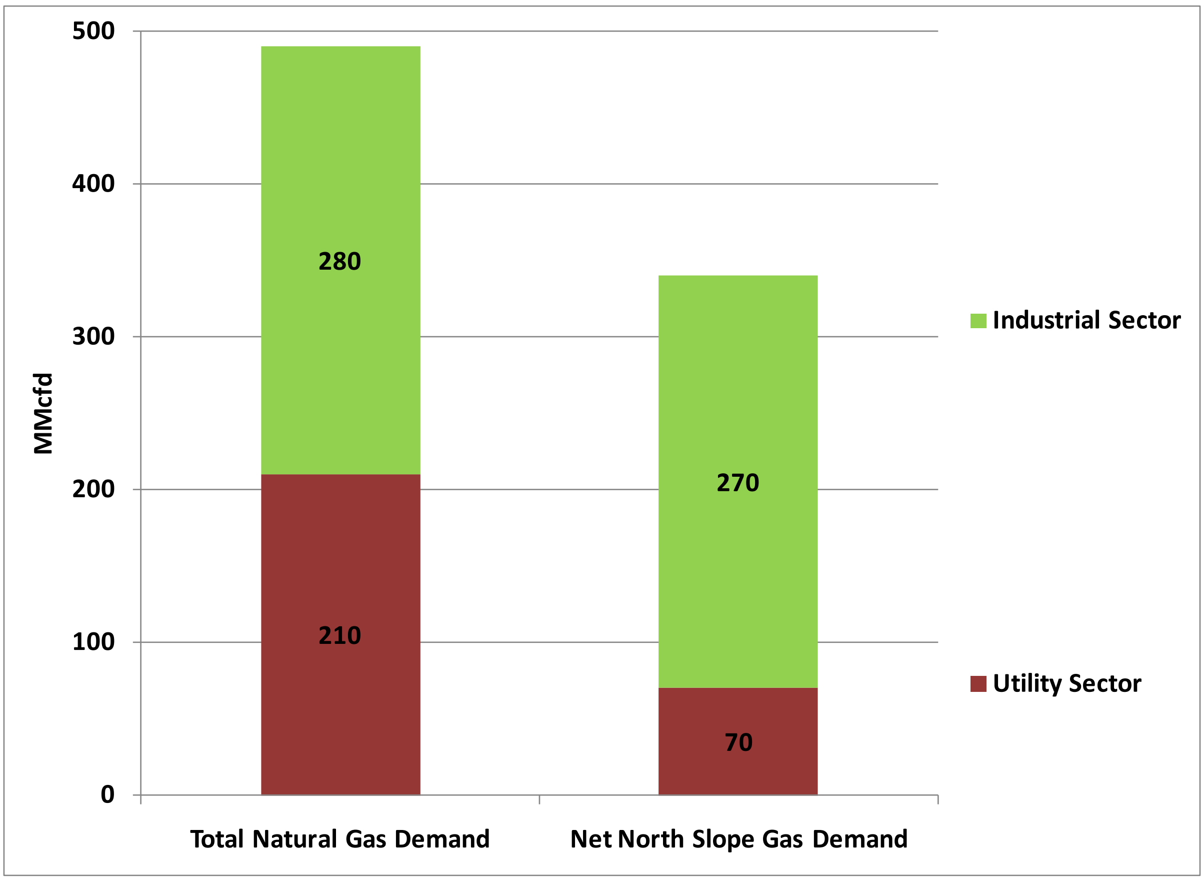
10.4 Net North Slope Natural Gas Demand

After the spur line is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence on natural gas with increased demand side management and energy efficiency, increased use of renewable energy sources, and expanded transmission systems. However, even with such diversification and new facilities, natural gas remains a major energy source for the Railbelt, even 50 years into the future. Given this long time frame, utilities would seek to diversify their supplies of natural gas and would consider gas from the North Slope, coal bed methane, landfill gas, underground coal gasification, and other sources. Utilities have indicated that Cook Inlet sources would remain as a very large percentage of their natural gas supplies even if North Slope gas is less expensive.

Discussions with several Southcentral utilities indicated that they might look to source 5 to 50 percent of their total gas demand from the North Slope. These percent estimates, when aggregated, suggest an average daily utility demand of about 40 MMcfd of North Slope Gas in the Southern Railbelt region in Years 1 to 5. In addition, industrial demand in the Southern Railbelt region for the current industry case is assumed to be met solely by North Slope gas. Therefore, under the Current Industry case for the Alberta Project, about 270 MMcfd of the total Southern Railbelt demand is projected to be supplied by North Slope gas, and about 160 MMcfd is assumed to be supplied by Cook Inlet gas.

As shown in Figure 36, for the Alberta Project, the total net demand for North Slope gas (including demand in the Northern Railbelt region) is projected to be about 340 MMcfd in Years 1 to 5 of pipeline operations.

Figure 36. Total Natural Gas Demand versus Total North Slope Natural Gas Demand, Current Industry Case, Year 1 to 5 of Pipeline Operations, Alberta Project



Source: Northern Economics, Inc., and SAIC, Inc., 2009.

For the Valdez Project, the total net demand for North Slope gas under the Current Industry case is projected to be about 350 MMcfd in Years 1 to 5 of pipeline operations.

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11 Potential Demand along the Pipeline Corridor

This section presents potential energy demand expressed as demand for natural gas of communities along the two pipeline routes under consideration, including the net effect of Cook Inlet production on the demand for North Slope gas.

Figure 37 shows the potential demand along the pipeline corridor in the first few years of pipeline operation. This figure shows the demand by community, as well as potential off-take points at Delta Junction or Glennallen, assuming a Richardson Highway or Glenn Highway spur line were built. If a Parks Highway spur were built instead of a Richardson Highway or Glenn Highway spur, similar demand would exist at a Parks Highway off-take location.

The demand shown for communities includes industrial demand as well as residential and commercial, and demand by the electric utilities. The demand at Livengood includes a proposed gold mine and the Fairbanks area demand includes demand by the two military bases in the community and the North Pole refineries, as well as power and residential and commercial demand.

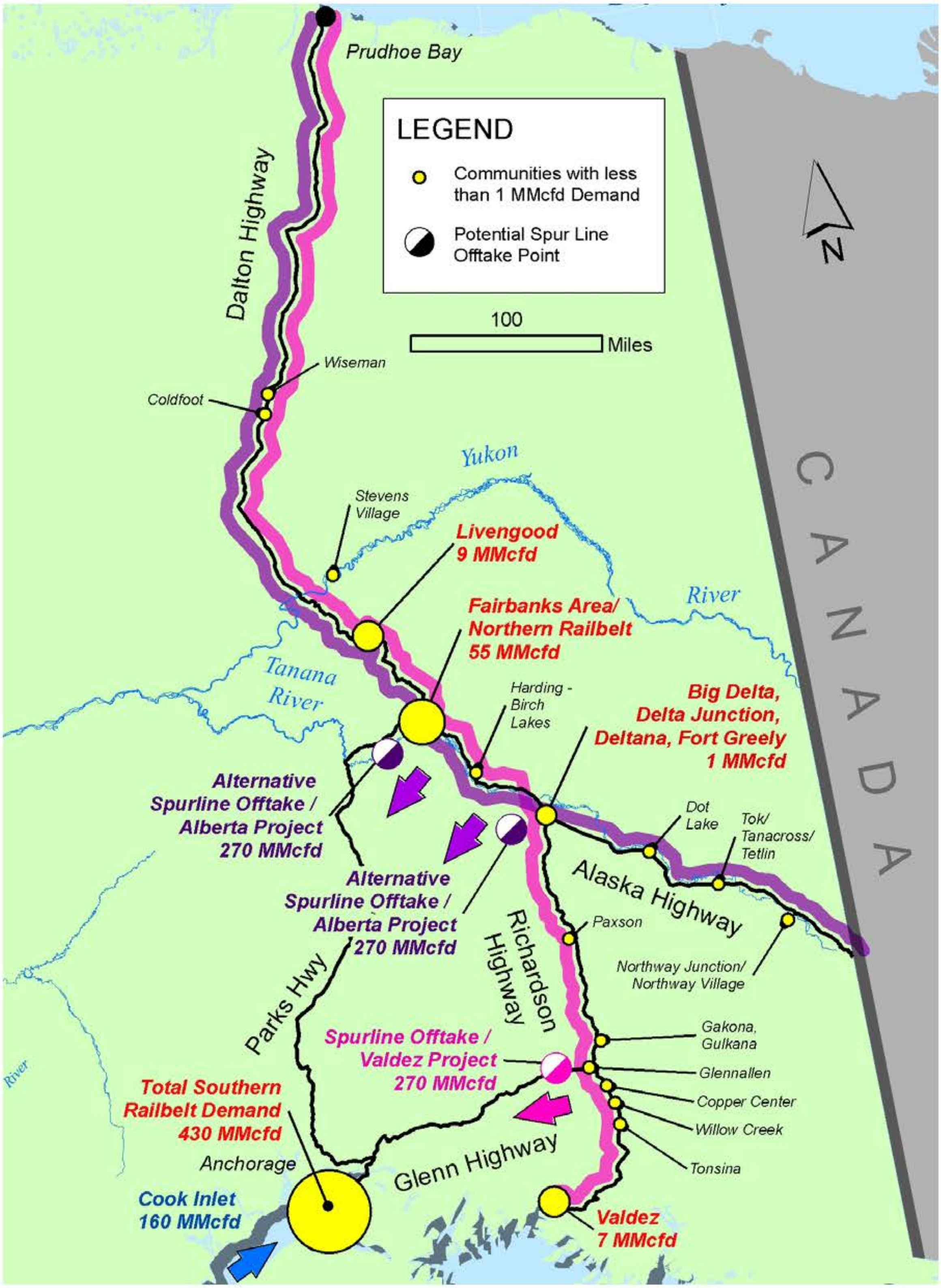
The projected demand (for the take-off volumes) for the Southern Railbelt and Valdez represent the results of the Current Industry demand scenario in the Year 1 to 5 timeframe as modeled in the combined demand probability analysis described in the previous section.

Table 30 and Table 31 show the results of the estimated potential annual average daily demand by location in more detail. The tables also show the net effect on demand for North Slope gas of the availability of Cook Inlet supplies. Projected Cook Inlet gas production is based on a study conducted by the Alaska Department of Natural Resources and with input from Southcentral utilities. The potential North Slope gas demand in the Southern Railbelt is reduced by Cook Inlet production.

Many of the communities along the pipeline routes have very small populations and typically have relatively small demand for natural gas or propane. As noted in Section 8, the capital cost for taking natural gas or propane off of the gas pipeline is very high per unit of energy, and for most small communities, it would be more cost-effective to truck propane from Fairbanks or another location to meet their energy requirements.

At the compressor stations along the pipeline, it is necessary to reduce the pressure to obtain gas for the compressor turbines, and propane could be produced at each compressor station with this pressure drop. No decision has been made regarding the potential for making propane available at any compressor stations, and the location of these stations is not yet confirmed. To the extent that propane was available at a compressor station and the station was closer to the community than Fairbanks or another large demand center, the cost of propane would be reduced for the community.

Figure 37. Potential Net Demand along the Pipeline Corridor, Current Industry Case, Year 1 to 5 of Pipeline Operations



Source: Alaska Map Company, 2009.

Table 30. Potential Annual Average Daily Demand along the Pipeline, Alberta Project (MMcfd)

Community	Total North Slope Demand
Spur Line off-take/ Southern Railbelt	270.0
Fairbanks Area/Northern Railbelt	55.0
Livengood	8.9
Big Delta, Delta Junction, Deltana, Fort Greely	1.4
Tok/Tanacross/Tetlin	0.4
Northway Junction/Northway Village	<0.1
Stevens Village	<0.1
Dot Lake	<0.1
Coldfoot	<0.1
Wiseman	<0.1

Source: Northern Economics estimates, 2009.

Table 31. Potential Annual Average Daily Demand along the Pipeline, Valdez Project (MMcfd)

Community	Total North Slope Demand
Spur Line off-take/ Southern Railbelt	270.0
Fairbanks Area/Northern Railbelt	55.0
Valdez	7.0
Livengood	8.9
Big Delta, Delta Junction, Deltana/Fort Greely	1.4
Copper Center	0.2
Glennallen	0.2
Gakona, Gulkana	0.2
Harding-Birch Lakes	<0.1
Willow Creek	<0.1
Tonsina	<0.1
Stevens Village	<0.1
Paxson	<0.1
Coldfoot	<0.1
Wiseman	<0.1

Source: Northern Economics estimates, 2009.

The demand estimates along each route suggest that potential off-take points should be considered for each potential spur line location and two or more may be required in the Fairbanks area, depending on the main gas pipeline alignment.

Table 32 shows the most likely off-take points based on the analysis conducted for this report. A proposed gold mine at Livengood is a likely candidate for a delivery point, one or more off-take points may be required in the Fairbanks area, and another one to provide for a Parks highway spur line to Southcentral Alaska, or for future growth along the Parks Highway. The communities in the Delta Junction area plus Fort Greely are a likely location for an off-take point, which could be on the main gas pipeline or on a proposed spur line that would generally parallel the Richardson and Glenn highways to the Cook Inlet region. The communities in the vicinity of Tok may not have sufficient demand at present to justify an off-take point, but there is the potential for future mineral development and associated demand in the region around Tok. Glennallen and Valdez would be obvious off-take points for the Valdez project since Glennallen would be the location of a spur line to Southcentral Alaska, and Valdez has community demand plus demand from the Alyeska marine terminal.

Table 32. Potential Off-Take Locations along the Alberta Line and the Valdez Line

	Route	
Location	**Alberta**	**Valdez**
Livengood	1	1
Fairbanks	1-2	1-2
Parks Highway spur	1	1
Delta Junction area/ Richardson Highway spur	1	1
Tok	1	NA
Glennallen	NA	1
Valdez	NA	1
Total	**5-6**	**6-7**

Source: Northern Economics, Inc.

At this time, ten years prior to the planned commencement of the TransCanada Alaska pipeline operation, the pro forma in-state gas tariff for the upcoming open season will be an estimate based on the demand for North Slope gas net of projected Cook Inlet supply as noted in this study. The actual tariff for the pipeline will be highly dependent on the actual contracted volume of the pipeline, which will be determined in the initial open season and subsequent open seasons.

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In-State Gas Demand Study
Volume II: Appendices

Prepared for

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January 2010

Northern Economics
Wisdom • Trust • Relevance • Innovation

In association with

- Institute of Social and Economic Research, University of Alaska
- Science Applications International Corporation

Appendix A: MAP Model Methodology, Assumptions, and Projection Summary

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Appendix A: MAP Projection Methodology, Assumptions, and Projection Summary

MAP Projection Methodology

The projections of economic, demographic, and fiscal variables for the state of Alaska and its regions have been generated using the Institute of Social and Economic Research (ISER) MAP Model. The MAP Model, or Man-in-the-Arctic Model, was originally created in 1975 with funding from the National Science Foundation to investigate the impacts of petroleum development on the state. (See Kresge, David and Seiver, Daniel. “Planning for A Resource Rich Region: The Case of Alaska” American Economic Review, 68(20), p 99-104. Kresge, David, Morehouse, Thomas, and Rogers, George. Issues in Alaska Development, University of Washington Press, 1977. Kresge, David et al. Regions and Resources: Strategies for Development, MIT Press, 1984.)

The model has been in continuous use since that time as the most sophisticated and comprehensive tool for projecting the long term future economic, demographic, and fiscal conditions in the state. The model components are constantly revised and updated to reflect the most current economic, demographic, and fiscal conditions.

Sometimes the model is used to analyze the impacts of a particular development or activity, such as the construction of a gas line, or to investigate the implications of a particular assumption about future economic conditions facing the state, such as the future price of oil. (For example, *Economic Analysis of Future Offshore Oil and Gas Development: Beaufort Sea, Chukchi Sea, and the North Aleutian Basin*, prepared for the Shell Oil Company with Northern Economics, March 2009) At other times the model is used to project the most likely future trend in economic and demographic activity to assist in planning efforts like investing in new electrical generating facilities (For example, *Economic Projections for Alaska and the Southern Railbelt: 2005-2030*, prepared for Chugach Electric Association, September 2005). Consequently, interpretation of the projections must be contingent upon the purpose for which the particular study has been designed.

There are 5 components to the MAP model: the ECONOMIC DEVELOPMENT SCENARIO, the ECONOMIC MODULE, the DEMOGRAPHIC MODULE, the FISCAL MODULE, and the REGIONAL MODEL. (They have been completely documented in *ISER MAP Alaska Economic Modeling Documentation*, prepared for the US Department of Interior, June 1986, available from ISER)

The model is driven by an **ECONOMIC DEVELOPMENT SCENARIO** which is a consistent set of assumptions about levels of future basic industry activity within the state, national variables, state fiscal policy variables, and other exogenous factors that are expected to influence the future pattern of economic and demographic trends. The scenario elements are compiled into a document that is an integral part of each projection.

The scenario elements are typically developed by the author in consultation with other Alaskan researchers in the private and public sectors as well as the client for whom the projection is being prepared.

The scenario elements for basic sector economic activity are a collection of both project-specific assumptions and generic industry assumptions. A typical project-specific element is the construction and operation of a gold mine at Fort Knox near Fairbanks while a typical generic element is the assumption of employment growth in the mining industry from projects not currently identified. In recognition of the fact that myopia prevents the identification of all potential projects that may occur over the next 20-50 years, there is a conscious effort in the creation of the scenarios to account for this bias through the inclusion of the generic elements. These generic elements have been developed to be as consistent as possible with historical patterns of industrial activity.

Past experience has shown that there are numerous combinations of scenario elements which, when combined into an ECONOMIC DEVELOPMENT SCENARIO, will yield essentially identical economic and demographic projections. This underscores the robustness of the method of dividing the scenario into a large number of assumptions, each of which individually has a small influence on the outcome.

(An example of this type of analysis is contained in *Economic and Demographic Projections for the Alaska Railbelt: 1988-2010*, for the Alaska Power Authority, August 1988).

At the same time, the projection results are quite sensitive to a small number of scenario assumptions. These include the rate of production and price of oil, the growth in average real wage rates in the US, and the growth of the non wage income of Alaska households.

The **ECONOMIC MODULE** takes the ECONOMIC DEVELOPMENT SCENARIO as input and produces projections of employment, payroll, and gross product by industry based upon econometrically determined relationships. Activity in the basic sectors of the economy, including primarily the natural resource producing sectors, federal spending, and tourism spending, generates payroll and other spending that, with other elements of personal income, results in employment and payroll in the support sectors. The support sectors are composed of portions of the service, trade, construction, utility, transportation, and finance industries.

Total employment is the sum of jobs in the basic and support sectors as well as state and local government and the self employed. Total labor income consists of wages and salaries, the income of the self employed, and supplements to wages (public and private benefits). Total personal income is the sum of labor income reduced by non resident earnings, dividends-interest-rent, and transfer payments. Total personal income ultimately determines the level of household consumption and the total amount of support sector economic activity.

Labor demand drives the **DEMOGRAPHIC MODULE** through changes in migration into the state. The size and age-sex-race composition of the population changes over time as a result of both natural increase (births minus deaths) and net migration. When employment growth increases the demand for labor, the supply of labor grows through an increase in net migration (in migrants minus out migrants) and vice versa. Labor force participation and household formation are both also age-sex-race specific. The demographic output is population and households by 5 year age cohorts by sex by race (Alaska Native and non-Native).

The **FISCAL MODULE** determines the revenues, expenditures, and employment of both state and local government, as well as the status of the Alaska Permanent Fund. The largest sources of revenues, petroleum taxes and royalties and federal grants, are derived from the ECONOMIC DEVELOPMENT SCENARIO. Projections of other revenues are determined within the module.

The level of state expenditures is determined by a set of rules that ensures a balance between revenues and expenditures over time. This is necessary because petroleum revenues will not be sufficient in the future to continue to fund a growing state budget. Consequently the ECONOMIC DEVELOPMENT SCENARIO includes assumptions about the growth rate of expenditures as well as the imposition of new taxes and the allocation of earnings of the Alaska Permanent Fund.

Local government spending is assumed to be equal to local government revenues.

The **REGIONAL MODEL** allocates a limited number of state projection variables—employment by major category, population, households, non labor income, and total personal income—to 27 census areas. This allocation is primarily based on the regional distribution of basic economic activity, included in the ECONOMIC DEVELOPMENT SCENARIO, and the historical pattern of population and income.

MAP Model Long Run Scenario Assumptions

Highlights:

- World oil price averages $100 (2009 $)
- Cumulative North Slope Oil Production = 4.1 Billion Barrels
- Henry Hub natural gas price averages $6.60 (2009 $)
- Gas pipeline operational in 2019 at 4.5 bcf/day
- OCS oil production from Beaufort Sea begins 2021
- Donlin Creek and Pebble Mines developed
- Active duty military force level trends slowly downward
- US recession slows Alaska economy in 2009 and 2010

A. BASIC INDUSTRY ASSUMPTIONS	
A.1. Petroleum	
1. Oil Price	Low sulfur light crude price averages $100 per barrel (2009 $) between 2009 and 2030 (Energy Information Administration, April 2009). This corresponds to an average wellhead price for North Slope crude of $98. (DOR.S08M).
2. North Slope Oil Production on State Lands (Colville to Canning)	Cumulative production of 4.1 billion barrels between 2009 and 2030 (Alaska Department of Natural Resources 2007 Annual Report). (DOR.S08M)
3. Employment (Petroleum and Construction) Associated with Oil Production on State Lands (Colville to Canning)	Constant employment thru 2025, then declining 2% per year (ONS.S08M)
4. Cook Inlet Petroleum Production	Employment constant thru 2020, then declining at 2% per year (OCI.S08M)
5. NPRA	Cumulative production of .5 billion barrels between 2009 and 2030. (NPR.S08M)
6. ANWR	None.
7. OCS	Exploration, development and production occur in the Beaufort and Chukchi Seas as well as the Aleutian Basin. Oil production begins in 2021 in the Beaufort rising to 700 million barrels per day by 2030 from all three areas. Gas production begins in 2024 in the Aleutian Basin and rises to .3 bcf per day by 2030 in all three areas. OCS development stimulates additional production from onshore state lands. (OCS.S08M)
8. Other Oil & Gas	Modest employment centered around Nenana and Copper River Basin. No significant production (OOT.S08M)
9. Trans-Alaska Pipeline	Pipeline continues to operate at current employment level (TAP.S08M)
10. Value Added Oil	Refining employment constant at current level.
11. Natural Gas Price	Henry Hub price averages $6.63 per mmbtu (2009$) between 2009 and 2030 (Energy Information Administration, April 2009) . (ONG.S08M)
12. North Slope Gas Pipeline	Gas pipeline along highway (including spur line) becomes operational in 2019 with initial capacity of 4.5 bcf per day to accommodate production from onshore fields. Subsequent modest capacity expansion allows for marketing of OCS gas (ONG.S08M)
13. LNG in Cook Inlet	Operational at reduced level thru 2018. (OOT.S08M)
14. Agrium Fertilizer	Not operational after 2008. (OMN.S08M)
15. In-state Gas Line (Bullet Line)	Not constructed

A.2. Mining	
1. Greens Creek Mine	Constant employment (MGC.S08)
2. Red Dog Mine	Constant employment (MRD.S08)
3. Pogo	Constant employment (MFG.S08)
4. Kensington Mine	Production begins in 2010 (MKN.S08M)
5. Fort Knox/True North	Production is constant through 2020, then declines 3% annually (MFK.S08)
6. Healy Coal for Export	Production constant (MHC.S08)
7. Livengood Mine	Production begins in 2015 (LIV.08M)
8. Donlin Creek Mine	Production begins in 2014 (MDK.08M)
9. Pebble Mine	Production begins in 2024 on modest scale (MPB.08M)
10. Beluga Coal Production	None
11. Matanuska Valley Coal	None
12. Other Mining Activity	Mining employment net of specifically identified projects increases by 2% annually (MOT.S08)
A.3. Seafood	
1. Commercial Fish Harvesting	Shore-based employment in fish harvesting is constant (SFH.S08M)
2. Commercial Fish Processing	Constant employment (SFP.S08M)
A.4. Tourism	
1. Tourism	Index of tourist visitor expenditures (measuring visitors, days, and real expenditures per visitor day) increases by 5% with visitor and employment growth of 2.5% thru 2025 then 1.5%. Tourism-related infrastructure development grows 2% annually thru 2015 and then 1% (TRN.S08M)
A.5. International Freight Handling	
1. Air Transport Employment	Employment at Anchorage and Fairbanks International airports associated with international freight handling continues to grow 2% annually through 2015 and 1% thereafter. (AIR.S08M)
A.6. Forest Products	
1. Logging and Sawmills	Growth at 1 percent in all regions that currently have logging. (FML.S08M)
2. Timber Manufacture	None. (FMP.S08M)
A.7. Agriculture	
1. Agriculture	Employment in agriculture, primarily for local markets, increases 1% annually. (AGR.S08M)
A.8. Retirees	
1. Retiree Public Income	.2 % real per capita growth rate (GRPITR.R)
2. Migration—Seniors (65+)	In and out migration rates constant based on 2000 census information (PAROLD)
3. Labor Force Participation Rate—Seniors	Constant based on 2000 census information in Labor Force participation rates for Senior population (65+)
A.9. Federal Government	
1. Military Employment	Basic strength level falls 1% annually starting in 2010 (FMI.S08M)
2. Military Expansion	None
3. Civilian Agency Employment	Employment increases at .25% annual rate consistent with long-term trend since 1960 (FCV.S04M)
4. Military and Agency Construction Procurement	Federally funded construction projects administered by federal agencies (including both civilian and military) declines by 5% annually starting in 2009 to a level consistent with the historical trend by 2016. (CON.S08M)
5. Grants to State Government	Grants to state government, for both capital projects and operations, contract until 2013 and then resume growth at the rate of population growth and inflation (FEDEX)
6. Grants to Nonprofits	Drop-in value added in nonprofit sector of $60 million between 2008 and 2013 (FEDNPX)
7. Transfers to Individuals (Medicare and Medicaid)	Growing at rate of population, prices, and income.
8. Cost-of-Living Adjustment	COLA falls from 25% to 15% over the period of 25 years starting in 2006. (FEDCOLA)

B. STATE FISCAL ASSUMPTIONS	
B.1. Petroleum Revenues on Current Production	
1. Severance (ACES) Taxes (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then 14% of wellhead value. (DOR.S08M)
2. Royalties (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then 12% of wellhead value. (DOR.S08M)
3. Petroleum Corporate Income Tax (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then 3% of wellhead value. (DOR.S08M)
4. Property Taxes (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then declining 3% annually in nominal dollars. (DOR.S08M)
5. Bonuses (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenues Sources through 2018 and continuing at constant nominal level. (DOR.S08M)
6. Rents (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018 and continuing at constant nominal level. (DOR.S08M)
7. Petroleum Settlements from Earlier Year Taxes	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018 and continuing at constant nominal level. (DOR.S08M)
8. Federal-State Petroleum-Related Shared Revenues	None. (DOR.S08M)
B.1. Petroleum Revenues on New Production	
1. NPRA Revenues	Royalties, production taxes, and corporate income taxes based on current state fiscal structure (NPR.S08M)
2. ANWR Revenues	None.
3. OCS Revenues	Royalties, property taxes, and corporate income taxes based on current state fiscal structure. (OCS.S08M)
4. Gas Pipeline Revenues	Royalties, production taxes, property taxes, and corporate income taxes based on current state fiscal structure as reflected in AGIA application (ONG.S08M)
B.3. Other State General Fund Revenues	
1. Personal Income Tax	No tax before 2030 due to high petroleum revenues (EXPIT)
2. Large Project Corporate Income Taxes	Captured in project specific scenario elements
3. Miscellaneous New Revenue Sources	None
4. New Federal-State Shared Revenues	None
5. Agency Transfers to State General Fund (AHFC, AIDEA)	$100 million (increasing with inflation) contributed to general fund annually (RMISX)
B.4. State General Fund Appropriations	
1. General Fund Appropriations	Growth at inflation rate plus population growth rate. (EXEL1, EXEL2)
2. General Fund Capital/Operations Split	90% operations; 10% capital (EXSPLITX)
3. General Obligation Bonds	Bond sales for capital expenditures are fixed percentage of GF capital appropriations (EXCPSGOB)
4. Special Appropriations to Permanent Fund & Other Special Appropriations in Excess of Normal General Fund Spending	None (PFTOGF)
5. Annual appropriation to PERS/TRS retirement accounts	$200 million (PERS)
6. New Matsu Prison	Annual employment of 500 phased in starting in 2011 (PMS.S08M)
7. Medicaid	Combined state and federal expenditures grow 5% annually.
8. Special Capital Expenditures Associated with Gas Line Construction	$500 million prior to gas line construction
9. Chakachamna Hydroelectric Project	Not constructed.
10. Susitna Hydroelectric Project	Not constructed.

B.5. State Non-General Fund Spending	
1. State Loan Programs	AHFC, AIDEA, and other programs function on existing capitalization
2. Grants from Federal Government	See Section A.8.
3. Other Restricted Fund Revenues and Expenditures	Growth at the rate of inflation plus population and per capita real income
B.6. Permanent Fund and Constitutional Budget Reserve, Fiscal Gap	
1. Permanent Fund Principal	Deposits from petroleum revenues continue at 25 % of royalties (EXPF1)
2. Permanent Fund Total Real Rate of Return	4.5 % (RORPPF)
3. Permanent Fund Earnings	After payment of dividend and inflation proofing, remainder accrues in earnings reserve, where it is used to supplement general fund revenues. When earnings reserve depleted, dividend reduced and those funds are used to support general fund (EXPFTOGF)
4. Permanent Fund Dividend	Half of annual earnings of fund paid out as dividend, until such time as Permanent Fund earnings are required to pay for general fund expenditures. Subsequent to that time the dividend payment gradually reduced to 25% of earnings. (EXPFDIV)
5. Constitutional Budget Reserve Real Rate of Return	3 % (ROR+RORPDF)
C. LOCAL GOVERNMENT FISCAL ASSUMPTIONS	
1. State-Local Wage Rates	Growth at rate of inflation and 80% of real increase in the national rate (EXWR)
2. Local Property Tax Rates	Rises from 1.3% to 1.5% by 2024 and then constant (RLPTRATE)
3. Federal - Local Revenue Sharing	None (RSFDNX)
4. Petroleum Property Taxes associated with existing production	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then declining 3% annually in nominal dollars. (DOR.S08M)
5. Petroleum Property Taxes and Federal Transfers associated with new production	See production scenarios. (RPPLOCAL and RLTFPX)
D. NATIONAL VARIABLE ASSUMPTIONS	
1. U.S. Inflation Rate	Approximately 2.5% annually from Energy Information Administration, April 2009. (GRUSCPI)
2. U.S. Real Average Weekly Earnings	.25% real growth (GRRWEUS)
3. U.S. Unemployment Rate	5.5 % (UUS)
4. Base Year for Converting Nominal to Real Dollars	2009
E. ALASKA PERSONAL INCOME	
1. Exxon Valdez Settlement	Alaska residents receive $700 million in settlements in 2009 and 2010. (PITRANX)
2. Dividend-Interest-Rent Income	.5 % real per capita growth (GRDIRPU)
F. POPULATION	
1. Birth Rates & Death Rates	Continuation of historical rates by age, sex and race from 2000 Census.
2. Migration—Work Related	Continuation of historical rates by age, sex, and race from 2000 Census.
3. Labor Force Participation Rate	Continuation of historical rates by age, sex and race from 2000 Census.
4. Households	Continuation of historical rates of household formation by age, sex, and race from 2000 Census.
G. REGIONAL ASSUMPTIONS	
1. Employment	Gradual migration of basic employment from Anchorage to Mat-Su Borough at a rate of 100 employees per year. (BASICSHFT)
2. Commuters	Share of workers filling basic sector jobs in Anchorage who commute from Matsu Borough increases .008 % annually. (RESSHFT1)

NOTES: Codes in parentheses indicate ISER names for MAP Model case files, and codes in brackets indicate MAP variable names.

These are the long-run assumptions. Values for some variable differ in the initial years to reflect the effects of the 2008-2010 recession and other short term conditions.

State Economic Projection Detail

TABLE 1A. PROJECTION SUMMARY
2009 BASE CASE FOR TRANSCANADA INSTATE GAS STUDY

	POPULATION (000)	HOUSEHOLDS (000)	TOTAL EMPLOY-MENT (000)	WAGE AND SALARY EMPLOYMENT (000)	PERSONAL INCOME (MILL 09$)	PER CAPITA PERSONAL INCOME (2009 $)	PETROLEUM REVENUES (FY) (MILL 09$)	OIL PRICE ANS WEST COAST (CY) (NOMINAL $)
2000	627.5	221.6	395.0	280.7	$23,628	$37,653	$2,378	$27
2001	632.0	224.2	401.6	287.9	$24,515	$38,792	$2,632	$22
2002	640.2	228.2	411.3	292.3	$24,903	$38,900	$1,824	$23
2003	647.2	230.6	410.9	296.9	$24,698	$38,162	$2,113	$28
2004	656.6	234.1	421.4	301.4	$25,692	$39,131	$2,405	$37
2005	663.1	238.0	430.9	307.8	$26,743	$40,331	$3,728	$50
2006	669.7	241.8	443.3	314.1	$27,910	$41,674	$4,664	$60
2007	674.5	243.6	441.7	317.2	$28,704	$42,556	$5,497	$67
2008	679.7	246.2	447.3	321.5	$29,967	$44,087	$11,789	$94
2009	680.7	247.8	440.9	316.6	$27,809	$40,852	$5,681	$40
2010	684.1	249.9	438.8	315.3	$27,846	$40,706	$2,889	$52
2011	690.8	253.1	440.4	316.8	$27,945	$40,454	$3,776	$66
2012	691.1	254.0	440.7	317.2	$27,922	$40,402	$4,915	$77
2013	691.3	254.8	441.4	318.0	$27,968	$40,458	$5,315	$88
2014	689.5	254.9	443.2	319.7	$28,237	$40,951	$5,993	$99
2015	693.4	256.9	449.5	324.7	$28,666	$41,344	$6,274	$109
2016	710.9	263.6	461.6	334.2	$29,458	$41,441	$6,214	$118
2017	730.4	271.0	468.2	339.4	$30,054	$41,149	$6,400	$126
2018	741.8	275.5	474.0	344.1	$30,553	$41,187	$6,635	$134
2019	752.9	280.0	477.2	346.7	$30,892	$41,032	$6,625	$140
2020	766.0	285.1	486.6	354.1	$31,542	$41,177	$7,088	$146
2021	783.9	291.9	496.2	361.6	$32,262	$41,157	$7,340	$151
2022	803.1	299.1	508.5	371.1	$33,111	$41,230	$7,016	$157
2023	821.3	305.9	517.0	377.7	$33,855	$41,220	$6,750	$162
2024	834.4	311.0	523.8	383.0	$34,433	$41,267	$6,502	$167
2025	847.1	316.0	530.8	388.4	$35,023	$41,344	$6,172	$172
2026	859.4	320.8	537.3	393.6	$35,578	$41,400	$5,952	$177
2027	870.1	325.0	542.8	397.9	$36,085	$41,471	$5,686	$183
2028	880.4	329.2	548.8	402.6	$36,592	$41,563	$5,565	$190
2029	890.7	333.3	555.1	407.5	$37,129	$41,683	$5,396	$197
2030	899.5	336.8	559.4	410.9	$37,531	$41,725	$5,224	$204

ANNUAL AVERAGE GROWTH RATE

2000-2010	0.87%	1.21%	1.06%	1.17%	1.66%	0.78%	1.97%	6.90%
2010-2020	1.14%	1.33%	1.04%	1.17%	1.25%	0.12%	9.39%	10.83%
2020-2030	1.62%	1.68%	1.41%	1.50%	1.75%	0.13%	-3.00%	3.40%
2000-2030	1.21%	1.41%	1.17%	1.28%	1.55%	0.34%	2.66%	7.00%

MAP MODEL SIMULATION	MODEL FOR ESTIMATING REGIONAL HOUSEHOLDS	
PREPARED FOR	NORTHERN ECONOMICS (TRANSCANADA)	
CREATED	AUGUST 15, 2009	
POPULATION	JULY 1 CENSUS DEFINITION	POP
HOUSEHOLDS	JULY 1 CENSUS DEFINITION	HH
TOTAL EMPLOYMENT	BEA DEFINITION INCLUDES ACTIVE DUTY MILITARY, RESERVISTS, PROPR	EM99.BEA
WAGE & SALARY EMPLOYMENT	ALASKA DEPT OF LABOR DEFINITION	EM97
PERSONAL INCOME	USDC BEA DEFINITION	DF.PIB
PER CAPITA PERSONAL INCOME	USDC BEA DEFINITION	
PETROLEUM REVENUES	INCLUDES PERMANENT FUND CONTRIBUTION BUT NOT CBR REVENUES	DF.RP9S
ANS WEST COAST PRICE	HISTORICAL IS US AVERAGE CRUDE PRICE	

Appendix: Regional Projection Detail

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
WAGE AND SALARY EMPLOYMENT (000)	314.04	315.54	316.00	316.80	318.49	323.48	332.99	338.20	342.83	345.50
North	18.22	18.56	18.61	18.99	19.16	19.82	21.59	22.00	21.73	21.27
Yukon - Koyukuk	2.36	2.37	2.43	2.57	2.61	2.70	3.18	3.26	3.07	2.73
Northern Railbelt	40.61	40.67	40.82	40.96	41.10	41.92	43.72	44.37	44.35	43.79
Denali	2.33	2.35	2.36	2.38	2.40	2.44	2.49	2.53	2.58	2.62
Frbks	38.29	38.32	38.46	38.58	38.70	39.48	41.23	41.84	41.77	41.17
SE Fairbanks	2.60	2.60	2.61	2.61	2.63	2.65	2.68	2.72	2.78	2.84
Yukon - Kuskokwim	9.35	9.54	9.75	9.69	9.52	9.80	9.92	10.08	10.33	10.57
South West	14.65	14.70	14.71	14.75	14.92	15.00	15.26	15.24	15.68	16.00
Southern Railbelt	186.10	186.72	186.52	186.63	187.78	190.21	194.34	197.53	201.19	204.06
Matsu	19.54	20.28	20.42	20.64	20.97	21.52	22.40	22.97	23.49	23.88
Anch	149.62	149.71	149.44	149.32	150.04	151.76	154.80	157.13	159.83	161.96
Kenai	16.94	16.73	16.67	16.67	16.77	16.93	17.14	17.44	17.87	18.22
Valdez-Cordova	4.49	4.51	4.59	4.59	4.61	4.86	5.35	5.45	5.27	4.93
South East	35.67	35.86	35.96	36.01	36.16	36.52	36.95	37.54	38.43	39.31
POPULATION (000)	684.09	690.78	691.11	691.28	689.53	693.36	710.85	730.39	741.80	752.87
North	24.12	24.45	24.55	24.58	24.44	24.44	24.74	25.32	25.76	26.32
Yukon - Koyukuk	5.71	5.76	5.81	5.92	5.91	5.94	6.31	6.47	6.35	6.15
Northern Railbelt	99.39	99.87	99.86	99.77	99.15	99.58	102.37	104.73	105.08	105.07
Denali	1.69	1.71	1.73	1.73	1.74	1.75	1.79	1.85	1.89	1.94
Frbks	97.70	98.15	98.14	98.03	97.42	97.83	100.58	102.88	103.19	103.13
SE Fairbanks	7.01	7.05	7.05	7.04	7.02	7.01	7.05	7.22	7.35	7.52
Yukon - Kuskokwim	25.08	25.49	25.75	25.67	25.32	25.41	25.47	26.02	26.50	27.14
South West	28.43	28.64	28.67	28.64	28.48	28.32	28.44	28.81	29.10	29.50
Southern Railbelt	414.86	419.11	418.73	418.97	418.79	421.89	434.21	447.27	455.43	463.16
Matsu	81.75	84.36	85.28	86.33	86.98	88.91	93.77	96.90	97.88	98.26
Anch	280.71	282.17	280.92	280.07	279.35	280.37	286.77	295.29	301.54	307.99
Kenai	52.40	52.58	52.53	52.57	52.46	52.61	53.67	55.08	56.01	56.91
Valdez-Cordova	9.53	9.63	9.73	9.73	9.68	9.93	10.59	10.88	10.69	10.36
South East	69.96	70.77	70.96	70.96	70.72	70.84	71.67	73.68	75.53	77.66
HOUSEHOLDS (000)	249.87	253.05	253.96	254.76	254.90	256.91	263.58	270.98	275.51	279.96
North	6.88	7.00	7.05	7.08	7.06	7.07	7.16	7.33	7.47	7.64
Yukon - Koyukuk	2.07	2.09	2.12	2.17	2.17	2.19	2.32	2.38	2.34	2.26
Northern Railbelt	37.10	37.39	37.52	37.59	37.47	37.72	38.80	39.71	39.87	39.91
Denali	0.72	0.73	0.74	0.75	0.75	0.76	0.78	0.80	0.82	0.85
Frbks	36.38	36.66	36.77	36.84	36.72	36.96	38.02	38.91	39.05	39.06
SE Fairbanks	2.43	2.46	2.46	2.47	2.47	2.47	2.48	2.54	2.60	2.66
Yukon - Kuskokwim	6.55	6.68	6.77	6.77	6.70	6.74	6.75	6.90	7.03	7.21
South West	8.45	8.55	8.58	8.60	8.57	8.53	8.57	8.70	8.81	8.95
Southern Railbelt	155.33	157.37	157.72	158.26	158.66	160.17	164.86	169.87	173.15	176.34
Matsu	29.30	30.34	30.78	31.25	31.58	32.36	34.15	35.28	35.67	35.84
Anch	106.02	106.89	106.76	106.75	106.79	107.43	109.92	113.23	115.75	118.39
Kenai	20.01	20.14	20.18	20.26	20.28	20.38	20.80	21.36	21.73	22.11
Valdez-Cordova	3.73	3.79	3.84	3.85	3.84	3.95	4.22	4.33	4.26	4.13
South East	27.33	27.73	27.90	27.98	27.97	28.08	28.41	29.21	29.98	30.86
PERSONAL INCOME (09 MILLION $)	$27,846	$27,945	$27,922	$27,968	$28,237	$28,666	$29,458	$30,054	$30,553	$30,892
North	$840	$846	$845	$847	$852	$865	$888	$906	$923	$938
Yukon - Koyukuk	$158	$159	$159	$161	$163	$166	$174	$179	$180	$180
Northern Railbelt	$3,596	$3,598	$3,592	$3,595	$3,620	$3,673	$3,783	$3,850	$3,884	$3,893
SE Fairbanks	$270	$271	$271	$271	$274	$277	$284	$289	$294	$297
Yukon - Kuskokwim	$617	$620	$620	$620	$625	$633	$643	$658	$676	$693
South West	$977	$980	$978	$979	$986	$998	$1,021	$1,037	$1,056	$1,070
Southern Railbelt	$18,024	$18,095	$18,080	$18,118	$18,311	$18,602	$19,140	$19,536	$19,864	$20,081
Valdez-Cordova	$379	$381	$382	$382	$385	$395	$413	$422	$424	$421
South East	$2,985	$2,997	$2,995	$2,996	$3,022	$3,058	$3,112	$3,177	$3,252	$3,319
PER CAPITA PERSONAL INCOME (09 THOU $)	$40.71	$40.45	$40.40	$40.46	$40.95	$41.34	$41.44	$41.15	$41.19	$41.03
North	$34.84	$34.59	$34.44	$34.45	$34.85	$35.37	$35.90	$35.78	$35.84	$35.65
Yukon - Koyukuk	$27.69	$27.54	$27.37	$27.11	$27.55	$27.88	$27.55	$27.64	$28.41	$29.31
Northern Railbelt	$36.19	$36.02	$35.97	$36.03	$36.51	$36.88	$36.95	$36.77	$36.97	$37.05
SE Fairbanks	$38.50	$38.40	$38.42	$38.55	$38.97	$39.60	$40.30	$40.08	$39.98	$39.54
Yukon - Kuskokwim	$24.58	$24.32	$24.09	$24.14	$24.67	$24.90	$25.23	$25.28	$25.50	$25.54
South West	$34.36	$34.21	$34.13	$34.17	$34.62	$35.25	$35.91	$36.00	$36.28	$36.27
Southern Railbelt	$43.45	$43.17	$43.18	$43.24	$43.72	$44.09	$44.08	$43.68	$43.62	$43.36
Valdez-Cordova	$39.80	$39.53	$39.24	$39.29	$39.81	$39.76	$39.01	$38.80	$39.64	$40.67
South East	$42.67	$42.34	$42.20	$42.22	$42.73	$43.17	$43.42	$43.12	$43.05	$42.73

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WAGE AND SALARY EMPLOYMENT (000)	352.85	360.34	369.83	376.48	381.78	387.21	392.35	396.64	401.33	406.26	409.67
North	21.03	21.58	22.51	23.08	23.12	23.31	23.51	23.42	23.62	23.91	23.60
Yukon - Koyukuk	2.81	2.89	2.92	2.99	3.05	3.10	3.14	3.19	3.23	3.27	3.30
Northern Railbelt	44.59	45.40	46.12	46.98	47.70	48.34	48.90	49.43	49.94	50.49	50.92
Denali	2.68	2.73	2.80	2.85	2.90	2.95	2.99	3.02	3.06	3.10	3.13
Frbks	41.91	42.66	43.33	44.13	44.80	45.39	45.92	46.40	46.88	47.39	47.78
SE Fairbanks	2.90	2.95	3.01	3.08	3.13	3.18	3.22	3.27	3.31	3.35	3.39
Yukon - Kuskokwim	10.77	10.95	11.18	11.44	11.68	11.88	12.05	12.21	12.37	12.52	12.66
South West	17.48	17.98	19.50	18.37	17.72	17.71	17.86	17.92	18.05	18.19	18.31
Southern Railbelt	208.19	212.74	217.82	222.75	226.66	230.19	233.47	236.36	239.35	242.45	244.81
Matsu	24.57	25.36	26.23	26.90	27.49	28.07	28.62	29.12	29.65	30.20	30.63
Anch	165.04	168.48	172.30	176.11	179.08	181.73	184.17	186.31	188.51	190.81	192.52
Kenai	18.58	18.90	19.30	19.73	20.09	20.40	20.67	20.93	21.19	21.44	21.66
Valdez-Cordova	5.00	5.07	5.12	5.21	5.30	5.37	5.43	5.49	5.54	5.60	5.66
South East	40.08	40.78	41.65	42.58	43.42	44.13	44.75	45.35	45.93	46.50	47.03
POPULATION (000)	766.01	783.87	803.08	821.33	834.39	847.11	859.37	870.12	880.41	890.74	899.47
North	26.55	26.94	27.38	27.95	28.38	28.75	29.08	29.38	29.65	29.91	30.16
Yukon - Koyukuk	6.22	6.32	6.35	6.47	6.56	6.63	6.69	6.76	6.81	6.86	6.92
Northern Railbelt	106.37	108.23	109.86	111.97	113.47	114.84	116.10	117.25	118.27	119.30	120.23
Denali	1.98	2.04	2.09	2.14	2.18	2.22	2.26	2.29	2.32	2.35	2.39
Frbks	104.38	106.20	107.77	109.83	111.29	112.61	113.84	114.96	115.95	116.95	117.85
SE Fairbanks	7.62	7.76	7.90	8.06	8.18	8.29	8.39	8.49	8.58	8.67	8.75
Yukon - Kuskokwim	27.40	27.73	28.07	28.60	29.04	29.40	29.71	30.03	30.28	30.52	30.80
South West	30.16	30.59	31.46	30.96	30.74	30.85	31.02	31.16	31.28	31.38	31.54
Southern Railbelt	472.13	484.92	498.74	511.79	520.64	529.35	537.88	545.13	552.35	559.70	565.40
Matsu	100.42	103.96	107.39	109.56	111.19	113.04	114.95	116.52	118.22	119.98	121.31
Anch	313.94	322.07	331.13	340.76	347.16	353.19	358.98	363.96	368.78	373.69	377.49
Kenai	57.77	58.89	60.22	61.47	62.29	63.12	63.95	64.65	65.34	66.03	66.59
Valdez-Cordova	10.50	10.67	10.82	10.99	11.14	11.28	11.41	11.54	11.65	11.76	11.87
South East	79.07	80.71	82.50	84.54	86.24	87.73	89.08	90.39	91.53	92.64	93.80
HOUSEHOLDS (000)	285.07	291.86	299.06	305.89	311.02	315.96	320.76	325.01	329.19	333.30	336.85
North	7.71	7.82	7.95	8.12	8.25	8.36	8.46	8.55	8.64	8.72	8.80
Yukon - Koyukuk	2.29	2.33	2.34	2.38	2.41	2.44	2.47	2.49	2.51	2.53	2.55
Northern Railbelt	40.43	41.15	41.77	42.56	43.16	43.71	44.21	44.68	45.11	45.54	45.93
Denali	0.87	0.89	0.92	0.94	0.96	0.97	0.99	1.01	1.02	1.04	1.05
Frbks	39.56	40.26	40.85	41.62	42.21	42.73	43.22	43.68	44.09	44.50	44.88
SE Fairbanks	2.70	2.75	2.80	2.85	2.90	2.94	2.98	3.02	3.05	3.09	3.12
Yukon - Kuskokwim	7.28	7.37	7.46	7.60	7.72	7.82	7.90	7.99	8.07	8.13	8.22
South West	9.19	9.33	9.61	9.45	9.38	9.41	9.48	9.53	9.57	9.61	9.67
Southern Railbelt	179.85	184.76	190.02	194.95	198.46	201.88	205.24	208.14	211.08	214.02	216.36
Matsu	36.64	37.94	39.18	39.95	40.56	41.25	41.96	42.56	43.22	43.88	44.40
Anch	120.75	123.92	127.42	131.11	133.67	136.06	138.38	140.39	142.38	144.37	145.96
Kenai	22.46	22.90	23.42	23.90	24.23	24.56	24.90	25.19	25.48	25.77	26.01
Valdez-Cordova	4.18	4.25	4.31	4.38	4.44	4.50	4.55	4.61	4.65	4.70	4.75
South East	31.44	32.10	32.80	33.60	34.30	34.91	35.46	36.00	36.49	36.96	37.45
PERSONAL INCOME (09 MILLION $)	$31,542	$32,262	$33,111	$33,855	$34,433	$35,023	$35,578	$36,085	$36,592	$37,129	$37,531
North	$956	$977	$1,003	$1,029	$1,048	$1,067	$1,084	$1,100	$1,116	$1,133	$1,144
Yukon - Koyukuk	$185	$190	$194	$200	$204	$209	$213	$217	$220	$224	$227
Northern Railbelt	$3,963	$4,042	$4,126	$4,210	$4,277	$4,343	$4,403	$4,461	$4,517	$4,576	$4,621
SE Fairbanks	$303	$310	$317	$324	$329	$334	$339	$343	$348	$353	$356
Yukon - Kuskokwim	$709	$725	$743	$764	$781	$798	$812	$827	$840	$854	$866
South West	$1,104	$1,131	$1,174	$1,177	$1,184	$1,201	$1,217	$1,233	$1,248	$1,264	$1,277
Southern Railbelt	$20,502	$20,985	$21,553	$22,054	$22,429	$22,812	$23,178	$23,504	$23,839	$24,193	$24,449
Valdez-Cordova	$430	$439	$450	$460	$468	$476	$484	$491	$498	$505	$511
South East	$3,390	$3,464	$3,550	$3,638	$3,712	$3,783	$3,846	$3,909	$3,967	$4,027	$4,079
PER CAPITA PERSONAL INCOME (09 THOU $)	$41.18	$41.16	$41.23	$41.22	$41.27	$41.34	$41.40	$41.47	$41.56	$41.68	$41.73
North	$36.00	$36.26	$36.64	$36.81	$36.92	$37.12	$37.28	$37.44	$37.62	$37.86	$37.94
Yukon - Koyukuk	$29.68	$29.99	$30.55	$30.86	$31.17	$31.48	$31.78	$32.06	$32.35	$32.67	$32.88
Northern Railbelt	$37.26	$37.35	$37.56	$37.60	$37.69	$37.82	$37.93	$38.05	$38.19	$38.36	$38.44
SE Fairbanks	$39.79	$39.92	$40.18	$40.17	$40.19	$40.29	$40.38	$40.44	$40.55	$40.72	$40.73
Yukon - Kuskokwim	$25.86	$26.14	$26.48	$26.70	$26.91	$27.13	$27.33	$27.53	$27.73	$27.97	$28.10
South West	$36.61	$36.96	$37.33	$38.01	$38.51	$38.92	$39.25	$39.56	$39.90	$40.29	$40.49
Southern Railbelt	$43.42	$43.28	$43.21	$43.09	$43.08	$43.10	$43.09	$43.12	$43.16	$43.22	$43.24
Valdez-Cordova	$40.99	$41.17	$41.55	$41.83	$42.01	$42.22	$42.40	$42.56	$42.75	$42.99	$43.07
South East	$42.88	$42.92	$43.03	$43.03	$43.05	$43.12	$43.18	$43.24	$43.33	$43.47	$43.48

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Appendix B: Summary Tables

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Appendix B: Summary Tables

Table B-1 summarizes the components and demand ranges applied in the probability model for each sector during the first five years of pipeline operation. All values are rounded to the ones place. Where demand ranges are applied, the single estimate value is shown in parenthesis below the range[1].

Table B-1. Summary of the Range of Natural Gas Demand Estimates by Sector for Year 1 to 5 of Pipeline Operations (MMcfd), (Single Estimate Values are shown in parenthesis)

Demand Source	Southern Railbelt	Northern Railbelt/ Livengood	Valdez[b]	Total Range[c]	
				Alberta Route	Valdez Route
Residential / Commercial[a]				106 to 142 *(122)*	107 to 143 *(123)*
Residential	68 to 82 *(75)*	1 to 8 *(4)*	<1		
Commercial	36 to 44 *(40)*	1 to 9 *(4)*	<1		
Power[d]	44 to 72 *(71)*	12 to 21 *(21)*	--	56 to 93 *(91)*	56 to 93 *(91)*
Military				*(17)*	*(17)*
Ft. Wainwright	--	8[e]	--		
Ft. Greeley	--	1[f]	--		
Eielson	--	8[f]	--		
Industry				33 to 653 *(263)*	38 to 658 *(268)*
Tesoro Refinery[g]	11	--	--		
Flint Hills Refinery	--	12[e]	--		
Petro Star Refineries	--	1[e]	3[h]		
Other Industrial (Livengood)	--	9			
Alyeska Pipeline/Terminal[i]	--	--	2[i]		
LNG (current)[g]	0 to 230 *(230)*	--	--		
LNG (expansion)[g]	0 to 245 *(0)*	--	--		
Fertilizer[g]	0 to 145 *(0)*	--	--		
Sum of Single Estimates	*(427)*	*(68)*	*(7)*	*(493)*	*(499)*

Note: Values with only single point estimates have a range less than ± 3 MMcfd.
[a] Based on gas utility demand projections and Interior Issues Council (2009)
[b] This demand is only projected to occur under the Valdez Pipeline Scenario
[c] Row sums may not equal the totals due to rounding
[d] Based on Black & Veatch (2008) and updated electric utility information
[e] Interior Issues Council (2009); and Jeff Cook, Flint Hills Refinery. Personal communication with Northern Economics, Inc. January 4, 2010.
[f] ENSTAR Market Study (*Natural Gas Line Load Analysis, Parks and Richardson Highway Routes*. Draft document, January 27, 2009).
[g] National Energy Technology Laboratory, 2006, Alaska Natural Gas Needs and Market Assessment
[h] Based on average projected gas demand per refinery capacity in Interior Issues Council (2009)
[i] Calculated based on information provided by Joe Robertson, Joint Pipeline Office and Department of Transportation Liaison, Alyeska Pipeline Service Company, personal communication with Northern Economics. January 7, 2009.

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[1] Single estimate values for the Residential/Commercial sector demand represent the 50th percentile of continuous distributions. Single estimate values for Power and Industrial sectors demand represent the mode of non-symmetric, discrete distributions.

Table B-2. Maximum Potential Propane Demand in Years 1-5 (Millions of Gallons)

Area	Residential & Commercial	Electric Power	Industrial	Total
Northwest-Arctic	10.4	10.5	24.1	45.0
Yukon - Koyukuk	2.0	3.2	0.0	5.2
Northern Railbelt	17.1	16.8	0.0	33.9
SE Fairbanks	4.1	4.0	1.0	9.1
Yukon - Kuskokwim	10.1	11.0	101.9	123.0
South West	16.9	21.0	117.6	155.5
Southern Railbelt	17.7	0.0	7.7	25.4
Valdez-Cordova	9.9	6.1	12.0	28.0
South East	43.3	11.7	40.0	95.0
Total	**131.5**	**84.3**	**304.3**	**520.1**

Source: Northern Economics, Inc.

Table B-2 shows the maximum potential demand for propane in Alaska without adjusting for possible reductions due to distillate fuels being less expensive when considering the costs of transport and storage of larger volumes of propane.

Appendix C: Power Sector Demand Analysis

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Appendix C: Potential Power Sector Natural Gas Demand

1 Introduction and Background

This appendix provides alternative estimates for natural gas consumption in Alaska's electric power sector for four alternative future scenarios. The assessment is limited to the interconnected portion of the electric power grid, called the Railbelt, encompassing Fairbanks, the Metropolitan Anchorage region and the Kenai Peninsula. The Alaska Energy Policy Task Force Report defined the Railbelt as: "the power-sharing area between Interior Alaska, from Fairbanks, and Southcentral, to Homer, connected by roads, generating facilities and transmission lines, which include the Alaska Intertie and the Bradley Lake Hydro Project."[1]

The current scenario assessment of the Railbelt power sector builds upon a previous 2008 study sponsored by the Alaska Energy Authority (AEA). This study by Black and Veatch evaluated the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA). The purpose of the REGA would be to manage and dispatch electric power on the Railbelt grid.[2] In order to evaluate the value of REGA, the study conducted detailed capacity and dispatch modeling of the region's existing electric power system with the model making economic decisions to select the technology and fuel options that minimize long-term costs for customers. This analysis is based upon the following:

- Application of a power cost model to perform a least-cost resource systems optimization to develop optimal portfolios of resources for each of four alternative scenarios.
- The cost and performance characteristics of the region's existing generation and transmission assets, as described below in Section 2.
- Cost and performance characteristics of various resources that could be added to the region's resource portfolio, as briefly described below in Section 3.

For the sake of consistency, this study does not perform independent utility systems modeling, but builds upon the outcomes of the REGA Study's utility capacity and dispatch modeling. Since the economy and energy outlook have changed since the REGA study, the TransCanada project made every effort obtain a current perspective on the future resource mix of the Railbelt utility companies to meet service area electricity demand. This analysis adjusts the REGA outcomes based on this new information.

1.1 Conclusions

Table 1 provides the projection of future natural gas (and propane) demand for year's 2019 and 2030 for the Fairbanks area and the South-Central area of the Railbelt and the total Railbelt power sector. Both daily and annual consumption is provided. The four Evaluation Scenarios provide a significant range of future natural gas consumption, although the most significant changes occur after 2019. By 2030, the Natural gas Scenario yields 20% greater consumption than the Large Hydro / Renewables / DSM / Energy Efficiency Scenario, almost 42% greater than the Mixed Resource Scenario, and 123% greater than the Coal Scenario.

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[1] http://www.akenergyauthority.org/EnergyPolicyTaskForce/FinalNonRailbeltReport.pdf

[2] Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008.

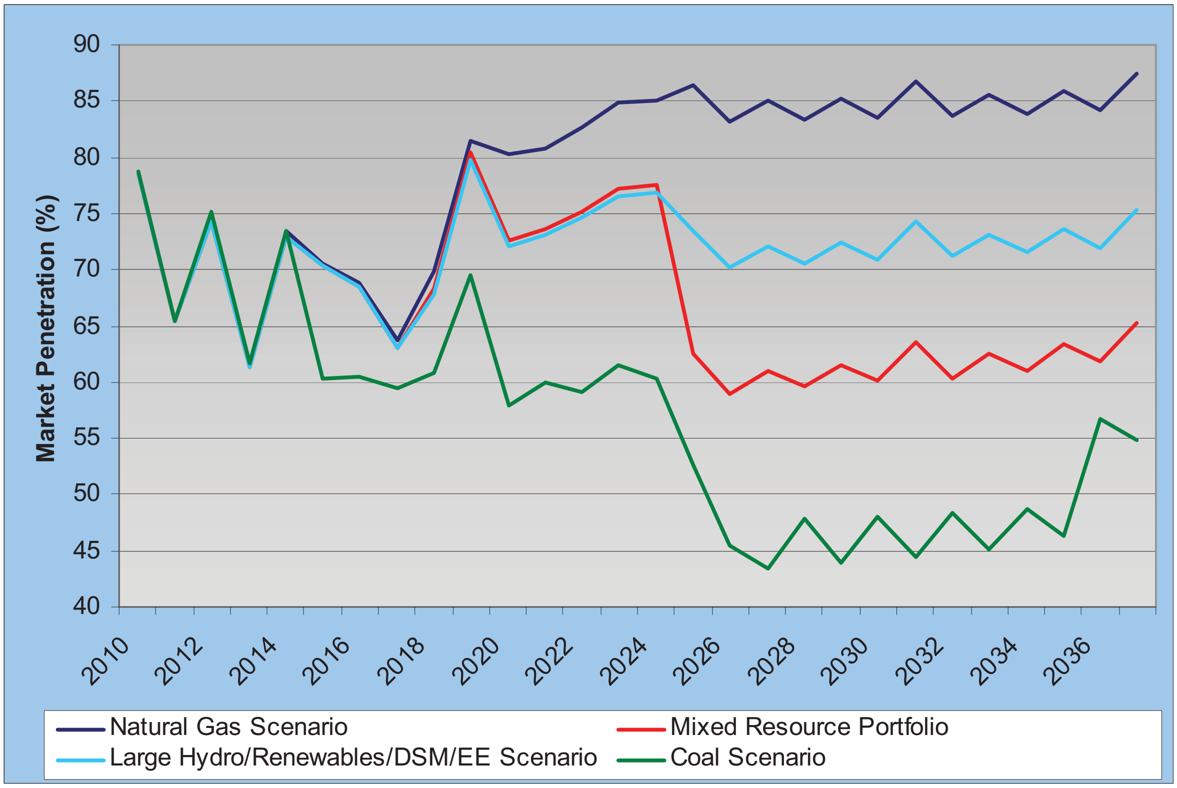
Table 1. Projected Future Natural Gas and Propane Demand for the Railbelt Utilities

Geographic Location	Year 2019			Year 2030		
	Dry Gas Btu/day mmcfd	Propane Btu/day bbld	Total Btu/Yr	Dry Gas Btu/day mmcfd	Propane Btu/day bbld	Total Btu/Yr
Large Hydro / Renewables / DSM / Energy Efficiency Scenario						
Power Sector (FAI)	19.99 / 19.72	N/A	7,298	25.96 / 25.60	N/A	9,475
Power Sector (ANC)	77.80 / 76.73	N/A	28,398	57.95 / 57.15	N/A	21,153
Total Power Sector	**97.80 / 96.45**	**N/A**	**35,696**	**83.91 / 82.75**	**N/A**	**30,628**
Natural Gas Scenario						
Power Sector (FAI)	22.55 / 22.24	N/A	8,231	29.40 / 29.00	N/A	10,733
Power Sector (ANC)	77.36 / 76.29	N/A	28,236	71.25 / 70.27	N/A	26,006
Total Power Sector	**99.91 / 98.53**	**N/A**	**36,467**	**100.65 / 99.27**	**N/A**	**36,739**
Coal Scenario						
Power Sector (FAI)	12.94 / 12.76	N/A	4,724	16.04 / 15.82	N/A	5,856
Power Sector (ANC)	47.85 / 47.19	N/A	17,465	29.20 / 28.80	N/A	10,659
Total Power Sector	**60.79 / 59.95**	**N/A**	**22,189**	**45.25 / 44.62**	**N/A**	**16,515**
Mixed Resource Scenario						
Power Sector (FAI)	19.42 / 19.15	N/A	7,089	14.94 / 14.73	N/A	5,451
Power Sector (ANC)	78.70 / 77.62	N/A	28,727	56.12 / 55.35	N/A	20,484
Total Power Sector	**98.13 / 96.77**	**N/A**	**35,816**	**71.06 / 70.08**	**N/A**	**25,936**

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

Overall natural gas market penetration, as a percentage of total Railbelt electricity generation produced from natural gas-based generators, is shown in Figure 1 below. As expected based on the Table 1 results, penetration is significantly different for the four Evaluation Scenarios. By 2030, the Natural gas Scenario yields 16% greater penetration than the Large Hydro / Renewables / DSM / Energy Efficiency Scenario, almost 34% greater than the Mixed Resource Scenario, and 60% greater market penetration than the Coal Scenario.

Figure 1. Projection of Railbelt Natural Gas Market Penetration as a Percentage of Power Generation Supply (Gas-Based Generation/Total Generation)



Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

2 The Electric Power System in South Central Alaska (Railbelt System)

The interconnected electric system for South Central Alaska (the Railbelt System) consists of six electric utilities in Fairbanks, the Greater Anchorage Area and the Kenai Peninsula. Table 2 lists the main transmission areas and the corresponding electric utilities.

Table 2. Transmission Areas and Utilities in the Railbelt System

Transmission Area	Utilities
Anchorage	Municipal Light & Power
	Chugach Electric Association
	Matanuska Electric Association
Kenai	Seward Electric System
	Homer Electric
Fairbanks-Healy	Golden Valley Electric Association

Source: SAIC

The six utilities that serve the Railbelt region are:

- **Anchorage Municipal Light and Power (ML&P)** – ML&P services an area of 19.9 contiguous miles, including a large portion of the commercial and high-density residential areas of the Anchorage Municipality.[3]

  In 2008, ML&P served an average of 24,108 residential customers and 6,240 commercial customers. ML&P also provides all-requirements power to two military bases. Approximately 81 percent of ML&P's retail revenue comes from commercial accounts and military bases.

  In 2008, ML&P sold 1,118,752 MWh to retail electric customers and retail sales totaled $89,545,097. ML&P's sales to other utilities (Chugach Electric Association and Golden Valley Electric Association) for resale were $16,137,134. ML&P's total electric operating revenue for 2008 was $107,207,803.

- **Chugach Electric Association (CEA)** - CEA serves more than 80,700 retail locations in a service territory which extends from Anchorage to the northern Kenai Peninsula, and from Whittier on Prince William Sound to Tyonek on the west side of Cook Inlet. CEA has 530.10 megawatts of installed capacity at five plants and provides power to Alaskans from Homer to Fairbanks through sales to wholesale and economy energy customers Matanuska Electric Association, Homer Electric Association, the City of Seward, Golden Valley Electric Association, and Anchorage Municipal Light & Power.[4]

  In 2008, CEA sold 1,210,000 MWh to retail electric customers, 1,320,000 MWh wholesale, and 256,100 MWh of economy energy power. Total electric operating revenue for 2008 was $107,207,803. Total electric operating revenue for 2008 was $289,500,000.

- **City of Seward Light and Power (SES)** – SES serves the City of Seward with approximately 2,500 customers. SES purchases power from CEA and provides backup generation.

- **Golden Valley Electric Association (GVEA) -** In 2008, GVEA served an average of 43,304 metered customers. GVEA serves nearly 100,000 interior residents in Fairbanks, Delta Junction, Nenana, Healy and Cantwell.

  In 2008, GVEA's peak load was 217.6 megawatts and total electric operating revenue for 2008 was $214,513,840. GVEA operates and maintains 3,077 miles of transmission and distribution lines and 35 substations. Its system is interconnected with Fort Wainwright, Eielson AFB, Fort Greely, the University of Alaska-Fairbanks in addition to the larger RailBelt grid. **Homer Electric Association (HEA)** – HEA services an area of 3,166 square-mile and 20,214 member-owners with 30,521 meter locations via 2,296 total miles of energized line.

  Homer Electric sold 523,300 MWh of electricity in 2008 with revenue from energy sales at $69.2 million.

- **Matanuska Electric Association (MEA)** - MEA had 52,310 customers as of year-end 2006, and combined revenues of more than $86.3 million. It currently purchases all of its power from Chugach Electric Association; MEA's wholesale power supply contract with CEA expires December 31, 2014 and the association is currently exploring the idea of constructing its own power generation facilities.

[3] Anchorage MLP website: http://www.mlandp.com/redesign/about_mlp.htm

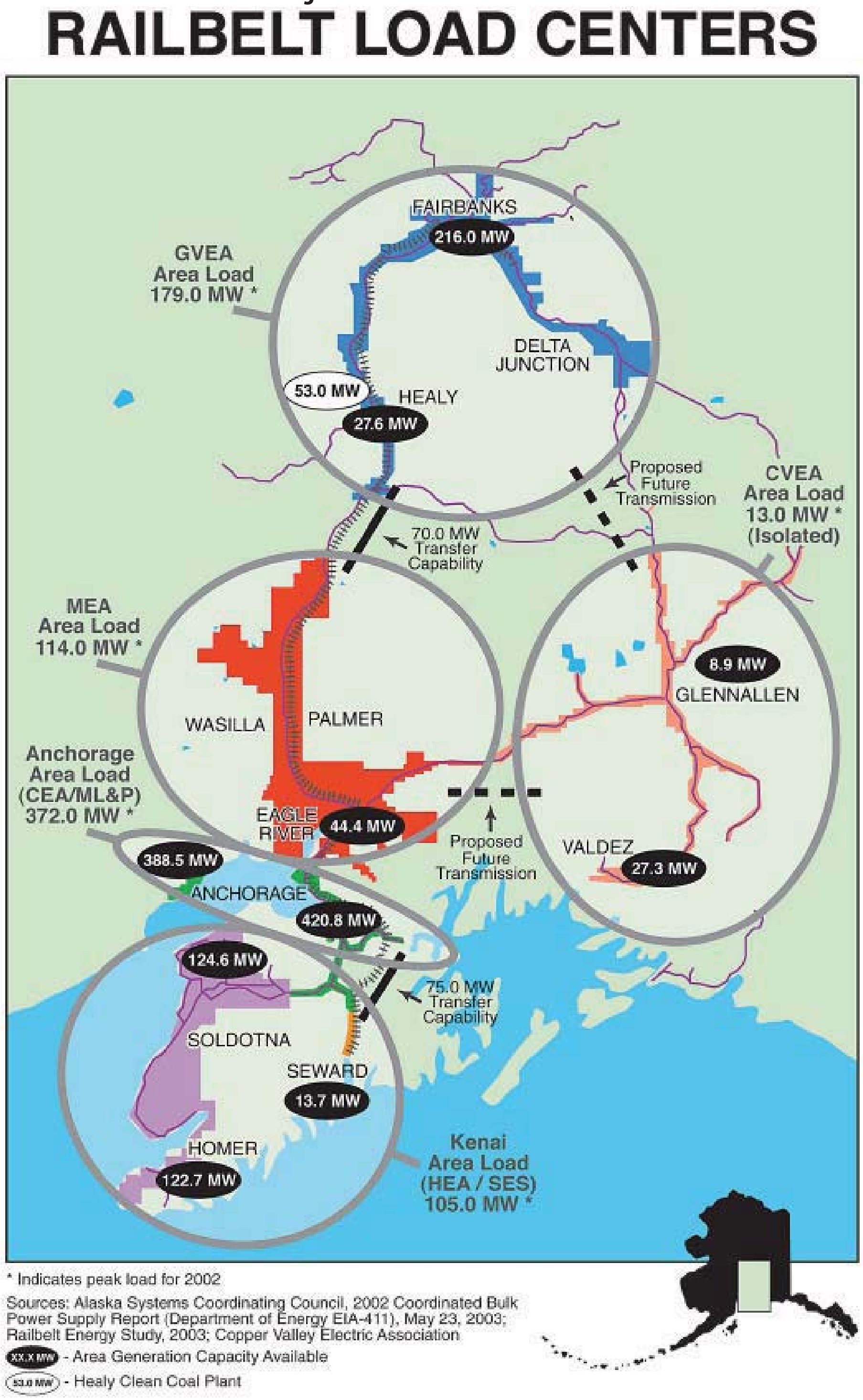
[4] 2008 Chugach Electric Annual Report, http://www.chugachelectric.com/pdfs/2008_annual_report.pdf

2.1 Characteristics of the Railbelt System

The total peak load of all six utilities is approximately 875 MW. The Railbelt electric transmission grid has been described as a "long straw," as opposed to the integrated, interconnected, and redundant grid that is in place throughout the lower-48 states. This characterization reflects the fact that the Railbelt electric transmission grid is an isolated grid with no external interconnections to other areas and that it is essentially a single transmission line running from Fairbanks to the Kenai Peninsula, with limited total transfer capabilities and redundancies.[2] Figure 1 identifies the major Railbelt load centers (Valdez and Glennallen are not currently connected to the Railbelt grid.)

As a result of the lack of redundancies and interconnections with other regions, each Railbelt utility is required to maintain much higher generation reserve margins than utilities in other locations in order to ensure reliability in the case of a transmission grid outage. Furthermore, the lack of interconnections and redundancies exacerbates a number of the other issues facing the Railbelt region.[2]

Figure 2. Railbelt Load Centers



GVEA's service area makes up the northern load center and is connected with 138 kV lines that flow through Delta Junction, Fairbanks, and Healy. The northern and the central load centers are interconnected via the Alaska Intertie, and the Healy-Fairbanks and Teeland-Douglas transmission lines. The Alaska Intertie is a 345 kV (operated at 138 kV), 170 mile transmission line that is owned by the AEA and runs between the Douglas and Healy substations. The Healy-Fairbanks transmission line is a 230 kV, 90-mile transmission line from the Healy to the Wilson substations which delivers power from the Alaska Intertie directly into the city of Fairbanks. Another 138 kV transmission line also runs from Healy to Nenana to Goldhill and delivers power to Fairbanks. The 138 kV, 20-mile Douglas-Teeland transmission line stretches between the Douglas and Teeland substations and connects the southern portion of the Alaska Intertie to the central load center.

Key B&V modeling assumptions for the Railbelt System are as follows:

- The transfer capability of the Alaska Intertie and Healy-Fairbanks transmission lines are 75 MW and 140 MW, respectively.
- The central load center consists of MEA's, ML&P's, and CEA's service territories.
  - MEA serves customers down the southern half of the intertie and south of the intertie through the towns of Wasilla and Palmer.
  - ML&P serves the load of the residents of Anchorage.
  - CEA serves some residents of Anchorage along with the area south of Anchorage and into the northern portion of the Kenai Peninsula.
- The central and southern load centers are connected via a 135-mile, 115 kV transmission line that connects the Chugach system to the Kenai Peninsula. The transfer capability of the southern intertie is assumed to be 75 MW.
- The southern load center consists of SES and HEA's service territories.
  - SES serves the customers of the city of Seward.
  - The HEA service area includes the cities of Homer and Soldotna.

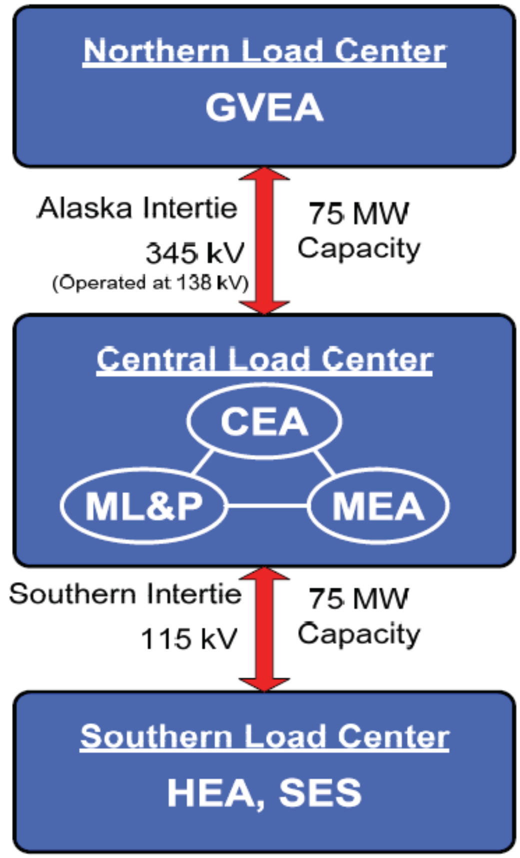
Figure 3 shows the region's three load centers and the existing transfer capability.

The Railbelt System is isolated from all other electric grids in North America. As such, it must be self sufficient in providing electric supply to its customers and this isolation poses special challenges in providing reliable service to customers.

The Railbelt System is characterized by an extremely high percentage of Simple-Cycle Combustion Turbine (SCCT) generating units. This situation exists for a variety of reasons: (1) historically, natural gas from the Cook Inlet has been sold to a captive market, depressing prices; (2) smaller system loads have limited generating technology choice to smaller sized units; and (3) technologies capable of rapid dispatch have been chosen to minimize outage time if a unit should fail.[5]

[5] NETL-RDS, "Alaska Natural Gas Needs and Market Assessment," NETL Strategic Center for Natural Gas and Coal, June 2006.

Figure 3. Existing Load Centers as Modeled by B&V

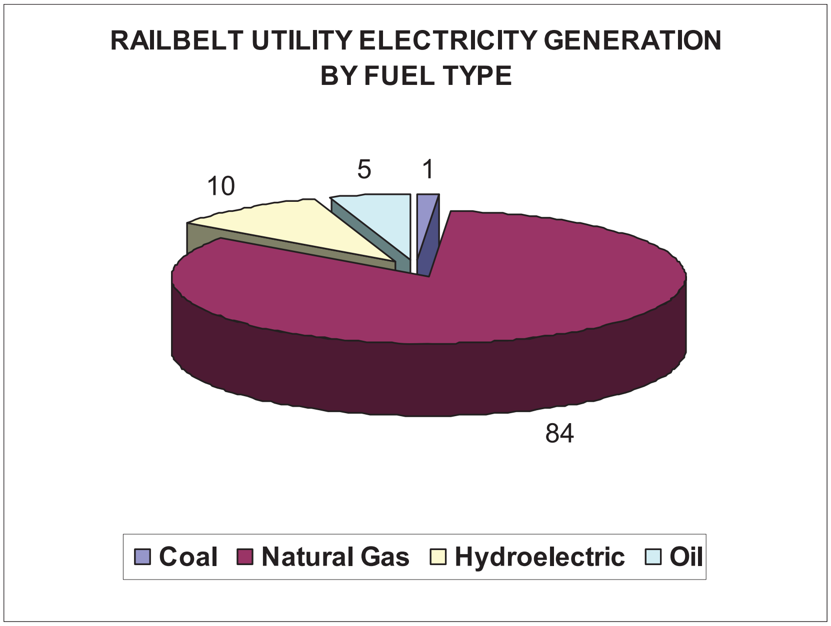


Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

There are a variety of existing generation resources that are owned and operated by the Railbelt utilities, as well as a transmission grid that extends from the Fairbanks area down to the Kenai Peninsula. There are also a broad array of supply-side resource options, both traditional and renewable resources, and demand-side resources (i.e., DSM and energy efficiency programs), available to meet the future electrical needs of the Railbelt region.

Natural gas has been the predominant source of fuel for electric generation used by the customers of ML&P, Chugach, MEA, Homer and Seward. Additionally, customers in Fairbanks have benefited from natural gas-generated economy energy sales in recent years. Figure 4 shows the current level of dependence level of on natural gas in the Railbelt System.

Figure 4. Railbelt Utility Electricity Generation by Fuel Type



Source: SAIC

2.2 Railbelt Utilities: Current and Planned Generation Resources

This section presents available information for the six Railbelt region utilities based on data and information from the B&V REGA Study[2] and updated information obtained by this project from each utility (only 4 of 6 utilities responded) and other sources. This study estimates that the current total Railbelt installed capacity is 1,246 MW based on the B&V study data and updated utility information provided through key informant interviews (see Table 2).

Table 3. Railbelt Installed Capacity (MW)

		Hydroelectric Plants: Existing Capacity			
Utility	**Thermal Plants: Existing Capacity**	**Bradley Lake**	**Eklutna Lake**	**Cooper Lake**	**TOTAL**
MEA	0	12.4	6.7	0	19.1
HEA	39	10.8	0	0	49.8
CEA	504	27.4	12	20	563.4
GVEA	275	15.2	0	0	290.2
ML&P	278	23.3	21.3	0	322.6
SES	0	0.9	0	0	0.9
TOTAL	**1,096**	**90**	**40**	**20**	**1246**

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008 and SAIC.

2.2.1 Anchorage Municipal Light and Power (ML&P)

ML&P did not respond to the project's request for current utility information. The REGA Study report identified the following existing thermal power plants:

- ML&P operates seven combustion turbines (Units 1-5, 7, and 8) between two power plants, which operate on natural gas, and one steam turbine (Unit 6), which derives its steam from un-fired heat recovery steam generators (HRSGs).
- Units 1, 2, and 4 are unavailable for commercial operation and are not considered in ML&P's approximate 400 MW of generating capability.
- Combustion turbines 5 and 7 have HRSGs, which allow them to operate in a combined cycle mode with the Unit 6 steam turbine. Unit 5 is frequently cycled when used in combined cycle or simple cycle mode. Unit 5 or Unit 7 may be operated in simple cycle mode when the steam turbine is unavailable.

ML&P's existing thermal units are shown in Table 4. Hydroelectric power is also purchased from Bradley Lake (23.3 MW) and Eklunta Lake (21.3 MW).

Table 4. MLP Existing Thermal and Hydroelectric Units[2]

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Anchorage ML&P - Plant 1	1*	Natural Gas	16.2	n/a
Anchorage ML&P - Plant 1	2*	Natural Gas	16.2	n/a
Anchorage ML&P - Plant 1	3	Natural Gas	32	n/a
Anchorage ML&P - Plant 1	4*	Natural Gas	34.1	n/a
Anchorage ML&P - Plant 2	5	Natural Gas	37.4	n/a
Anchorage ML&P - Plant 2	5/6	Natural Gas	49.2	n/a
Anchorage ML&P - Plant 2	7	Natural Gas	81.8	2030
Anchorage ML&P - Plant 2	7/6	Natural Gas	109.5	2030
Anchorage ML&P - Plant 2	8	Natural Gas	87.6	2030
Anchorage ML&P - Plant 2	6	n/a	n/a	2030

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
ML&P	25.9	90,333	23.3	7.0	53.3	87,412	21.3	0.0	0.0	0.0

* Denotes units not available for commercial operation
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

ML&P, along with CEA, is currently planning to build the so-called Southcentral Power Plant (SPP) to be completed in mid-2013. This will be a 183 MW gas fired combined-cycle plant using three GE LM6000 gas turbines and one steam turbine. Chugach will own 70% and ML&P will own 30%.

2.2.2 Chugach Electric Association (CEA)

The REGA Study report identified the following existing thermal power plants:

- CEA operates 13 combustion turbines between three power plants (Bernice 2-4, Beluga 1-7, and International 1-3) which operate on natural gas
- One steam turbine (Beluga 8) derives its steam from heat recovery steam generators (HRSGs).

In response to the project's request for current utility information, CEA Sent copy of their Tariff Filing Letter dated May 12, 2009.[6] CEA's existing thermal units are shown below in Table 5. As indicated in

[6] Chugach Tariff Letter 305-8, May 12, 2009.

Table 5, CEA also purchases hydroelectric power from Cooper Lake (20 MW), Eklutna Lake (12 MW), and Bradley Lake (27.4 MW).

Chugach depends on natural gas to produce about 90% of the power needed to serve its retail and wholesale member-customers. At present, Chugach uses approximately 27 Bcf of gas per year in its power plants. The gas that Chugach purchases for its fuel requirements all comes from Cook Inlet gas fields. At present, Chugach has no alternative source of gas to fuel its generation facilities.

Table 5. CEA Existing Thermal and Hydroelectric Units[2]

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Bernice	2	Natural Gas	19	2014
Bernice	3	Natural Gas	26	2014
Bernice	4	Natural Gas	22.5	2014
Beluga	1	Natural Gas	19.6	2011
Beluga	2	Natural Gas	19.6	2011
Beluga	3	Natural Gas	64.8	2014
Beluga	5	Natural Gas	68.7	2014
Beluga	6	Natural Gas	82	2020
Beluga	6/8	Natural Gas	108.5	2014
Beluga	7	Natural Gas	82	2021
Beluga	7/8	Natural Gas	108.5	2014
International	1	Natural Gas	14.1	2011
International	2	Natural Gas	14.1	2011
International	3	Natural Gas	18.5	2011

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
CEA	30.4	111,269	27.4	8.2	30.0	87,412	49,200	100.0	50,000	20.0

* Denotes units not available for commercial operation
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

For more than twenty years, Chugach has obtained its gas requirements under a series of long-term gas contracts with the following gas producers: ConocoPhillips (COP), Chevron, Marathon Oil ("MOC"), and Shell (now Anchorage ML&P). The volumes available under these existing long-term contracts will run out in 2010 (in MOC's case) and 2011. For at least the past five years, Chugach has spent a significant amount of time and effort working to obtain replacement gas supplies for the period after the present gas supplies end.

CEA, along with ML&P, is currently planning to build the so-called **Southcentral Power Plant (SPP)** to be completed in mid-2013. This will be a **183 MW** gas fired combined-cycle plant using three GE LM6000 gas turbines and one steam turbine. Chugach will own 70% and ML&P will own 30%.

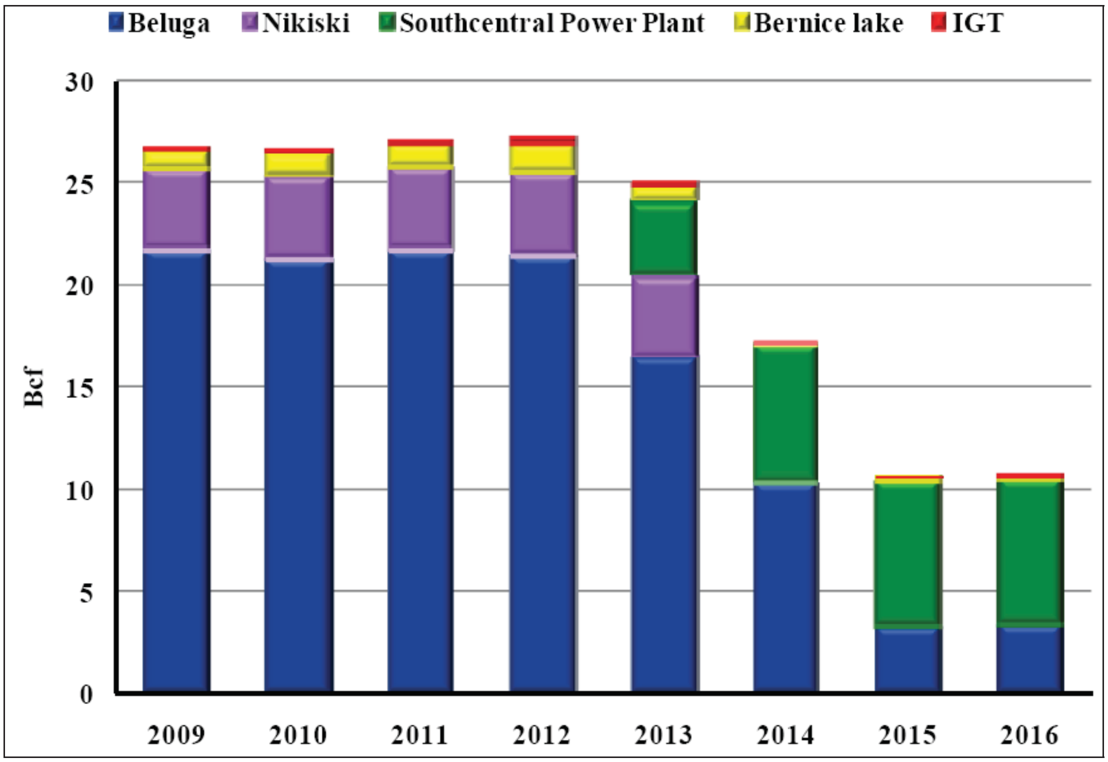
Figure 5 projects a breakdown of Chugach's requirements by generation facility for 2009 through 2016. Note that during the next seven years, the gas usage of various plants is expected to change as more efficient generation is brought on line in mid 2013. Consequently the delivery points and transportation needs will shift accordingly.

Chugach has negotiated a contract with COP (the Chugach-COP Contract) to meet a significant portion of its gas supply needs. The contract enables Chugach to meet 100% of unmet gas requirements through

April 2011, roughly 50% of Chugach's unmet gas requirements from June 2011 through 2015 and about 25% of Chugach's unmet needs in 2016. See Figure 5.

The Contract provides that Chugach will buy from COP a "Firm Gas Supply Tranche" described as "the total volume of Gas equal to 100% of the Gas volumes utilized at the Bernice Lake Power Plant, the Nikiski Power Plant and the International Power Plant, 40% of the Gas volumes utilized at the Beluga Power Plant, and 40% of the Buyer's share of the Southcentral Power Plant excluding any Gas utilized to generate economy energy sales at any or all of those facilities. (Chugach Tariff Letter 305-8, May 12, 2009).

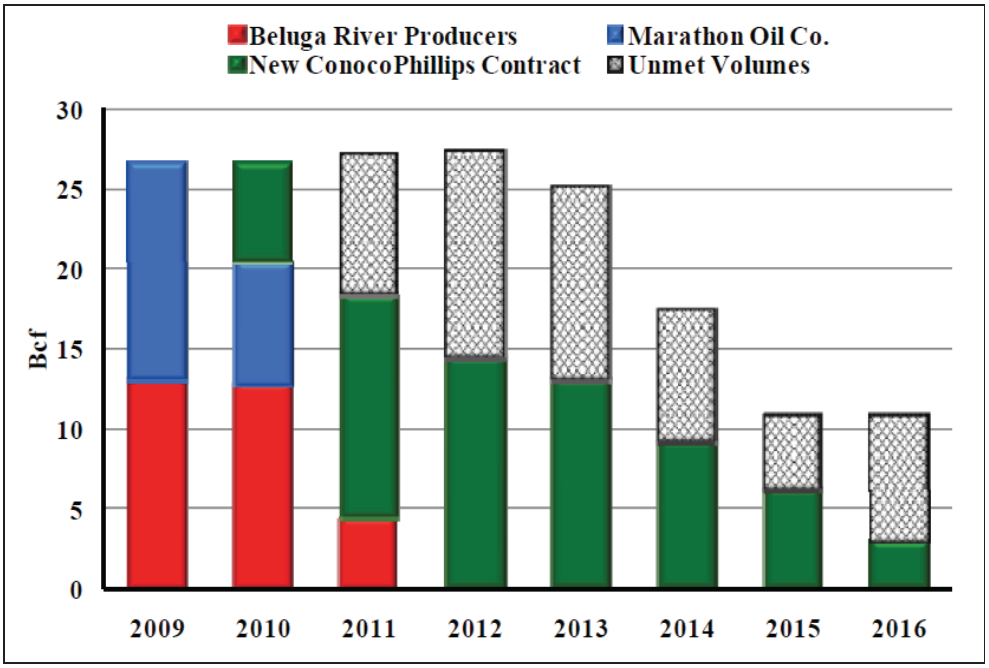
Figure 5. CEA Projection of Natural Gas Required by Plant[6]



Source: Chugach Tariff Letter 305-8, May 12, 2009

Figure 6 presents CEA's projection of natural gas volumes purchased under the Chugach-COP Gas Contract and from other suppliers, including unmet volumes.

Figure 6. CEA Projected Gas Supply by Producer[6]



Source: Chugach Tariff Letter 305-8, May 12, 2009

2.2.3 City of Seward Light and Power (SES)

SES did not respond to the project's request for current utility information. SES has no thermal plant capacity of its own, but does generate power through hydroelectric capacity (see Table 6

Table 6. SES Existing Hydroelectric Units[2]

Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
SES	1.0	3,660	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

2.2.4 Golden Valley Electric Association (GVEA)

In response to the project's request for current utility information, SAIC interviewed Henri Dale, Power Systems Manager.[7] Information provided by HEA is included in the following discussion.

The REGA Study report identified the following existing thermal power plants:

GVEA's generating capability of 277 MW is supplied by six generating facilities.

- Healy Power Plant provides 27 MW, is coal-fired and located adjacent to the Usibelli Coal Mine.
- GVEA's 190 MW North Pole Power Plant is oil-fired and built next to the Flint Hills refinery.
- Oil-fired Zehnder Power Plant in Fairbanks can provide 36 MW.
- Delta Power Plant (DPP), formerly the Chena 6 Power Plant can produce 25 MW.

[7] Telephone interview with Henri Dale, GVEA Power Systems Manager, July 1, 2009.

GVEA's existing thermal units are shown below in Table 7. As also indicated in Table 7, hydroelectric power is also purchased from Bradley Lake (15.2 MW).

GVEA comments about their existing capacity utilization are:

- While North Pole GT1 and GT2 could statistically be ready for retirement by 2017 and 2018 respectively, they are both currently in good shape with no known technical issues.
- DPP unit is strictly an emergency-type plant that is a backup unit for the Alaska pipeline pumping station and Fort Greely. It does have black-start capability. It is located at the end of a 100-mile transmission line.
- GVEA is required to keep 30% reserve capacity over peak load.
- Current peak load demand was quoted at 223.1 MW in the REGA report. Therefore, a nameplate capacity of about 290 MWe is technically required.
- Stated that plant retirement dates in the REGA study were calculated statistically and that GVEA expects most of the plants to operate longer than the listed retirement dates. No exact dates given.
- Confirmed that the original Healy coal plant (1967 start, 26.7 MWe) will likely be retired in 2022.

Table 7. GVEA Existing Thermal and Hydroelectric Units[2,7]

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Zehnder	GT1	HAGO	17.7	2030
Zehnder	GT2	HAGO	17.7	2030
North Pole	GT1	HAGO	60[a]	2017
North Pole	GT2	HAGO	64	2018
North Pole	GT3	Naphtha	52	2042
North Pole	ST4	Steam	12	2042
Healy	ST1	Coal	26.7	2022
DPP	1	HAGO	24.9	2030

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
GVEA	16.9	52,894	15.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0

[a] Originally reported as 62 MW in GVEA report. Other minor capacity differences exist; these are possibly due to various capacity numbers given for different bases, i.e. max capacity, nameplate, winter, summer, etc.
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

GVEA comments about future load requirements are as follows:

- Load growth has historically seen approximately 2%.
- Fort Knox gold mine is expected to shut down permanently sometime between the years 2015 to 2017. This is a 31 MW load that will go away. Originally, a 25 mile, 138 kV transmission line was built to connect the mine to the GVEA grid.
- The recent economic slowdown has resulted in a 6% load decrease that hasn't returned and is not expected to recover.

GVEA comments about future capacity retrofit and additions are:

- The REGA study projected 86 MW of capacity (two 43 MW units) coming online immediately (2008-2009). This projection was due to the model determining that additional new gas plants would be economical in the long run even if the demand was not present at the time due to the more efficient use of low price gas in the new units. *However, GVEA believes that these early units are highly unlikely*.

- The new Healy "Clean Coal" plant will be about 60MW when completed and expects to be operational in 2011, with reliable output achieved in 2012. GVEA expects to retire the unit in 2044. The state of Alaska currently owns the plant, but GVEA has made an offer to purchase the plant and all of the output would be purchased by Homer City Electric. *It was announced on July 22, 2009 that GVEA has worked out a settlement for HCCP. GVEA has agreed to purchase the plant from its owner, the Alaska Industrial Development and Export Authority, for $50 million. AIDEA has agreed to loan GVEA up to an additional $45 million for plant startup and system integration costs. The sale will be completed by August 1, 2009.*[8]
- Healy 1 (current coal-fired plant) would not consider retrofitting to natural gas because it is too old and not economical.
- Combustion turbines fueled with natural gas is most likely option for future generation.
- The original North Pole plant (Units 1 & 2, 120 MWe) could be retrofit with natural gas, but the building that houses the units would be "expensive to retrofit," negating the possibility of a retrofit with gas.
- Expansion of the 60 MWe LM6000 combined cycle unit (GT3) at North Pole would essentially double its capacity, adding 60 MW of generating capacity; the steam headers at the facility were double-sized to prepare for a possible expansion. The project entails installing a 47-MW combustion turbine with a steam turbine that allows us to generate an additional 13 MW (would be designated GT4). GT3 and GT4 could be converted to natural gas for approximately $1 million. GT3 currently fires Naphtha, an extremely clean burning fuel, produced next-door at the Flint Hills refinery. Note that unlike natural gas, oil-firing is not an economical alternative.
- Delta Power (DPP, old Chena 6) is used only about 10 hours per year as backup and emergency generation source to sensitive load points at end of long radial.
- New coal plants will be difficult to pursue given the potential for carbon constraints.
- Nuclear is unlikely option for GVEA.
- Wind and solar are seriously being studied, but GVEA is likely limited to a relatively small amount of wing generation. Intermittent sources present a variability problem that only backup capacity and energy storage can handle. GVEA is studying wind patterns northwest of Healy and on Murphy Dome. Meteorological towers located in interior Alaska continue to collect data. By analyzing this information, GVEA will determine how to best utilize this resource. GVEA is focusing efforts to construct a 24 – 50 MWe wind farm in Eva Creek near Healy – stated as close to shovel-ready with all permitting and internal studies completed. The project would minimally include 16 turbines at 1.5 MW each. This would represent about 20 percent of their peak load.
  - A Delta region group is studying a 50 MW project south of Delta – waiting on financing. A capacity factor of u 31 to 33% is expected based on meteorological studies.
- Note that GVEA currently operates a large battery storage facility (BESS – Battery Energy Storage System) that can provide 27 MWe of output for 15 minutes. Fifteen minutes is long enough for the co-op to start up local generation when there are problems with the Intertie or power plants in Anchorage. This facility was designed strictly to improve system reliability.

[8] GVEA press release, July 22, 2009. http://www.gvea.com/about/hccp/

2.2.5 Homer Electric Association (HEA)

In response to the project's request for current utility information, HEA sent a written answer to questions. Information provided by HEA is included in the following discussion.

HEA's existing thermal and hydroelectric units are shown below in Table 8.

- HEA owns the natural gas Nikiski combustion turbine. During the summer months it can produce a maximum of 35 MW, whereas in the winter it provides 39 MW.
- Hydroelectric power is also purchased from Bradley Lake (10.8 MW).

Table 8. HEA Existing Thermal and Hydroelectric Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Nikiski	1	Natural Gas	39	N/A
Seldovia (Standby only)	1	Diesel	1	?
Seldovia (Standby only)	2	Diesel	1	?
Port Graham (Standby only)	1	Diesel	0.35	?

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
HEA	12.0	41,139	10.8	3.2	0.0	0.0	0.0	0.0	0.0	0.0

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

HEA comments about their existing capacity utilization included:

- No retirements of existing units is presently planned.

GVEA comments about future load requirements are as follows:

- Summer peak 70 MW expected over the next 5 to 10 year period
- Winter Peak 90 MW expected over the next 5 to 10 year period
- Limited industrial growth (10 MW) expected over the next 5-10 years. Minimal growth expected in non-industrial electric sales over the long term. Due to the small nature of the HEA system, we are sensitive to the activities of any large scale industrial customer that may add to or change its operation on the Kenai Peninsula.

HEA comments about future capacity retrofit and additions are:

- HEA is planning an additional 60 to 90 MW of natural gas fired generation prior to January 1, 2014.
- HEA is no longer a partner in the CEA/MLP Southcentral Power Plant.
- HEA is pursuing renewables to the best of its abilities. The stated goal may only be reached through the construction of extraordinarily expensive (large-scale hydro) or intermittently available (wind or tidal) generating facilities. HEA will continue to pursue this renewable goal and intends to be a leader in accommodating and embracing renewables, but at this time we do not foresee an affordable and reliable method by which this goal can be achieved.

2.2.6 Matanuska Electric Association (MEA)

In response to the project's request for current utility information, MEA sent a written answer to questions. Information provided by MEA is included in the following discussion.

MEA's existing thermal and hydroelectric units are shown below in Table 9.

- MEA owns four backup diesel engine-generators, one of which is retires and two of which are very close to retirement. *All three units will be retired in 2010 and replaced with new diesel fuel generators.*
- Hydroelectric power is purchased from Bradley Lake (12.4 MW) and Eklutna Lake (6.7 MW), operated so as to fully utilize these available water resources.

MEA comments about future load requirements are as follows:

- The MEA, Unalakleet Division 5 and 10 year electric seasonal winter peak demand is projected to be 850 kW (2015) and 850 kW (2020), respectively.
- The MEA, Unalakleet Division 5 and 10 year electric seasonal summer peak demand is projected to be 320 kW and 375 kW, respectively.
- The MEA, Palmer Division 5 and 10 year electric seasonal winter peak demand is projected to be 172 MW (2015) and 186 MW (2020) respectively.
- The MEA, Palmer Division 5 and 10 year electric seasonal summer peak demand is projected to be 84 MW and 90 MW respectively.

Table 9. MEA Existing Thermal and Hydroelectric Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Unalakleet Division (Backup Only)	1	Diesel	0.5	Only 12,000 hours service
Unalakleet Division (Backup Only)	2	Diesel	0.3	Retired
Unalakleet Division (Backup Only)	3	Diesel	0.53	Soon:120,000 hours service
Unalakleet Division (Backup Only)	4	Diesel	0.53	Soon: 120,000 hours service

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
MEA	13.8	50,508	12.4	3.7	16.7	27,388	6.7	0.0	0.0	0.0

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

MEA comments about future capacity retrofit and additions are:

- MEA Palmer Division's future generation plant is not characterized correctly in the REGA Study. As of September 12, 2009, MEA was planning a 130 to 180 MW natural gas fired power plant beginning commercial operation by January 1, 2015. To this end MEA has purchased approximately 70 acres of land in Eklutna, AK (approximately 10 miles south of MEA's headquarters in Palmer, AK). MEA is engaged in an Engineering, Procurement and Construction/Independent Power Producer procurement process to identify the best power generation fit to serve MEA's members. This process is expected to conclude in 2010. More recent information (http://www.adn.com/money/story/936507.html) suggests that MEA may be unable to build a plant of this size since gas contracts for the plant cannot be obtained.
- Wind turbines will be added into the Unalakleet Division grid in 2009 or 2010. The wind turbines will not be owned by MEA under current plans.
- MEA's Palmer Division is in the final planning and land acquisition process for development of a natural gas fueled generation plant within its service territory by 2014. The prime mover type and capacity for this plant is not currently known.

- MEA's Palmer Division is currently in negotiations with developers to purchase the output of two proposed run-of-the-river hydroelectric projects, and is hoping to develop a landfill gas generation project within its service territory. With these resources, a few household size wind generators interconnected with MEA's distribution system, and MEA Palmer Division's existing hydroelectric generation resources, renewable sources are projected to meet approximately 9% of MEA Palmer Division's 2025 load. MEA is actively participating in discussions related to the development of renewable resource generation capacity within the Railbelt Region, and desires to expand its renewable resource generation portfolio to the extent that such expansion is consistent with prudent utility practice. MEA's Unalakleet Division has been approached by Unalakleet Valley Electric Cooperative (UVEC) about interconnecting wind turbines with MEA's Unalakleet system. Those discussions are ongoing.

2.3 Drivers for Natural Gas Demand in the Railbelt System in Alaska

Natural gas demand for electric power usage in Alaska's Railbelt region is ultimately driven by electricity demand, relative fuel pricing, fuel availability, and the relative efficiency of the electric generators employed. Although natural gas usage for electric power is currently ranging from 35 to 40 Bcf per year, this quantity could change substantially in the future depending on the future generation alternatives. Such a change may not be proportional to the amount of electric power generated for the following reasons.

- Natural gas is available for electric power generation throughout the interconnected electricity grid in Alaska with the exception of Fairbanks. Traditionally, natural gas has been very inexpensive and only competed with existing hydroelectric technologies as a viable fuel choice. However, with the potential introduction of an interconnected natural gas supply with the balance of the continent, local prices will be driven by continental prices. Future increases in natural gas prices may make competing technologies more attractive.
- The existing inventory of electric generating units in the interconnected portion of Alaska is generally older and less efficient. As new more efficient generating units are introduced they will be able to generate the same quantity of electric power using less fuel. For example, the average heat rate of existing natural gas fired plants in Alaska is about 11,000 Btu/kWh; as new efficient plants are built, heat rates could go as low as 7,000 Btu/kWh (a decrease of more than 35%).

3 Electric Power Market Modeling Methodology

As discussed in Section 1, this study does not perform independent utility systems modeling, but builds upon the outcomes of the AEA-sponsored REGA Study, which performed detailed utility capacity and dispatch modeling for four different future energy supply futures. However, since the economy and energy outlook have changed since the REGA study was performed, this study made every effort obtain a current perspective on the future resource mix of the Railbelt utility companies to meet service area electricity demand and adjust the REGA outcomes accordingly.

3.1 Overview of Black and Veatch REGA Study

The Alaska Energy Authority retained B&V to evaluate the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA), whose purpose is to manage and dispatch electric power on the Railbelt grid. The study's objectives were to:

- Identify and assess a list of options for the management, operation, access rules, ownership, resource planning, and regulatory structures of the Railbelt generation and transmission system.

- For certain agreed-upon options, further analyze and provide recommendations of possible alternative structures to manage and dispatch electric power throughout the Railbelt region.
- Provide a final work product for stakeholders and decision-makers to consider in planning how to meet the Railbelt region's energy needs over the next 30 years.

The REGA study report is available at:
http://www.aidea.org/aea/REGAFiles/9-12-08_AlaskaRailbeltREGAStudy_MasterFinalReport.pdf

3.2 Methodology Overview

The original B&V REGA report did not contain enough detail to perform the current study. Therefore, SAIC requested supporting data from B&V on May 26, 2009. The information requested included the following:

- Fuel consumption by fuel type, year, utility, scenario
- Electricity generation (kW-hr) by technology type (e.g., gas turbine, coal-fired PC, wind), year, utility, scenario
- Plant retirements by technology type, year, utility, scenario (not sure the plants were retired by the model per the projected retirement dates)
- Busbar electricity prices by technology type, year, utility, scenario
- Average delivered electricity price by utility, year, scenario
- Emissions (e.g., CO_2, SO_2, etc.) by year, utility, scenario

B&V sent data responding to our request on July 23, 2009. The response included data for four scenarios that are further defined in Section 3.3:

- Scenario 1 - Large Hydro/Renewables/DSM/Energy Efficiency
- Scenario 2 - Natural Gas
- Scenario 3 – Coal
- Scenario 4 - Mixed Resource Portfolio

Data provided at the *company level* included: 1) fuel consumption by fuel type (1000MBtu/Year), 2) gaseous emissions by type (Tons), 3) electricity busbar price by fuel ($/MWh), and 4) average delivered electricity price ($/MWh). Data was provided in a spreadsheet format. Data provided at the *unit level* included: 1) electricity generation in million kW-hours for each unit by company and fuel type. Data was provided in a spreadsheet format. All of the B&V data was incorporated into an Excel workbook (project workbook).

In addition to the data provided by B&V, SAIC created two new sets of data in the project workbook for each scenario based on the B&V data: a calculated fuel consumption sheet and a capacity sheet. The study calculates average fuel consumption using the generation and heat rate information provided by B&V while the capacity sheet adds the capacity of each available generating unit to provide overall capacity by utility.

SAIC sent email requests to each utility in mid-June in an effort to schedule phone interviews with appropriate company staff regarding current and projected use of natural gas for electricity generation. Information collected during these interviews along with reports and data received from the utilities and information obtained in the public sector and on utility websites was incorporated into the project workbook.

3.3 Railbelt Power Market Scenarios

B&V developed four "Evaluation Scenarios" that are considered alternative energy futures for the Railbelt region. These are defined as follows:

Natural Gas Scenario: Assumes that all of the future generation resources will be natural gas-fired facilities, continuing the region's dependence upon natural gas.

Mixed Resource Portfolio Scenario: Assumes that a combination of large hydroelectric, renewables, DSM/energy efficiency programs, coal and natural gas resources is added over the next 30 years to meet the future needs of the region.

Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and DSM and energy efficiency programs.

Coal Scenario: Assumes the addition of coal plants to meet the future needs of the region.

Discussions were held with Jim Strandberg of AEA and Kevin Harper, the B&V project manager for the RIRP study, to assess the probability of occurrence of these scenarios. The following table presents the consensus from the two of them regarding the probability of each scenario in our two subject years. The probability of the natural gas scenario is higher in 2019 than 2030 because gas is considered a "bridge fuel" until other alternatives can be brought onboard.

Table 10. Assumed Probabilities of Occurrence for Alternative Energy Scenarios

Scenario	Year	
	2019	2030
Natural Gas	45%	20%
Mixed	25%	60%
Large hydro	20%	15%
Coal	10%	5%

Source: Jim Strandberg, AEA

3.4 B&V REGA Modeling Assumptions

The issues and uncertainties that impacted the original B&V REGA analysis include, but are not limited to, the following:[2]

- Future fuel supplies and costs
- Load growth, military base realignment, economic development, and power exports
- Aging generation and transmission assets and planned retirements
- Future desirability and costs of major generation facilities (e.g., coal, nuclear, and hydro facilities)
- Impact of a major power project coming on-line in the Railbelt, such as a large hydropower project
- Potential growth in non-utility generation (e.g., qualifying facilities, QFs, and independent power producers, IPPs)
- Potential transmission system expansions
- DSM/energy efficiency programs, renewables, and distributed generation resources - resource potential, relative economics, and policy-driven targets and growth
- Environmental legislation (including carbon taxes), regulations and constraints.
- Financing – access to capital, costs, and tax implications

- Outcome of proposed Chugach/ML&P merger, coordinated operations, and or joint project development
- Future role of the State, AEA and AIDEA – expand, maintain or sell State-owned energy assets

B&V's conducted their detailed evaluation of power costs over a forward looking 30-year evaluation period between 2008 through 2037. Their evaluation of each Evaluation Scenario utilized nominal dollars with the annual costs discounted to 2009 dollars for comparison using range of discount rates selected to represent reasonable discount rates for the Railbelt utilities. The study used discount rates of 6.0 percent, 8.0 percent, 10.0 percent, and 15.0 percent, with the 6.0 percent set as the base case. For evaluation purposes, the study assumed a general inflation and escalation rate of 3.0 percent

The study developed fixed charge rates for new capital additions based on the cost of capital for each utility for new generating unit additions and used a joint fixed charge rate based for the joint commitment, dispatch, and planning path. The joint fixed charge rate was based on the assumption of being able to obtain taxable and tax-exempt financing, and further assumed 100 percent debt financing. The assumed cost of capital and fixed charge rates presented in Table 11 are based on the following assumptions:

- Financial advisors were consulted and a general consensus developed for purposes of estimating the cost of capital for evaluation purposes.
- MEA, HEA, and CEA were assumed to use National Rural Utilities Cooperative Finance Corporation (CFC) financing with an interest rate of 6.75 percent.
- GVEA was assumed to use RUS financing with an interest rate of 5.0 percent.
- ML&P was assumed to use tax-exempt municipal bond financing with an interest rate of 5.0 percent.
- Fixed charge rates were developed only considering principle and interest for financing terms of 20, 25, and 30 years based on the expected financing lifetimes of the various alternatives.

Table 11. REGA Study Cost of Capital and Fixed Charge Rates[2]

Utility	Cost of Capital (%)	Fixed Charge Rate (%) Financing Terms (Years)		
		20	25	30
MEA	6.75	9.26	8.39	7.86
HEA	6.75	9.26	8.39	7.86
CEA	6.75	9.26	8.39	7.86
GVEA	5.00	8.02	7.10	6.51
ML&P	5.00	8.02	7.10	6.51
Joint Tax-Exempt	5.00	8.02	7.10	6.51
Joint Taxable	6.75	9.26	8.39	7.86

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

B&V developed a load forecast for each utility through the end of the study period based on the load forecasts provided by the utilities. The load forecast includes consideration of existing DSM and conservation programs, but does not include future plans for additional DSM and conservation. Table 12 below presents the load forecast for each utility from 2008 through 2037.

Table 12. REGA Study Railbelt Load Forecast for Evaluation (2008 – 2037)[2]

Year	Utility Peak Demand (MW)					
	ML&P	CEA	GVEA	HEA	MEA	SES
2008	158	477	230	81	141	10
2010	168	489	237	78	149	10
2015	172	272	218	80	172	11
2020	177	285	226	80	186	12
2025	180	296	234	81	201	12
2030	185	307	243	82	216	13
2035	189	319	252	83	231	14
2037	191	324	256	84	237	14

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

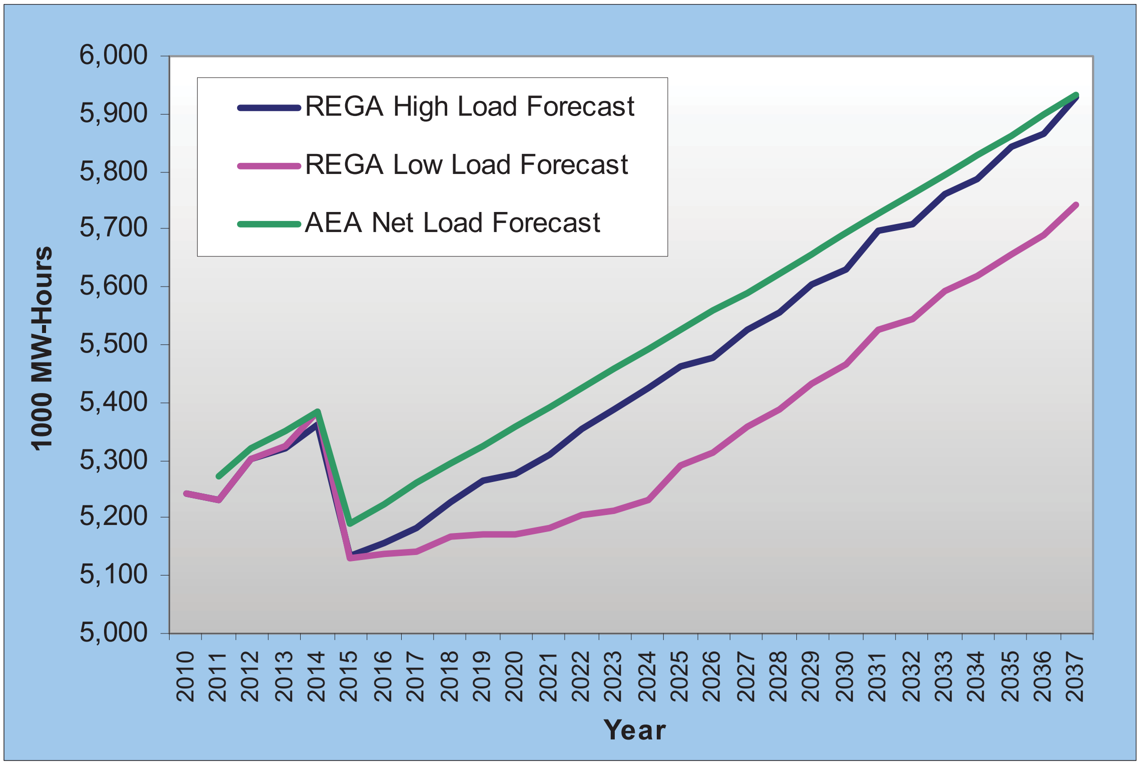
Table 13 lists the total Railbelt load forecast by generation (MW-Hours/Year) for each scenario and compares these values with the Alaska Energy Agency's (AEA) "utility net energy for load forecast"; the latter are generally less than 1% greater than the B&V "High Load Forecast" and up to 4.7% greater than the "Low Load Forecast." Figure 7compares these load forecasts.

Table 13. Electricity Demand Forecasts Used for Modeling

	Railbelt Electricity Demand Forecasts (1000 MW-Hours/Year)				
Year	Large Hydro/ Renewables/DSM/ Energy Efficiency	Natural Gas	Coal	Mixed Resource Portfolio	AEA Net Load Forecast
2010	5,243	5,243	5,243	5,243	--
2011	5,233	5,233	5,233	5,233	5,273
2012	5,304	5,302	5,304	5,304	5,322
2013	5,324	5,322	5,322	5,324	5,353
2014	5,385	5,384	5,383	5,385	5,384
2015	5,130	5,152	5,140	5,130	5,189
2016	5,139	5,182	5,177	5,139	5,225
2017	5,140	5,201	5,210	5,140	5,262
2018	5,170	5,253	5,246	5,168	5,294
2019	5,173	5,269	5,277	5,171	5,326
2020	5,172	5,284	5,296	5,170	5,359
2021	5,184	5,319	5,327	5,183	5,392
2022	5,208	5,359	5,368	5,207	5,425
2023	5,212	5,393	5,398	5,211	5,458
2024	5,232	5,431	5,441	5,231	5,491
2025	5,274	5,466	5,466	5,290	5,525
2026	5,301	5,494	5,493	5,315	5,558
2027	5,341	5,536	5,530	5,356	5,591
2028	5,373	5,569	5,566	5,388	5,625
2029	5,413	5,614	5,605	5,433	5,659
2030	5,446	5,645	5,642	5,467	5,692
2031	5,492	5,700	5,688	5,526	5,726
2032	5,520	5,722	5,719	5,543	5,760
2033	5,562	5,770	5,762	5,593	5,795
2034	5,595	5,801	5,797	5,619	5,829
2035	5,638	5,850	5,842	5,658	5,863
2036	5,672	5,881	5,878	5,689	5,898
2037	5,719	5,930	5,929	5,742	5,933

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008 and AEA.

Figure 7. Comparison of Natural Gas, Mixed Resource, and AEA Load Forecasts (Excluding SES)



Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008 and AEA.

For consistency purposes, the REGA study used a single reference fuel price forecast for all of the utilities in this analysis. The fuel price forecast reflects a general inflation rate of 3.0 percent and fuel prices are on a $/MMBtu basis.

- **Natural Gas:** Henry Hub spot natural gas prices were taken from the EIA *2008 Annual Energy Outlook* (AEO) projections and used as a starting point to forecast the price of natural gas. Natural gas is assumed to be available from the North Slope in 2020. Natural gas from the North Slope is assumed to be at a $2.00/MMBtu discount to Henry Hub, but transportation costs to the central and southern portions of the Railbelt will offset that discount. ML&P owns gas in the Beluga River Unit (BRU) gas fields. Projected prices and volumes for BRU gas were provided by ML&P.
- **Coal:** Coal price forecasts were developed by escalating the given price per ton annually at two-thirds (66 percent) the general inflation rate (2.0 percent).
- **Fuel Oil:** Average crude wellhead prices for the lower 48 states were taken from the EIA's *2008 Annual Energy Outlook* and used as a starting point for developing heavy atmospheric gas oil (HAGO) and naphtha fuel price forecasts. Distillate fuel oil prices were based on the EIA's 2008 AEO distillate fuel oil price forecast.

The fuel cost projections are shown below in Table 14.

Table 14. REGA Study Fuel Price Reference Forecast ($/MBtu)[2]

Year	Henry Hub Natural Gas	Coal	HAGO	Naphtha	Distillate Fuel Oil
2008	7.67	2.59	17.33	18.75	18.41
2009	8.03	2.67	17.91	19.40	15.57
2010	7.77	2.75	17.65	19.00	15.33
2011	7.61	2.83	17.49	18.73	14.98
2012	7.61	2.92	17.06	18.13	14.56
2013	7.58	3.01	16.60	17.49	14.17
2014	7.58	3.10	16.26	17.00	14.26
2015	7.65	3.19	15.85	16.41	13.93
2016	7.82	3.29	15.46	15.85	13.79
2017	8.16	3.38	15.87	16.25	14.22
2018	8.51	3.49	16.04	16.36	14.85
2019	8.89	3.59	16.60	16.96	15.53
2020	9.00	3.70	17.04	17.40	16.18
2021	9.06	3.81	17.69	18.08	16.83
2022	9.55	3.92	18.38	18.82	17.54
2073	10.05	4.04	19.14	19.63	18.41
2024	10.64	4.16	19.82	20.35	19.38
2025	11.21	4.29	20.72	21.35	20.33
2026	11.84	4.42	21.72	22.44	21.41
2027	12.29	4.55	22.70	23.52	22.40
2028	13.15	4.69	23.83	24.77	23.47
2029	13.93	4.83	24.79	25.81	24.68
2030	14.68	4.97	25.69	26.78	25.83
2031	15.48	5.12	26.80	27.99	27.07
2032	16.34	5.27	27.95	29.25	28.37
2033	17.24	5.43	29.15	30.58	29.73
2034	18.18	5.59	30.41	31.96	31.15
2035	19.18	5.76	31.72	33.40	32.65
2036	20.24	5.94	33.09	34.92	34.21
2037	21.35	6.11	34.52	36.50	35.85

Source: Black and Veatch, “Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report,” 9-12-2008.

Table 15 shows the unit characteristics assumed for the conventional and emerging technologies. Estimates for costs and performance parameters were based on B&V project experience, vendor inquiries, and a literature review; the generic cost estimates for renewable technologies developed by B&V included consideration of specific projects in Alaska, where available, and numerous other projects with costs adjusted for Alaska. Capital costs reflect the total project cost, including direct and indirect costs.

Table 15. Conventional and Emerging Technology Unit Characteristics (All Costs in 2008 Dollars)

Name	Net Output (MW)	Total Cost ($millions)	Primary Fuel	Forced Outage Rate (%)	Full Load Net Heat Rate (Btu/kWh) HHV	Annual Scheduled Maintenance (Days/Yr)	CO2 Emission Rate (lb/MMbtu)
GE 6B Simple Cycle	42.1	52.8	Natural Gas	2.0%	12,270	10	115
GE LMS100 Simple Cycle	98.8	123.4	Natural Gas	2.0%	8,260	10	115
GE LM6000 Simple Cycle	43.0	74.0	Natural Gas	2.0%	9,020	10	115
1x1 GE 6FA Combined Cycle	116.0	253.8	Natural Gas	3.0%	7,300	14	115
2x1 GE 6FA Combined Cycle	235.0	402.5	Natural Gas	4.0%	7,160	17	115
Sub-critical Pulverized Coal	100.0	462.4	Coal	5.0%	10,140	21	211

Source: Black and Veatch, “Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report,” 9-12-2008.

With regard to technology choice, wind and hydroelectric were the only two renewable technologies assumed for future generation resource additions in the REGA study.

Wind generation projects were assumed to be installed in 50 MW blocks. The wind generation was apportioned to each of the Railbelt Utilities in proportion to their 2007 peak demands. The estimated total installed cost for the wind generation was assumed to be $2,500/kW in 2008 dollars. The estimated annual capacity factor was 35 percent. The estimated fixed O&M costs were $18.00/kW-year in 2008 dollars. Ten (10) percent of the net capacity of the wind generation was assumed to contribute to the planning reserve margins. Transmission losses to deliver the wind generation to the transmission system are assumed to be 3.0 percent.

Large hydroelectric generation projects were assumed to be installed in 300 MW blocks. Each hydroelectric project was assumed to have four hydroelectric turbines, each with 75 MW capacity. The hydroelectric generation was apportioned to each of the Railbelt Utilities in proportion to their 2007 peak demands. The estimated total installed cost for the hydroelectric projects was $5,600/kW in 2008 dollars. The estimated fixed O&M and variable O&M costs were $7.50/kW-year and $6.00/MWh, respectively in 2008 dollars. Transmission losses to deliver the hydroelectric generation to the transmission system were also assumed to be 3.0 percent.

3.5 Data Modifications of the B&V REGA Projections

This study incorporated the following data into the B&V data:

- **GVEA:**
  - Based on a phone interview with Henri Dale at GVEA we adjusted the retirement data for the North Pole unit 2. The retirement date was extended 5 years with the unit producing the average of all prior years generation for the first three years and half of that amount for the remaining two years. It was assumed that this unit would scale back generation during the last two years of service.
  - Based on information from an article in Vol. 14, No. 30 of North of 60 Mining News it was confirmed that the Healy Clean Coal Plant (Healy CCP) would be sold to GVEA and that the agreement also provides that Homer Electric will purchase from Golden Valley half of the plant’s energy and capacity, starting in 2014.

- Based on information from GVEA's website (http://www.gvea.com/about/_hccp/) it was confirmed that the Healy CCP would be approximately 50MW. However, the interview with GVEA's Henri Dale indicated that the output would be 60 MW, so it was decided to use the higher value.
- According to Black & Veatch, GVEA's two LM6000 units (both 43MW) were assumed to be burn HAGO until 2020 instead of natural gas. However, we modified this to reflect the assumption that the pipeline start year for this study is 2019.
- Updated GVEA North Pole 1x1 CC plant to burn natural gas starting in 2019, listed as burning naphtha.
- Delayed launch of REGA-projected GVEA's two LM6000 units until 2015 based on utility interview response stating that the early launch (2008 – 2009) of these units is highly unlikely.

- **CEA**
  - Mr. Thibert confirmed that the Southcentral natural gas plant will be 183MW with 70% (128MW) going to CEA and 30% (55MW) going to ML&P. The unit will be in service in 2014. Mr. Thibert confirmed that HEA was no longer planning to share power from this plant. Based on this information HEA's share of power from the Southcentral natural gas plant was removed.
- **HEA**
  - It was assumed that the power that HEA would have received from its share of the Southcentral plant would now be purchased from the Healy CCP. This information was incorporated into the data.\
- **MEA**
  - Updated Matanuska LMS100 (2015) units from 98.8 MW to 90 MW based on response from Matanuska to utility interview questions. MEA is still determining the optimum size for this plant, but 90 MW is used in this analysis.

4 Modeling Results

The following sub-sections outline this study's updated natural gas, mixed portfolio, and large hydro renewable results.

4.1 Natural Gas Scenario Results

Table 16, Table 17, and Table 18 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 19 provides total energy consumption for all Railbelt utilities by fuel type.

Table 16. Natural Gas Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	98.8	8,262	New LMS100 (2018)	1	Natural Gas	1/2038
	98.8	8,262	New LMS100 (2022)	1	Natural Gas	1/2042
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	Bradley Lake - 08-13	1	Water	12/2013
	27.4	--	Bradley Lake - 2014	2	Water	12/2014
	27.4	--	Bradley Lake (2015+)	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake (2015+)	2	Water	1/2040
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013
CT Gas	42.1	12,268	New 6B SC (2031)	1	Natural Gas	1/2051
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2019)	1	Natural Gas	1/2039
Combined	52.0	8,269	North Pole 1x1 CC	1	Naphtha	1/2042
	116.0	7,298	New 1X1 6FA CC (2028)	1	Natural Gas	1/2053
CT Oil	62.0	10,100	North Pole	1	HAGO	12/2017
	64.0	9,910	North Pole	2	HAGO	12/2018
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	24.9	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
MLP						
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	43.0	9,023	New LM6000 (2037)	1	Natural Gas	1/2057
	98.8	8,262	New LMS100 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
	21.3	--	Eklutna Lake	1	Water	1/2040
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
MEA						
CT Gas	42.1	12,268	New 6B SC (2021)	1	Natural Gas	1/2041
	42.1	12,268	New 6B SC (2032)	1	Natural Gas	1/2052
	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
	98.8	8,262	New LMS100 (2035)	2	Natural Gas	1/2055
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040

Source: Estimates by SAIC from B&V, 2008.

Table 17. Natural Gas Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,919	2,336	2,751	2,277	2,555	1,054	1,159	931	1,233	1,262	987	1,012	1,328	1,485	1,391	1,545	1,581	1,635	1,579	1,633	1,597	1,601	1,598	1,636	1,618	1,549	1,559	1,527
GVEA	648	1,339	860	1,565	894	999	1,126	1,403	1,097	1,486	1,600	1,730	1,494	1,580	1,488	1,630	1,781	1,724	1,846	1,840	1,861	1,946	1,874	1,896	1,897	1,836	1,901	1,721
MLP	1,675	1,558	1,691	1,480	1,849	1,554	1,966	1,560	1,936	1,346	1,869	1,477	1,805	1,342	1,736	1,171	1,081	1,067	1,074	1,020	1,088	925	1,093	995	1,101	994	1,101	1,109
HEA	0	0	0	0	86	61	87	75	86	47	52	52	51	48	51	46	58	51	58	51	59	46	58	51	58	50	58	46
MEA	0	0	0	0	0	1,484	845	1,232	902	1,129	776	1,049	682	938	766	1,075	993	1,058	1,012	1,069	1,040	1,182	1,097	1,192	1,127	1,420	1,263	1,526
TOTAL	5,243	5,233	5,302	5,322	5,384	5,152	5,182	5,201	5,253	5,269	5,284	5,319	5,359	5,393	5,431	5,466	5,494	5,536	5,569	5,614	5,645	5,700	5,722	5,770	5,801	5,850	5,881	5,930
NG GENERATION BY UTILITY																												
CEA	2,612	2,028	2,444	1,970	2,247	747	892	745	1,046	1,075	800	825	1,141	1,298	1,204	1,358	1,394	1,448	1,392	1,446	1,410	1,414	1,412	1,449	1,431	1,362	1,372	1,341
GVEA	0	0	0	0	0	0	0	0	0	984	1,031	1,185	1,038	1,236	1,145	1,365	1,328	1,365	1,395	1,483	1,408	1,668	1,417	1,538	1,436	1,485	1,442	1,451
MLP	1,508	1,391	1,524	1,313	1,682	1,387	1,799	1,393	1,770	1,179	1,702	1,310	1,638	1,175	1,569	1,004	914	900	907	853	921	759	927	828	934	828	934	942
HEA	0	0	0	0	21	20	27	18	26	3	8	8	6	4	7	1	15	8	15	8	15	2	15	8	15	6	15	1
MEA	0	0	0	0	0	1,484	845	1,156	826	1,053	700	973	606	862	690	999	917	982	935	993	964	1,106	1,021	1,116	1,051	1,344	1,187	1,450
TOTAL	4,120	3,420	3,968	3,283	3,950	3,638	3,564	3,313	3,667	4,293	4,241	4,302	4,429	4,575	4,615	4,727	4,568	4,704	4,644	4,783	4,718	4,949	4,792	4,939	4,867	5,025	4,949	5,185
GENERATION BY FUEL																												
Coal	67	146	147	389	457	395	483	394	470	309	377	351	335	221	292	212	399	306	401	307	403	228	407	307	410	301	409	221
Natural Gas	4,120	3,420	3,968	3,283	3,950	3,638	3,564	3,313	3,667	4,293	4,241	4,302	4,429	4,575	4,615	4,727	4,568	4,704	4,644	4,783	4,718	4,949	4,792	4,939	4,867	5,025	4,949	5,185
Oil	528	1,140	660	1,124	449	592	609	971	592	143	143	143	71	73	0	2	4	2	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	527	527	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	5,243	5,233	5,302	5,322	5,384	5,152	5,182	5,201	5,253	5,269	5,284	5,319	5,359	5,393	5,431	5,466	5,494	5,536	5,569	5,614	5,645	5,700	5,722	5,770	5,801	5,850	5,881	5,930
Generation Percentage																												
Coal	1	3	3	7	8	8	9	8	9	6	7	7	6	4	5	4	7	6	7	5	7	4	7	5	7	5	7	4
Natural Gas	79	65	75	62	73	71	69	64	70	81	80	81	83	85	85	86	83	85	83	85	84	87	84	86	84	86	84	87
Oil	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9	9	9
Hydroelectric	10	22	12	21	8	11	12	19	11	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 18. Natural Gas Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	27.25	20.40	25.11	17.61	19.32	5.42	6.44	5.40	7.53	8.15	5.69	5.96	8.24	9.80	8.75	10.42	10.30	11.02	10.28	11.00	10.44	10.88	10.44	11.03	10.60	10.32	10.12	10.28
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.12	8.50	9.83	8.48	10.23	9.37	11.32	11.03	11.32	10.46	11.19	10.58	12.71	10.65	11.64	10.81	11.20	10.85	10.92
MLP	14.42	13.41	14.59	12.38	16.32	13.24	17.64	13.31	17.31	11.09	16.54	12.41	15.82	11.00	15.03	9.28	7.52	7.58	7.45	7.15	7.17	5.99	7.21	6.51	7.28	6.51	7.28	7.48
HEA	0.00	0.00	0.00	0.00	0.23	0.22	0.31	0.21	0.29	0.03	0.09	0.09	0.07	0.04	0.08	0.02	0.16	0.09	0.17	0.09	0.17	0.02	0.17	0.08	0.17	0.07	0.16	0.02
MEA	0.00	0.00	0.00	0.00	0.00	12.09	6.88	9.42	6.73	8.58	5.70	7.95	4.94	7.03	5.62	8.17	7.49	8.03	7.64	8.11	7.87	9.05	8.35	9.13	8.60	10.95	9.67	11.82
Total Natural Gas	41.67	33.81	39.71	29.98	35.87	30.98	31.27	28.34	31.86	35.96	36.53	36.25	37.56	38.10	38.85	39.20	36.50	38.03	36.00	37.54	36.23	38.65	36.83	38.40	37.46	39.05	38.08	40.52
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.12	8.50	9.83	8.48	10.23	9.37	11.32	11.03	11.32	10.46	11.19	10.58	12.71	10.65	11.64	10.81	11.20	10.85	10.92
ANC Nat Gas	41.67	33.81	39.71	29.98	35.87	30.98	31.27	28.34	31.86	27.85	28.03	26.42	29.07	27.87	29.48	27.88	25.47	26.71	25.54	26.36	25.65	25.94	26.18	26.76	26.65	27.85	27.23	29.59

Source: Estimates by SAIC from B&V, 2008.

Table 19. Natural Gas Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,216	5,168	4,440	5,243	4,330	5,107	3,412	4,104	3,827	3,649	2,254	2,977	2,166	4,056	3,112	4,081	3,118	4,098	2,322	4,135	3,124	4,167	3,060	4,152	2,258
Natural Gas	42,255	34,279	40,262	30,402	36,375	31,409	31,710	28,738	32,306	36,467	37,043	36,761	38,083	38,630	39,393	39,745	37,014	38,562	36,505	38,069	36,739	39,192	37,345	38,936	37,985	39,600	38,612	41,083
Naphtha	2,174	2,910	2,187	2,953	1,737	2,285	2,182	2,422	2,175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,641	7,950	3,946	7,864	2,374	2,926	3,290	6,203	3,149	1,421	1,420	1,427	707	725	7	32	49	30	2	4	3	0	0	0	0	0	0	0
Total	48,015	46,886	48,158	45,434	45,654	41,059	42,425	41,692	42,737	41,300	42,567	42,015	42,439	41,609	42,377	41,943	41,119	41,704	40,588	41,192	40,840	41,514	41,479	42,059	42,153	42,659	42,764	43,341

Source: Estimates by SAIC from B&V, 2008.

4.2 Mixed Resource Portfolio Scenario Results

Table 20, Table 21, and Table 22 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 23 provides total energy consumption for all Railbelt utilities by fuel type.

Table 20. Mixed Resource Portfolio Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
New Coal	100.0	10,140	New Coal (2025)	1	Coal	1/2055
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	98.8	9,023	New LM6000 (2018)	1	Natural Gas	1/2038
	98.8	8,262	New LMS100 (2022)	1	Natural Gas	1/2042
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,298	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	BradleyLake - 08-13	1	Water	12/2013
	27.4	--	BradleyLake - 2014	2	Water	12/2014
	27.4	--	BradleyLake - 2015+	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake - 2015+	2	Water	1/2040
	80.1	--	New Hydro (2020)	1	Water	1/2040
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013
	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	42.1	12,268	New 6B SC (2019)	1	Natural Gas	1/2039
	42.1	12,268	New 6B SC (2031)	1	Natural Gas	1/2051
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2028)	1	Natural Gas	1/2048
Combined	52.0	7,298	North Pole 1x1 CC	1	Naphtha	1/2042

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CT Oil	62.0	10,100	North Pole	1	HAGO	12/2017
	62.0	9,910	North Pole	2	HAGO	12/2018
	64.0	8,269	T 1X1 North Pole Retrofit (2031)	1	Natural Gas	1/2056
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	24.9	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
	77.7	--	New Hydro (2020)	1	Water	1/2040
Wind	13.0	--	New Wind (2012)	1	Wind	1/2037
MLP						
New Coal	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	43.0	9,023	New LM6000 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040
	21.3	--	Eklutna Lake	1	Water	1/2040
	64.5	--	New Hydro (2020)	1	Water	1/2040
Wind	10.7	--	New Wind (2012)	1	Wind	1/2037
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
	27.9	--	New Hydro (2020)	1	Water	1/2040
Wind	4.6	--	New Wind (2012)	1	Wind	1/2037
MEA						
New Coal	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
Combined	116.0	7,298	New 1X1 6FA CC (2035)	1	Natural Gas	1/2060
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040
	49.8	--	New Hydro (2020)	1	Water	1/2040
Wind	8.3	--	New Wind (2012)	1	Wind	1/2037

Source: Estimates by SAIC from B&V, 2008.

Table 21. Mixed Resource Portfolio Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,919	2,336	2,740	2,276	2,503	937	1,068	933	1,055	939	774	900	1,289	1,349	1,303	1,509	1,626	1,628	1,625	1,611	1,674	1,621	1,692	1,662	1,700	1,573	1,611	1,546
GVEA	648	1,339	861	1,558	898	983	1,108	1,388	1,126	1,354	1,440	1,626	1,098	1,394	1,134	1,088	1,167	1,173	1,247	1,319	1,460	1,701	1,506	1,669	1,579	1,308	1,316	1,352
MLP	1,675	1,558	1,694	1,482	1,849	1,558	1,962	1,563	1,975	1,390	1,970	1,593	1,896	1,464	1,838	1,455	1,264	1,272	1,262	1,224	1,062	904	1,058	964	1,049	882	985	789
HEA	0	0	3	3	129	104	86	76	89	50	87	89	83	82	84	162	176	169	175	169	182	163	186	169	187	167	174	163
MEA	0	0	6	5	5	1,548	915	1,181	923	1,438	899	975	841	923	872	1,076	1,082	1,114	1,080	1,111	1,090	1,136	1,101	1,128	1,105	1,728	1,603	1,893
TOTAL	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,168	5,171	5,170	5,183	5,207	5,211	5,231	5,290	5,315	5,356	5,388	5,433	5,467	5,526	5,543	5,593	5,619	5,658	5,689	5,742
NG GENERATION BY UTILITY																												
CEA	2,612	2,028	2,423	1,959	2,228	741	872	737	859	743	496	622	1,012	1,071	1,026	989	1,101	1,106	1,104	1,089	1,152	1,098	1,167	1,140	1,179	1,051	1,090	1,024
GVEA	0	0	0	0	0	0	0	0	0	840	750	990	530	930	682	501	398	490	478	634	688	1,092	726	981	798	637	550	755
MLP	1,508	1,391	1,521	1,308	1,675	1,384	1,788	1,389	1,801	1,216	1,730	1,353	1,656	1,224	1,598	1,020	825	835	825	787	626	466	619	528	613	446	550	353
HEA	0	0	0	0	20	19	25	18	27	3	10	11	7	6	8	2	14	9	14	8	18	2	19	9	20	7	14	2
MEA	0	0	0	0	0	1,467	834	1,099	842	1,357	767	842	709	790	740	793	796	830	795	826	806	851	814	843	821	1,443	1,319	1,609
TOTAL	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,529	4,160	3,753	3,818	3,914	4,022	4,054	3,305	3,136	3,270	3,217	3,345	3,290	3,509	3,345	3,501	3,430	3,585	3,523	3,743
GENERATION BY FUEL																												
Coal	67	146	147	384	455	394	477	393	480	312	412	357	359	255	314	1,121	1,316	1,223	1,308	1,225	1,314	1,154	1,335	1,228	1,326	1,210	1,303	1,136
Natural Gas	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,529	4,160	3,753	3,818	3,914	4,022	4,054	3,305	3,136	3,270	3,217	3,345	3,290	3,509	3,345	3,501	3,430	3,585	3,523	3,743
Oil	528	1,140	653	1,113	447	568	586	947	602	143	142	144	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	524	524	524	524	524	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830
Wind	0	0	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,168	5,171	5,170	5,183	5,207	5,211	5,231	5,290	5,315	5,356	5,388	5,433	5,467	5,526	5,543	5,593	5,619	5,658	5,689	5,742
GENERATION PERCENTAGE																												
Coal	1	3	3	7	8	8	9	8	9	6	8	7	7	5	6	21	25	23	24	23	24	21	24	22	24	21	23	20
Natural Gas	79	65	74	61	73	70	68	63	68	80	73	74	75	77	78	62	59	61	60	62	60	64	60	63	61	63	62	65
Oil	10	22	12	21	8	11	11	18	12	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	10	10	10	10	10	10	10	10	10	10	16	16	16	16	16	16	16	15	15	15	15	15	15	15	15	15	15	14
Wind	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 22. Mixed Resource Portfolio Scenario: Natural Gas Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	27.25	20.40	24.87	17.58	19.26	5.46	6.40	5.42	6.24	5.78	3.61	4.54	7.33	8.06	7.44	7.51	8.06	8.34	8.08	8.20	8.48	8.39	8.59	8.62	8.69	7.89	7.96	7.79
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.99	6.28	8.33	4.27	7.74	5.61	3.99	3.19	3.90	3.65	4.91	5.38	8.79	5.74	7.83	6.28	4.94	4.24	5.90
MLP	14.42	13.41	14.55	12.33	16.25	13.21	17.52	13.26	17.67	11.47	16.86	12.89	16.03	11.51	15.36	9.44	6.72	7.00	6.72	6.56	4.96	3.80	4.89	4.26	4.84	3.51	4.26	2.76
HEA	0.00	0.00	0.00	0.00	0.23	0.22	0.29	0.20	0.30	0.03	0.12	0.12	0.08	0.07	0.09	0.02	0.16	0.10	0.16	0.10	0.20	0.02	0.21	0.10	0.23	0.08	0.15	0.02
MEA	0.00	0.00	0.00	0.00	0.00	11.95	6.79	8.96	6.86	11.05	6.25	6.86	5.78	6.44	6.03	6.46	6.49	6.76	6.48	6.73	6.57	6.93	6.64	6.87	6.69	10.85	9.85	12.20
Total Natural Gas	41.67	33.81	39.42	29.91	35.73	30.84	31.00	27.84	31.08	35.32	33.12	32.75	33.48	33.82	34.53	27.42	24.62	26.09	25.09	26.50	25.58	27.93	26.07	27.68	26.72	27.27	26.47	28.67
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.99	6.28	8.33	4.27	7.74	5.61	3.99	3.19	3.90	3.65	4.91	5.38	8.79	5.74	7.83	6.28	4.94	4.24	5.90
ANC Nat Gas	41.67	33.81	39.42	29.91	35.73	30.84	31.00	27.84	31.08	28.33	26.84	24.42	29.21	26.08	28.92	23.43	21.43	22.20	21.44	21.59	20.20	19.15	20.33	19.85	20.44	22.33	22.23	22.76

Source: Estimates by SAIC from B&V, 2008.

Table 23. Mixed Resource Portfolio Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,167	5,143	4,434	5,181	4,316	5,214	3,443	4,462	3,919	3,913	2,595	3,194	11,383	13,359	12,413	13,275	12,434	13,348	11,710	13,567	12,467	13,483	12,274	13,219	11,532
Natural Gas	42,255	34,279	39,976	30,331	36,233	31,271	31,432	28,227	31,511	35,816	33,582	33,204	33,950	34,296	35,011	27,807	24,967	26,460	25,440	26,875	25,936	28,324	26,432	28,065	27,098	27,651	26,836	29,069
Naphtha	1,919	2,568	1,929	2,586	1,533	2,011	1,925	2,121	1,920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,641	7,950	3,872	7,769	2,352	2,711	3,089	6,011	3,239	1,420	1,414	1,428	704	709	1	0	0	0	1	0	0	0	0	0	0	0	0	0
Total	47,760	46,544	47,540	44,853	45,261	40,426	41,626	40,675	41,885	40,679	39,457	38,551	38,568	37,600	38,207	39,191	38,326	38,873	38,716	39,309	39,284	40,034	39,999	40,533	40,581	39,925	40,055	40,601

Source: Estimates by SAIC from B&V, 2008.

4.3 Large Hydro/Renewables/DSM/Energy Efficiency Scenario Results

Table 24, Table 25 and Table 26 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 27 provides total energy consumption for all Railbelt utilities by fuel type.

Table 24. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	43.0	8,262	New LM6000 (2018)	1	Natural Gas	1/2038
	98.8	8,262	New LMS100 (2022)	1	Natural Gas	1/2042
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	Bradley Lake - 08-13	1	Water	12/2013
	27.4	--	Bradley Lake - 2014	2	Water	12/2014
	27.4	--	Bradley Lake (2015+)	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake (2015+)	2	Water	1/2040
	80.1	--	New Hydro (2020)	1	Water	1/2040
	80.1	--	New Hydro (2025)	1	Water	1/2040
Wind	13.4	--	New Wind (2013)	1	Wind	1/2038
	13.4	--	New Wind (2018)	1	Wind	1/2043
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CT Gas	42.1	12,268	New 6B SC (2019)	1	Natural Gas	1/2039
	42.1	12,268	New 6B SC (2030)	1	Natural Gas	1/2050
	42.1	12,268	New 6B SC (2031)	1	Natural Gas	1/2051
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2026)	1	Natural Gas	1/2046
Combined	52.0	8,269	North Pole 1x1 CC	1	Naphtha	1/2042
	62.0	10,100	North Pole	1	HAGO	12/2017
	64.0	9,910	North Pole	2	HAGO	12/2018
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	25.68	25,679	Zehnder EMD	5	Distillate Fuel Oil	1/2000
	25.68	25,679	Zehnder EMD	6	Distillate Fuel Oil	1/2000
	13.36	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
	77.7	--	New Hydro (2020)	1	Water	1/2040
	77.7	--	New Hydro (2025)	1	Water	1/2040
Wind	13.0	--	New Wind (2013)	1	Wind	1/2038
	13.0	--	New Wind (2018)	1	Wind	1/2043
MLP						
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	98.8	8,262	New LMS100 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040
	21.3	--	Eklutna Lake	1	Water	1/2040
	64.5	--	New Hydro (2020)	1	Water	1/2040
	64.5	--	New Hydro (2025)	1	Water	1/2040
Wind	10.7	--	New Wind (2013)	1	Wind	1/2038
	10.7	--	New Wind (2018)	1	Wind	1/2043
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
	27.9	--	New Hydro (2020)	1	Water	1/2040
	27.9	--	New Hydro (2025)	1	Water	1/2040
Wind	4.6	--	New Wind (2013)	1	Wind	1/2038
	4.6	--	New Wind (2018)	1	Wind	1/2043

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
MEA						
CT Gas	42.1	12,268	New 6B SC (2026)	1	Natural Gas	1/2046
	42.1	12,268	New 6B SC (2037)	1	Natural Gas	1/2057
	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
	98.8	8,262	New LMS100 (2035)	2	Natural Gas	1/2055
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040
	49.8	--	New Hydro (2020)	1	Water	1/2040
	49.8	--	New Hydro (2025)	1	Water	1/2040
Wind	8.3	--	New Wind (2013)	1	Wind	1/2038
	8.3	--	New Wind (2018)	1	Wind	1/2043

Source: Estimates by SAIC from B&V, 2008.

Table 25. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,919	2,336	2,740	2,276	2,503	937	1,068	933	1,050	942	774	901	1,297	1,341	1,311	1,411	1,412	1,380	1,424	1,394	1,412	1,362	1,428	1,391	1,437	1,358	1,418	1,329
GVEA	648	1,339	861	1,558	898	983	1,108	1,388	1,128	1,352	1,430	1,619	1,091	1,392	1,127	1,383	1,793	1,797	1,834	1,813	1,755	1,765	1,735	1,799	1,783	1,692	1,702	1,621
MLP	1,675	1,558	1,694	1,482	1,849	1,558	1,962	1,563	1,976	1,395	1,974	1,597	1,901	1,467	1,844	1,341	910	897	921	913	1,090	983	1,123	1,041	1,131	1,002	1,087	943
HEA	0	0	3	3	129	104	86	76	92	53	90	92	86	85	87	108	119	113	120	113	120	108	120	113	121	111	120	108
MEA	0	0	6	5	5	1,548	915	1,181	924	1,432	904	974	834	927	864	1,031	1,067	1,154	1,074	1,179	1,069	1,274	1,114	1,217	1,123	1,474	1,345	1,718
TOTAL	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,170	5,173	5,172	5,184	5,208	5,212	5,232	5,274	5,301	5,341	5,373	5,413	5,446	5,492	5,520	5,562	5,595	5,638	5,672	5,719
NG GENERATION BY UTILITY																												
CEA	2,612	2,028	2,423	1,959	2,228	741	872	737	845	737	488	615	1,010	1,054	1,025	1,047	1,048	1,016	1,060	1,030	1,048	998	1,064	1,027	1,073	994	1,054	965
GVEA	0	0	0	0	0	0	0	0	0	830	734	977	517	922	669	946	1,180	1,268	1,219	1,283	1,138	1,316	1,113	1,266	1,158	1,168	1,077	1,178
MLP	1,508	1,391	1,521	1,308	1,675	1,384	1,788	1,389	1,795	1,214	1,728	1,350	1,654	1,220	1,597	1,032	601	588	611	604	780	674	813	732	822	693	778	634
HEA	0	0	0	0	20	19	25	18	27	3	10	10	7	6	8	2	14	8	14	8	14	2	15	8	15	6	14	1
MEA	0	0	0	0	0	1,467	834	1,099	837	1,345	766	836	696	789	726	844	881	968	888	993	883	1,088	927	1,031	937	1,288	1,159	1,532
TOTAL	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,504	4,129	3,725	3,789	3,884	3,993	4,024	3,871	3,724	3,847	3,793	3,918	3,863	4,077	3,932	4,065	4,004	4,150	4,083	4,311
GENERATION BY FUEL																												
Coal	67	146	147	384	455	394	477	393	479	312	408	355	357	252	312	215	390	306	393	308	395	227	400	310	404	301	402	221
Natural Gas	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,504	4,129	3,725	3,789	3,884	3,993	4,024	3,871	3,724	3,847	3,793	3,918	3,863	4,077	3,932	4,065	4,004	4,150	4,083	4,311
Oil	528	1,140	653	1,113	447	568	586	947	597	143	142	143	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	524	524	524	524	524	830	830	830	830	830	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121
Wind	0	0	33	33	33	33	33	33	66	66	66	66	66	66	66	66	66	66	66	66	66	66	67	66	66	66	66	66
TOTAL	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,170	5,173	5,172	5,184	5,208	5,212	5,232	5,274	5,301	5,341	5,373	5,413	5,446	5,492	5,520	5,562	5,595	5,638	5,672	5,719
GENERATION PERCENTAGE																												
Coal	1	3	3	7	8	8	9	8	9	6	8	7	7	5	6	4	7	6	7	6	7	4	7	6	7	5	7	4
Natural Gas	79	65	74	61	73	70	68	63	68	80	72	73	75	77	77	73	70	72	71	72	71	74	71	73	72	74	72	75
Oil	10	22	12	21	8	11	11	18	12	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	10	10	10	10	10	10	10	10	10	10	16	16	16	16	16	21	21	21	21	21	21	20	20	20	20	20	20	20
Wind	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 26. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	27.25	20.40	24.87	17.50	19.13	5.37	6.29	5.33	6.02	5.58	3.48	4.40	7.19	7.81	7.30	7.88	7.48	7.49	7.58	7.61	7.48	7.49	7.61	7.59	7.69	7.32	7.53	7.22
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.20	6.39	8.57	4.41	8.00	5.76	8.22	9.75	10.47	10.06	10.60	9.34	10.89	9.14	10.46	9.52	9.58	8.81	9.66
MLP	14.42	13.41	14.55	12.33	16.25	13.21	17.52	13.26	17.61	11.44	16.83	12.85	16.01	11.47	15.34	9.57	4.71	4.77	4.80	4.91	6.01	5.29	6.28	5.72	6.35	5.39	5.99	4.97
HEA	0.00	0.00	0.00	0.00	0.23	0.22	0.29	0.20	0.30	0.03	0.11	0.12	0.08	0.07	0.09	0.02	0.16	0.09	0.16	0.09	0.16	0.02	0.17	0.09	0.17	0.07	0.16	0.02
MEA	0.00	0.00	0.00	0.00	0.00	11.95	6.79	8.96	6.82	10.96	6.24	6.81	5.67	6.43	5.92	6.88	7.19	7.91	7.25	8.12	7.21	8.90	7.57	8.43	7.66	10.50	9.44	12.49
Total Natural Gas	41.67	33.81	39.42	29.83	35.60	30.74	30.88	27.74	30.74	35.20	33.05	32.75	33.35	33.79	34.39	32.57	29.29	30.73	29.86	31.34	30.21	32.60	30.77	32.29	31.38	32.87	31.93	34.35
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.20	6.39	8.57	4.41	8.00	5.76	8.22	9.75	10.47	10.06	10.60	9.34	10.89	9.14	10.46	9.52	9.58	8.81	9.66
ANC Nat Gas	41.67	33.81	39.42	29.83	35.60	30.74	30.88	27.74	30.74	28.01	26.66	24.18	28.94	25.78	28.64	24.35	19.54	20.27	19.80	20.74	20.86	21.70	21.63	21.83	21.86	23.28	23.12	24.69

Source: Estimates by SAIC from B&V, 2008.

Table 27. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,167	5,143	4,434	5,181	4,316	5,196	3,440	4,422	3,895	3,892	2,573	3,181	2,191	3,970	3,117	4,000	3,130	4,021	2,317	4,071	3,153	4,106	3,061	4,089	2,259
Natural Gas	42,255	34,279	39,976	30,249	36,100	31,173	31,315	28,129	31,171	35,696	33,513	33,207	33,813	34,259	34,876	33,025	29,701	31,165	30,276	31,779	30,628	33,054	31,204	32,739	31,817	33,328	32,380	34,829
Naphtha	2,174	2,910	2,186	2,930	1,737	2,278	2,181	2,403	2,175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,641	7,950	3,872	7,769	2,352	2,711	3,089	6,011	3,195	1,420	1,413	1,426	704	708	1	4	2	1	2	2	0	0	0	0	0	0	0	0
DFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	48,015	46,886	47,796	45,115	45,332	40,595	41,766	40,859	41,738	40,556	39,348	38,529	38,410	37,540	38,058	35,221	33,673	34,283	34,278	34,911	34,649	35,371	35,274	35,892	35,924	36,389	36,469	37,088

Source: Estimates by SAIC from B&V, 2008.

4.4 Coal Scenario Results

Table 28, Table 29, and Table 30 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 31 provides total energy consumption for all Railbelt utilities by fuel type.

Table 28. Coal Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
New Coal	26.7	10,138	New Coal (2015)	1	Coal	1/2045
	26.7	10,138	New Coal (2020)	1	Coal	1/2050
	26.7	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	42.1	12,268	New 6B SC (2021)	1	Natural Gas	1/2041
	42.1	12,268	New 6B SC (2022)	1	Natural Gas	1/2042
	43.0	9,023	New LM6000 (2018)	1	Natural Gas	1/2038
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,298	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	Bradley Lake - 08-13	1	Water	12/2013
	27.4	--	Bradley Lake - 2014	2	Water	12/2014
	27.4	--	Bradley Lake (2015+)	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake (2015+)	2	Water	1/2040
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013
	25.9	10,138	New Coal (2015)	1	Coal	1/2045
	25.9	10,138	New Coal (2020)	1	Coal	1/2050
	25.9	10,138	New Coal (2025)	1	Coal	1/2055

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CT Gas	42.1	12,268	New 6B SC (2036)	1	Natural Gas	1/2056
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2028)	1	Natural Gas	1/2048
Combined	52.0	7,298	North Pole 1x1 CC	1	Naphtha	1/2042
CT Oil	62.0	10,100	North Pole	1	HAGO	12/2017
	62.0	9,910	North Pole	2	HAGO	12/2018
	64.0	8,269	T 1X1 North Pole Retrofit (2031)	1	Natural Gas	1/2056
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	24.9	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
MLP						
New Coal	21.5	10,138	New Coal (2015)	1	Coal	1/2045
	21.5	10,138	New Coal (2020)	1	Coal	1/2050
	21.5	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	43.0	9,023	New LM6000 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040
	21.3	--	Eklutna Lake	1	Water	1/2040
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
	9.3	10,138	New Coal (2015)	1	Coal	1/2045
	9.3	10,138	New Coal (2020)	1	Coal	1/2050
	9.3	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
MEA						
New Coal	16.6	10,138	New Coal (2015)	1	Coal	1/2045
	16.6	10,138	New Coal (2020)	1	Coal	1/2050
	16.6	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	42.1	12,268	New 6B SC (2034)	1	Natural Gas	1/2054
	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
	98.8	8,262	New LMS100 (2035)	2	Natural Gas	1/2055
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040

Source: Estimates by SAIC from B&V, 2008.

Table 29. Coal Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,897	2,336	2,748	2,277	2,486	1,093	1,122	966	1,032	1,060	1,060	1,331	1,391	1,382	1,461	1,451	1,564	1,539	1,519	1,545	1,535	1,534	1,545	1,550	1,554	1,531	1,559	1,465
GVEA	639	1,339	841	1,566	891	1,095	1,168	1,223	1,195	1,314	1,102	1,375	1,210	1,400	1,193	1,480	1,746	1,726	1,829	1,745	1,849	1,794	1,869	1,819	1,884	1,798	1,893	1,791
MLP	1,707	1,558	1,715	1,480	1,918	1,667	2,001	1,677	2,038	1,476	2,209	1,727	2,147	1,659	2,050	1,519	1,088	1,092	1,090	1,103	1,094	1,050	1,106	1,089	1,117	1,082	1,120	1,026
HEA	0	0	0	0	89	115	102	107	84	80	206	59	65	65	72	101	113	153	118	159	123	146	127	165	129	153	127	115
MEA	0	0	0	0	0	1,169	783	1,236	897	1,347	718	835	555	891	664	915	982	1,020	1,011	1,053	1,041	1,165	1,072	1,138	1,113	1,277	1,178	1,532
	5,243	5,233	5,304	5,322	5,383	5,140	5,177	5,210	5,246	5,277	5,296	5,327	5,368	5,398	5,441	5,466	5,493	5,530	5,566	5,605	5,642	5,688	5,719	5,762	5,797	5,842	5,878	5,929
NG GENERATION BY UTILITY																												
CEA	2,589	2,028	2,441	1,970	2,178	578	647	571	638	665	409	682	742	732	810	650	1,002	777	1,002	778	1,001	692	1,005	773	1,003	767	1,006	643
GVEA	0	0	0	0	0	0	0	0	0	579	297	526	293	607	316	526	643	712	720	732	738	838	753	809	771	787	776	835
MLP	1,541	1,391	1,548	1,313	1,751	1,471	1,817	1,480	1,852	1,278	1,997	1,514	1,938	1,449	1,849	1,287	372	396	431	405	429	340	437	387	443	379	444	316
HEA	0	0	0	0	24	12	12	11	13	2	6	2	4	2	5	0	5	3	5	3	5	1	5	3	5	3	5	0
MEA	0	0	0	0	0	1,040	654	1,031	692	1,141	355	473	198	529	303	417	475	513	503	546	535	658	564	631	607	771	1,102	1,456
	4,130	3,420	3,989	3,283	3,953	3,101	3,130	3,094	3,195	3,666	3,064	3,196	3,176	3,319	3,283	2,881	2,497	2,401	2,661	2,465	2,708	2,529	2,764	2,604	2,828	2,706	3,332	3,250
GENERATION BY FUEL																												
Coal	67	146	147	389	465	1,015	1,052	1,016	1,058	945	1,573	1,471	1,601	1,487	1,634	2,062	2,471	2,605	2,381	2,617	2,410	2,636	2,431	2,634	2,446	2,612	2,022	2,155
Natural Gas	4,130	3,420	3,989	3,283	3,953	3,101	3,130	3,094	3,195	3,666	3,064	3,196	3,176	3,319	3,283	2,881	2,497	2,401	2,661	2,465	2,708	2,529	2,764	2,604	2,828	2,706	3,332	3,250
Oil	519	1,140	641	1,124	439	497	468	577	470	142	135	136	68	68	0	0	1	1	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	527	527	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	5,243	5,233	5,304	5,322	5,383	5,140	5,177	5,210	5,246	5,277	5,296	5,327	5,368	5,398	5,441	5,466	5,493	5,530	5,566	5,605	5,642	5,688	5,719	5,762	5,797	5,842	5,878	5,929
GENERATION PERCENTAGE																												
Coal	1	3	3	7	9	20	20	19	20	18	30	28	30	28	30	38	45	47	43	47	43	46	43	46	42	45	34	36
Natural Gas	79	65	75	62	73	60	60	59	61	69	58	60	59	61	60	53	45	43	48	44	48	44	48	45	49	46	57	55
Oil	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9	9	9
Hydroelectric	10	22	12	21	8	10	9	11	9	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 30. Coal Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	26.98	20.40	25.08	17.69	18.78	4.26	4.77	4.21	4.64	5.04	2.98	5.03	5.45	5.42	5.95	4.81	7.29	5.73	7.28	5.74	7.28	5.20	7.31	5.69	7.29	5.63	7.32	4.74
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.66	2.28	4.21	2.16	4.93	2.36	4.21	5.35	5.86	5.63	5.72	5.78	6.58	5.94	6.34	6.04	6.16	6.08	6.55
MLP	14.78	13.41	14.86	12.38	17.10	14.23	17.90	14.34	18.31	12.16	20.04	14.79	19.38	14.04	18.33	12.32	2.77	3.05	3.19	3.13	3.18	2.64	3.24	2.98	3.30	2.90	3.30	2.42
HEA	0.00	0.00	0.00	0.00	0.27	0.14	0.13	0.13	0.15	0.03	0.06	0.02	0.05	0.03	0.05	0.00	0.05	0.03	0.05	0.03	0.06	0.01	0.06	0.04	0.06	0.03	0.06	0.01
MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Natural Gas	41.76	33.81	39.94	30.06	36.15	18.62	22.81	18.67	23.10	21.88	25.37	24.05	27.03	24.41	26.70	21.34	15.46	14.67	16.15	14.62	16.29	14.43	16.55	15.05	16.69	14.73	16.76	13.72
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.66	2.28	4.21	2.16	4.93	2.36	4.21	5.35	5.86	5.63	5.72	5.78	6.58	5.94	6.34	6.04	6.16	6.08	6.55
ANC Nat Gas	41.76	33.81	39.94	30.06	36.15	18.62	22.81	18.67	23.10	17.22	23.09	19.84	24.87	19.48	24.34	17.14	10.11	8.81	10.52	8.90	10.51	7.85	10.61	8.71	10.65	8.57	10.68	7.17

Source: Estimates by SAIC from B&V, 2008.

Table 31. Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,216	5,244	10,715	10,954	10,600	11,059	9,924	16,222	15,187	16,472	15,082	16,579	20,906	25,067	26,420	24,255	26,747	24,557	26,929	24,785	26,939	24,937	26,696	20,639	21,995
Natural Gas	42,344	34,279	40,497	30,483	36,654	18,883	23,128	18,931	23,426	22,189	25,723	24,389	27,413	24,751	27,074	21,642	15,679	14,873	16,375	14,823	16,515	14,633	16,785	15,262	16,923	14,933	16,992	13,914
Naphtha	1,918	2,569	1,930	2,606	1,533	2,000	1,923	2,009	1,918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,548	7,951	3,753	7,864	2,271	2,083	2,001	2,792	2,026	1,437	1,338	1,345	669	680	0	6	15	13	4	3	3	0	0	0	0	0	0	0
Total	47,757	46,545	47,942	45,169	45,701	33,681	38,007	34,332	38,429	33,550	43,283	40,921	44,555	40,513	43,653	42,554	40,760	41,306	40,633	41,574	41,076	41,563	41,570	42,200	41,860	41,629	37,631	35,909

Source: Estimates by SAIC from B&V, 2008.

Appendix D: Alaskan Propane Extraction Facilities Cost Estimates for 0.5, 65, and 300 MMSCFD Plants

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GAS LIQUIDS ENGINEERING

Alaskan Propane Extraction Facilities Cost Estimates For 0.5, 65, & 300 MMSCFD Plants

Final Report

Revision Release: October 13, 2009 Rev. 4

Print Format – Double Sided

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Revision Log

Rev.	Description	Revision Date	Completed by
0	Preliminary report	July 10, 2009	IMcK
1	Final Report	August 14, 2009	IMcK
2	Complete Report (for final review)	August 28, 2009	IMcK
3	Final Report	September 8, 2009	IMcK
4	Final Report - confidentiality statement removed	October 13, 2009	IMcK

Notes: 1. Data for Revision 0 was developed during the period from June 24 to July 10, 2009.

Note to Reader

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It is recommended that each new revision or release of this publication be reviewed in its entirety in order to ensure a comprehensive understanding of the contents of this document.

Report Prepared by: Ian McKay

Ian McKay

Signature

October 13, 2009

Date

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1.0 EXECUTIVE SUMMARY

On the Alaskan North Slope, there are 35 trillion cubic feet of recoverable natural gas. Currently this gas either remains in place or is co-produced with oil, separated, and returned to the producing formation. There is no export of this natural gas due to the lack of a pipeline for this purpose.

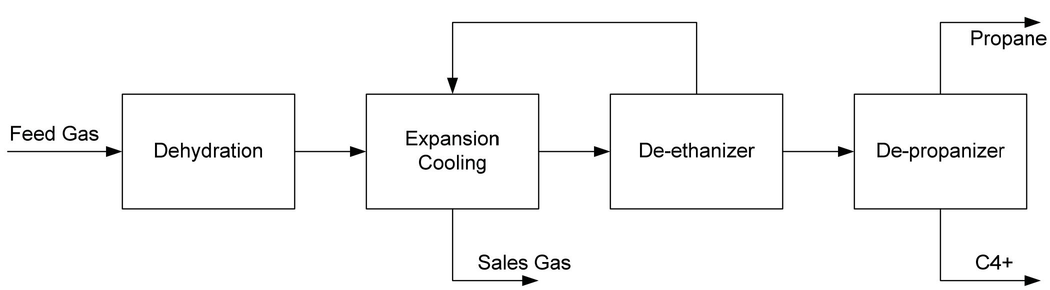
Subsidiaries of TransCanada Corporation have been awarded a license from the State of Alaska (December 5, 2008) for the Alaska Pipeline Project (APP) under the Alaska Gasline Inducement Act (AGIA) and has reached an agreement with ExxonMobil (June 11, 2009) to work together on the project. Following these announcements, "*TransCanada has moved forward with project development, which includes engineering, environmental reviews, Alaska Native and Canadian Aboriginal engagement, and commercial work to conclude an initial binding open season by July 2010*."

Consistent with the requirements as stipulated in the 2005 FERC Open Season Regulations for Alaska Natural Gas Transportation Projects, TransCanada has commissioned Northern Economics to conduct an in-state gas demand study. Included in the study is an assessment of the potential propane demand in-state. This involves analyzing the costs of separating liquid propane, and potentially utility grade sales gas, from the North Slope pipeline gas, for use in local communities as heating/cooking fuel and for potential use in local power generation. This option may provide an improved cost position relative to the fuels that are currently used for these purposes.

Potential scenarios for propane recovery could include so-called "straddle" plants located at communities along the Alaska gas Pipeline route (e.g. Fairbanks, Tok) and/or at the South-central area (e.g. Anchorage) which would require a spur-line to bring raw gas from the Alaska gas pipeline to the community of interest.

TransCanada has retained the services of Gas Liquids Engineering Ltd. (GLE) to validate conceptual design work and provide cost estimation for three propane extraction facilities covering a range of the potential community sizes and locations relevant to Alaska's demographics. The cost estimation data for the propane extraction facilities, provided by GLE, is then used by Northern Economics as inputs in evaluating the overall cost of providing locally produced propane to Alaskan communities.

Gas Liquids Engineering has designed a fractionation facility based on the following block flow arrangement.



Gas Liquids Engineering has found that the design of the expansion cooling section has a major impact on the propane recovery capability of the plant design. GLE has evaluated several designs for the expansion cooling section and has focused on a design which is capable of delivering the 97 weight percent propane recovery to maximize propane recovery from the raw gas.

GLE has also evaluated a range of potential inlet pressures for the feed gas to the facilities and confirmed that the required propane recovery is feasible with the preferred plant design over a range of plant inlet pressures from 1500 to 2400 psia.

Cost estimates for the three facilities have been based on the use of budgetary estimates for major capital and electrical equipment, percentage factors for minor capital and engineering expenses, and factors for installation and owner's costs. In addition a location factor has been determined for each facility to allow for the increased cost of construction in different locations in Alaska relative to western Canada and/or the lower 48 states. Probable costs (P10, P50, P90) were assigned to all capital items, engineering cost, and installation factors. Fixed factors were used for location and owner's cost factors. Monte Carlo simulation was then used in combination with the cost equation, below, to generate probability distribution estimates for the three facilities.

(Plant Capex + Minor Capex + EIC Capex + Engineering) x Installation Factor x Location Factor x Owner's Cost

A summary of the three facilities and estimated costs is provided in the following table.

Facility	Raw Gas Feed Rate (MMSCFD)	Propane Production (BPD)	Sales Gas Production (MMSCFD	Cost Estimates (USD Millions)		
				P10	P50	P90
Tok	0.5	11.7	0.48	6.44	7.27	8.25
Fairbanks	65	1526	25(1)	79.62	90.45	103.71
Anchorage	300	7046(2)	289.3	165.13	185.80	211.24

(1) The remainder of separated gas is recompressed and returned to the Alaskan gas pipeline.

(2) C4+ production of 1832 bpd is also available from this facility.

The estimates above are at the Class 5 level as defined by the Association for the Advancement of Cost Engineering (AACE International) in Recommended Practice No. 18R-97. Going forward, the accuracy and precision of these estimates can be improved through advancing the extent of engineering activity (basic, FEED, detailed,…) which will support detailed and formal cost estimation.

As more engineering detail is developed, it will also be prudent to scrutinize and refine the values for the estimation factors (installation, location, owner's costs) to reduce the uncertainty associated with estimation, and to improve on the accuracy of the forecast values.

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2.0 INTRODUCTION & BACKGROUND

"*Discovered recoverable natural gas resources on the Alaska North Slope are estimated to be about 35 trillion cubic feet. No natural gas is currently exported off the North Slope because there is no gas pipeline to transport the gas to markets*."[1] This quotation, taken from a 2007 US Department of Energy report, succinctly summarizes the size and current status of the Alaskan North Slope natural gas reserves.

With initial activities beginning in the 1970s and a continued and strong presence today, TransCanada Corporation has sought to design and execute a project to provide a natural gas pipeline for transportation of Alaskan North Slope gas across the State of Alaska, through the Yukon Territory and the Province of British Columbia into Alberta. In Alberta, the new pipeline would connect to existing infrastructure allowing shipment to terminal points in the lower 48 States.

On December 5, 2008 the State of Alaska awarded a license to subsidiaries of TransCanada Corporation for the Alaska Pipeline Project under the Alaska Gasline Inducement Act (AGIA). Following this decision, TransCanada has stated, "*This ratification of our license under AGIA will facilitate TransCanada's continuing commercial negotiations with potential shippers, improving the likelihood of a successful open season and the construction of a natural gas delivery system from Prudhoe Bay to Lower 48 markets*."[2]

On June 11, 2009 TransCanada announced that it had reached an agreement with ExxonMobil to work together on the APP.[3] Following these announcements, "*TransCanada has moved forward with project development, which includes engineering, environmental reviews, Alaska Native and Canadian Aboriginal engagement, and commercial work to conclude an initial binding open season by July 2010*."

Consistent with the requirements as stipulated in the 2005 FERC Open Season Regulations for Alaska Natural Gas Transportation Projects, TransCanada has commissioned Northern Economics to conduct an in-state gas demand study, which includes an evaluation of various options for the provision of propane and natural gas as fuels for local consumption in Alaskan communities (heating, cooking, power generation, etc.).

Assuming construction of the Alaska gas pipeline, the most preferred routes to obtaining propane for communities along the pipeline route would be to use so-called "straddle" plants to recover propane and sales quality natural gas from a slipstream taken from the main pipeline. Unwanted residual gas would be recompressed and returned to the main pipeline. For locations at a distance from the Alaska gas pipeline (e.g. Anchorage), a spur-line would be required to bring raw gas to a suitable fractionation plant.

In preparation for Northern Economics evaluations, TransCanada has retained the services of Gas Liquids Engineering Ltd. (GLE) to provide preliminary cost estimation for three facilities for propane extraction. These facilities differ in their location (proximity to the Alaska gas pipeline) and scale (0.5, 65, or 300 MMSCFD of gas processing). Each, in its own way, would contribute to the recovery of, and potential distribution for, propane and natural gas to Alaskan communities.

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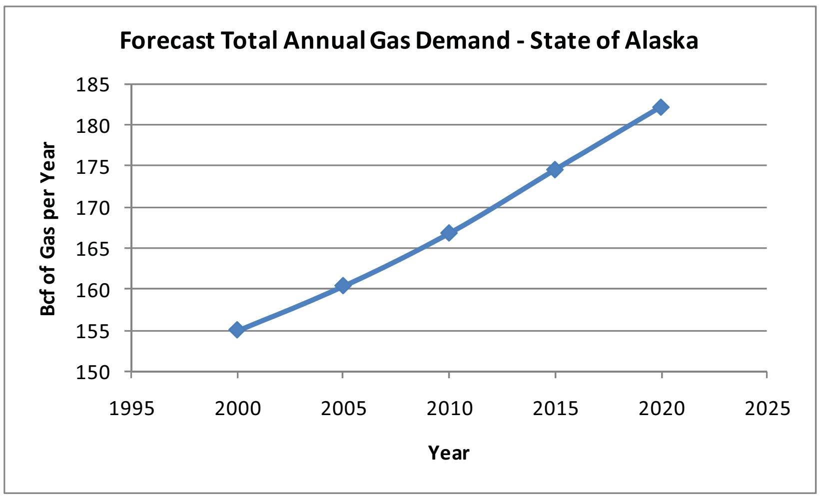
The State of Alaska, working through the Alaska Department of Natural Resources, and Alaska Natural Gas Development Authority (ANGDA), have been developing information on natural gas/propane demand and various supply options over recent years. A brief summary of key studies in this regard follows.

In 2002 the Alaska Department of Natural Resources issued a report, prepared by Econ One Research and the Acadian Consulting Group, addressing the subject of future, in-state demand for natural gas.[4] The study forecast average annual growth rates for natural gas demand in Alaska to be 1.8, 1.0, 0.5 and 0.7 % for the residential, commercial, industrial, and utility sectors, respectively. In aggregate, the average annual growth rate in natural gas demand for the state is expected to be a little less than 1 percent. Total forecast gas demand is shown in Figure 2.1.

Figure 2.1 Forecast Total Annual Natural Gas Demand – Alaska.[1]



Also in 2002, the Alaska Natural Gas Development Authority (ANGDA) was created as a public corporation with the objectives of getting natural gas to communities in Alaska and identifying areas where use of liquefied natural gas (LNG) would be viable.[5]

For natural gas supply, ANGDA has focused its efforts around construction of a natural gas spur-line that connects with the Alaska gas pipeline at around Delta Junction. Routing for the spur-line would follow the Richardson highway to Glennallen and then proceed westwards to Anchorage.[5]

In addition to the development of a natural gas pipeline into the Anchorage area, ANGDA has worked to identify a viable distribution network for propane supply to over 99 % of the state's population.[6] Several studies have served as key building blocks in the development of ANGDA's plan for improved distribution of natural gas and propane in the Alaskan market.[7-11]

In 2004 ANGDA received a report from Michael Baker Jr., Inc. (Baker) who, in turn, worked with Linde BOC Process Plants LLC (Linde BOCPP) to investigate plant configurations for propane and possibly natural gas extraction facilities to be located along a major gas pipeline through Alaska.[7] In the Baker study, Linde BOCPP proposed a plant configuration using turbo-expansion cooling and two fractionation towers to produce three product streams; natural gas, propane, and C4+. For the scenario in which only propane is used locally, the natural gas and C4+ streams are blended, compressed, cooled to 28 F and returned to the pipeline.

The plant was designed to process 10 MMSCFD of pipeline gas. In the full configuration, the plant was estimated to have a capital cost of $10.5 million (USD). Removal of propane refrigeration (for gas returned to the pipeline) would reduce the cost to $7.9 million and removal of both refrigeration and re-compression (natural gas used locally) would reduce the plant cost to $6.1 million.

In 2006, ANGDA received a report titled “ANGDA 06-0414 Spur-line Terminal Conceptual Design July 2006” from the Shaw Group’s affiliate, Stone & Webster Management Consultants Inc. (Stone & Webster).[8] This study looked at options to process large amounts of gas (4500, 900, and 500 MMSCFD cases) and included features for gas fractionation, ethylene, and polyethylene production. Of potential interest to the study work described herein is the 500 MMSCFD case for which only gas fractionation was considered. The capital cost associated with this option (propane and natural gas products provided) was $347 million.

In 2007, ANGDA produced a series of three reports dealing with the subjects of propane/NGL recovery. The first of these reports addressed a potential 1000 barrel per day (BPD) propane extraction plant to be located at the junction of the Dalton highway and Yukon River.[9] In a second 2007 report, ANGDA discusses a 100 - 200 MMSCFD NGL extraction facility to be located at Cook Inlet.[10] The third ANGDA staff report from February of 2007 investigates the subject of extracting 20 percent of the natural gas liquids transported via the Alaska North Slope (ANS) pipeline.[11] A key difficulty faced in each of these reports is ANGDA’s lack of cost estimation data for suitably sized facilities. A 500 MMSCFD plant is the smallest facility for which ANGDA has reasonable data.[8]

The facilities design and cost evaluation work provided by Gas Liquids Engineering in this report has been produced to support Northern Economics’ assessment of the potential demand for propane and natural gas in Alaska as part of the TransCanada’s preparation for the 2010 open season for the APP.

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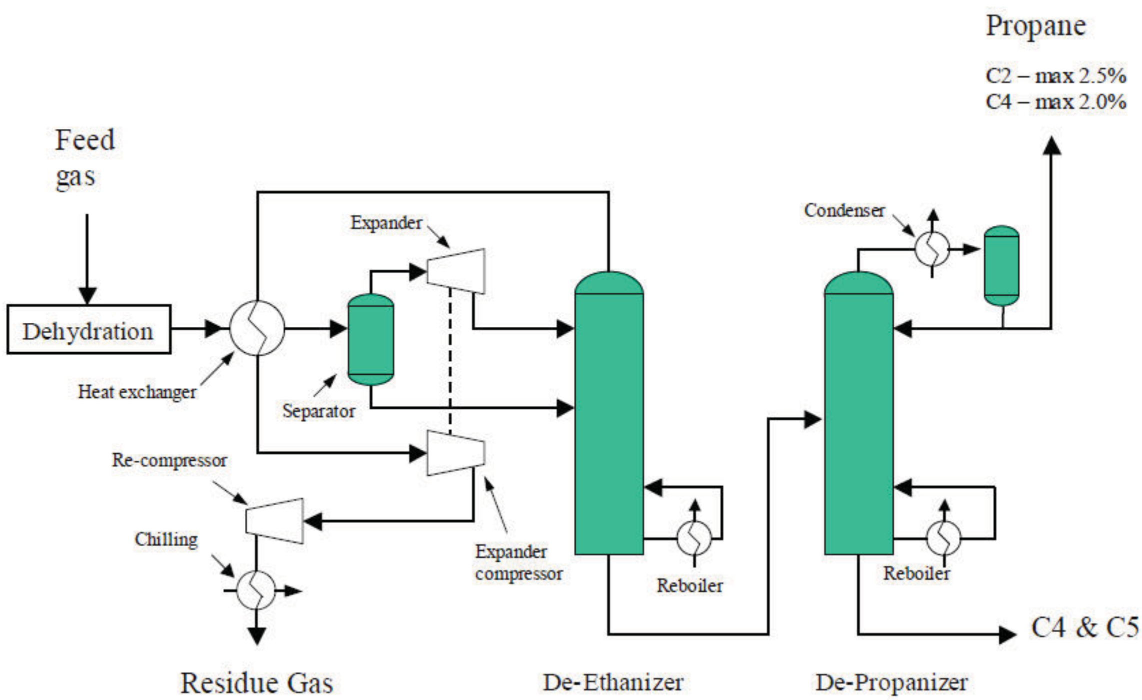
3.0 TECHNOLOGY DEFINITION AND COST ESTIMATION

ANGDA has received process designs for NGL recovery plants from Linde BOCPP and Stone & Webster.[7,8] In subsequent ANGDA staff reports, the analyses have been based on use of the Stone & Webster configuration, shown in Figure 3.1.

Figure 3.1 Configuration of LPG Extraction Plant.[7]



The plant design shown is schematic and does not include all of the associated pipes, valves, and minor equipment that are a part of the fully functional design.

GLE has based its designs for the three facilities (Tok, Fairbanks, Anchorage) on the Stone & Webster configuration. To allow for complete simulation of plant performance, GLE has included additional valves and lines where needed in order to appropriately control pressure and fluid flow in the design. Practical consideration of design/operating pressures for various plant units has contributed to simulation work, which has allowed for optimization of the technical performance of the plant design (need approximately 97 % propane recovery) and provided the basis for cost estimation.

It is important to note that GLE has not been retained to provide multiple potential plant designs, nor a comparative analysis of potential designs in terms of technical performance and estimated cost. However, where appropriate, GLE has provided some commentary on alternative design features/options.

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The three facilities to be estimated are summarized in Table 3.1.

Table 3.1 Description of Propane/Natural Gas Extraction Facilities.

Location in Alaska	**Tok**	**Fairbanks**	**Anchorage**
Scale (MMSCFD)	0.5	65	300
Proximity to ANS pipeline	Adjacent	Adjacent	Remote
Products Recovered	C3, Nat. Gas	C3, some Nat. Gas	Nat. Gas, C3, C4+
Gas Re-injected to ANS Pipeline (1)	No	Partial	No
Facility Inlet Pressure (psia)	1500	1500	1500
Returned Gas Pressure (psia)	n.a.	1500	n.a.

- Re-injection of gas will require gas recompression and possibly refrigeration facilities.

Key assumptions of the simulation and design work presented herein are the facility inlet and returned gas pressures. Values of 1500 psia, for both of these pressures, were assumed in this study, although pipeline system design data indicates inlet pressures in the range from roughly 1900 – 2100 psia if the straddle plants were located at the suction of the nearest main-line compressor stations, or may even be at 2300 - 2400 psia range if the straddle plants were located near the communities of interest (Tok, Fairbanks, and Anchorage).

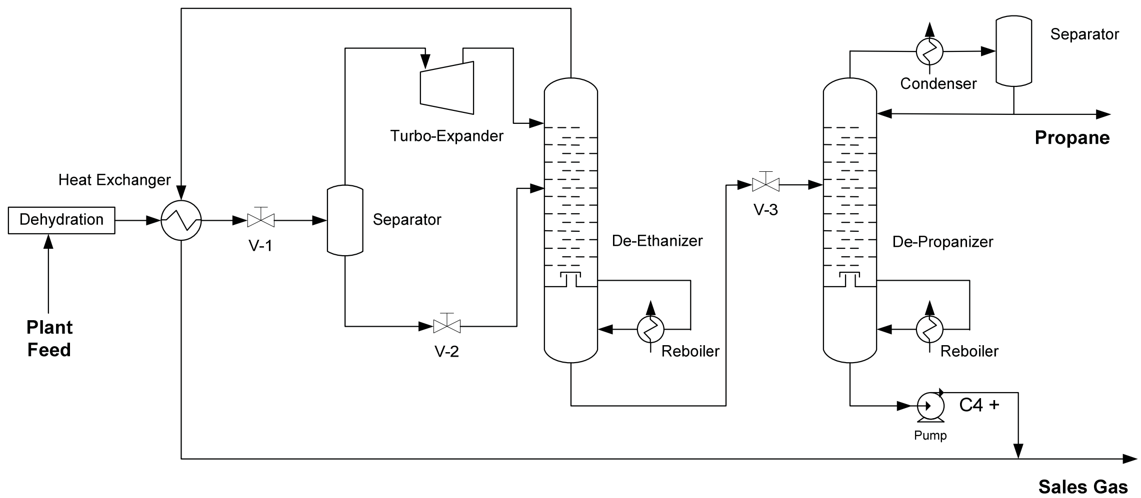
GLE does not believe that an increased inlet pressure would greatly impact the estimated plant cost due to the configuration of the plant design, in particular the early reduction of pressure to 500 psia in valve V1 (see Figure 3.1.1.),. GLE has provided some "directional" information of the impact(s) of increased facility inlet and return pressures on plant performance and estimated cost in this report.

Each of the three plants is addressed separately in following sub-sections of this report. Plant design and simulation work has been performed using VMGSim software from the Virtual Materials Group. Cost estimations are based on budgetary quotation(s) for capital equipment and factoring of additional cost contributors to enable Monte Carlo simulations for creation of probability distributions for the required plant investments.

3.1 0.5 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Tok, Alaska

A schematic of the expander + two tower design for the Tok plant is shown in Figure 3.1.1.

Figure 3.1.1. Tok Plant Schematic - 0.5 MMSCFD.



Key features of the design include:

- Molecular sieve dehydration of inlet feed (to prevent hydrate formation)
- Inlet feed heat exchange (to provide initial feed cooling and warm sales gas)
- Initial pressure reduction (V-1; cooling with initial vapour-liquid separation and pressure drop into an acceptable range for turbo-expander casing design)
- Turbo-expander (for coldest feed to top of de-ethanizer tower)
- J-T valve (V-2; for liquid stream pressure drop and cold feed to intermediate stage of de-ethanizer tower)
- De-ethanizer tower (C1 and C2 in overhead vapour and liquid LPG as bottoms product)
- De-propanizer tower (Condensed C3 product from overhead vapour and C4+ as bottoms product)
- C4+ pump (to return C4+ to the sales gas stream for local consumption)

After dehydration and initial feed cooling in the inlet heat exchanger, the pressure is dropped to 500 psia through the Joule-Thomson valve, V-1. As indicated in the bullets above, this initial pressure drop provides sufficient cooling to liquefy a portion of the feed. The gas-liquid separation allows a methane-ethane-rich vapour stream to be routed to the turbo-expander and then the top section of the de-ethanizer tower. The C3+ enriched liquid stream is routed to a second Joule-Thomson valve and thereafter enters the intermediate section of the de-ethanizer. This initial feed fractionation, before the de-ethanizer, improves the overall separation performance of the facilities.

The pressure drop in V-1 also allows for a reduced casing design pressure for the turbo-expander, which reduces the expander cost and opens the field of potential suppliers, many of whom provide units capable of handling inlet pressures in the region of 500 psia.

Turbo-expanders provide isentropic (constant entropy) cooling which allows for greater cooling than the isenthalpic (constant enthalpy a.k.a. adiabatic) cooling achieved with a Joule-Thompson valve. Increased cooling improves the overall performance of the facilities (increased C3 recovery), and when appropriate the work harnessed by the expander can be used for recompression, or power generation, for example.

A simulation flow sheet, with stream table and equipment duty information, is provided in Appendix 1.

For this plant configuration, simulation work has been done assuming the “rich” gas composition from the previous studies and an inlet pressure of 1500 psia[7-11]. Some prior studies appear to have used an inlet pressure of 2000 psia, which was the average value along the Alaska gas pipeline section (assuming 2500 psia exiting compression, dropping to 1500 psia at inlet to next compression station).

GLE believes that there would be logistical and cost synergies associated with locating C3 fractionation facilities near compressor stations for the “straddle” plants. Therefore, taking fractionation plant feed at the lowest pressure (i.e. 1500 psia) is the most likely and cost-effective option. Low plant inlet pressure is the most challenging design case in terms of C3 recovery and is therefore a prudent choice for initial plant design and economic analysis

Based on the considerations above , the Tok plant design, with an inlet feed rate of 0.5 MMSCFD of raw pipeline gas should achieve the following performance levels:

- C1-C2 gas product with gross heating value (GHV) of 1044.5 Btu/scf and dew point of -117.4 F (225 psia) at a rate of 0.478 MMSCFD (925.1 lb/h) (see next 2 bullets).
- C4+ liquid product at a rate of 3.05 bpd (25.8 lb/h) which GLE recommends to be blended with the C1-C2 product stream (see next bullet item).
- Sales gas stream (C1-C2 & C4+) with GHV of 1063.2 Btu/scf and dew point of -47.6 F (220 psia) at a rate of 0.482 MMSCFD (951 lb/h) (**this is a blend of the two intermediate streams, above**)
- C3 liquid product with ≤ 2 wt % ethane and ≤ 2.5 wt % C4+ at a rate of 11.7 bpd (86.1 lb/h)

With this small plant, blending the C4+ stream into the C1-C2 stream increases the gross heating value of sales gas to only marginally above the normal upper limit for utility grade gas (1063 vs. 1050 Btu/scf). Even with the C4+ blended into the sales gas, the dew point at 220 psia is -47.6 F. At atmospheric pressure, sales gas dew point is calculated to be -107 F and for an intermediate pressure of 50 psia, the dew point is -81.1 F. Data for the period from 1971 to 2000, taken from the Alaska Climate Research Center shows the lowest average minimum daily temperature in Fairbanks to be -20 F.[12] Record low temperatures have reached the -65 F region (2008 lowest temperature was -48 F). Under normal conditions, liquid precipitation should not be a significant issue at plant pressure (220 psia). At relatively low pressures (e.g. 50 psia), liquid precipitation should not occur, even at the record low temperatures for Fairbanks. Hence, blending C4+ back into the sales gas is likely the most pragmatic solution for disposition of the C4+ stream. In detailed design, it might be prudent to consider including a knock out drum to catch C4+ liquids on the coldest possible days just in case fluctuations in plant feed lead to a coincidence of unusually high C4+ content on record cold days.

For the plant design shown herein, C3 recovery is 96.7 wt % with a C3 content in the propane product of 97.8 wt % (i.e. C2 and C4+ contents are well below spec. limits).

As stated previously, this plant uses a particular configuration of J-T valves with a turbo-expander, and has been initially simulated using a feed inlet pressure of 1500 psia. For comparison, GLE has modeled two additional plant configurations. In the first of these, the turbo-expander is replaced by a J-T valve (3 J-T valve configuration). In the second, alternate configuration, the separator, turbo-expander, and J-T valve (V-2) are removed and only the single J-T valve (V-1) is used for expansion cooling. Further, for each of the three plant configurations (base case plus two alternatives), GLE has evaluated C3 recovery against three inlet pressures, namely 1500, 1900, and 2400 psia. Full details of the alternate plant configurations and simulation runs are not provided with this report. A tabulation of the C3 recovery results is presented below.

Table 3.1.1 C3 Recovery as a Function of Plant Configuration and Feed Inlet Pressure.

Plant Configuration ➔	Base Configuration	3 J-T Valves	1 J-T Valve
Inlet Pressure (psia) 🡻	C3 Recovery (mass percent)		
1500	96.70	90.69	85.40
1900	97.46	93.36	87.93
2400	97.74	94.73	89.64

For the range of inlet pressures from 1500 to 2400 psia, the proposed base plant configuration provides superior propane recovery. The single J-T valve plant is not capable of reaching even 90 % propane recovery. Simply replacing the turbo-expander with a J-T valve (3 J-T valve configuration) results in a 6 % decrease in C3 recovery at 1500 psia. This gap decreases to 3 % with an inlet pressure of 2400 psia (base config is 3 % more efficient than 3 J-T valve config. at 2400 psia).

Of the three plant configurations examined above, only the base configuration can provide the required ~97 % propane recovery. Note that at the most likely inlet pressures (1900 - 2400 psia), propane recovery with the base configuration will be above 97 weight percent.

GLE has identified design improvements that can push C3 recovery to ≥99 wt % if needed. This would involve addition of a vapour feed super-cooler. A portion of the vapour currently fed to the turbo-expander would be re-routed to the super-cooler wherein cooling would be provided by the liquid stream exiting valve V-2. The cooled feed stream would then be expanded through a J-T valve, which would reduce temperature further. This super-cooled stream would enter the top of the de-ethanizer, while the turbo-expanded stream and V-2 expanded stream would be fed to lower locations in the tower. With a 1900 psia inlet pressure, the design with super-cooler is estimated to provide 99.3 weight percent C3 recovery.

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For cost estimation purposes herein, GLE has used the plant configuration shown in Figure 3.1.1. This is the simplest plant configuration capable of meeting the 97 wt % propane recovery target.

Cost Estimation

The estimation work described herein targets a Class 5 estimate. The Association for the Advancement of Cost Engineering (AACE International) has published Recommended Practice No. 18R-97, which provides the basis for an estimate classification system for the process industry.[13] The classification matrix from this publication is reproduced in Figure 3.1.2, below.

Figure 3.1.2. Estimate Classification Matrix from AACE Recommended Practice No. 18R-97.[13]

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

A review of the table indicates that a Class 5 estimate is typically performed at the earliest stage of project definition (i.e. little to no definition) and therefore involves a wide range of expected accuracy. GLE typically finds these estimates being performed to an accuracy level of from -20 to +50 % and has used these levels in the preparation of the cost estimates provided herein.

For capital cost estimation, GLE has used the simulation flow sheet information (pressures, temperatures, compositions, flow rates, equipment duties), in combination with some preliminary equipment sizing as the bases of a request to two vendors for budgetary price quotations. The simulation flow sheet for the Tok facility is provided in Appendix 1. The equipment summary is provided in Appendix 2.

Of the two vendors approached, one provided a response containing reasonably detailed, itemized lists of equipment (with design/specification data) and overall budgetary prices for the three facilities within this study. This estimate (Enerflex Systems Ltd.) is provided in Appendix 3.

The facilities estimate was provided without inclusion of electrical and control equipment and wiring. A separate budgetary estimate for this equipment was received from Kilowatts Design Company, and is provided in Appendix 4. For the Kilowatts estimates items 2 - 4 are treated as EIC Capex (Electrical Instrumentation and Control Capital Expense). The engineering (item 1) and field construction (item 5) costs are rolled up in the engineering and installation factor portions of the cost estimates.

These costs have been taken as the primary input for cost assessment.

Data for input into Monte Carlo simulation is provided in Table 3.1.2.

Table 3.1.2 Input Data for Probabilistic Cost Estimation of 0.5 MMSCFD C3 Fractionation Facility for Tok, Alaska.

Item	P10	P50	P90
Plant CAPEX	$688,000	$860,000	$1,290,000
Minor CAPEX	$137,600	$172,000	$258,000
EIC CAPEX	$520,000	$650,000	$975,000
Engineering (pre-factored) – see note 5	$269,120	$336,400	$504,600
Installation Factor	1.56	1.70	2.05
Location Factor	1.55	1.55	1.55
Owner's Costs	1.2	1.2	1.2

Notes:

1. Monetary values are in US Dollars. Cdn to USD exchange rate taken as 1.16 Cdn = 1.00 USD.
2. Plant capex includes all major process vessels and equipment, skid mounted, piped, valved and fully instrumented. Some equipment (e.g. coolers) will be off-skid and installed on foundations.
3. Minor capex includes storage tanks, utilities (compressed air, heat medium), flare(s), drains, and "straddle" piping. It is assumed that electrical power is taken from the grid, or local power generation. This minor capex value has been set at 20 % of the Plant Capex cost.
4. EIC capex includes wire process skid(s), wire/electrical controls building(s), electrical and control equipment.
5. Engineering costs include all engineering services associated with the EPCM contract for the project. Note that actual engineering cost is the "pre-factored" cost multiplied by the installation, location, and owner's cost factors (i.e. the total estimated engineering cost, P50, for the Tok facility is $336,400 x 1.7 x 1.55 x 1.2 = $1,063,397).

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6. Installation factor includes the cost of labour and installation equipment required for construction of the project. The values used herein were determined by GLE senior staff taking into consideration the content included in the plant capex and EIC capex estimates, the separation of minor capex as an explicit line item, and GLE project experience.
7. Location factor is based on the Richardson International Construction Factors (2007 data) with consideration of points of manufacture, facilities locations, and the Cdn-USD exchange rate (see note 1).
8. Owners costs are based on the description provided by Stone and Webster, "typically include environmental permitting costs, site preparation costs, offices, warehouse, shops, and laboratory buildings and furnishing, insurance costs, interest cost during construction, financing costs, legal and other consultants' cost, working capital, etc." GLE has used the Stone & Webster estimate of owner's costs being 20 % of the EPC contract cost.

For the first five items in Table 3.1.2, ranges are provided for the estimates with the P10 value being P50 - 20 %, P50 = median estimate, and P90 being P50 + 50 % as per the Class 5 estimate error limits discussed previously. For the final two items in Table 3.1.2, namely location factor and owner's cost, a single value was used for each rather than a distribution.

As indicated in note 7, above, Richardson International Construction Factors for 2007 were used to scale the estimates to reflect the costs of installation in the various Alaskan locations. Available data and relative factors are presented in Table 3.1.3.

Table 3.1.3 Richardson International Location Factor Data and Relative Factors used to Scale Estimates from Calgary to Alaskan Locations.

Location	Rate	Location Factor	Relative Location Factor
Anchorage, Alaska	1.00 USD	1.32	1.40
Fairbanks, Alaska	1.00 USD	1.38	1.47
Houston, Texas	1.00 USD	0.90	0.96
Calgary, Alberta	1.16 USD	0.94	1.00

Note that for the even more remote community of Tok, GLE has arbitrarily assigned a relative location factor of 1.55, which is higher than the values for Achorage and Fairbanks. Stone & Webster used relative location factors of 1.44 and 1.52 for Anchorage and Fairbanks in their 2006 study for ANGDA.[8] These values are only marginally higher than those used in this study.

The Owner's Cost estimate was set as described in Note 8, above.

Monte Carlo simulations were performed using Crystal Ball software working as an add-in to Microsoft Excel. For each of the 50,000 iterations performed, probabilistic estimates for the first 5 variables (Table 3.1.1.) were generated and then a single point estimate was calculated using the formula;

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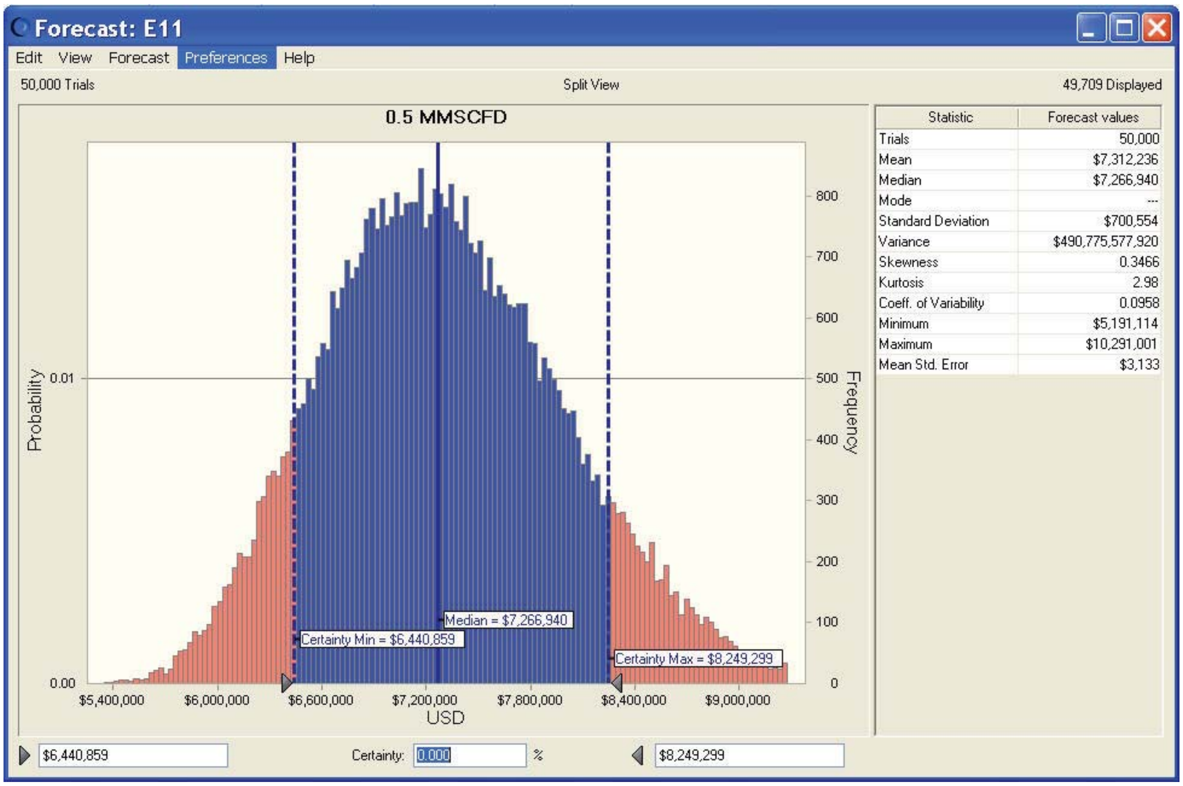
(Plant Capex + Minor Capex + EIC Capex + Engineering) x Installation Factor x Location Factor x Owner's Cost

The 50,000 point estimates, taken together, produce a distribution of probable costs for the completed facilities. The probability distribution for the 0.5 MMSCFD plant to be located in Tok, Alaska, is provided in Figure 3.1.3.

Figure 3.1.3. Probable Distribution of Cost Estimate for 0.5 MMSCFD LPG/C3 Extraction Facility (Tok, Alaska).



The median (P50) estimated cost for the completed facility is USD 7.27 million. P10 (Certainty Min) and P90 (Certainty Max) values are USD 6.44 million and USD 8.25 million, respectively.

GLE has not added a contingency amount to these estimates. Rather, GLE believes that consideration of contingency is built into the range of values provided with the probabilistic estimation procedure.

Increased inlet pressure would only affect the dehydration section, inlet heat exchanger, and valve V-1. All other down-stream units operate at reduced pressure. Upon qualitative review of the estimate, GLE believes that operating at an increased inlet pressure on the order of 2000 psia would not increase the installed plant cost by more than 5 percent, for the Tok facilities. This is well within the margin of error for the original estimate.

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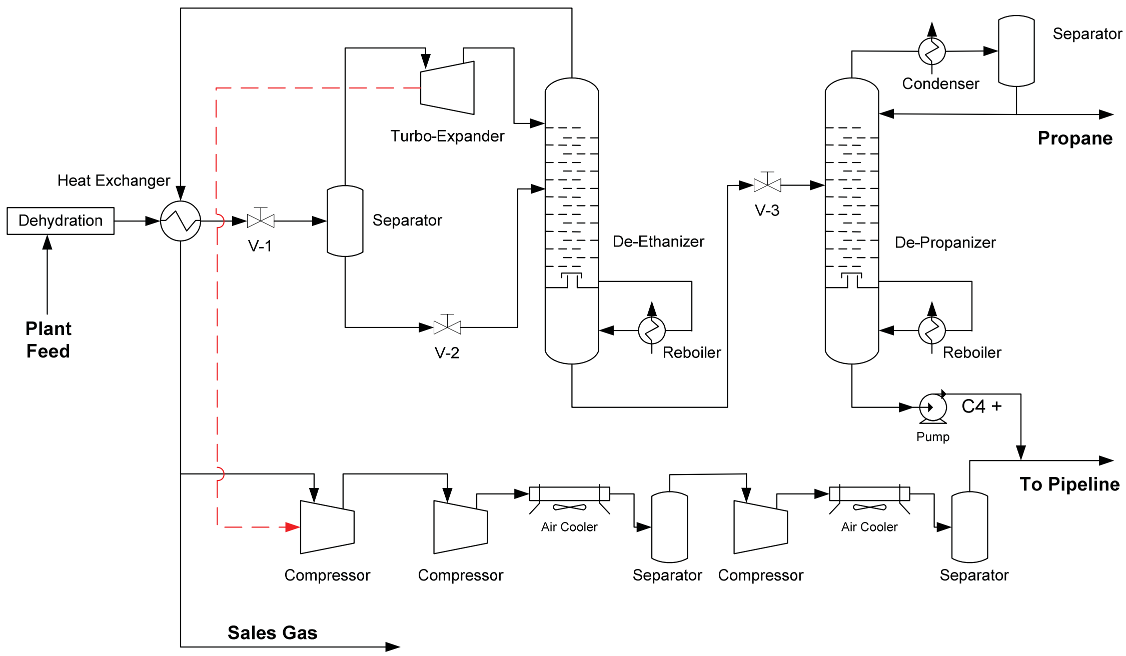
3.2 65 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Fairbanks, Alaska

A schematic of the expander + two tower design for the Fairbanks plant is shown in Figure 3.2.1.

Figure 3.2.1. Fairbanks Plant Schematic - 65 MMSCFD.



The Fairbanks facility is fundamentally the same as the Tok facility in terms of LPG recovery and propane fractionation, albeit at a substantially larger scale. The additional facilities in the Fairbanks plant allow for local use of some of the relatively low pressure, lean sales gas, and for recompression of a sizeable fraction of the lean gas for return to the main pipeline. The entire C4+ stream will be pumped up to pipeline pressure and re-injected with the pressurized lean gas returning to the main pipeline.

The propane product recovered in Fairbanks is estimated to have the same characteristics as that produced in Tok, with the same extent of propane recovery (i.e. 96.7 wt %). Propane production from this facility is estimated at a rate of 1526 bpd (11,196 lb/h). The design rate for lean natural gas off-take for local consumption in Fairbanks is 25 MMSCFD with a gross heating value of 1044.5 Btu/scf and a dew point at 220 psia of -117 F. As local demand in Fairbanks grows, the off-take can be increased substantially provided this is factored into detailed design work for the compression train and associated pipes/valves.

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Cost Estimation

The cost estimate distribution for the Fairbanks facility has been constructed with the same methodology as that for the Tok Plant. The simulation flow sheet for the Fairbanks facility is provided in Appendix 5. The equipment summary is provided in Appendix 6. Budgetary quotations for the fractionation plant and electrical/DCS facilities are provided in Appendices 3, and 4, respectively (see 65 MMSCFD plant sections of these appendices).

Data for input into Monte Carlo simulation is provided in Table 3.2.1.

Table 3.2.1 Input Data for Probabilistic Cost Estimation of 65 MMSCFD C3 Fractionation Facility for Fairbanks, Alaska.

Item	P10	P50	P90
Plant CAPEX	$13,792,000	$17,240,000	$25,860,000
Minor CAPEX	$2,758,400	$3,448,000	$5,172,000
EIC CAPEX	$3,120,000	$3,900,000	$5,850,000
Engineering (pre-factored) – see note 5	$2,950,560	$3,688,200	$5,532,300
Installation Factor	1.48	1.60	1.90
Location Factor	1.47	1.47	1.47
Owner's Costs	1.2	1.2	1.2

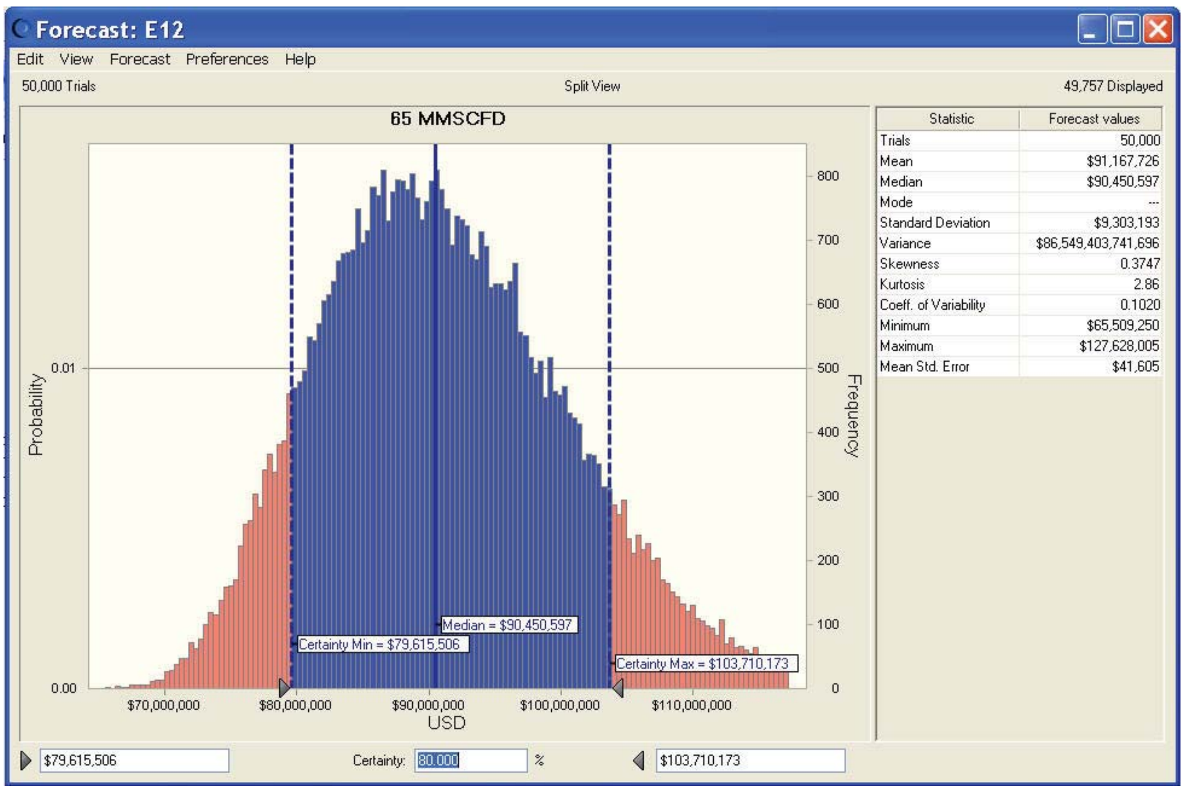
Notes:

1. Monetary values are in US Dollars. Cdn to USD exchange rate taken as 1.16 Cdn = 1.00 USD.
2. Plant capex includes all major process vessels and equipment, skid mounted, piped, valved and fully instrumented. Some equipment (e.g. coolers) will be off-skid and installed on foundations.
3. Minor capex includes storage tanks, utilities (compressed air, heat medium), flare(s), drains, and "straddle" piping. It is assumed that electrical power is taken from the grid, or local power generation. This minor capex value has been set at 20 % of the Plant Capex cost.
4. EIC capex includes wire process skid(s), wire/electrical controls building(s), electrical and control equipment.
5. Engineering costs include all engineering services associated with the EPCM contract for the project. Note that actual engineering cost is the "pre-factored" cost multiplied by the installation, location, and owner's cost factors (i.e. the total estimated engineering cost, P50, for the Fairbanks facility is $3,688,200 x 1.6 x 1.47 x 1.2 = $10,409,576).
6. Installation factor includes the cost of labour and installation equipment required for construction of the project. The values used herein were determined by GLE senior staff taking into consideration the content included in the plant capex and EIC capex estimates, the separation of minor capex as an explicit line item, and GLE project experience.
7. Location factor is based on the Richardson International Construction Factors (2007 data) with consideration of points of manufacture, facilities locations, and the Cdn-USD exchange rate (see note 1).

8. Owners costs are based on the description provided by Stone and Webster, "typically include environmental permitting costs, site preparation costs, offices, warehouse, shops, and laboratory buildings and furnishing, insurance costs, interest cost during construction, financing costs, legal and other consultants' cost, working capital, etc." GLE has used the Stone & Webster estimate of owner's costs being 20 % of the EPC contract cost.

The probability distribution for the 65 MMSCFD plant to be located in Fairbanks, Alaska, is provided in Figure 3.2.2.

Figure 3.2.2. Probable Distribution of Cost Estimate for 65 MMSCFD LPG/C3 Extraction Facility (Fairbanks, Alaska).



The median (P50) estimated cost for the completed facility is USD 90.45 million. P10 and P90 values are USD 79.62 million and USD 103.71 million, respectively.

As for the Tok facility, and increased inlet pressure (on the order of 2000 psia) will affect the design for the dehydration unit and the inlet heat exchanger and valve V1. The remainder of the separation facilities operate at reduced pressure and should not be affected. However, increased compression capacity would be required to return the unused gas to the pipeline.

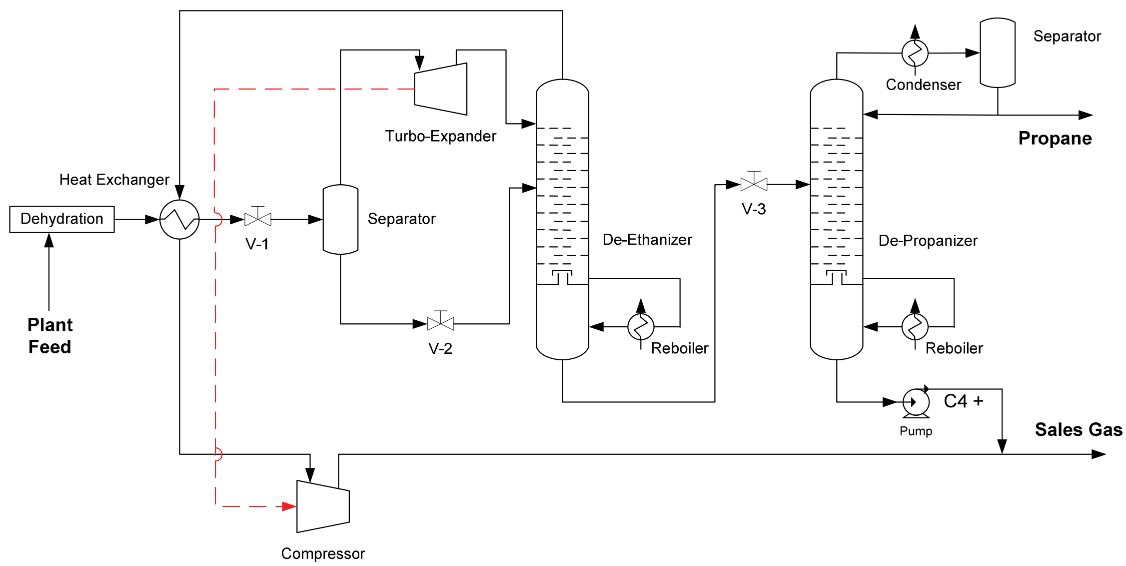
GLE has investigated the incremental cost to increase the return pressure from 1500 psia to 2400 psia (see Appendix 7). The incremental capital cost for the increased compression is $650,000 CDN ($3,650,000 (2400 psig unit) - $3,000,000 (1500 psia unit) CDN). Taking into account the CDN/USD exchange rate and the installation, location, and owner's cost factors leads to a rough estimate of 1.6 million USD as the incremental cost associated with the increased compression requirement. Note that this assumes a return pressure of 2400 psia, which is the most pessimistic case for cost estimation purposes (1900 - 2100 psia appears to be most probable).

The median cost estimate for the Fairbanks facility operating at 1500 psia inlet pressure is roughly $90 million USD. To operate at higher pressure (~2000 psia) will incur increased costs for the inlet section of the plant (dehydration, heat exchange, valve V1) and residue gas recompression. Based on a mixture of qualitative and quantitative assessment, GLE does not believe that the cost estimate would increase by more than 5 % to accommodate an increased inlet pressure of roughly 2000 psia. This is well within the error limits of the original estimate.

3.3 300 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Anchorage, Alaska

A schematic of the expander + two tower design for the Anchorage plant is shown in Figure 3.3.1.

Figure 3.3.1. Anchorage Plant Schematic - 300 MMSCFD.



The LPG recovery and propane fractionation portion of the Anchorage plant is of the same design as those for the Tok and Fairbanks plants. In the small, Tok plant, GLE has assumed the work/power generated by the turbo-expander would be braked using a small hydraulic system. For the Fairbanks facility, the expander would be coupled to a first stage boost compressor in the compression train used to raise gas pressure up to pipeline pressure for gas re-injection. In the Anchorage facility, the best option is to use only the boost compression stage to provide a modest increase in sales gas pressure for local distribution and a suitable braking system for the large turbo-expander.

The propane product recovered in Anchorage should have the same characteristics as that produced in Tok and Fairbanks, with the same extent of propane recovery (i.e. 96.7 wt %). Propane production from this facility is estimated at a rate of 7046 bpd (51,680 lb/h).

In the plant configuration shown in Figure 3.3.1, C4+ is blended into the sales gas resulting in the same sales gas GHV and dew point as predicted for Tok. However, if there is a local market for C4+ (possible additional fractionation into butanes, natural gasoline) it could be processed separately. In this case the sales gas would have the characteristics of the lean gas stream simulated for local use in Fairbanks. C4+ production is estimated to be nearly 1832 bpd (15,500 lb/hr) and therefore it might be of interest to study the possibilities for local fractionation and use, or export to other markets.

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Cost Estimation

The cost estimate distribution for the Anchorage facility has been constructed with the same methodology as that for the Tok Plant.

Data for input into Monte Carlo simulation is provided in Table 3.3.1.

Table 3.3.1 Input Data for Probabilistic Cost Estimation of 300 MMSCFD C3 Fractionation Facility for Anchorage, Alaska.

Item	P90	P50	P10
Plant CAPEX	$33,024,000	$41,280,000	$61,920,000
Minor CAPEX	$6,604,800	$8,256,000	$12,384,000
EIC CAPEX	$9,280,000	$11,600,000	$17,400,000
Engineering (pre-factored) – see note 5	$7,336,320	$9,170,400	$13,755,600
Installation Factor	1.32	1.40	1.60
Location Factor	1.4	1.40	1.4
Owner's Costs	1.2	1.2	1.2

Notes:

1. Monetary values are in US Dollars. Cdn to USD exchange rate taken as 1.16 Cdn = 1.00 USD.
2. Plant capex includes all major process vessels and equipment, skid mounted, piped, valved and fully instrumented. Some equipment (e.g. coolers) will be off-skid and installed on foundations.
3. Minor capex includes storage tanks, utilities (compressed air, heat medium), flare(s), drains, and “straddle” piping. It is assumed that electrical power is taken from the grid, or local power generation. This minor capex value has been set at 20 % of the Plant Capex cost.
4. EIC capex includes wire process skid(s), wire/electrical controls building(s), electrical and control equipment.
5. Engineering costs include all engineering services associated with the EPCM contract for the project. Note that actual engineering cost is the “pre-factored” cost multiplied by the installation, location, and owner’s cost factors (i.e. the total estimated engineering cost, P50, for the Anchorage facility is $9,170,400 x 1.4 x 1.4 x 1.2 = $21,568,780).
6. Installation factor includes the cost of labour and installation equipment required for construction of the project. The values used herein were determined by GLE senior staff taking into consideration the content included in the plant capex and EIC capex estimates, the separation of minor capex as an explicit line item, and GLE project experience.
7. Location factor is based on the Richardson International Construction Factors (2007 data) with consideration of points of manufacture, facilities locations, and the Cdn-USD exchange rate (see note 1).

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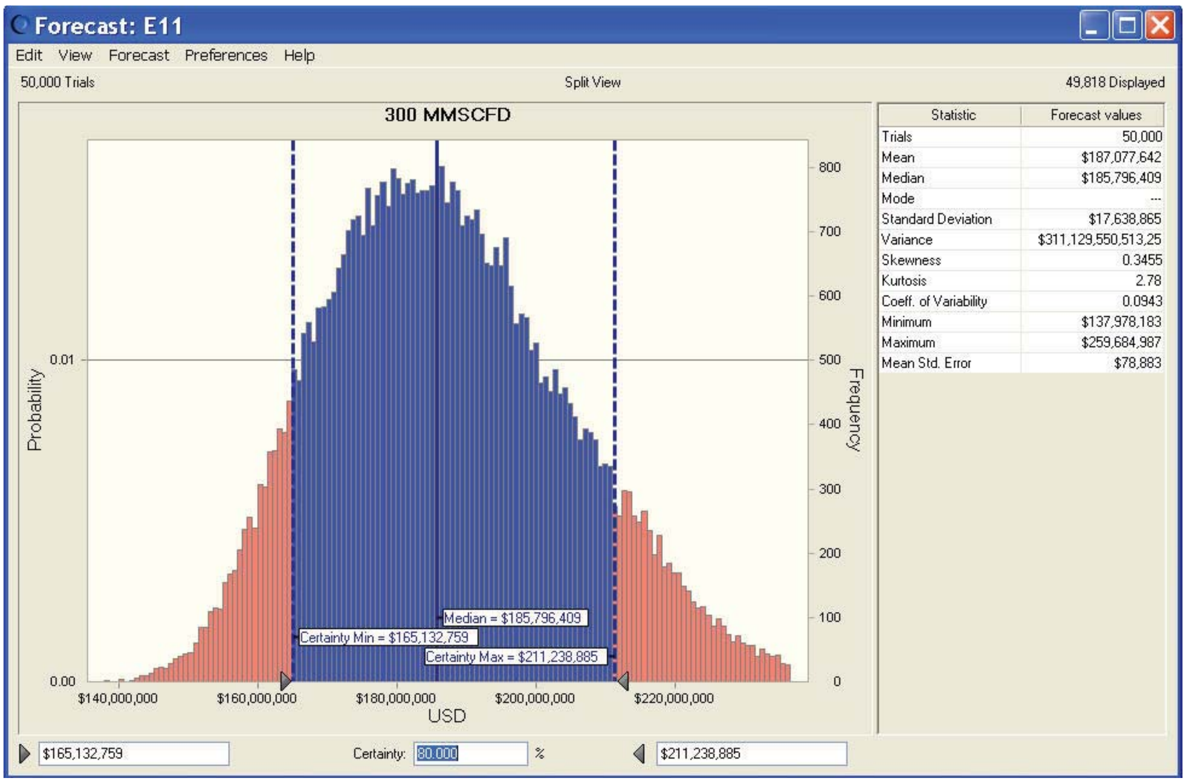
8. Owners costs are based on the description provided by Stone and Webster, "typically include environmental permitting costs, site preparation costs, offices, warehouse, shops, and laboratory buildings and furnishing, insurance costs, interest cost during construction, financing costs, legal and other consultants' cost, working capital, etc." GLE has used the Stone & Webster estimate of owner's costs being 20 % of the EPC contract cost.

The probability distribution for the 300 MMSCFD plant to be located in Anchorage, Alaska, is provided in Figure 3.3.2.

Figure 3.3.2. Probable Distribution of Cost Estimate for 300 MMSCFD LPG/C3 Extraction Facility (Anchorage, Alaska).



The median (P50) estimated cost for the completed facility is USD 185.8 million. P90 and P10 values are USD 165.1 million and USD 211.2 million, respectively.

Increased inlet pressure (to ~2000 psia) for the Anchorage facility would require design modifications to the inlet section of the plant (dehydration, inlet heat exchange, and valve V-1). After propane and/or C4+ extraction, natural gas is to be used locally and hence there is no residue gas recompression. GLE does not believe that an increased inlet pressure to something on the order of 2000 psia would increased the estimated cost for the Anchorage facility by more than 5 %, which is well within the error range of the original plant cost estimate.

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4.0 CONCLUSIONS AND RECOMMENDATIONS

Using the data and methodology provided herein leads to the Class 5 estimates for the three facilities of interest that are summarized in Table 4.1.

Table 4.1 Class 5 Cost Estimates for Alaskan C3 Recovery Facilities.

Facility	P10 Estimate	P50 Estimate	P90 Estimate
	Estimates in USD thousands		
0.5 MMSCFD Gas - Tok, Alaska	6,441	7,267	8,249
65 MMSCFD Gas – Fairbanks, Alaska	79,616	90,451	103,710
300 MMSCFD Gas – Anchorage, Alaska	165,132	185,796	211,239

GLE has reviewed the methodology for estimation and the results of estimation for this study with several internal experts and has cross-checked the estimates against another internal study. Based on this review, and the quality of input obtained for the estimates provided herein, GLE is quite comfortable with the results obtained.

Going forward, one would improve on the level of engineering detail available through conducting more formal engineering phases (basic, FEED, detailed, etc.) and using the information available to improve the quality of Capex estimates.

The use of factors for installation, location, and owner's cost introduces considerable multipliers into the estimation calculations. As more engineering detail is developed, it will also be prudent to scrutinize and refine the estimates for these factors to reduce the uncertainty associated with estimation, and to improve on the accuracy of the forecast values.

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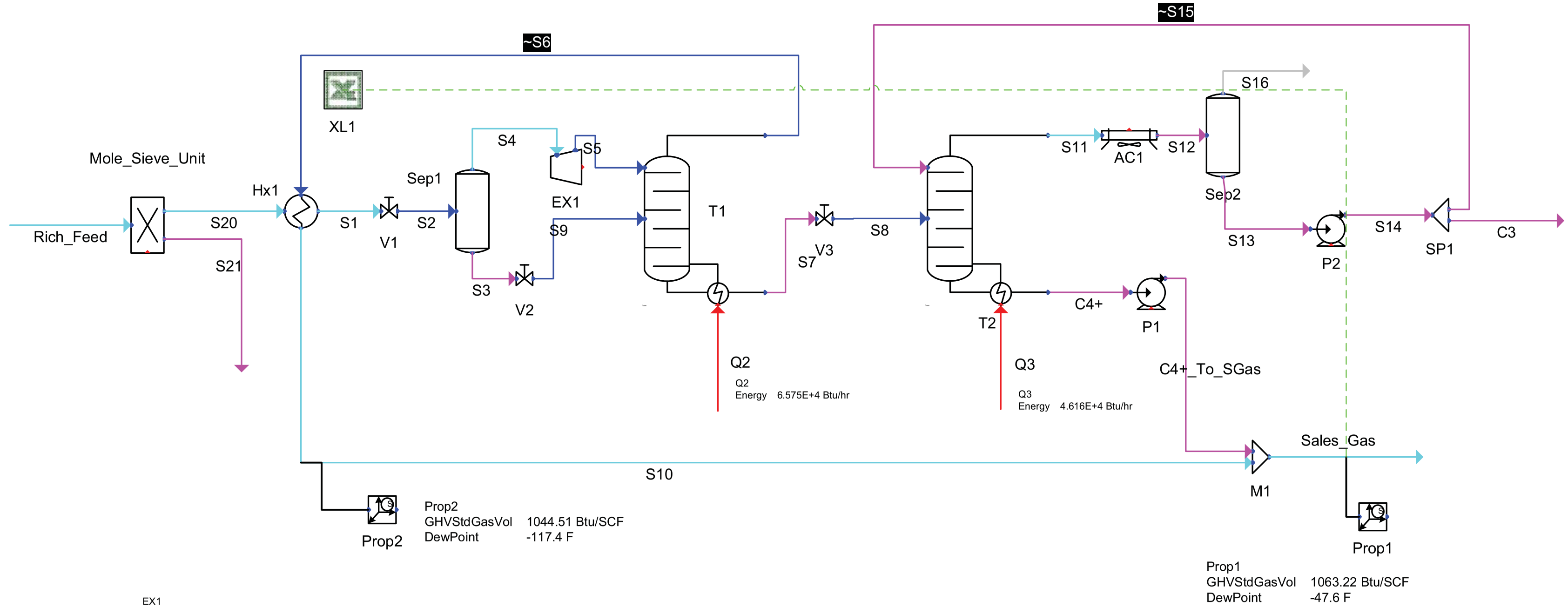
APPENDIX 1

Process Simulation Flowsheet
0.5 MMSCFD Propane Fractionation Facility

Propane Recovery Unit with Recombination of Lean Gas and C4+ for Local Sales Gas
0.5 MMSCFD Feed

Gas Liquids Engineering



Hx1	
DT Tube	-139.74 F
DT Shell	59.35 F
DP Tube	*5.00 psi
DP Shell	*1.00 psi
UA	2440.33 Btu/hr-F
TApproach_Tube_Shell_AppT	*5.00 F

EX1	
Duty	4.976E+0 HorsePower
DP	270.00 psi
Efficiency	81.08 %
In.T	-97.7 F
In.P	500.00 psia
Out.T	-146.8 F
Pout	*230.00 psia

P1	
Duty	1.678E-3 HorsePower
DP	20.00 psi
Efficiency	*75.00 %
Pout	*225.00 psia

Name	Rich_Feed	S1	S2	S3	S4	S5	S6	S7	S8	C3	C4+
VapFrac	1	1	0.76995	0	1	0.94248	0.99999	0	0.05319	0	0
T [F]	28	-31.3	-97.7	-97.7	-97.7	-146.8	-116.7	125.6	116.7	100.9	200.8
P [psia]	1500	1499	500	500	500	230	225	230	205	250	205
MoleFlow [lbmole/h]	54.9	54.9	54.9	12.63	42.27	42.27	52.51	2.39	2.39	1.96	0.43
MassFlow [lb/h]	1037.07	1037.06	1037.06	315.84	721.22	721.22	925.14	111.94	111.94	86.1	25.81
MoleFraction [Fraction]											
CARBON DIOXIDE	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0
METHANE	0.864	0.864	0.864	0.6001	0.9429	0.9429	0.9034	0	0	0	0
ETHANE	0.071	0.071	0.071	0.1973	0.0333	0.0333	0.0735	0.0156	0.0156	0.019	0
PROPANE	0.036	0.036	0.036	0.1402	0.0049	0.0049	0.0011	0.8012	0.8012	0.9748	0.0135
ISOBUTANE	0.003	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0039	0.363
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.4966
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1269

Name	Sales_Gas	C4+_To_SGas	S20	S21	S9	S10	S11	S12	S13	S14	S15	S16
VapFrac	1	0	1	0	0.26163	1	1	0	0	0	0	1
T [F]	21	201.2	28	28	-135.8	23	103.9	100	100	100.9	100.9	100
P [psia]	220	225	1500	1500	230	220	200	200	200	250	250	200
MoleFlow [lbmole/h]	52.94	0.43	54.9	0	12.63	52.51	7.84	7.84	7.84	7.84	5.88	0
MassFlow [lb/h]	950.95	25.81	1037.06	0	315.84	925.14	344.41	344.41	344.41	344.41	258.28	0
MoleFraction [Fraction]												
CARBON DIOXIDE	0.0156	0	0.015	0	0.0273	0.0157	0	0	0	0	0	0
NITROGEN	0.0062	0	0.006	0	0.0013	0.0063	0	0	0	0	0	0
METHANE	0.896	0	0.864	0	0.6001	0.9034	0	0	0	0	0	0
ETHANE	0.0729	0	0.071	0	0.1973	0.0735	0.019	0.019	0.019	0.019	0.019	0.0493
PROPANE	0.0012	0.0135	0.036	0	0.1402	0.0011	0.9748	0.9748	0.9748	0.9748	0.9748	0.9481
ISOBUTANE	0.003	0.363	0.003	0	0.0126	0	0.0039	0.0039	0.0039	0.0039	0.0039	0.0017
n-BUTANE	0.0041	0.4966	0.004	0	0.017	0	0.0023	0.0023	0.0023	0.0023	0.0022	0.0009
n-PENTANE	0.001	0.1269	0.001	0	0.0043	0	0	0	0	0	0	0

APPENDIX 2

Major Equipment List
0.5 MMSCFD Propane Fractionation Facility

Summary of Plant Unit Design Information
0.5 MMSCFD Facility

Unit	Water Removal Rate (lb/h)
Molecular Sieve	0.0036

Hx 1	Name		**Value**		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**2440.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-69132.5**		
	PortName	**InTube**	**InShell**	**OutTube**	**OutShell**
	UnitOperation				
	Is Recycle Port				
	Connected Stream/Unit Op	/S6.Out	/S20.Out	/Sales_Gas.In	/S1.In
	Connected Port				
	VapFrac	1.00	1.00	1.00	1.00
	T [F]	-116.7	28.0	23.0	-31.3
	P [psia]	225.0	1500.0	220.0	1499.0
	MoleFlow [lbmole/h]	52.506	54.899	52.506	54.899
	MassFlow [lb/h]	925.136	1037.063	925.136	1037.063
	VolumeFlow [ft3/s]	0.201	0.034	0.325	0.021
	StdLiqVolumeFlow [ft3/s]	0.013	0.014	0.013	0.014
	StdGasVolumeFlow [MMSCFD]	0.478	0.500	0.478	0.500
	Properties (Alt+R)				
	Energy [Btu/hr]	126199.137	144325.579	195331.626	75193.090
	H [Btu/lbmol]	2403.911	2629.353	3720.785	1369.883
	S [Btu/lbmol-F]	36.083	34.245	39.349	31.481
	MolecularWeight	17.620	18.890	17.620	18.890
	MassDensity [lb/ft3]	1.282	8.409	0.791	14.011
	Cp [Btu/lbmol-F]	9.815	17.297	9.312	24.800
	ThermalConductivity [Btu/hr-ft-F]	0.012	0.029	0.018	0.037
	Viscosity [cp]	0.008	0.016	0.010	0.024
	molarV [ft3/lbmol]	13.748	2.246	22.286	1.348
	ZFactor	0.840	0.648	0.946	0.445
	Fraction [Fraction]				
	CARBON DIOXIDE	0.015684	0.015000	0.015684	0.015000
	NITROGEN	0.006273	0.006000	0.006273	0.006000
	METHANE	0.903379	0.864000	0.903379	0.864000
	ETHANE	0.073527	0.071000	0.073527	0.071000
	PROPANE	0.001126	0.036000	0.001126	0.036000
	ISOBUTANE	0.000007	0.003000	0.000007	0.003000
	n-BUTANE	0.000004	0.004000	0.000004	0.004000
	n-PENTANE	0.000000	0.001000	0.000000	0.001000
	WATER	0.000000	0.000000	0.000000	0.000000

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

V1	Name	Value	
	Delta P [psi]	999	
	Cv	0.20844	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S1.Out	/S2.In
	Connected Port		
	VapFrac	1.00	0.77
	T [F]	-31.3	-97.7
	P [psia]	1499.0	500.0
	MoleFlow [lbmole/h]	54.899	54.899
	MassFlow [lb/h]	1037.063	1037.063
	VolumeFlow [ft3/s]	0.021	0.065
	StdLiqVolumeFlow [ft3/s]	0.014	0.014
	StdGasVolumeFlow [MMSCFD]	0.500	0.500
	Properties (Alt+R)		
	Energy [Btu/hr]	75193.090	75193.090
	H [Btu/lbmol]	1369.883	1369.883
	S [Btu/lbmol-F]	31.481	32.476
	MolecularWeight	18.890	18.890
	MassDensity [lb/ft3]	14.011	4.400
	Cp [Btu/lbmol-F]	24.800	14.767
	ThermalConductivity [Btu/hr-ft-F]	0.037	0.032
	Viscosity [cp]	0.024	0.019
	molarV [ft3/lbmol]	1.348	4.294
	ZFactor	0.445	0.553
	Fraction [Fraction]		
	CARBON DIOXIDE	0.015000	0.015000
	NITROGEN	0.006000	0.006000
	METHANE	0.864000	0.864000
	ETHANE	0.071000	0.071000
	PROPANE	0.036000	0.036000
	ISOBUTANE	0.003000	0.003000
	n-BUTANE	0.004000	0.004000
	n-PENTANE	0.001000	0.001000
	WATER	0.000000	0.000000

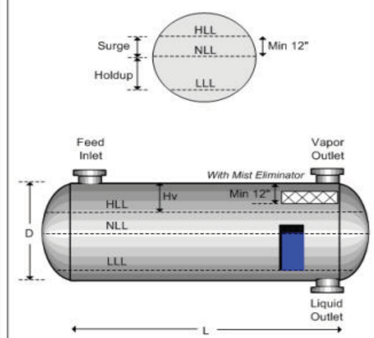
Summary of Plant Unit Design Information

0.5 MMSCFD Facility

Separator 1	PortName	In	Liq0	Vap
	UnitOperation			
	Is Recycle Port			
	Connected Stream/Unit Op	/S2.Out	/S3.In	/S4.In
	Connected Port			
	VapFrac	0.77	0.00	1.00
	T [F]	-97.7	-97.7	-97.7
	P [psia]	500.0	500.0	500.0
	MoleFlow [lbmole/h]	54.899	12.630	42.270
	MassFlow [lb/h]	1037.063	315.841	721.222
	VolumeFlow [ft3/s]	0.065	0.003	0.062
	StdLiqVolumeFlow [ft3/s]	0.014	0.004	0.010
	StdGasVolumeFlow [MMSCFD]	0.500	0.115	0.385
	Properties (Alt+R)			
	Energy [Btu/hr]	75193.090	-17397.379	92590.468
	H [Btu/lbmol]	1369.883	-1377.712	2190.847
	S [Btu/lbmol-F]	32.476	26.662	34.213
	MolecularWeight	18.890	25.007	17.062
	MassDensity [lb/ft3]	4.400	27.925	3.214
	Cp [Btu/lbmol-F]	14.767	18.430	13.672
	ThermalConductivity [Btu/hr-ft-F]	0.032	0.070	0.016
	Viscosity [cp]	0.019	0.101	0.009
	molarV [ft3/lbmol]	4.294	0.896	5.309
	ZFactor	0.553	0.109	0.685
	Fraction [Fraction]			
	CARBON DIOXIDE	0.015000	0.027284	0.011330
	NITROGEN	0.006000	0.001259	0.007417
	METHANE	0.864000	0.600091	0.942855
	ETHANE	0.071000	0.197252	0.033277
	PROPANE	0.036000	0.140246	0.004852
	ISOBUTANE	0.003000	0.012574	0.000139
	n-BUTANE	0.004000	0.016974	0.000123
	n-PENTANE	0.001000	0.004321	0.000008
	WATER	0.000000	0.000000	0.000000

Variables	Value
Design Variables	
VesselDesignType	**Sep2PhaseHorizontal**
MaxIteration	**50**
HoldupTime [day]	**0.0174**
SurgeTime [day]	**0.0035**
VapMassFlow [lb/h]	**721.22**
LiqMassFlow [lb/h]	**315.84**
VapDensity [lb/ft3]	**3.2139**
LiqDensity [lb/ft3]	**27.9253**
P [psia]	**500.00**
WithMistEliminator	**0**
Min_Design_L/D	**1.50**
Max_Design_L/D	**6.00**
Calculated Variables	
VesselLength [in]	137.1272
VesselDiameter [in]	24.000
L/Dratio	5.71
VapDisengagementHeight [in]	12.000
NormalLiqLevel [in]	11.5072
HighLiqLevel [in]	12.000
LowLiqLevel [in]	9.000
VesselWeight [lb]	1652.59
VesselWallThickness [in]	0.5026

Two-Phase Horizontal Separator



Nomenclature

L = Vessel Length
D = Vessel Internal Diameter
Hv = Vapor Disengagement Height
HLL = High Liquid Level
NLL = Normal Liquid Level
LLL = Low Liquid Level

Notes

- Design values are only first estimation. It is not recommended for final dimension
- Stokes' Law constant, K is calculated using York-Demister equation
- For wall thickness calculation;
- Assume carbon-steel for material stress, X-rayed joints for joint efficiency and corrosion allowance = 1/16 inch
- Material = Carbon-steel
- For calculation purposes, mist eliminator thickness/height is assumed to be 4.8 inches

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

V2	Name	Value	
	Delta P [psi]	270	
	Cv	0.05742	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S3.Out	/S9.In
	Connected Port		
	VapFrac	0.00	0.26
	T [F]	-97.7	-135.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	12.630	12.630
	MassFlow [lb/h]	315.841	315.841
	VolumeFlow [ft3/s]	0.003	0.014
	StdLiqVolumeFlow [ft3/s]	0.004	0.004
	StdGasVolumeFlow [MMSCFD]	0.115	0.115
	Properties (Alt+R)		
	Energy [Btu/hr]	-17397.379	-17397.379
	H [Btu/lbmol]	-1377.712	-1377.712
	S [Btu/lbmol-F]	26.662	26.945
	MolecularWeight	25.007	25.007
	MassDensity [lb/ft3]	27.925	6.429
	Cp [Btu/lbmol-F]	18.430	15.013
	ThermalConductivity [Btu/hr-ft-F]	0.070	0.066
	Viscosity [cp]	0.101	0.086
	molarV [ft3/lbmol]	0.896	3.890
	ZFactor	0.109	0.254
	Fraction [Fraction]		
	CARBON DIOXIDE	0.027284	0.027284
	NITROGEN	0.001259	0.001259
	METHANE	0.600091	0.600091
	ETHANE	0.197252	0.197252
	PROPANE	0.140246	0.140246
	ISOBUTANE	0.012574	0.012574
	n-BUTANE	0.016974	0.016974
	n-PENTANE	0.004321	0.004321
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

Ex 1	Name		Value
	OutQ [HorsePower]		4.98
	Delta P [psi]		270.00
	Pressure Ratio		2.17
	Adiabatic Efficiency [%]		81.08
	Polytropic Efficiency [%]		80.00
	Speed [rpm]		
	Adiabatic Head [ft]		16849.64
	Polytropic Head [ft]		17077.15
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S4.Out	/S5.In
	Connected Port		
	VapFrac	1.00	0.94
	T [F]	-97.7	-146.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	42.270	42.270
	MassFlow [lb/h]	721.222	721.222
	VolumeFlow [ft3/s]	0.062	0.130
	StdLiqVolumeFlow [ft3/s]	0.010	0.010
	StdGasVolumeFlow [MMSCFD]	0.385	0.385
	Properties (Alt+R)		
	Energy [Btu/hr]	92590.468	79928.479
	H [Btu/lbmol]	2190.847	1891.243
	S [Btu/lbmol-F]	34.213	34.438
	MolecularWeight	17.062	17.062
	MassDensity [lb/ft3]	3.214	1.536
	Cp [Btu/lbmol-F]	13.672	10.476
	ThermalConductivity [Btu/hr-ft-F]	0.016	0.017
	Viscosity [cp]	0.009	0.009
	molarV [ft3/lbmol]	5.309	11.110
	ZFactor	0.685	0.761
	Fraction [Fraction]		
	CARBON DIOXIDE	0.011330	0.011330
	NITROGEN	0.007417	0.007417
	METHANE	0.942855	0.942855
	ETHANE	0.033277	0.033277
	PROPANE	0.004852	0.004852
	ISOBUTANE	0.000139	0.000139
	n-BUTANE	0.000123	0.000123
	n-PENTANE	0.000008	0.000008
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information			
0.5 MMSCFD Facility			
T1	Condenser	No	
	Reboiler	Yes	
	# Ideal Stages	20	Includes Condenser and Reboiler
	Total stages = 20		
	FEED	overheadFeed	Lower_Feed
	Stage	1	8
	Connected Obj	/S5.Out	/S9.Out
	Details		
	VapFrac	0.9425	0.2616
	T [F]	-146.8	-135.8
	P [psia]	230.0	230.0
	MoleFlow [lbmole/h]	42.270	12.630
	MassFlow [lb/h]	721.222	315.841
	VolumeFlow [ft3/s]	0.130	0.014
	StdLiqVolumeFlow [ft3/s]	0.010	0.004
	StdGasVolumeFlow [MMSCFD]	0.385	0.115
	Molar Composition		
	CARBON DIOXIDE	0.011330	0.027284
	NITROGEN	0.007417	0.001259
	METHANE	0.942855	0.600091
	ETHANE	0.033277	0.197252
	PROPANE	0.004852	0.140246
	ISOBUTANE	0.000139	0.012574
	n-BUTANE	0.000123	0.016974
	n-PENTANE	0.000008	0.004321
	WATER	0.000000	0.000000
	DRAW	overheadV	reboilerL
	Stage	1	20
	Type	VapourDraw	LiquidDraw
	Connected Obj	/S6.In	/S7.In
	Details		
	VapFrac	1.0000	0.0000
	T [F]	-116.8	125.6
	P [psia]	225.0	230.0
	MoleFlow [lbmole/h]	52.506	2.393
	MassFlow [lb/h]	925.128	111.935
	VolumeFlow [ft3/s]	0.201	0.001
	StdLiqVolumeFlow [ft3/s]	0.013	0.001
	StdGasVolumeFlow [MMSCFD]	0.478	0.022
	reboilerQ (Btu/hr)	**65744.0**	

Section	Section_1
Start	1
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[1in] Pall Rings (M)**
Fp	56.00
PackingAreaperVol [ft2/f3]	68.12
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	0.500
TotalTrayArea [ft2]	0.1963
PackingLengthperSection [ft]	28.500

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information			
0.5 MMSCFD Facility			
V3	Name	Value	
	Delta P [psi]	25	
	Cv	0.06539	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S7.Out	/S8.In
	Connected Port		
	VapFrac	0.00	0.05
	T [F]	125.6	116.7
	P [psia]	230.0	205.0
	MoleFlow [lbmole/h]	2.393	2.393
	MassFlow [lb/h]	111.935	111.935
	VolumeFlow [ft3/s]	0.001	0.002
	StdLiqVolumeFlow [ft3/s]	0.001	0.001
	StdGasVolumeFlow [MMSCFD]	0.022	0.022
	Properties (Alt+R)		
	Energy [Btu/hr]	2077.511	2077.511
	H [Btu/lbmol]	868.193	868.193
	S [Btu/lbmol-F]	34.117	34.134
	MolecularWeight	46.770	46.770
	MassDensity [lb/ft3]	29.209	17.215
	Cp [Btu/lbmol-F]	35.358	33.569
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.080	0.078
	molarV [ft3/lbmol]	1.601	2.717
	ZFactor	0.058	0.089
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.015555	0.015555
	PROPANE	0.801162	0.801162
	ISOBUTANE	0.068671	0.068671
	n-BUTANE	0.091674	0.091674
	n-PENTANE	0.022938	0.022938
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

T2	Condenser	Yes		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED			
	Stage	2		
	Connected Obj	/S8.Out		
	Details			
	VapFrac	0.0532		
	T [F]	116.7		
	P [psia]	205.0		
	MoleFlow [lbmole/h]	2.393		
	MassFlow [lb/h]	111.935		
	VolumeFlow [ft3/s]	0.002		
	StdLiqVolumeFlow [ft3/s]	0.001		
	StdGasVolumeFlow [MMSCFD]	0.022		
	Molar Composition			
	CARBON DIOXIDE	0.000000		
	NITROGEN	0.000000		
	METHANE	0.000000		
	ETHANE	0.015555		
	PROPANE	0.801162		
	ISOBUTANE	0.068671		
	n-BUTANE	0.091674		
	n-PENTANE	0.022938		
	WATER	0.000000		
	DRAW	condenserL	condenserV	reboilerL
	Stage	1	1	20
	Type	LiquidDraw	VapourDraw	LiquidDraw
	Connected Obj		/C3.In	/C4+.In
	Details			
	VapFrac	0.0000	1.0000	0.0000
	T [F]	105.9	105.9	198.1
	P [psia]	200.0	200.0	202.0
	MoleFlow [lbmole/h]	0.000	1.981	0.412
	MassFlow [lb/h]	0.000	87.391	24.545
	VolumeFlow [ft3/s]	0.000	0.013	0.000
	StdLiqVolumeFlow [ft3/s]	0.000	0.001	0.000
	StdGasVolumeFlow [MMSCFD]	0.000	0.018	0.004
	ENERGY	condenserQ		reboilerQ
	Stage	1		20
	Type	EnergyOut		EnergyIn
	Connected Obj	/Q4.In		/Q3.Out
	Value [Btu/hr]	32798.1		44285.9

Section	Section_1
Start	2
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[1in] Pall Rings (M)**
Fp	56.00
PackingAreaperVol [ft2/f3]	68.12
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	0.500
TotalTrayArea [ft2]	0.1963
PackingLengthperSection [ft]	27.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

P1	Name	Value	
	InQ [HorsePower]	0.00183	
	Delta P [psi]	23	
	Pressure Ratio	1.114	
	Efficiency [%]	75	
	Speed [rpm]		
	Head [ft]	110.55	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/C4+.Out	/C4+_To_SGas.In
	Connected Port		
	VapFrac	0.00	0.00
	T [F]	198.1	198.6
	P [psia]	202.0	225.0
	MoleFlow [lbmole/h]	0.410	0.410
	MassFlow [lb/h]	24.540	24.540
	VolumeFlow [ft3/s]	0.000	0.000
	StdLiqVolumeFlow [ft3/s]	0.000	0.000
	StdGasVolumeFlow [MMSCFD]	0.004	0.004
	Properties (Alt+R)		
	Energy [Btu/hr]	1334.057	1338.706
	H [Btu/lbmol]	3238.977	3250.266
	S [Btu/lbmol-F]	34.642	34.646
	MolecularWeight	59.582	59.582
	MassDensity [lb/ft3]	29.958	29.996
	Cp [Btu/lbmol-F]	45.094	44.915
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.087	0.088
	molarV [ft3/lbmol]	1.989	1.986
	ZFactor	0.057	0.063
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.000000	0.000000
	PROPANE	0.027024	0.027024
	ISOBUTANE	0.350867	0.350867
	n-BUTANE	0.491006	0.491006
	n-PENTANE	0.131103	0.131103
	WATER	0.000000	0.000000

APPENDIX 3

Budget Pricing - Propane Recovery Unit
Enerflex Systems Ltd.

ENERFLEX

2009 07 03

File: C11166

Gas Liquids Engineering Ltd.
#300, 2749 - 39th Avenue N.E.
Calgary, Alberta
T1Y 4T8

Attention: Richard Piche
Sr. Project Manager

Re: Budget Pricing
Propane Recovery Unit

We wish to take this opportunity to thank you for the above enquiry, and allowing us the opportunity to present our offer for the supply of the referenced materials.

Our budget offer is for the supply of

(A) 300 MMSCFD Propane Recovery Unit
(B) 65 MMSCFD Propane Recovery Unit
(C) 0.5 MMSCFD Propane Recovery Unit

The equipment selection, capacity and operating ranges are based upon interpretation of the information supplied to us within your enquiry documents, or by assumptions we have made in the absence of such information.

Again, thank you for your consideration and we look forward to further discussing our proposal with you at your convenience.

Regards,

Steven C. Graham, P.Eng
General Manager
Production and Processing
Enerflex Systems Ltd.

Cc: Mike Tearoe – BD Manager
Jim Forsyth – Account Manager

A) PROPANE RECOVERY UNIT WITH RESIDUE GAS RECOMPRESSION & C4+RECOMBINATION FOR RE-INJECTION TO PIPELINE 300 MMSCFD FEED

1. Molecular Sieve Dehydration Unit:

1.1. Equipment:

Equipment shall be provided as follows:

1.1.1. Inlet Filter Separator

-Vertical Inlet Coalescing Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.2. Adsorption Vessels

-Vertical vessel, adsorbent material supported on a fixed grid
-Adsorbent: Molecular Sieves on 316 floating screen
-C.A.:1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA516 Gr. 70N

1.1.3. Dust Filter Separator

-Horizontal Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.4. Regeneration Gas Separator Vessel

-Vertical Separator with inlet deflector and demister
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
-Material: SA516 Gr. 70N

1.1.5. Regeneration Gas Heater

-Fired Heater type furnace
-Combustion Section: Lined with fiber block insulation, c/w exhaust stack
-Burner: Forced draft type c/w air blower
-Re-circulation fan: Yes c/w TEFC motor
-Control Panel: NEMA 4x enclosure, Class1 Div.2

1.1.6. Regeneration Gas Cooler/Condenser

-Type: Forced draft aerial cooler
-Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

1.1.7. Regeneration Gas Compressor

-Type: Vertical, single stage centrifugal
-Driver: TEFC motor and vibrations switch

2. Hydrocarbon Dew Point Control Unit:

2.1. Equipment:

Equipment shall be provided as follows:

2.1.1. Gas / Gas Exchanger

- Type: NEN
- TEMA "R" / ASME Section VIII, Division 1 construction
- Duty: 41.479 MMBTU/h
- Tube Material: SA-249-TP-304
- Shell Material: SA-312- TP-304L

2.1.2. Turbo Expander Compressor

- Variable inlet vanes system
- Lubrication system
- Seal gas system
-Power: 2985.80 hp
- Control/annunciator system

2.1.3. Expander Suction Vessel

- Size: 144" O.D. x 33'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
- Radiography: Full per RT-2
- P.W.H.T.: as required by code
- 2 phase controls
- Stainless Steel construction

2.1.4. De-Methanizer Column

- Size: 108" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA-240-304L

2.1.5. De-Methanizer Reboiler

- Duty: 39.45 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3. Propane Recovery Unit:

3.1. Equipment:

Equipment shall be provided as follows:

3.1.1. De-Propanizer Column

- Size: 90" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA516 Gr. 70

3.1.2. De-Propanizer Reboiler

- Duty: 26.60 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3.1.3. De-Propanizer Condenser

- Duty: 19.69 MMBTU/h
- Type: Forced draft aerial cooler
- Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

3.1.4. C4+ Pump

-Type: Centrifugal, ANSI
- Flow: 61.49 USGPM
- Power: 3.35 hp
-Driver: TEFC motor and vibrations switch

B) PROPANE RECOVERY UNIT WITH RESIDUE GAS RECOMPRESSION & C4+RECOMBINATION FOR RE-INJECTION TO PIPELINE 65 MMSCFD FEED

1. Molecular Sieve Dehydration Unit:

1.1. Equipment:

Equipment shall be provided as follows:

1.1.1. Inlet Filter Separator

-Vertical Inlet Coalescing Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.2. Adsorption Vessels

-Vertical vessel, adsorbent material supported on a fixed grid
-Adsorbent: Molecular Sieves on 316 floating screen
-C.A.:1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA516 Gr. 70N

1.1.3. Dust Filter Separator

-Horizontal Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.4. Regeneration Gas Separator Vessel

-Vertical Separator with inlet deflector and demister
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
-Material: SA516 Gr. 70N

1.1.5. Regeneration Gas Heater

-Fired Heater type furnace
-Combustion Section: Lined with fiber block insulation, c/w exhaust stack
-Burner: Forced draft type c/w air blower
-Re-circulation fan: Yes c/w TEFC motor
-Control Panel: NEMA 4x enclosure, Class1 Div.2

1.1.6. Regeneration Gas Cooler/Condenser

-Type: Forced draft aerial cooler
-Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

1.1.7. Regeneration Gas Compressor

-Type: Vertical, single stage centrifugal
-Driver: TEFC motor and vibrations switch

2. Hydrocarbon Dew Point Control Unit:

2.1. Equipment:

Equipment shall be provided as follows:

2.1.1. Gas / Gas Exchanger

- Type: NEN
- TEMA "R" / ASME Section VIII, Division 1 construction
- Duty: 8.98 MMBTU/h
- Tube Material: SA-249-TP-304
- Shell Material: SA-312- TP-304L

2.1.2. Turbo Expander Compressor

- Variable inlet vanes system
- Lubrication system
- Seal gas system
- Power: 646.92 hp
- Control/annunciator system

2.1.3. Expander Suction Vessel

- Size: 90" O.D. x 20'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
- Radiography: Full per RT-2
- P.W.H.T.: as required by code
- 2 phase controls
- Stainless Steel construction

2.1.4. De-Methanizer Column

- Size: 48" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA-240-304L

2.1.5. De-Methanizer Reboiler

- Duty: 8.54 MMBTU/h
- TEMA "R" / ASME Section VIII, Division 1 construction
- Type: BKU
- Material: SA516 Gr. 70

2.1.6. Residue Gas Compressor

-Type: Vertical, two stage centrifugal
-Driver: TEFC motor and vibrations switch
-Power: 3814 hp

3. Propane Recovery Unit:

3.1. Equipment:

Equipment shall be provided as follows:

3.1.1. De-Propanizer Column

- Size: 42" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA516 Gr. 70

3.1.2. De-Propanizer Reboiler

- Duty: 5.764 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3.1.3. De-Propanizer Condenser

- Duty: 4.27 MMBTU/h
- Type: Forced draft aerial cooler
- Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

3.1.4. C4+ Pump

-Type: Centrifugal, ANSI
- Flow: 13.46 USGPM
- Power: 13.46 hp
-Driver: TEFC motor and vibrations switch

C) PROPANE RECOVERY UNIT & C4+RECOMBINATION FOR RE-INJECTION TO PIPELINE 0.5 MMSCFD FEED

1. Molecular Sieve Dehydration Unit:

1.1. Equipment:

Equipment shall be provided as follows:

1.1.1. Inlet Filter Separator

-Vertical Inlet Coalescing Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.2. Adsorption Vessels

-Vertical vessel, adsorbent material supported on a fixed grid
-Adsorbent: Molecular Sieves on 316 floating screen
-C.A.:1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA516 Gr. 70N

1.1.3. Dust Filter Separator

-Horizontal Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.4. Regeneration Gas Separator Vessel

-Vertical Separator with inlet deflector and demister
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
-Material: SA516 Gr. 70N

1.1.5. Regeneration Gas Heater

-Fired Heater type furnace
-Combustion Section: Lined with fiber block insulation, c/w exhaust stack
-Burner: Forced draft type c/w air blower
-Re-circulation fan: Yes c/w TEFC motor
-Control Panel: NEMA 4x enclosure, Class1 Div.2

1.1.6. Regeneration Gas Cooler/Condenser

-Type: Forced draft aerial cooler
-Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

1.1.7. Regeneration Gas Compressor

-Type: Vertical, single stage centrifugal
-Driver: TEFC motor and vibrations switch

2. Hydrocarbon Dew Point Control Unit:

2.1. Equipment:

Equipment shall be provided as follows:

2.1.1. Gas / Gas Exchanger

- Type: NEN
- TEMA “R” / ASME Section VIII, Division 1 construction
- Duty: 0.06913 MMBTU/h
- Tube Material: SA-249-TP-304
- Shell Material: SA-312- TP-304L

2.1.2. Gas Expander

- Variable inlet vanes system
- Lubrication system
- Seal gas system
-Power: 4.98 hp
- Control/annunciator system

2.1.3. Expander Suction Vessel

- Size: 24” O.D. x 12’-0” S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
- Radiography: Full per RT-2
- P.W.H.T.: as required by code
- 2 phase controls
- Stainless Steel construction

2.1.4. De-Methanizer Column

- Size: 6" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA-240-304L

2.1.5. De-Methanizer Reboiler

- Duty: 0.0657 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3. Propane Recovery Unit:

3.2. Equipment:

Equipment shall be provided as follows:

3.1.1. De-Propanizer Column

- Size: 6" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA516 Gr. 70

3.1.2. De-Propanizer Reboiler

- Duty: 0.0442 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3.1.3. De-Propanizer Condenser

- Duty: 0.03279 MMBTU/h
- Type: Forced draft aerial cooler
- Fan:TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

3.1.4. C4+ Pump

-Type: Centrifugal, ANSI
- Power: 0.0183 hp
-Driver: TEFC motor and vibrations switch

CODES

Minimum requirements are to be in accordance with applicable codes and governmental requirements. Specifically:

- CSA W59 Welded Steel Construction
- The Boiler and Pressure Vessel Act of Alberta (registered in Alberta) and B.C.
- ASME Pressure Vessel Code
- ANSI/ASME B31.3 Refinery Piping
- B.C. / Alberta Building Code
- Canadian Standards Association

PACKAGE

The package shall be skid mounted, piped, valved and fully instrumented. Some of the items like coolers, etc. will be off-skid and installed on foundations.

INSTRUMENTATION

Instrumentation shall include electronic and pneumatic pressure, level and temperature controls. Instruments shall be run on instrument air which shall be supplied to skid. No PLC / DCS is included in the offer.

PIPING

All piping shall be brought to skid edge. Process streams and sweet, dry fuel gas shall be brought to the skid. Pressure relief valves shall be manifolded into a header and brought to skid perimeter. Drains shall be manifolded together into a 2" drain header and brought to skid perimeter. No inter-connecting piping between skids, between field erected equipment and skids has been considered.

INSULATION/PAINTING

The package shall be insulated commercially sandblasted (blast, primer and 2 finish coats of alkyd enamel.

4. PRICE

Unit	Budget Price (±30%) Ex-Works Nisku, Alberta
300 MMSCFD Plant	$48,000,000.00 CDN
65 MMSCFD Plant	$20,000,000.00 CDN
0.5 MMSCFD Plant	$1,000,000.00 CDN

APPENDIX 4

Cost Estimate for Electrical/DCS for C3 Fractionation Plants
Kilowatts Design Company Inc.

Ian McKay

From: Marc P. Bouchard [MBouchard@kilowatts.com]
Sent: July 9, 2009 11:33 AM
To: Ian McKay
Subject: RE: Ball Park Cost for Electrical/DCS for C3 Fractionation Plants

Ian,
Here is what I've estimated for the costs of the Electrical, Instrumentation and Controls portion for each of these projects.

For the .5mmscfd option:
1. Engineering, PM, Drafting, PLC programming, startup and commissioning - $300K
2. Wire 14' x 40' process skid - $250K
3. Wire 14' x 20' electrical/controls building - $200K
4. Electrical and control equipment - $300K
5. Field construction - $300K

Total: $1.35 million

For the 65mmscfd option:
1. Engineering, PM, Drafting, PLC programming, startup and commissioning - $1,000K
2. Wire process skids - $1,000K
3. Wire electrical/controls buildings - $1,000K
4. Electrical and control equipment - $2,500K
5. Field construction - $2,000K

Total: $7.5 million

For the 300mmscfd option:
1. Engineering, PM, Drafting, PLC programming, startup and commissioning - $3,000K
2. Wire process skids - $3,000K
3. Wire electrical/controls buildings - $3,000K
4. Electrical and control equipment - $7,500K
5. Field construction - $6,000K

Total: $22.5 million

Best regards,

Marc Bouchard
Senior Project Manager

Kilowatts Design Company Inc.
Unit 90 2150 - 29th Street NE, Calgary, AB T1Y 7G4

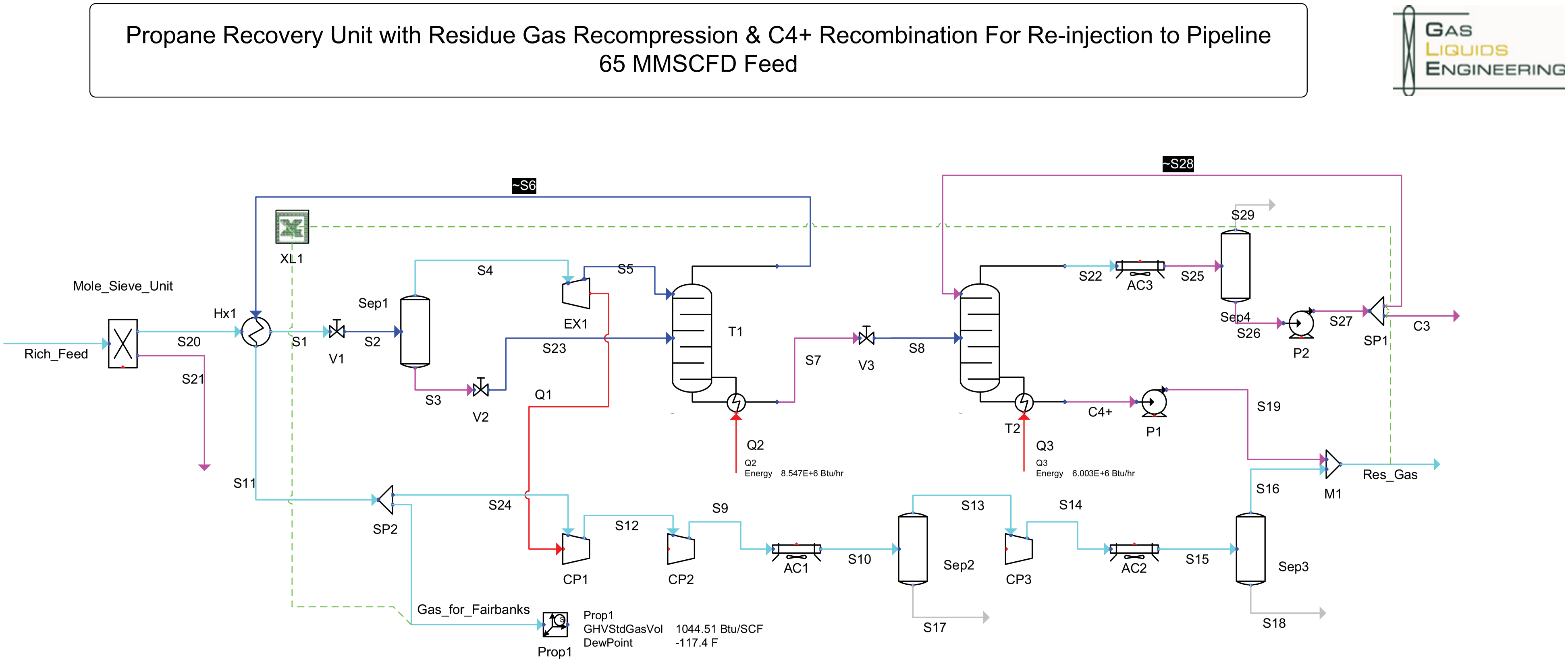
Direct 403.204.6616 Cell 403.807.8515
Main 403.272.9404 Fax 403.272.9433

mbouchard@kilowatts.com

APPENDIX 5

Process Simulation Flowsheet
65 MMSCFD Propane Fractionation Facility

Propane Recovery Unit with Residue Gas Recompression & C4+ Recombination For Re-injection to Pipeline
65 MMSCFD Feed



Hx1	
DT Tube	-139.74 F
DT Shell	59.35 F
DP Tube	*5.00 psi
DP Shell	*1.00 psi
UA	3.17E+05 Btu/hr-F
TApproach_Tube_Shell_AppT	*5.00 F

EX1	
Duty	6.469E+2 HorsePower
DP	270.00 psi
Efficiency	81.08 %
In.T	-97.7 F
In.P	500.00 psia
Out.T	-146.8 F
Pout	*230.00 psia

CP1	
Duty	6.469E+2 HorsePower
DP	83.50186 psi
Efficiency	*75.00 %
In.T	23.0 F
In.P	220.00 psia
Out.T	71.7 F
Pout	303.50 psia

CP2	
Duty	1.896E+3 HorsePower
DP	379.37733 psi
Efficiency	*75.00 %
In.T	71.7 F
In.P	303.50 psia
Out.T	207.1 F
Pout	682.88 psia

CP3	
Duty	1.918E+3 HorsePower
DP	832.12081 psi
Efficiency	*75.00 %
In.T	104.0 F
In.P	677.88 psia
Out.T	243.6 F
Pout	*1510.00 psia

P1	
Duty	1.419E+1 HorsePower
DP	1300.00 psi
Efficiency	*75.00 %
Pout	*1505.00 psia

Name	Rich_Feed	S1	S2	S3	S4	S5	S6	S7	S8	C3	C4+	S11	S12
VapFrac	1	1	0.76995	0	1	0.94248	0.99999	0	0.05319	0	0	1	1
T [F]	28	-31.3	-97.7	-97.7	-97.7	-146.8	-116.7	125.6	116.7	100.9	200.8	23	71.7
P [psia]	1500	1499	500	500	500	230	225	230	205	250	205	220	303.50186
MoleFlow [lbmole/h]	7136.94	7136.92	7136.92	1641.88	5495.04	5495.04	6825.81	311.13	311.13	254.94	56.22	6825.81	4080.83
MassFlow [lb/h]	134818.67	134818.21	134818.21	41059.34	93758.87	93758.87	120267.71	14551.65	14551.65	11196.18	3356.62	120267.71	71902.44
StdGasVolumeFlow [MMSCFD]	6.50E+01	6.50E+01	6.50E+01	1.50E+01	5.00E+01	5.00E+01	6.22E+01	2.83E+00	2.83E+00	2.32E+00	5.12E-01	6.22E+01	3.72E+01
MoleFraction [Fraction]													
CARBON DIOXIDE	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0	0.0157	0.0157
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0	0.0063	0.0063
METHANE	0.864	0.864	0.864	0.6001	0.9429	0.9429	0.9034	0	0	0	0	0.9034	0.9034
ETHANE	0.071	0.071	0.071	0.1973	0.0333	0.0333	0.0735	0.0156	0.0156	0.019	0	0.0735	0.0735
PROPANE	0.036	0.036	0.036	0.1402	0.0049	0.0049	0.0011	0.8012	0.8012	0.9748	0.0135	0.0011	0.0011
ISOBUTANE	0.003	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0039	0.3633	0	0
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.4965	0	0
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1267	0	0

Name	S9	S10	S13	S14	S15	S16	S17	S18	S19	Res_Gas	S20	S21
VapFrac	1	1	1	1	1	1	0	0	0	1	1	0
T [F]	207.1	104	104	243.6	104	104	104	104	221.5	104.4	28	28
P [psia]	682.87919	677.87919	677.87919	1510	1505	1505	677.87919	1505	1505	1505	1500	1500
MoleFlow [lbmole/h]	4080.83	4080.83	4080.83	4080.83	4080.83	4080.83	0	0	56.22	4137.05	7136.92	0.03
MassFlow [lb/h]	71902.44	71902.44	71902.44	71902.44	71902.44	71902.44	0	0	3356.62	75259.06	134818.21	0.46
StdGasVolumeFlow [MMSCFD]	3.72E+01	3.72E+01	3.72E+01	3.72E+01	3.72E+01	3.72E+01	2.01E-42	2.01E-42	5.12E-01	3.77E+01	6.50E+01	2.35E-04
MoleFraction [Fraction]												
CARBON DIOXIDE	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0	0.0155	0.015	0
NITROGEN	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0	0.0062	0.006	0
METHANE	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0	0.8911	0.864	0
ETHANE	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0	0.0725	0.071	0
PROPANE	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0135	0.0013	0.036	0
ISOBUTANE	0	0	0	0	0	0	0	0	0.3633	0.0049	0.003	0
n-BUTANE	0	0	0	0	0	0	0	0	0.4965	0.0067	0.004	0
n-PENTANE	0	0	0	0	0	0	0	0	0.1267	0.0017	0.001	0

Name	S23	S24	Gas_for_Fairbanks	S22	S25	S26	S27	S28	S29
VapFrac	0.26163	1	1	1	0	0	0	0	[illegible]
T [F]	-135.8	23	23	103.9	100	100	100.9	100.9	100
P [psia]	230	220	220	200	200	200	250	250	200
MoleFlow [lbmole/h]	1641.88	4080.83	2744.98	1019.77	1019.77	1019.77	1019.77	764.85	0
MassFlow [lb/h]	41059.34	71902.44	48365.27	44784.72	44784.72	44784.72	44784.72	33589.69	0
StdGasVolumeFlow [MMSCFD]	1.50E+01	3.72E+01	2.50E+01	9.29E+00	9.29E+00	9.29E+00	9.29E+00	6.97E+00	2.01E-42
MoleFraction [Fraction]									
CARBON DIOXIDE	0.0273	0.0157	0.0157	0	0	0	0	0	0
NITROGEN	0.0013	0.0063	0.0063	0	0	0	0	0	0
METHANE	0.6001	0.9034	0.9034	0	0	0	0	0	0
ETHANE	0.1973	0.0735	0.0735	0.019	0.019	0.019	0.019	0.019	0.0492
PROPANE	0.1402	0.0011	0.0011	0.9748	0.9748	0.9748	0.9748	0.9748	0.9485
ISOBUTANE	0.0126	0	0	0.0039	0.0039	0.0039	0.0039	0.004	0.0018
n-BUTANE	0.017	0	0	0.0023	0.0023	0.0023	0.0023	0.0022	[illegible]
n-PENTANE	0.0043	0	0	0	0	0	0	0	0

APPENDIX 6

Major Equipment List
65 MMSCFD Propane Fractionation Facility

Summary of Plant Unit Design Information

65 MMSCFD Facility

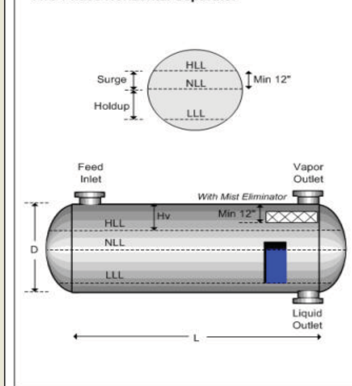
Unit	**Water Removal Rate (lb/h)**				
Molecular Sieve	0.4645				
Hx 1	Name		**Value**		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**317242.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-8987220.9**		
	PortName	**InTube**	**InShell**	**OutTube**	**OutShell**
	UnitOperation				
	Is Recycle Port				
	Connected Stream/Unit Op	/S6.Out	/S20.Out	/S11.In	/S1.In
	Connected Port				
	VapFrac	1.00	1.00	1.00	1.00
	T [F]	-116.7	28.0	23.0	-31.3
	P [psia]	225.0	1500.0	220.0	1499.0
	MoleFlow [lbmole/h]	6825.810	7136.920	6825.810	7136.920
	MassFlow [lb/h]	120267.710	134818.210	120267.710	134818.210
	VolumeFlow [ft3/s]	26.067	4.453	42.255	2.673
	StdLiqVolumeFlow [ft3/s]	1.703	1.828	1.703	1.828
	StdGasVolumeFlow [MMSCFD]	62.166	65.000	62.166	65.000
	Properties (Alt+R)				
	Energy [Btu/hr]	16405890.304	18762325.277	25393111.206	9775104.375
	H [Btu/lbmol]	2403.912	2629.353	3720.785	1369.884
	S [Btu/lbmol-F]	36.083	34.245	39.349	31.481
	MolecularWeight	17.620	18.890	17.620	18.890
	MassDensity [lb/ft3]	1.282	8.409	0.791	14.011
	Cp [Btu/lbmol-F]	9.815	17.297	9.312	24.800
	ThermalConductivity [Btu/hr-ft-F]	0.012	0.029	0.018	0.037
	Viscosity [cp]	0.008	0.016	0.010	0.024
	molarV [ft3/lbmol]	13.748	2.246	22.286	1.348
	ZFactor	0.840	0.648	0.946	0.445
	Fraction [Fraction]				
	CARBON DIOXIDE	0.015684	0.015000	0.015684	0.015000
	NITROGEN	0.006273	0.006000	0.006273	0.006000
	METHANE	0.903379	0.864000	0.903379	0.864000
	ETHANE	0.073527	0.071000	0.073527	0.071000
	PROPANE	0.001126	0.036000	0.001126	0.036000
	ISOBUTANE	0.000007	0.003000	0.000007	0.003000
	n-BUTANE	0.000004	0.004000	0.000004	0.004000
	n-PENTANE	0.000000	0.001000	0.000000	0.001000
	WATER	0.000000	0.000000	0.000000	0.000000

Summary of Plant Unit Design Information			
65 MMSCFD Facility			
V1	Name	Value	
	Delta P [psi]	999	
	Cv	27.09706	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S1.Out	/S2.In
	Connected Port		
	VapFrac	1.00	0.77
	T [F]	-31.3	-97.7
	P [psia]	1499.0	500.0
	MoleFlow [lbmole/h]	7136.920	7136.920
	MassFlow [lb/h]	134818.210	134818.210
	VolumeFlow [ft3/s]	2.673	8.512
	StdLiqVolumeFlow [ft3/s]	1.828	1.828
	StdGasVolumeFlow [MMSCFD]	65.000	65.000
	Properties (Alt+R)		
	Energy [Btu/hr]	9775000.000	9775000.000
	H [Btu/lbmol]	1369.900	1369.900
	S [Btu/lbmol-F]	31.481	32.476
	MolecularWeight	18.890	18.890
	MassDensity [lb/ft3]	14.011	4.400
	Cp [Btu/lbmol-F]	24.800	14.767
	ThermalConductivity [Btu/hr-ft-F]	0.037	0.032
	Viscosity [cp]	0.024	0.019
	molarV [ft3/lbmol]	1.348	4.294
	ZFactor	0.445	0.553
	Fraction [Fraction]		
	CARBON DIOXIDE	0.015000	0.015000
	NITROGEN	0.006000	0.006000
	METHANE	0.864000	0.864000
	ETHANE	0.071000	0.071000
	PROPANE	0.036000	0.036000
	ISOBUTANE	0.003000	0.003000
	n-BUTANE	0.004000	0.004000
	n-PENTANE	0.001000	0.001000
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information				
65 MMSCFD Facility				
Separator 1	PortName	**In**	**Liq0**	**Vap**
	UnitOperation			
	Is Recycle Port			
	Connected Stream/Unit Op	/S2.Out	/S3.In	/S4.In
	Connected Port			
	VapFrac	0.77	0.00	1.00
	T [F]	-97.7	-97.7	-97.7
	P [psia]	500.0	500.0	500.0
	MoleFlow [lbmole/h]	7136.920	1641.880	5495.040
	MassFlow [lb/h]	134818.210	41059.340	93758.870
	VolumeFlow [ft3/s]	8.512	0.408	8.104
	StdLiqVolumeFlow [ft3/s]	1.828	0.483	1.344
	StdGasVolumeFlow [MMSCFD]	65.000	14.953	50.046
	Properties (Alt+R)			
	Energy [Btu/hr]	9775104.375	-2261658.876	12036763.057
	H [Btu/lbmol]	1369.884	-1377.712	2190.847
	S [Btu/lbmol-F]	32.476	26.662	34.213
	MolecularWeight	18.890	25.007	17.062
	MassDensity [lb/ft3]	4.400	27.925	3.214
	Cp [Btu/lbmol-F]	14.767	18.430	13.672
	ThermalConductivity [Btu/hr-ft-F]	0.032	0.070	0.016
	Viscosity [cp]	0.019	0.101	0.009
	molarV [ft3/lbmol]	4.294	0.896	5.309
	ZFactor	0.553	0.109	0.685
	Fraction [Fraction]			
	CARBON DIOXIDE	0.015000	0.027280	0.011330
	NITROGEN	0.006000	0.001260	0.007420
	METHANE	0.864000	0.600090	0.942850
	ETHANE	0.071000	0.197250	0.033280
	PROPANE	0.036000	0.140250	0.004850
	ISOBUTANE	0.003000	0.012570	0.000140
	n-BUTANE	0.004000	0.016970	0.000120
	n-PENTANE	0.001000	0.004320	0.000010
	WATER	0.000000	0.000000	0.000000

Variables	Value
Design Variables	
VesselDesignType	**Sep2PhaseHorizontal**
MaxIteration	**50**
HoldupTime [day]	**0.0174**
SurgeTime [day]	**0.0035**
VapMassFlow [lb/h]	**93758.87**
LiqMassFlow [lb/h]	**41059.34**
VapDensity [lb/ft3]	**3.2139**
LiqDensity [lb/ft3]	**27.9253**
P [psia]	**500.00**
WithMistEliminator	**0**
Min_Design_L/D	**1.50**
Max_Design_L/D	**6.00**
Calculated Variables	
VesselLength [in]	234.6176
VesselDiameter [in]	90.000
L/Dratio	2.61
VapDisengagementHeight [in]	12.000
NormalLiqLevel [in]	65.4569
HighLiqLevel [in]	78.000
LowLiqLevel [in]	11.000
VesselWeight [lb]	40799.76
VesselWallThickness [in]	1.713

Two-Phase Horizontal Separator



Nomenclature

L = Vessel Length
D = Vessel Internal Diameter
Hv = Vapor Disengagement Height
HLL = High Liquid Level
NLL = Normal Liquid Level
LLL = Low Liquid Level

Notes

- Design values are only first estimation. It is not recommended for final dimension
- Stokes' Law constant, K is calculated using York-Demister equation
- For wall thickness calculation;
- Assume carbon-steel for material stress, X-rayed joints for joint efficiency and corrosion allowance = 1/16 inch
- Material = Carbon-steel
- For calculation purposes, mist eliminator thickness/height is assumed to be 4.8 inches

Summary of Plant Unit Design Information			
65 MMSCFD Facility			
V2	Name	Value	
	Delta P [psi]	270	
	Cv	7.46485	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S3.Out	/S9.In
	Connected Port		
	VapFrac	0.00	0.26
	T [F]	-97.7	-135.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	1641.881	1641.881
	MassFlow [lb/h]	41059.336	41059.336
	VolumeFlow [ft3/s]	0.408	1.774
	StdLiqVolumeFlow [ft3/s]	0.483	0.483
	StdGasVolumeFlow [MMSCFD]	14.953	14.953
	Properties (Alt+R)		
	Energy [Btu/hr]	-2261658.876	-2261658.876
	H [Btu/lbmol]	-1377.712	-1377.712
	S [Btu/lbmol-F]	26.662	26.945
	MolecularWeight	25.007	25.007
	MassDensity [lb/ft3]	27.925	6.429
	Cp [Btu/lbmol-F]	18.430	15.013
	ThermalConductivity [Btu/hr-ft-F]	0.070	0.066
	Viscosity [cp]	0.101	0.086
	molarV [ft3/lbmol]	0.896	3.890
	ZFactor	0.109	0.254
	Fraction [Fraction]		
	CARBON DIOXIDE	0.027284	0.027284
	NITROGEN	0.001259	0.001259
	METHANE	0.600091	0.600091
	ETHANE	0.197252	0.197252
	PROPANE	0.140246	0.140246
	ISOBUTANE	0.012574	0.012574
	n-BUTANE	0.016974	0.016974
	n-PENTANE	0.004321	0.004321
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

65 MMSCFD Facility

Unit	Name	In	Out		Unit	Name	In	Out
Ex 1	Name		Value		**CP1**	Name		Value
	OutQ [HorsePower]		646.92			InQ [HorsePower]		646.92
	Delta P [psi]		270.00			Delta P [psi]		83.50
	Pressure Ratio		2.17			Pressure Ratio		1.38
	Adiabatic Efficiency [%]		81.08			Adiabatic Efficiency [%]		75.00
	Polytropic Efficiency [%]		80.00			Polytropic Efficiency [%]		75.91
	Speed [rpm]					Speed [rpm]		
	Adiabatic Head [ft]		16849.64			Adiabatic Head [ft]		13360.89
	Polytropic Head [ft]		17077.15			Polytropic Head [ft]		13523.77
	PortName	In	Out			PortName	In	Out
	UnitOperation					UnitOperation		
	Is Recycle Port					Is Recycle Port		
	Connected Stream/Unit Op	/S4.Out	/S5.In			Connected Stream/Unit Op	/S24.Out	/S12.In
	Connected Port					Connected Port		
	VapFrac	1.00	0.94			VapFrac	1.00	1.00
	T [F]	-97.7	-146.8			T [F]	23.0	71.7
	P [psia]	500.0	230.0			P [psia]	220.0	303.5
	MoleFlow [lbmole/h]	5495.040	5495.040			MoleFlow [lbmole/h]	4080.830	4080.830
	MassFlow [lb/h]	93758.870	93758.870			MassFlow [lb/h]	71902.440	71902.440
	VolumeFlow [ft3/s]	8.104	16.958			VolumeFlow [ft3/s]	25.262	20.159
	StdLiqVolumeFlow [ft3/s]	1.344	1.344			StdLiqVolumeFlow [ft3/s]	1.018	1.018
	StdGasVolumeFlow [MMSCFD]	50.046	50.046			StdGasVolumeFlow [MMSCFD]	37.166	37.166
	Properties (Alt+R)					Properties (Alt+R)		
	Energy [Btu/hr]	12040000	10390000			Energy [Btu/hr]	15180000	16830000
	H [Btu/lbmol]	2190.800	1891.200			H [Btu/lbmol]	3720.800	4124.200
	S [Btu/lbmol-F]	34.213	34.438			S [Btu/lbmol-F]	39.349	39.540
	MolecularWeight	17.060	17.060			MolecularWeight	17.620	17.620
	MassDensity [lb/ft3]	3.214	1.536			MassDensity [lb/ft3]	0.791	0.991
	Cp [Btu/lbmol-F]	13.672	10.476			Cp [Btu/lbmol-F]	9.312	9.627
	ThermalConductivity [Btu/hr-ft-F]	0.016	0.017			ThermalConductivity [Btu/hr-ft-F]	0.018	0.021
	Viscosity [cp]	0.009	0.009			Viscosity [cp]	0.010	0.011
	molarV [ft3/lbmol]	5.309	11.110			molarV [ft3/lbmol]	22.286	17.784
	ZFactor	0.685	0.761			ZFactor	0.946	0.946
	Fraction [Fraction]					Fraction [Fraction]		
	CARBON DIOXIDE	0.011330	0.011330			CARBON DIOXIDE	0.015684	0.015684
	NITROGEN	0.007417	0.007417			NITROGEN	0.006273	0.006273
	METHANE	0.942855	0.942855			METHANE	0.903379	0.903379
	ETHANE	0.033277	0.033277			ETHANE	0.073527	0.073527
	PROPANE	0.004852	0.004852			PROPANE	0.001126	0.001126
	ISOBUTANE	0.000139	0.000139			ISOBUTANE	0.000007	0.000007
	n-BUTANE	0.000123	0.000123			n-BUTANE	0.000004	0.000004
	n-PENTANE	0.000008	0.000008			n-PENTANE	0.000000	0.000000
	WATER	0.000000	0.000000			WATER	0.000000	0.000000

Summary of Plant Unit Design Information

65 MMSCFD Facility

T1	Condenser	No		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED	overheadFeed	Lower_Feed	
	Stage	1	8	
	Connected Obj	/S5.Out	/S23.Out	
	Details			
	VapFrac	0.9425	0.2616	
	T [F]	-146.8	-135.8	
	P [psia]	230.0	230.0	
	MoleFlow [lbmole/h]	5495.037	1641.881	
	MassFlow [lb/h]	93758.870	41059.336	
	VolumeFlow [ft3/s]	16.958	1.774	
	StdLiqVolumeFlow [ft3/s]	1.344	0.483	
	StdGasVolumeFlow [MMSCFD]	50.046	14.953	
	Molar Composition			
	CARBON DIOXIDE	0.011330	0.027284	
	NITROGEN	0.007417	0.001259	
	METHANE	0.942855	0.600091	
	ETHANE	0.033277	0.197252	
	PROPANE	0.004852	0.140246	
	ISOBUTANE	0.000139	0.012574	
	n-BUTANE	0.000123	0.016974	
	n-PENTANE	0.000008	0.004321	
	WATER	0.000000	0.000000	
	DRAW	overheadV	reboilerL	
	Stage	1	20	
	Type	VapourDraw	LiquidDraw	
	Connected Obj	/S6.In	/S7.In	
	Details			
	VapFrac	1.0000	0.0000	
	T [F]	-116.8	125.6	
	P [psia]	225.0	230.0	
	MoleFlow [lbmole/h]	6825.787	311.131	
	MassFlow [lb/h]	120266.593	14551.612	
	VolumeFlow [ft3/s]	26.066	0.138	
	StdLiqVolumeFlow [ft3/s]	1.703	0.125	
	StdGasVolumeFlow [MMSCFD]	62.166	2.834	
	reboilerQ (Btu/hr)	**8546730.8**		

Section	Section_1	Section_2	Section_3	Section_4
Start	1	2	8	10
End	1	7	9	19
internalType	Packed	Packed	Packed	Packed
Design Variables				
PackedDesignBasis	**FLOODFACTOR**	**FLOODFACTOR**	**FLOODFACTOR**	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000	0.8000	0.8000	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**	**0.5000**	**0.5000**	**0.5000**
PackingHoldupMethod	**ESG**	**ESG**	**ESG**	**ESG**
SystemFactor [Fraction]	1.00	1.00	1.00	1.00
PackingName	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**
Fp	27.00	27.00	27.00	27.00
PackingAreaperVol [ft2/f3]	34.32	34.32	34.32	34.32
PackingType	RP	RP	RP	RP
PackingLengthperStage [ft]	**1.500**	**1.500**	**1.500**	**1.500**
SectionAreaFactor [Fraction]	0.8000	0.8000	0.8000	0.8000
Calculated Variables				
TrayDiameter [ft]	5.000	3.000	3.500	4.000
TotalTrayArea [ft2]	19.63	7.07	9.62	12.57
PackingLengthperSection [ft]	1.500	9.000	3.000	15.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

65 MMSCFD Facility

V3	Name	Value	
	Delta P [psi]	25	
	Cv	8.50107	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S7.Out	/S8.In
	Connected Port		
	VapFrac	0.00	0.05
	T [F]	125.6	116.7
	P [psia]	230.0	205.0
	MoleFlow [lbmole/h]	311.130	311.130
	MassFlow [lb/h]	14551.610	14551.610
	VolumeFlow [ft3/s]	0.138	0.235
	StdLiqVolumeFlow [ft3/s]	0.125	0.125
	StdGasVolumeFlow [MMSCFD]	2.834	2.834
	Properties (Alt+R)		
	Energy [Btu/hr]	270100.000	270100.000
	H [Btu/lbmol]	868.200	868.200
	S [Btu/lbmol-F]	34.117	34.134
	MolecularWeight	46.770	46.770
	MassDensity [lb/ft3]	29.209	17.215
	Cp [Btu/lbmol-F]	35.358	33.569
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.080	0.078
	molarV [ft3/lbmol]	1.601	2.717
	ZFactor	0.058	0.089
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.015555	0.015555
	PROPANE	0.801162	0.801162
	ISOBUTANE	0.068671	0.068671
	n-BUTANE	0.091674	0.091674
	n-PENTANE	0.022938	0.022938
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

65 MMSCFD Facility

T2	Condenser	Yes		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED			
	Stage	2		
	Connected Obj	/S8.Out		
	Details			
	VapFrac	0.0532		
	T [F]	116.7		
	P [psia]	205.0		
	MoleFlow [lbmole/h]	311.131		
	MassFlow [lb/h]	14551.612		
	VolumeFlow [ft3/s]	0.235		
	StdLiqVolumeFlow [ft3/s]	0.125		
	StdGasVolumeFlow [MMSCFD]	2.834		
	Molar Composition			
	CARBON DIOXIDE	0.000000		
	NITROGEN	0.000000		
	METHANE	0.000000		
	ETHANE	0.015555		
	PROPANE	0.801162		
	ISOBUTANE	0.068671		
	n-BUTANE	0.091674		
	n-PENTANE	0.022938		
	WATER	0.000000		
	DRAW	condenserL	condenserV	reboilerL
	Stage	1	1	20
	Type	LiquidDraw	VapourDraw	LiquidDraw
	Connected Obj		/C3.In	/C4+.In
	Details			
	VapFrac	0.0000	1.0000	0.0000
	T [F]	105.9	105.9	199.5
	P [psia]	200.0	200.0	205.0
	MoleFlow [lbmole/h]	0.000	257.578	53.553
	MassFlow [lb/h]	0.000	11360.799	3190.813
	VolumeFlow [ft3/s]	0.000	1.660	0.030
	StdLiqVolumeFlow [ft3/s]	0.000	0.100	0.025
	StdGasVolumeFlow [MMSCFD]	0.000	2.346	0.488
	ENERGY	condenserQ		reboilerQ
	Stage	1		20
	Type	EnergyOut		EnergyIn
	Connected Obj	/Q4.In		/Q3.Out
	Value [Btu/hr]	4267536.4		5764214.9

Section	Section_1
Start	2
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[2in] Pall Rings (M)**
Fp	27.00
PackingAreaperVol [ft2/f3]	34.32
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	3.500
TotalTrayArea [ft2]	9.62
PackingLengthperSection [ft]	27.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

65 MMSCFD Facility

P1	Name	Value	
	InQ [HorsePower]	13.46514	
	Delta P [psi]	1300	
	Pressure Ratio	7.341	
	Efficiency [%]	75	
	Speed [rpm]		
	Head [ft]	6266.67	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/C4+.Out	/C4+_To_SGas.In
	Connected Port		
	VapFrac	0.00	0.00
	T [F]	199.5	220.2
	P [psia]	205.0	1505.0
	MoleFlow [lbmole/h]	53.550	53.550
	MassFlow [lb/h]	3190.810	3190.810
	VolumeFlow [ft3/s]	0.030	0.028
	StdLiqVolumeFlow [ft3/s]	0.025	0.025
	StdGasVolumeFlow [MMSCFD]	0.488	0.488
	Properties (Alt+R)		
	Energy [Btu/hr]	176600.000	210900.000
	H [Btu/lbmol]	3299.100	3939.000
	S [Btu/lbmol-F]	34.731	34.999
	MolecularWeight	59.580	59.580
	MassDensity [lb/ft3]	29.872	31.648
	Cp [Btu/lbmol-F]	45.297	40.348
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.055
	Viscosity [cp]	0.087	0.110
	molarV [ft3/lbmol]	1.995	1.883
	ZFactor	0.058	0.380
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.000000	0.000000
	PROPANE	0.027025	0.027025
	ISOBUTANE	0.350865	0.350865
	n-BUTANE	0.491008	0.491008
	n-PENTANE	0.131102	0.131102
	WATER	0.000000	0.000000

APPENDIX 7

Cost Estimates for Residue Gas Compression - Fairbanks Facility

Ian McKay

From: Dan.Fixter@enerflex.com
Sent: July 29, 2009 1:44 PM
To: Mike Richardson
Cc: Ian McKay; Jim.Forsyth@enerflex.com; Barclay.Sexsmith@enerflex.com
Subject: Re: FW: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location
Attachments: 5500 hp Ariel JGZ6 3 stage pd 2400 psi.pdf; Report.pdf

Mike, as per you request enclosed is our budget:

See attached compressor performance run.

5200 HP @ 885 rpm electric motor / Ariel JGZ/6, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,650,000 +/- 20%, approx. delivery 30-36 weeks

Daniel Fixter
Business Development Manager
Optimization Services

ENERFLEX

Enerflex Systems Ltd.
Phone: 403.236-6656
Fax: 403.279-0367
Cell: 403.620-6278
Email: daniel.fixter@enerflex.com
Website: www.enerflex.com

From: Mike Richardson <MRichardson@gasliquids.com>
To: "Jim.Forsyth@enerflex.com" <Jim.Forsyth@enerflex.com>, "daniel.fixter@enerflex.com" <daniel.fixter@enerflex.com>
Cc: Ian McKay <IMcKay@gasliquids.com>
Date: 07/29/2009 11:50 AM
Subject: FW: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Jim:

One more time with Dan’s e-mail correct. I guess the “r” finger was broken.

Regards,

Mike Richardson

From: Mike Richardson

Sent: July 29, 2009 11:48 AM
To: 'Jim.Forsyth@enerflex.com'; 'daniel.fixter@eneflex.com'
Cc: Ian McKay
Subject: RE: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Jim:

We have another application for the same client, same location, for the same flow at much higher pressure. Please find the run attached. At this time, we are looking at electric drive only. Could you provide us with another cost estimate ASAP, and send it to myself and Ian MacKay?

Regards,

Mike Richardson

From: Jim.Forsyth@enerflex.com [mailto:Jim.Forsyth@enerflex.com]
Sent: June 29, 2009 11:23 AM
To: Mike Richardson
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Mike,

Please see the attached requested budget. Note Barclay's comment on engine IC design
ambient.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/29/2009 11:16AM -----
To: Jim Forsyth/EMFG/Enerflex@EFX
From: Barclay Sexsmith/EMFG/Enerflex
Date: 06/29/2009 11:04AM
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Note: Cooling of the G3612LE IC to the requested 90 degF would have to be discussed to insure that the customer can provide the required cooling medium.

----- Forwarded by Barclay Sexsmith/EMFG/Enerflex on 06/29/2009 11:03 AM -----

From: Barclay Sexsmith/EMFG/Enerflex

To: Jim Forsyth/EMFG/Enerflex@EFX

Date: 06/29/2009 11:03 AM

Subject: Re: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Caterpillar G3612LE / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,700,000 +/- 20%, delivery, approx. 20 weeks

4000 HP @ 900 rpm electric motor / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,000,000 +/- 20%, approx. delivery 30-36 weeks

Jim Forsyth---06/26/2009 10:02:47 AM---Barclay,

From: Jim Forsyth/EMFG/Enerflex

To: Barclay.Sexsmith@enerflex.com

Date: 06/26/2009 10:02 AM

Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Barclay,

Pls. see this additional budget request from Mike.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/26/2009 10:00AM -----

To: "jim.forsyth@enerflex.com" <jim.forsyth@enerflex.com>
From: Mike Richardson <MRichardson@gasliquids.com>
Date: 06/25/2009 07:13PM
cc: Ian McKay <IMcKay@gasliquids.com>
Subject: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Jim:

Please find attached two performance runs for Ariel JGZ/4 for a gas and an electric driver. As we discussed, the hp required is slightly over a standard Cat 3612 130 IC, so I have used the hp for a Cat 3612 90 IC. The units should be packaged and housed, 3 piece shippable, low temp piping/cooler, sweet trim, EFX (Guardian) AB PLC. The electric motor list would include Westinghouse, Siemens, GE, Reliance, and ABB. I have assumed that the cooler is electric motor driven. Only one unit, either electric or gas drive, will be purchased. If possible, the AFE estimate price and delivery is needed by Monday PM or early Tuesday AM.

Regards,

Mike Richardson, P. Eng.

Senior Specialized Mechanical Engineer

Gas Liquids Engineering Ltd.

#300, 2749 - 39th Avenue NE

Calgary, AB T1Y 4T8

Ph: 403.250.2950

Fax: 403.291.9730

E-mail: mrichardson@gasliquids.com

[attachment "Residue Compressor 1000 RPM 3612 LE 90 IC.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex] [attachment "Residue Compressor 885 RPM electric drive.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex]

Ariel Performance

Company:	Enerflex	Customer:	Gas Liquids Engineering
Quote:		Inquiry:	
7.6.0.1 Case 1:		Project:	Residue Gas

Compressor Data:

Elevation,ft:	1095.00	Barmtr,psia:	14.116	Ambient,°F:	95.00	Type:	Electric
Frame:	JGZ/6	Stroke, in:	6.75	Rod Dia, in:	2.875	Mfg:	TBA
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000	Model:	TBA
Rated RPM:	1000	Rated BHP:	7800.0	Rated PS FPM:	1125.0	BHP:	5200 (4727)
Calc RPM:	885.0	BHP:	4643	Calc PS FPM:	995.6	Avail:	4727 (0)

Driver Data: (last two columns above)

Services	**Service 1**					
Stage Data:	**1**	---	---	**2**	---	**3**
Flow Req'd, MMSCFD	37.200	---	---	37.200	---	37.200
Flow Calc, MMSCFD	37.200	---	---	37.200	---	37.200
Cyl BHP per Stage	1857.1	---	---	1648.1	---	1076.7
Specific Gravity	0.61	---	---	0.61	---	0.61
Ratio of Sp Ht (N)	1.2874	---	---	1.2888	---	1.2937
Comp Suct (Zs)	0.9435	---	---	0.9067	---	0.8424
Comp Disch (Zd)	0.9392	---	---	0.9221	---	0.8849
Pres Suct Line, psig	303.00	---	---	N/A	---	N/A
Pres Suct Flg, psig	299.83	---	---	742.17	---	1551.39
Pres Disch Flg, psig	752.17	---	---	1563.79	---	2438.28
Pres Disch Line, psig	N/A	---	---	N/A	---	2414.00
Pres Ratio F/F	2.441	---	---	2.086	---	1.567
Temp Suct, °F	71.70	---	---	120.00	---	120.00
Temp Clr Disch, °F	120.00	---	---	120.00	---	120.00
Cylinder Data:	**Throw 2**	**Throw 4**	**Throw 6**	**Throw 3**	**Throw 5**	**Throw 1**
Cyl Model	11Z	11Z	11Z	8-3/8Z	8-3/8Z	7-1/4Z-VS
Cyl Bore, in	10.500	10.500	10.500	7.875	7.875	7.250
Cyl RDP (API), psig	1154.5	1154.5	1154.5	2181.8	2181.8	3181.8
Cyl MAWP, psig	1270.0	1270.0	1270.0	2400.0	2400.0	3500.0
Cyl Action	DBL	DBL	DBL	DBL	DBL	DBL
Cyl Disp, CFM	576.2	576.2	576.2	314.3	314.3	263.0
Pres Suct Intl, psig	285.58	285.58	285.58	706.82	706.82	1431.78
Temp Suct Intl, °F	77	77	77	124	124	123
Suct Zsph	0.9455	0.9455	0.9455	0.9094	0.9094	0.8456
Pres Disch Intl, psig	783.14	783.14	783.14	1644.41	1644.41	2598.31
Temp Disch Intl, °F	208	208	208	245	245	207
HE Suct Gas Vel, FPM	7164	7164	7164	7651	7651	9529
HE Disch Gas Vel, FPM	6270	6270	6270	7382	7382	8049
HE Spcrs Used/Max	0/4	0/4	0/4	0/4	0/4	0/0
HE Vol Pkt Avail, %	0.67+38.83	0.67+38.83	0.67+38.83	0.66+37.33	0.66+37.33	0.44+34.96
Vol Pkt Used, %	36.26 (V)	36.26 (V)	36.26 (V)	0.00 (V)	0.00 (V)	0.00 (V)
HE Min Clr, %	17.80	17.80	17.80	14.82	14.82	18.19
HE Total Clr, %	32.55	32.55	32.55	15.48	15.48	18.64
CE Suct Gas Vel, FPM	6627	6627	6627	6631	6631	8031
CE Disch Gas Vel, FPM	5800	5800	5800	6398	6398	6783
CE Spcrs Used/Max	0/4	0/4	0/4	0/4	0/4	0/0
CE Min Clr, %	18.06	18.06	18.06	18.81	18.81	23.07
CE Total Clr, %	18.06	18.06	18.06	18.81	18.81	23.07
Suct Vol Eff HE/CE, %	61.5/75.8	61.5/75.8	61.5/75.8	82.8/80.4	82.8/80.4	88.1/86.6
Disch Event HE/CE, ms	11.9/15.3	11.9/15.3	11.9/15.3	15.3/16.9	15.3/16.9	18.6/20.3
Suct Pseudo-Q HE/CE	4.6/4.0	4.6/4.0	4.6/4.0	5.8/4.3	5.8/4.3	5.9/4.2
Gas Rod Ld Comp, %	56.3 C	56.3 C	56.3 C	63.2 C	63.2 C	72.3 C
Gas Rod Ld Tens, %	50.5 T	50.5 T	50.5 T	46.4 T	46.4 T	41.6 T
Gas Rod Ld Total, %	55.3	55.3	55.3	56.9	56.9	59.4
Xhd Pin Deg/%Rvrsl lbf	154/86.4	154/86.4	154/86.4	176/57.6	176/57.6	133/58.6
Flow Calc, MMSCFD	12.400	12.400	12.400	18.600	18.600	37.200
Cyl BHP	619.0	619.0	619.0	824.0	824.0	1076.7

Ian McKay

From: Mike Richardson
Sent: June 29, 2009 5:59 PM
To: Ian McKay
Subject: FW: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Ian:

Please find the cost estimate for the gas and electric drives for your application. The Caterpillar engine is shy on hp with the standard 130 F intercooler. I ran the performance with a 90 F intercooler, which will work fine for most of the year. There will be a possibility of about two weeks that the hp will not be available on the 90F intercooler (daylight heating hours which can be long at this location). We can either accept the derate, or provide a cooling medium besides air.

Regards,

Mike R

From: Jim.Forsyth@enerflex.com [mailto:Jim.Forsyth@enerflex.com]
Sent: June 29, 2009 11:23 AM
To: Mike Richardson
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Mike,

Please see the attached requested budget. Note Barclay's comment on engine IC design ambient.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/29/2009 11:16AM -----

To: Jim Forsyth/EMFG/Enerflex@EFX
From: Barclay Sexsmith/EMFG/Enerflex
Date: 06/29/2009 11:04AM
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Note: Cooling of the G3612LE IC to the requested 90 degF would have to be discussed to insure that the customer can provide the required cooling medium.

----- Forwarded by Barclay Sexsmith/EMFG/Enerflex on 06/29/2009 11:03 AM -----

From: Barclay Sexsmith/EMFG/Enerflex

To: Jim Forsyth/EMFG/Enerflex@EFX

Date: 06/29/2009 11:03 AM

Subject: Re: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Caterpillar G3612LE / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,700,000 +/- 20%, delivery, approx. 20 weeks

4000 HP @ 900 rpm electric motor / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,000,000 +/- 20%, approx. delivery 30-36 weeks

Jim Forsyth---06/26/2009 10:02:47 AM---Barclay,

From: Jim Forsyth/EMFG/Enerflex

To: Barclay.Sexsmith@enerflex.com

Date: 06/26/2009 10:02 AM

Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Barclay,

Pls. see this additional budget request from Mike.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/26/2009 10:00AM -----

To: "jim.forsyth@enerflex.com" <jim.forsyth@enerflex.com>
From: Mike Richardson <MRichardson@gasliquids.com>
Date: 06/25/2009 07:13PM
cc: Ian McKay <IMcKay@gasliquids.com>
Subject: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Jim:

Please find attached two performance runs for Ariel JGZ/4 for a gas and an electric driver. As we discussed, the hp required is slightly over a standard Cat 3612 130 IC, so I have used the hp for a Cat 3612 90 IC. The units should be packaged and housed, 3 piece shippable, low temp piping/cooler, sweet trim, EFX (Guardian) AB PLC. The electric motor list would include Westinghouse, Siemens, GE, Reliance, and ABB. I have assumed that the cooler is electric motor driven. Only one unit, either electric or gas drive, will be purchased. If possible, the AFE estimate price and delivery is needed by Monday PM or early Tuesday AM.

Regards,

Mike Richardson, P. Eng.

Senior Specialized Mechanical Engineer

Gas Liquids Engineering Ltd.

#300, 2749 - 39th Avenue NE

Calgary, AB T1Y 4T8

Ph: 403.250.2950

Fax: 403.291.9730

E-mail: mrichardson@gasliquids.com

[attachment "Residue Compressor 1000 RPM 3612 LE 90 IC.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex] [attachment "Residue Compressor 885 RPM electric drive.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex]

Ariel Performance

Company:	Gas Liquids Engineering Ltd.	Customer:	TBA
Quote:	Size Residue Gas Comp	Inquiry:	
7.6.0.1 Case 1:		Project:	09107

Compressor Data:

Elevation,ft:	*2500.00*	Barmtr,psia:	13.400	Ambient,°F:	95.00	**Driver Data:**			
Frame:	JGZ/4	Stroke, in:	6.75	Rod Dia, in:	2.875	Type:	Nat. Gas		
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000	Mfg:	Caterpillar		
Rated RPM:	1000	Rated BHP:	5200.0	Rated PS FPM:	1125.0	Model:	G3612LE L 90		
Calc RPM:	1000.0	BHP:	3630	Calc PS FPM:	1125.0	BHP:	3785		
						Avail:	3785 (0)		

Services	**Service 1**			
Stage Data:	**1**	---	**2**	**3**
Flow Req'd, MMSCFD	37.200	---	37.200	37.200
Flow Calc, MMSCFD	37.200	---	37.200	37.200
Cyl BHP per Stage	1379.3	---	933.2	1271.0
Specific Gravity	0.6083	---	0.6083	0.6083
Ratio of Sp Ht (N)	1.2955	---	1.2986	1.3039
Comp Suct (Zs)	0.9459	---	0.9209	0.8869
Comp Disch (Zd)	0.9415	---	0.9220	0.9012
Pres Suct Line, psia	303.50	---	N/A	N/A
Pres Suct Flg, psia	303.50	---	587.14	886.36
Pres Disch Flg, psia	607.14	---	916.36	1535.00
Pres Disch Line, psia	N/A	---	N/A	1505.00
Pres Ratio F/F	2.000	---	1.561	1.732
Temp Suct, °F	71.70	---	110.00	110.00
Temp Clr Disch, °F	110.00	---	110.00	110.00
Cylinder Data:	**Throw 1**	**Throw 3**	**Throw 4**	**Throw 2**
Cyl Model	13-5/8ZM	13-5/8ZM	12-1/2ZL	9-5/8Z
Cyl Bore, in	13.125	13.125	12.000	9.125
Cyl RDP (API), psig	986.4	986.4	1227.3	1727.3
Cyl MAWP, psig	1085.0	1085.0	1350.0	1900.0
Cyl Action	DBL	DBL	DBL	DBL
Cyl Disp, CFM	1031.7	1031.7	858.2	485.6
Pres Suct Intl, psia	296.21	296.21	573.50	830.64
Temp Suct Intl, °F	77	77	113	114
Suct Zsph	0.9475	0.9475	0.9225	0.8898
Pres Disch Intl, psia	623.67	623.67	942.35	1638.02
Temp Disch Intl, °F	176	176	182	212
HE Suct Gas Vel, FPM	5145	5145	5183	8551
HE Disch Gas Vel, FPM	4959	4959	5058	8036
HE Spcrs Used/Max	0/4	0/4	0/4	0/4
HE Vol Pkt Avail, %	0.32+101.87	0.32+101.87	No Pkt	No Pkt
Vol Pkt Used, %	19.85 (V)	19.85 (V)	No Pkt	No Pkt
HE Min Clr, %	37.80	37.80	43.16	14.31
HE Total Clr, %	58.33	58.33	43.16	14.31
CE Suct Gas Vel, FPM	4898	4898	4886	7702
CE Disch Gas Vel, FPM	4721	4721	4768	7238
CE Spcrs Used/Max	0/4	0/4	0/4	0/4
CE Min Clr, %	40.53	40.53	46.53	17.22
CE Total Clr, %	40.53	40.53	46.53	17.22
Suct Vol Eff HE/CE, %	53.2/65.7	53.2/65.7	77.3/75.9	87.3/85.9
Disch Event HE/CE, ms	10.5/13.7	10.5/13.7	15.0/16.7	15.5/17.0
Suct Pseudo-Q HE/CE	3.1/2.8	3.1/2.8	3.3/3.0	7.3/5.9
Gas Rod Ld Comp, lbf	46203 C	46203 C	45437 C	58444 C
Gas Rod Ld Tens, lbf	40288 T	40288 T	35614 T	42019 T
Gas Rod Ld Total, lbf	86491	86491	81051	100463
Xhd Pin Deg/%Rvrsl lbf	177/61.6	177/61.6	167/74.1	167/65.1
Flow Calc, MMSCFD	18.600	18.600	37.200	37.200
Cyl BHP	689.6	689.6	933.2	1271.0

Ariel Performance

7.6.0.1	Company:	Gas Liquids Engineering Ltd.	Customer:	TBA
	Quote:	Size Residue Gas Comp	Inquiry:	
	Case 1:		Project:	09107

Compressor Data:

Elevation,ft:	2500.00	Barmtr,psia:	13.400	Ambient,°F:	95.00	Type:	Unselected
Frame:	JGZ/4	Stroke, in:	6.75	Rod Dia, in:	2.875	Mfg:	
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000	Model:	
Rated RPM:	1000	Rated BHP:	5200.0	Rated PS FPM:	1125.0	BHP:	0
Calc RPM:	885.0	BHP:	3603	Calc PS FPM:	995.6	Avail:	0 (0)

Driver Data: (columns 7–8 above)

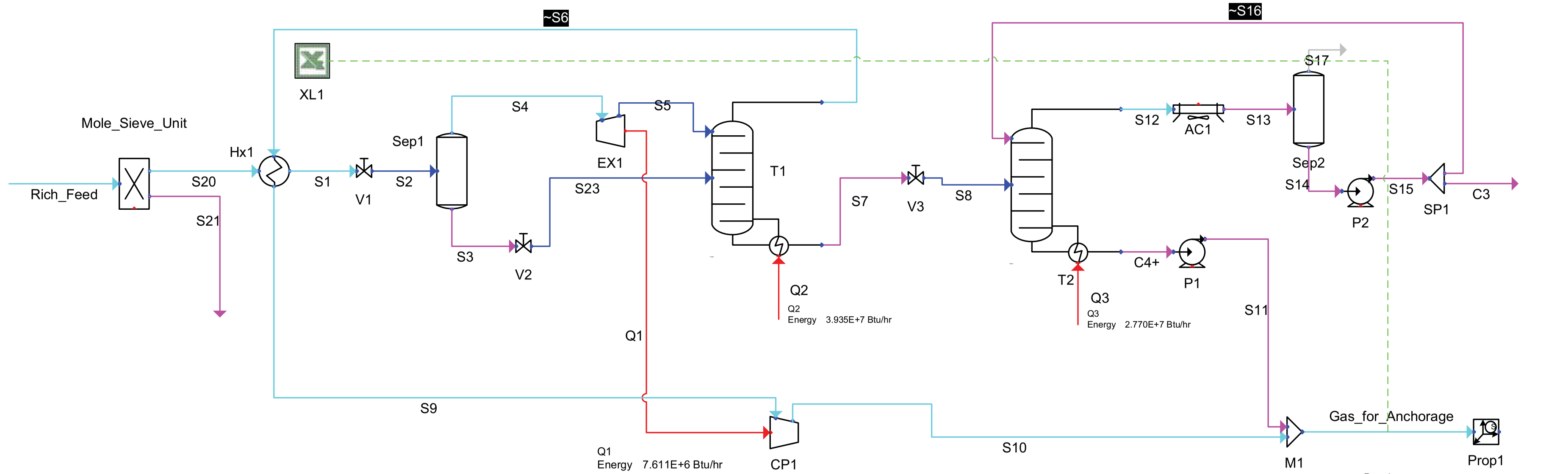
Services	**Service 1**			
Stage Data:	**1**	---	**2**	**3**
Flow Req'd, MMSCFD	37.200	---	37.200	37.200
Flow Calc, MMSCFD	37.200	---	37.200	37.200
Cyl BHP per Stage	1382.9	---	906.2	1273.1
Specific Gravity	0.6083	---	0.6083	0.6083
Ratio of Sp Ht (N)	1.2955	---	1.2988	1.3038
Comp Suct (Zs)	0.9459	---	0.9205	0.8872
Comp Disch (Zd)	0.9415	---	0.9215	0.9016
Pres Suct Line, psia	303.50	---	N/A	N/A
Pres Suct Flg, psia	303.50	---	590.80	883.17
Pres Disch Flg, psia	610.80	---	913.17	1535.00
Pres Disch Line, psia	N/A	---	N/A	1505.00
Pres Ratio F/F	2.013	---	1.546	1.738
Temp Suct, °F	71.70	---	110.00	110.00
Temp Clr Disch, °F	110.00	---	110.00	110.00
Cylinder Data:	**Throw 1**	**Throw 3**	**Throw 4**	**Throw 2**
Cyl Model	13-5/8ZM	13-5/8ZM	12-1/2ZL	9-5/8Z
Cyl Bore, in	13.625	13.625	12.500	9.625
Cyl RDP (API), psig	986.4	986.4	1227.3	1727.3
Cyl MAWP, psig	1085.0	1085.0	1350.0	1900.0
Cyl Action	DBL	DBL	DBL	DBL
Cyl Disp, CFM	985.6	985.6	826.0	480.6
Pres Suct Intl, psia	296.85	296.85	578.08	828.84
Temp Suct Intl, °F	77	77	113	114
Suct Zsph	0.9475	0.9475	0.9221	0.8902
Pres Disch Intl, psia	625.97	625.97	937.25	1635.82
Temp Disch Intl, °F	176	176	181	213
HE Suct Gas Vel, FPM	4906	4906	4977	8419
HE Disch Gas Vel, FPM	4729	4729	4857	7913
HE Spcrs Used/Max	0/4	0/4	0/4	0/4
HE Vol Pkt Avail, %	0.30+94.53	0.30+94.53	No Pkt	No Pkt
Vol Pkt Used, %	15.33 (V)	15.33 (V)	No Pkt	No Pkt
HE Min Clr, %	36.82	36.82	38.34	11.87
HE Total Clr, %	51.62	51.62	38.34	11.87
CE Suct Gas Vel, FPM	4688	4688	4714	7668
CE Disch Gas Vel, FPM	4519	4519	4600	7207
CE Spcrs Used/Max	0/4	0/4	0/4	0/4
CE Min Clr, %	38.39	38.39	41.16	14.22
CE Total Clr, %	38.39	38.39	41.16	14.22
Suct Vol Eff HE/CE, %	57.5/66.9	57.5/66.9	79.6/78.5	88.5/87.3
Disch Event HE/CE, ms	12.4/15.6	12.4/15.6	17.5/19.2	17.7/19.4
Suct Pseudo-Q HE/CE	2.8/2.6	2.8/2.6	3.1/2.8	7.1/5.9
Gas Rod Ld Comp, lbf	49884 C	49884 C	47821 C	64337 C
Gas Rod Ld Tens, lbf	43959 T	43959 T	38013 T	47947 T
Gas Rod Ld Total, lbf	93843	93843	85834	112284
Xhd Pin Deg/%Rvrsl lbf	143/85.1	143/85.1	177/70.0	179/70.3
Flow Calc, MMSCFD	18.600	18.600	37.200	37.200
Cyl BHP	691.5	691.5	906.2	1273.1

APPENDIX 8

Process Simulation Flowsheet
300 MMSCFD Propane Fractionation Facility

Propane Recovery Unit with Recombination of Lean Gas and C4+ for Local Sales Gas
300 MMSCFD Feed

GAS LIQUIDS ENGINEERING



Prop1
GHVStdGasVol 1063.23 Btu/SCF
DewPoint -43.2 F

Hx1	
DT Tube	-139.74 F
DT Shell	59.17 F
DP Tube	*0.07856 psi
DP Shell	*0.06871 psi
UA	1.54E+06 Btu/hr-F
TApproach_Tube_Shell_AppT	*4.99 F

EX1	
Duty	2.991E+3 HorsePower
DP	270.00 psi
Efficiency	81.08 %
In.T	-97.6 F
In.P	500.00 psia
Out.T	-146.7 F
Pout	*230.00 psia

Name	Rich_Feed	S1	S2	S3	S4	S5	S6	S7	S8	C3	C4+
VapFrac	1	1	0.77084	0	1	0.94258	0.99999	0	0.05319	0	0
T [F]	28	-31.2	-97.6	-97.6	-97.6	-146.7	-116.7	125.6	116.7	100.9	200.8
P [psia]	1500	1499.93129	500	500	500	230	225	230	205	250	205
MoleFlow [lbmole/h]	32939.74	32939.62	32939.62	7548.36	25391.26	25391.26	31503.85	1435.78	1435.78	1176.55	259.44
MassFlow [lb/h]	622240.01	622237.87	622237.87	188939.06	433298.81	433298.81	555086.33	67151.94	67151.94	51668.99	15491.35
StdGasVolumeFlow [MMSCFD]	3.00E+02	3.00E+02	3.00E+02	6.87E+01	2.31E+02	2.31E+02	2.87E+02	1.31E+01	1.31E+01	1.07E+01	2.36E+00
MoleFraction [Fraction]											
CARBON DIOXIDE	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0
METHANE	0.864	0.864	0.864	0.5992	0.9427	0.9427	0.9034	0	0	0	0
ETHANE	0.071	0.071	0.071	0.1976	0.0334	0.0334	0.0735	0.0156	0.0156	0.019	0
PROPANE	0.036	0.036	0.036	0.1407	0.0049	0.0049	0.0011	0.8011	0.8011	0.9748	0.0135
ISOBUTANE	0.003	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0038	0.3627
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.497
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1268

Name	S20	S21	S23	Gas_for_Anchorage	S9	S10	S11	S12	S13	S14	S15	S16	S17
VapFrac	1	0	0.26155	1	1	1	0	1	0	0	0	0	1
T [F]	28	28	-135.7	50	23	52.3	202.1	103.9	100	100	100.9	100.9	100
P [psia]	1500	1500	230	273.5475	224.92144	273.5475	275	200	200	200	250	250	200
MoleFlow [lbmole/h]	32939.62	0.12	7548.36	31763.29	31503.85	31503.85	259.44	4706.18	4706.18	4706.18	4706.18	3529.84	[illegible]
MassFlow [lb/h]	622237.87	2.14	188939.06	570577.67	555086.33	555086.33	15491.35	206675.97	206675.97	206675.97	206675.97	155015.38	0
StdGasVolumeFlow [MMSCFD]	3.00E+02	1.08E-03	6.87E+01	2.89E+02	2.87E+02	2.87E+02	2.36E+00	4.29E+01	4.29E+01	4.29E+01	4.29E+01	3.21E+01	2.01E-42
MoleFraction [Fraction]													
CARBON DIOXIDE	0.015	0	0.0273	0.0156	0.0157	0.0157	0	0	0	0	0	0	0
NITROGEN	0.006	0	0.0013	0.0062	0.0063	0.0063	0	0	0	0	0	0	0
METHANE	0.864	0	0.5992	0.896	0.9034	0.9034	0	0	0	0	0	0	0
ETHANE	0.071	0	0.1976	0.0729	0.0735	0.0735	0	0.019	0.019	0.019	0.019	0.019	0.0493
PROPANE	0.036	0	0.1407	0.0012	0.0011	0.0011	0.0135	0.9748	0.9748	0.9748	0.9748	0.9748	0.9481
ISOBUTANE	0.003	0	0.0126	0.003	0	0	0.3627	0.0038	0.0038	0.0038	0.0038	0.0038	0.001[illegible]
n-BUTANE	0.004	0	0.017	0.0041	0	0	0.497	0.0023	0.0023	0.0023	0.0023	0.0023	0.000[illegible]
n-PENTANE	0.001	0	0.0043	0.001	0	0	0.1268	0	0	0	0	0	0

APPENDIX 9

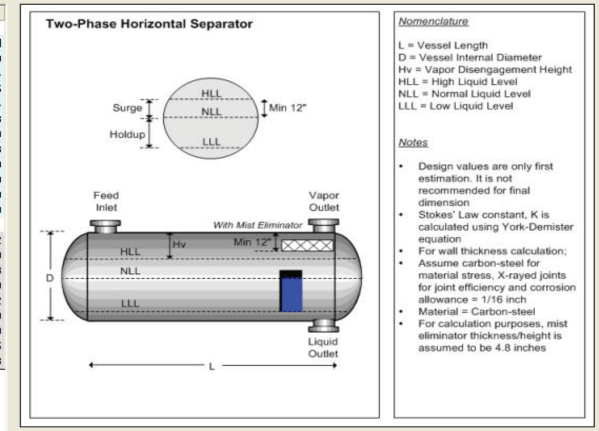
Major Equipment List
300 MMSCFD Propane Fractionation Facility

Summary of Plant Unit Design Information					
300 MMSCFD Facility					
Unit	**Water Removal Rate (lb/h)**				
Molecular Sieve	2.14				
Hx 1	Name		**Value**		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**1464195.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-41479481.4**		
	PortName	**InTube**	**InShell**	**OutTube**	**OutShell**
	UnitOperation				
	Is Recycle Port				
	Connected Stream/Unit Op	/S6.Out	/S20.Out	/S11.In	/S1.In
	Connected Port				
	VapFrac	1.00	1.00	1.00	1.00
	T [F]	-116.7	28.0	23.0	-31.3
	P [psia]	225.0	1500.0	220.0	1499.0
	MoleFlow [lbmole/h]	31503.750	32939.620	31503.750	32939.620
	MassFlow [lb/h]	555081.780	622237.870	555081.780	622237.870
	VolumeFlow [ft3/s]	120.309	20.554	195.023	12.336
	StdLiqVolumeFlow [ft3/s]	7.858	8.435	7.858	8.435
	StdGasVolumeFlow [MMSCFD]	286.920	300.000	286.920	300.000
	Properties (Alt+R)				
	Energy [Btu/hr]	75720000.000	86600000.000	117200000.000	45120000.000
	H [Btu/lbmol]	2403.900	2629.400	3720.800	1369.900
	S [Btu/lbmol-F]	36.083	34.245	39.349	31.481
	MolecularWeight	17.620	18.890	17.620	18.890
	MassDensity [lb/ft3]	1.282	8.409	0.791	14.011
	Cp [Btu/lbmol-F]	9.815	17.297	9.312	24.800
	ThermalConductivity [Btu/hr-ft-F]	0.012	0.029	0.018	0.037
	Viscosity [cp]	0.008	0.016	0.010	0.024
	molarV [ft3/lbmol]	13.748	2.246	22.286	1.348
	ZFactor	0.840	0.648	0.946	0.445
	Fraction [Fraction]				
	CARBON DIOXIDE	0.015684	0.015000	0.015684	0.015000
	NITROGEN	0.006273	0.006000	0.006273	0.006000
	METHANE	0.903379	0.864000	0.903379	0.864000
	ETHANE	0.073527	0.071000	0.073527	0.071000
	PROPANE	0.001126	0.036000	0.001126	0.036000
	ISOBUTANE	0.000007	0.003000	0.000007	0.003000
	n-BUTANE	0.000004	0.004000	0.000004	0.004000
	n-PENTANE	0.000000	0.001000	0.000000	0.001000
	WATER	0.000000	0.000000	0.000000	0.000000

Summary of Plant Unit Design Information			
300 MMSCFD Facility			
V1	Name	Value	
	Delta P [psi]	999	
	Cv	125.06335	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S1.Out	/S2.In
	Connected Port		
	VapFrac	1.00	0.77
	T [F]	-31.3	-97.7
	P [psia]	1499.0	500.0
	MoleFlow [lbmole/h]	32939.623	32939.623
	MassFlow [lb/h]	622237.871	622237.871
	VolumeFlow [ft3/s]	12.336	39.286
	StdLiqVolumeFlow [ft3/s]	8.435	8.435
	StdGasVolumeFlow [MMSCFD]	299.999	299.999
	Properties (Alt+R)		
	Energy [Btu/hr]	45120000	45120000
	H [Btu/lbmol]	1369.900	1369.900
	S [Btu/lbmol-F]	31.481	32.476
	MolecularWeight	18.890	18.890
	MassDensity [lb/ft3]	14.011	4.400
	Cp [Btu/lbmol-F]	24.800	14.767
	ThermalConductivity [Btu/hr-ft-F]	0.037	0.032
	Viscosity [cp]	0.024	0.019
	molarV [ft3/lbmol]	1.348	4.294
	ZFactor	0.445	0.553
	Fraction [Fraction]		
	CARBON DIOXIDE	0.015000	0.015000
	NITROGEN	0.006000	0.006000
	METHANE	0.864000	0.864000
	ETHANE	0.071000	0.071000
	PROPANE	0.036000	0.036000
	ISOBUTANE	0.003000	0.003000
	n-BUTANE	0.004000	0.004000
	n-PENTANE	0.001000	0.001000
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information				
300 MMSCFD Facility				
Separator 1	PortName	In	Liq0	Vap
	UnitOperation			
	Is Recycle Port			
	Connected Stream/Unit Op	/S2.Out	/S3.In	/S4.In
	Connected Port			
	VapFrac	0.77	0.00	1.00
	T [F]	-97.7	-97.7	-97.7
	P [psia]	500.0	500.0	500.0
	MoleFlow [lbmole/h]	32939.620	7577.910	25361.710
	MassFlow [lb/h]	622237.870	189504.630	432733.240
	VolumeFlow [ft3/s]	39.286	1.885	37.401
	StdLiqVolumeFlow [ft3/s]	8.435	2.230	6.205
	StdGasVolumeFlow [MMSCFD]	300.000	69.016	230.980
	Properties (Alt+R)			
	Energy [Btu/hr]	45120000.000	-10440000.000	55550000.000
	H [Btu/lbmol]	1369.900	-1377.700	2190.800
	S [Btu/lbmol-F]	32.476	26.662	34.213
	MolecularWeight	18.890	25.010	17.060
	MassDensity [lb/ft3]	4.400	27.925	3.214
	Cp [Btu/lbmol-F]	14.767	18.430	13.672
	ThermalConductivity [Btu/hr-ft-F]	0.032	0.070	0.016
	Viscosity [cp]	0.019	0.101	0.009
	molarV [ft3/lbmol]	4.294	0.896	5.309
	ZFactor	0.553	0.109	0.685
	Fraction [Fraction]			
	CARBON DIOXIDE	0.015000	0.027284	0.011330
	NITROGEN	0.006000	0.001259	0.007417
	METHANE	0.864000	0.600091	0.942855
	ETHANE	0.071000	0.197252	0.033277
	PROPANE	0.036000	0.140246	0.004852
	ISOBUTANE	0.003000	0.012574	0.000139
	n-BUTANE	0.004000	0.016974	0.000123
	n-PENTANE	0.001000	0.004321	0.000008
	WATER	0.000000	0.000000	0.000000

Variables	Value
Design Variables	
VesselDesignType	Sep2PhaseHorizontal
MaxIteration	50
HoldupTime [day]	0.0174
SurgeTime [day]	0.0035
VapMassFlow [lb/h]	432733.24
LiqMassFlow [lb/h]	189504.63
VapDensity [lb/ft3]	3.2139
LiqDensity [lb/ft3]	27.9253
P [psia]	500.00
WithMistEliminator	0
Min_Design_L/D	1.50
Max_Design_L/D	6.00
Calculated Variables	
VesselLength [in]	393.1992
VesselDiameter [in]	144.000
L/Dratio	2.73
VapDisengagementHeight [in]	12.000
NormalLiqLevel [in]	108.442
HighLiqLevel [in]	132.000
LowLiqLevel [in]	13.000
VesselWeight [lb]	1.71E+05
VesselWallThickness [in]	2.7033



Summary of Plant Unit Design Information			
300 MMSCFD Facility			
V2	Name	Value	
	Delta P [psi]	270	
	Cv	34.45313	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S3.Out	/S9.In
	Connected Port		
	VapFrac	0.00	0.26
	T [F]	-97.7	-135.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	7577.910	7577.910
	MassFlow [lb/h]	189504.630	189504.630
	VolumeFlow [ft3/s]	1.885	8.188
	StdLiqVolumeFlow [ft3/s]	2.230	2.230
	StdGasVolumeFlow [MMSCFD]	69.016	69.016
	Properties (Alt+R)		
	Energy [Btu/hr]	-10440000	-10440000
	H [Btu/lbmol]	-1377.700	-1377.700
	S [Btu/lbmol-F]	26.662	26.945
	MolecularWeight	25.010	25.010
	MassDensity [lb/ft3]	27.925	6.429
	Cp [Btu/lbmol-F]	18.430	15.013
	ThermalConductivity [Btu/hr-ft-F]	0.070	0.066
	Viscosity [cp]	0.101	0.086
	molarV [ft3/lbmol]	0.896	3.890
	ZFactor	0.109	0.254
	Fraction [Fraction]		
	CARBON DIOXIDE	0.027284	0.027284
	NITROGEN	0.001259	0.001259
	METHANE	0.600091	0.600091
	ETHANE	0.197252	0.197252
	PROPANE	0.140246	0.140246
	ISOBUTANE	0.012574	0.012574
	n-BUTANE	0.016974	0.016974
	n-PENTANE	0.004321	0.004321
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

300 MMSCFD Facility

Ex 1	Name		Value	**CP1**	Name		Value
	OutQ [HorsePower]		2985.80		InQ [HorsePower]		2985.80
	Delta P [psi]		270.00		Delta P [psi]		47.41
	Pressure Ratio		2.17		Pressure Ratio		1.22
	Adiabatic Efficiency [%]		81.08		Adiabatic Efficiency [%]		75.00
	Polytropic Efficiency [%]		80.00		Polytropic Efficiency [%]		75.57
	Speed [rpm]				Speed [rpm]		
	Adiabatic Head [ft]		16849.64		Adiabatic Head [ft]		7987.85
	Polytropic Head [ft]		17077.15		Polytropic Head [ft]		8048.03
	PortName	In	Out		PortName	In	Out
	UnitOperation				UnitOperation		
	Is Recycle Port				Is Recycle Port		
	Connected Stream/Unit Op	/S4.Out	/S5.In		Connected Stream/Unit Op	/S24.Out	/S12.In
	Connected Port				Connected Port		
	VapFrac	1.00	0.94		VapFrac	1.00	1.00
	T [F]	-97.7	-146.8		T [F]	23.0	52.2
	P [psia]	500.0	230.0		P [psia]	220.0	267.4
	MoleFlow [lbmole/h]	25361.710	25361.710		MoleFlow [lbmole/h]	31503.750	31503.750
	MassFlow [lb/h]	432733.240	432733.240		MassFlow [lb/h]	555081.780	555081.780
	VolumeFlow [ft3/s]	37.401	78.269		VolumeFlow [ft3/s]	195.023	170.156
	StdLiqVolumeFlow [ft3/s]	6.205	6.205		StdLiqVolumeFlow [ft3/s]	7.858	7.858
	StdGasVolumeFlow [MMSCFD]	230.980	230.980		StdGasVolumeFlow [MMSCFD]	286.920	286.920
	Properties (Alt+R)				Properties (Alt+R)		
	Energy [Btu/hr]	55550000	47960000		Energy [Btu/hr]	117200000	124800000
	H [Btu/lbmol]	2190.800	1891.200		H [Btu/lbmol]	3720.800	3962.000
	S [Btu/lbmol-F]	34.213	34.438		S [Btu/lbmol-F]	39.349	39.467
	MolecularWeight	17.060	17.060		MolecularWeight	17.620	17.620
	MassDensity [lb/ft3]	3.214	1.536		MassDensity [lb/ft3]	0.791	0.906
	Cp [Btu/lbmol-F]	13.672	10.476		Cp [Btu/lbmol-F]	9.312	9.498
	ThermalConductivity [Btu/hr-ft-F]	0.016	0.017		ThermalConductivity [Btu/hr-ft-F]	0.018	0.020
	Viscosity [cp]	0.009	0.009		Viscosity [cp]	0.010	0.011
	molarV [ft3/lbmol]	5.309	11.110		molarV [ft3/lbmol]	22.286	19.444
	ZFactor	0.685	0.761		ZFactor	0.946	0.946
	Fraction [Fraction]				Fraction [Fraction]		
	CARBON DIOXIDE	0.011330	0.011330		CARBON DIOXIDE	0.015684	0.015684
	NITROGEN	0.007417	0.007417		NITROGEN	0.006273	0.006273
	METHANE	0.942855	0.942855		METHANE	0.903379	0.903379
	ETHANE	0.033277	0.033277		ETHANE	0.073527	0.073527
	PROPANE	0.004852	0.004852		PROPANE	0.001126	0.001126
	ISOBUTANE	0.000139	0.000139		ISOBUTANE	0.000007	0.000007
	n-BUTANE	0.000123	0.000123		n-BUTANE	0.000004	0.000004
	n-PENTANE	0.000008	0.000008		n-PENTANE	0.000000	0.000000
	WATER	0.000000	0.000000		WATER	0.000000	0.000000

Summary of Plant Unit Design Information

300 MMSCFD Facility

T1	Condenser	No		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED	overheadFeed	Lower_Feed	
	Stage	1	8	
	Connected Obj	/S5.Out	/S23.Out	
	Details			
	VapFrac	0.9425	0.2616	
	T [F]	-146.8	-135.8	
	P [psia]	230.0	230.0	
	MoleFlow [lbmole/h]	25361.710	7577.913	
	MassFlow [lb/h]	432733.242	189504.629	
	VolumeFlow [ft3/s]	78.269	8.188	
	StdLiqVolumeFlow [ft3/s]	6.205	2.230	
	StdGasVolumeFlow [MMSCFD]	230.983	69.016	
	Molar Composition			
	CARBON DIOXIDE	0.011330	0.027284	
	NITROGEN	0.007417	0.001259	
	METHANE	0.942855	0.600091	
	ETHANE	0.033277	0.197252	
	PROPANE	0.004852	0.140246	
	ISOBUTANE	0.000139	0.012574	
	n-BUTANE	0.000123	0.016974	
	n-PENTANE	0.000008	0.004321	
	WATER	0.000000	0.000000	
	DRAW	overheadV	reboilerL	
	Stage	1	20	
	Type	VapourDraw	LiquidDraw	
	Connected Obj	/S6.In	/S7.In	
	Details			
	VapFrac	1.0000	0.0000	
	T [F]	-116.8	125.6	
	P [psia]	225.0	230.0	
	MoleFlow [lbmole/h]	31503.633	1435.990	
	MassFlow [lb/h]	555076.601	67161.270	
	VolumeFlow [ft3/s]	120.305	0.639	
	StdLiqVolumeFlow [ft3/s]	7.858	0.577	
	StdGasVolumeFlow [MMSCFD]	286.921	13.078	
	reboilerQ (Btu/hr)	**39446236.2**		

Section	Section_1	Section_2	Section_3
Start	1	2	8
End	1	7	19
internalType	Packed	Packed	Packed
Design Variables			
PackedDesignBasis	**FLOODFACTOR**	**FLOODFACTOR**	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000	0.8000	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**	**0.5000**	**0.5000**
PackingHoldupMethod	**ESG**	**ESG**	**ESG**
SystemFactor [Fraction]	1.00	1.00	1.00
PackingName	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**
Fp	27.00	27.00	27.00
PackingAreaperVol [ft2/f3]	34.32	34.32	34.32
PackingType	RP	RP	RP
PackingLengthperStage [ft]	**1.500**	**1.500**	**1.500**
SectionAreaFactor [Fraction]	0.8000	0.8000	0.8000
Calculated Variables			
TrayDiameter [ft]	10.000	6.500	8.500
TotalTrayArea [ft2]	78.54	33.18	56.75
PackingLengthperSection [ft]	1.500	9.000	18.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information			
300 MMSCFD Facility			
V3	Name	Value	
	Delta P [psi]	25	
	Cv	39.23569	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S7.Out	/S8.In
	Connected Port		
	VapFrac	0.00	0.05
	T [F]	125.6	116.7
	P [psia]	230.0	205.0
	MoleFlow [lbmole/h]	1435.990	1435.990
	MassFlow [lb/h]	67161.270	67161.270
	VolumeFlow [ft3/s]	0.639	1.084
	StdLiqVolumeFlow [ft3/s]	0.577	0.577
	StdGasVolumeFlow [MMSCFD]	13.078	13.078
	Properties (Alt+R)		
	Energy [Btu/hr]	1247000.000	1247000.000
	H [Btu/lbmol]	868.200	868.200
	S [Btu/lbmol-F]	34.117	34.134
	MolecularWeight	46.770	46.770
	MassDensity [lb/ft3]	29.209	17.215
	Cp [Btu/lbmol-F]	35.358	33.569
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.080	0.078
	molarV [ft3/lbmol]	1.601	2.717
	ZFactor	0.058	0.089
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.015555	0.015555
	PROPANE	0.801162	0.801162
	ISOBUTANE	0.068671	0.068671
	n-BUTANE	0.091674	0.091674
	n-PENTANE	0.022938	0.022938
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

300 MMSCFD Facility

T2	Condenser	Yes			
	Reboiler	Yes			
	# Ideal Stages	20	Includes Condenser and Reboiler		
	Total stages = 20				
	FEED				
	Stage	2			
	Connected Obj	/S8.Out			
	Details				
	VapFrac	0.0532			
	T [F]	116.7			
	P [psia]	205.0			
	MoleFlow [lbmole/h]	1435.990			
	MassFlow [lb/h]	67161.270			
	VolumeFlow [ft3/s]	1.084			
	StdLiqVolumeFlow [ft3/s]	0.577			
	StdGasVolumeFlow [MMSCFD]	13.078			
	Molar Composition				
	CARBON DIOXIDE	0.000000			
	NITROGEN	0.000000			
	METHANE	0.000000			
	ETHANE	0.015555			
	PROPANE	0.801162			
	ISOBUTANE	0.068671			
	n-BUTANE	0.091674			
	n-PENTANE	0.022938			
	WATER	0.000000			
	DRAW	condenserL	condenserV	reboilerL	
	Stage	1	1	20	
	Type	LiquidDraw	VapourDraw	LiquidDraw	
	Connected Obj		/C3.In	/C4+.In	
	Details				
	VapFrac	0.0000	1.0000	0.0000	
	T [F]	105.9	105.9	199.5	
	P [psia]	200.0	200.0	205.0	
	MoleFlow [lbmole/h]	0.000	1188.823	247.167	
	MassFlow [lb/h]	0.000	52434.528	14726.742	
	VolumeFlow [ft3/s]	0.000	7.664	0.137	
	StdLiqVolumeFlow [ft3/s]	0.000	0.464	0.113	
	StdGasVolumeFlow [MMSCFD]	0.000	10.827	2.251	
	ENERGY	condenserQ		reboilerQ	
	Stage	1		20	
	Type	EnergyOut		EnergyIn	
	Connected Obj	/Q4.In		/Q3.Out	
	Value [Btu/hr]	19696133.4		26603971.9	

Section	Section_1
Start	2
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[2in] Pall Rings (M)**
Fp	27.00
PackingAreaperVol [ft2/f3]	34.32
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	7.500
TotalTrayArea [ft2]	44.18
PackingLengthperSection [ft]	27.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information			
300 MMSCFD Facility			
P1	Name	Value	
	InQ [HorsePower]	3.34635	
	Delta P [psi]	70	
	Pressure Ratio	1.341	
	Efficiency [%]	75	
	Speed [rpm]		
	Head [ft]	337.44	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/C4+.Out	/C4+_To_SGas.In
	Connected Port		
	VapFrac	0.00	0.00
	T [F]	199.5	200.8
	P [psia]	205.0	275.0
	MoleFlow [lbmole/h]	247.170	247.170
	MassFlow [lb/h]	14726.740	14726.740
	VolumeFlow [ft3/s]	0.137	0.136
	StdLiqVolumeFlow [ft3/s]	0.113	0.113
	StdGasVolumeFlow [MMSCFD]	2.251	2.251
	Properties (Alt+R)		
	Energy [Btu/hr]	815298.060	823812.654
	H [Btu/lbmol]	3299.125	3333.580
	S [Btu/lbmol-F]	34.731	34.744
	MolecularWeight	59.582	59.582
	MassDensity [lb/ft3]	29.872	29.989
	Cp [Btu/lbmol-F]	45.297	44.757
	ThermalConductivity [Btu/hr-ft-F]	0.046	0.047
	Viscosity [cp]	0.087	0.088
	molarV [ft3/lbmol]	1.995	1.987
	ZFactor	0.058	0.077
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.000000	0.000000
	PROPANE	0.027020	0.027020
	ISOBUTANE	0.350870	0.350870
	n-BUTANE	0.491010	0.491010
	n-PENTANE	0.131100	0.131100
	WATER	0.000000	0.000000

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Appendix E: Fuel Price Forecasts

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Appendix E: Fuel Price Forecasts

In this report, it is assumed that fuel prices in Alaska during the study period (i.e., the first 15 years of pipeline operation) will be related to fuel prices in the Lower 48. Natural gas prices in Alaska are derived from the Lower 48 natural gas price forecast for Henry Hub (Erath, LA), adjusted by tariff differences in the delivery of North Slope gas to Alaska versus to Henry Hub. The subsequent sections describe the development of the Lower 48 fuel price forecasts, natural gas pipeline tariff assumptions, and resulting fuel prices in Alaska under both the Alberta and Valdez pipeline scenarios.

1 Lower 48 Fuel Prices

Fuel price forecasts used in this report were developed with the National Energy Modeling System (NEMS) and subsequent adjustments as needed to reflect commencement of Alaska pipeline operation at the beginning of 2019. NEMS is a computer-based, energy-economy model developed by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). It is designed to represent the important interactions of supply and demand in U.S. energy markets. Primary assumptions include the estimated size of economically recoverable fossil fuel reserves, and changes in world energy supply and demand. The projections reflect known technological and demographic trends under business-as-usual circumstances.

NEMS is used by EIA to develop their annual energy projections as published in the *Annual Energy Outlook (AEO)*. The AEO forecasts incorporate laws and regulations in effect at the time of the NEMS runs, and do not incorporate pending or proposed legislation, regulations, and standards. As such, the March 2009 publication of *AEO2009* does not reflect effects of the stimulus package (i.e., American Recovery and Reinvestment Act, ARRA), which was enacted less than a month prior to publication of the *AEO2009*. However, in April 2009, the EIA released an update of the *AEO2009* "reference case" to reflect the enactment of the ARRA. This revision does not include other scenarios published in *AEO2009*—in particular, the cases for high and low fuel prices, and the "no Alaska" case under which there is no future natural gas pipeline between the North Slope and the Lower 48.

1.1 Natural Gas Prices

For fuel price forecasts under the Alberta pipeline scenario, SAIC conducted a NEMS run with the same inputs as applied for the revised *AEO2009* "reference case" with incorporation of ARRA. Using these assumptions, the economic analyses within NEMS calculate commencement of Alaskan pipeline operation in 2022, and a subsequent dip in natural gas prices to reflect market response to an increased supply. Over the following years, prices increase to previous levels as demand and supply re-establish the balance that was in place prior to Alaskan pipeline operation.

For the purposes of this report, the NEMS "reference case" forecast of natural gas prices in 2019 and subsequent years were adjusted to reflect a similar dip representing pipeline commencement in late-2018/ early-2019 rather than mid 2022. This adjusted NEMS "reference case" with ARRA is the "mid-price" natural gas forecast under the Alberta pipeline scenario in this report.

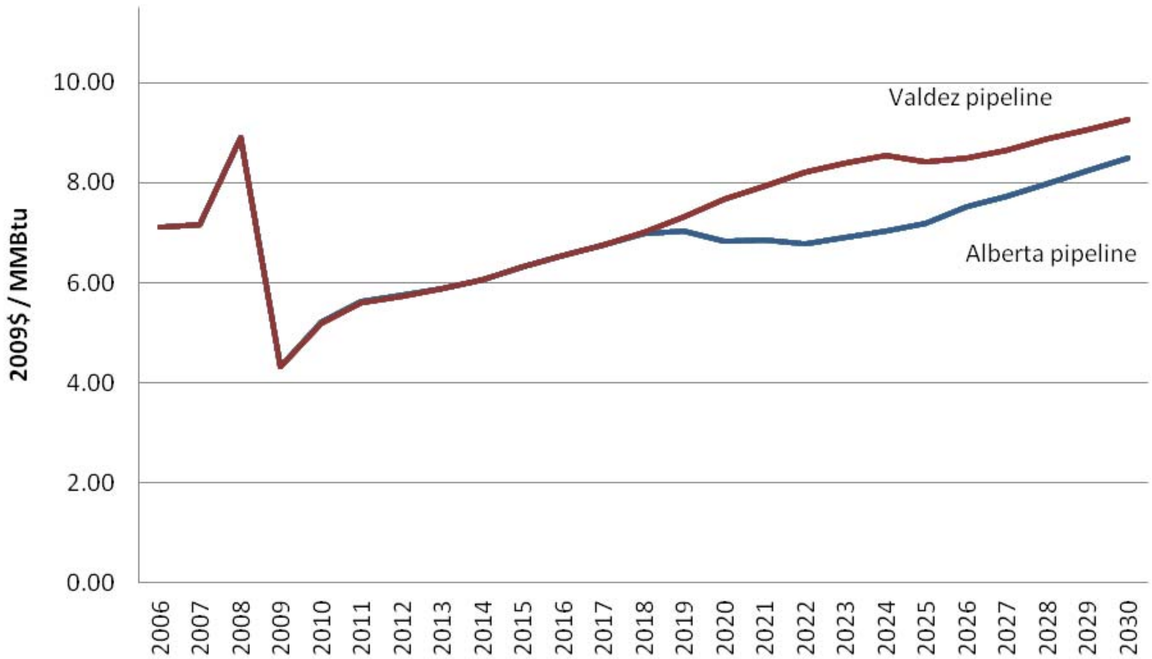
A high fuel price scenario was developed based on another NEMS run with the similar inputs as applied for the EIA "high price" scenario, but with incorporation of ARRA. Under this scenario, the NEMS calculates that the Alaska pipeline will be operational in 2020. To roughly reflect commencement of pipeline operation in 2019, modeled natural gas prices in 2019 were reduced by one percent, which effectively makes the 2019 price the same as in 2020, and prices in subsequent years were retained unaltered.

The NEMS input parameters for simulation of the EIA low price scenario were not known, thus the low natural gas forecast is based on reducing the mid-price forecast by the difference between the high price and mid-price forecasts. Figure 1 shows the low, mid, and high natural gas price forecasts for Henry Hub that were used in this report to project natural gas prices in Alaska under the Alberta pipeline scenario.

Figure 1. Forecast natural gas prices at Henry Hub under the Alberta pipeline scenario

For fuel price forecasts under the Valdez pipeline scenario, a NEMS run was conducted with the same inputs as for the AEO2009 "reference case" with ARRA, except with a single change to disallow commencement of Alaska pipeline operations. This run was used as the mid-price forecast under the Valdez pipeline scenario. High price and low natural gas price forecasts were developed by manually applying the relationship between the AEO2009 "reference case" and "low price" scenarios, and the "reference case" and "high price" scenarios (as published in March 2009, without ARRA) to the mid-price forecast (with ARRA and with adjustment to reflect pipeline operation in 2019). The natural gas mid-price forecasts for Henry Hub under both the Valdez and Alberta pipeline scenarios are shown in Figure 2.

Figure 2. Henry Hub natural gas mid-price forecasts under the Alberta and Valdez pipeline scenarios



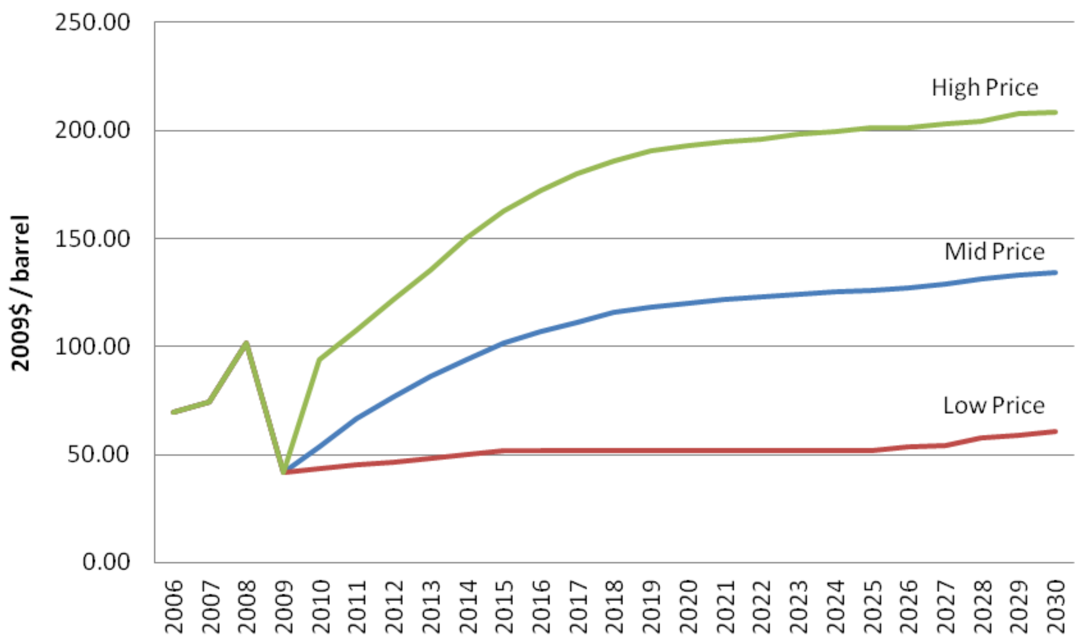
1.2 Petroleum Liquid Fuel Prices

In the NEMS model, natural gas prices are based on the average price of crude oil after taking into account many additional economic and supply considerations. While the NEMS model indicates that the Alaska natural gas pipeline will cause a temporary dip in natural gas prices, no such effect is seen on the price of crude oil and other petroleum products, including jet fuel and diesel. Thus, no adjustments were made to NEMS "reference case" forecasts for liquid fuels, and these are the same as the mid-price forecasts for liquid fuels in this report.

For liquid fuel prices, the AEO2009 (without ARRA) "low price" forecast appears to set price floors of approximately $46.45/bbl for imported crude, and $50.28/bbl for low sulfur light crude (i.e., the average prices from 2024 to 2030, each with a standard deviation of 0.04). The low price crude forecast in this study was developed based on reducing the mid-price forecast by the difference between the high price and mid-price forecast until similar floors were reached. For the high price forecast of crude oil and other petroleum products, the high price NEMS run was retained unaltered.

Liquid fuels price forecasts under the AEO2009 "reference case" and "no Alaska pipeline" case were not significantly different; hence, the same liquid fuel price forecasts were used for the Valdez pipeline scenario as for the Alberta pipeline scenario. Figure 3 shows low, mid, and high forecasts for Lower 48 low sulfur crude oil prices.

Figure 3. Forecast average Lower 48 low sulfur crude oil prices



2 Alaska Natural Gas Prices

Alaskan natural gas prices at primary delivery points were calculated based on the forecasts of Lower 48 natural gas prices at Henry Hub (described above), and estimates of the difference in transportation costs for pipeline natural gas in Alaska versus Henry Hub. Primary Alaskan delivery points are defined as at the main pipeline take-off points, and at the end of a spur line to Southcentral Alaska. The tariff estimates, and average natural gas prices during the periods analyzed in this report (i.e., Years 1 to 5 and Years 10 to 15 of Alaska pipeline operation) are described below.

2.1 Tariff Estimates

TransCanada provided regional average tariff estimates for the Alaska pipeline as nominal, levelized values for 2018 to 2030. Under the Alberta pipeline scenario, a single weighted average estimate was provided for all Alaska destinations. Under the Valdez pipeline scenario, two tariff estimates were provided, one for delivery to the pipeline terminal in Valdez, and the other for the single weighted average of all other in-state take-off points. The TransCanada tariff estimates were given a ± 25% range to represent high and low tariff estimates. The tariff between Alberta and the Lower 48 was based on the historical difference in prices between the Alberta trading hub, AECO, and the US trading, Henry Hub—no range was applied to this tariff.

The route of a spur line to Southcentral and its take-off point from the main Alaska pipeline has not yet been determined. However, for the purposes of developing spur line tariff estimates for this report, it is assumed that under the Alberta pipeline scenario, the spur could extend from Fairbanks or Delta Junction to Beluga. Under the Valdez pipeline scenario, the spur is assumed to extend from Glennallen to Beluga. A range for the spur line tariff was set to encompass the range reflected in a review of estimates developed by several different sources including: Black & Veatch, Paragon Engineering Services, Inc., Michael Baker Jr., Inc., and ANGDA. This range represents the cost of service for varying sizes of pipeline and various throughputs. The mid-price estimate for the spur line tariff is based on spur line throughput that approximates future Southcentral natural gas demand, rather than the mid-point of the range.

Table 1 displays low, mid, and high estimates of tariff prices in mid-2009$ for various segments of the main pipeline to Henry Hub, and for the spur line to Southcentral. Note that these preliminary estimates will change with filing of the open season plan.

Table 1. Low, Mid, and High Pipeline Tariff Estimates, 2009$, MMBtu

	Low	Mid	High
Alberta Route			
North Slope to Canadian border	$1.13	$1.50	$1.88
Canadian Border to AECO	$0.84	$1.12	$1.40
AECO to Henry Hub	$0.75	$0.75	$0.75
In-State Delivery Toll	$0.93	$1.25	$1.56
Spur Line to Southcentral	$1.00	$2.25	$4.00
Valdez Route			
In-State Delivery Toll	$0.93	$1.25	$1.56
LNG Export in Valdez	$1.40	$1.87	$2.34
AECO to Henry Hub	$0.75	$0.75	$0.75
Spur Line to Southcentral	$0.60	$1.40	$2.50

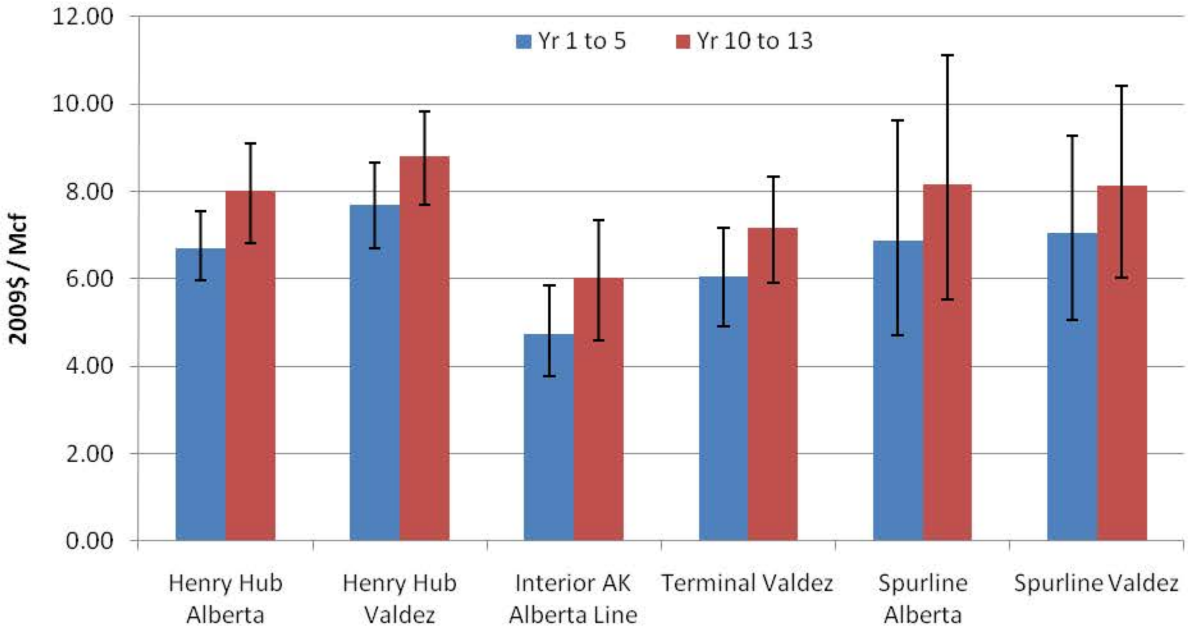
2.2 Average Study-Period Prices

The periods of interest for this study are the first 5 years of pipeline operations (i.e., 2019 to 2023), and years 10 to 15 of pipeline operation (i.e., 2028 to 2032). Average prices during these periods were calculated from the forecast of natural gas prices in the Lower 48, as described above. Note that this forecast extends to 2030; hence, the average price estimate for Years 10 to 15 of pipeline operation is based only on the first three years of this period.

For natural gas prices in Alaska, the total tariff from North Slope to Henry Hub was subtracted from the forecast Henry Hub price to determine the wellhead value of North Slope gas. The addition of tariffs from North Slope to Alaskan locations (Table 1) was then added to the wellhead price to develop an Alaskan price forecast.

Figure 4 displays the average natural gas prices applied in this study at various locations during the two periods of interest. The error bars in this graph represent uncertainty in gas prices, as indicated by the low and high price forecasts, and uncertainty in transportation costs (i.e., tariffs) as indicated by low and high tariff price estimates.

Figure 4. Average forecast natural gas prices under Alberta and Valdez pipeline scenarios, during Years 1 to 5 and Years 10 to 13 of pipeline operation



Appendix F: Industrial Product Price Forecasts

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Appendix F: Industrial Product Price Forecasts

Product markets for the modeled industries were assessed to determine preferred markets based on both market prices and shipping distances. Candidate LNG markets include the North American West Coast (e.g., British Columbia, Baja Mexico), Japan, and Korea. In recent years, LNG has sold at a significant premium in Japan and Korea, making these markets preferred for this product. LNG shipping costs from Alaska to Japan are roughly equivalent to, or less than other suppliers competing for the Japanese market.

For Alaskan fertilizer, the US west coast and Asia, are good candidates for future markets, sales to Korea were modeled in the NPV analysis. For GTL products, the US west coast and Alaska are good candidates for future markets. GTL jet fuel sales within Alaska were modeled in the NPV analysis recognizing that the lower shipping costs associated with an in-state market would be preferable. However, ultimately, for all industrial products, the market of choice will be contingent on the balance of local supply and demand.

Forecast prices for LNG, ammonia/fertilizer, and GTL jet fuel are described below.

1 LNG Price Forecast

Global LNG trade has traditionally been dominated by East Asian importers, particularly Japan and South Korea. East Asian importers, including China and Taiwan, accounted for 45% of the world's contracted LNG or about 124.3 million tonnes per annum (MTA) in 2009 (6.1 trillion cubic feet). Japan and South Korea are mature markets for LNG. According to EIA's International Energy Outlook 2009, Japanese natural gas consumption is projected to grow modestly from 3.3 trillion cubic feet (Tcf) in 2010 to 3.7 Tcf in 2030. Korea's consumption is projected to grow from 1.3 Tcf in 2010 to 1.7 Tcf in 2030.

Japanese and Korean LNG prices are typically higher than those in the United States and Europe. The differentials are due to the formulae for calculating the LNG price: in the U.S. and Europe, the LNG price is typically linked to the pre-burner price of alternative fuels (heating oil, heavy fuel oil, coal, etc.) while in Japan and Korea, LNG prices are typically linked to the price of crude oil. East Asian buyers also pay higher rates due to an "Asian Premium," which is attributed to the lack of indigenous sources of natural gas supply and the security-conscious, long-term nature of most East Asian energy contracts. In energy equivalent terms, the Asian Premium on LNG has been found to be greater than the Asian Premium on crude oil.

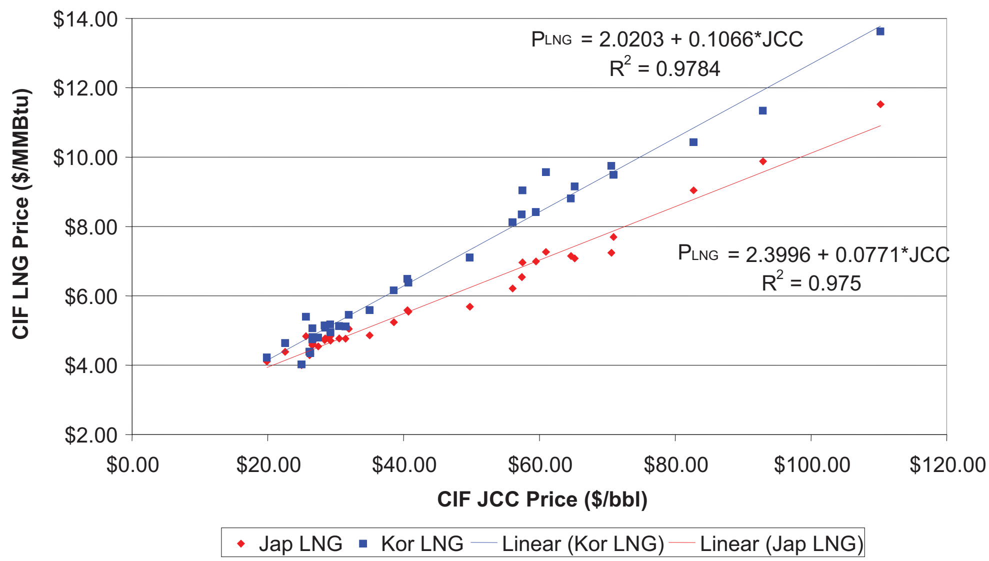
Different LNG contracts employ different pricing formulae, which are rarely disclosed, but it is widely known that Japanese and Korean contracts are linked to the "Japanese Crude Cocktail" (JCC) price, which is a weighted-average of all crude import prices reported by the Japanese Customs office. East Asian LNG contracts also typically include "S-curves," which act as shock absorbers to dampen the effect of large upward or downward swings in the price of crude oil. A simple example of an East Asian LNG pricing formula is shown below:

$P_{LNG} = a + b*JCC - S$

Here, P_{LNG} is the LNG price represented in \$/MMBtu and JCC is the Japanese Crude Cocktail CIF price represented in \$/bbl. The constant "a" is a price floor that prevents the LNG price from falling below a certain level, so LNG exporters can guarantee recovery of capital costs. The coefficient "b" is greater than 0 and less than 1 and provides the link to crude oil prices. The "S" factor is a constant that reduces the LNG price but is only active when crude oil prices move outside of a preset range. Typically, this preset range covers all upside oil price eventualities that seem likely to occur when the contract is negotiated. The precise values of a, b, and S are negotiated between buyers and sellers and can change depending on the price environment and whether the market favors producers or consumers.

East Asian LNG pricing formulae can be surmised from observing the relationship between LNG prices and the JCC price. Figure 1 plots Japanese and Korean LNG prices against the Japanese Crude Cocktail price from the first quarter of 2000 to the second quarter of 2008. Linear trend-lines are fitted and the inferred pricing formula is shown for each data set. The high R-squared values show that these relationships are highly significant.

Figure 1. Japanese and Korean CIF LNG Prices versus CIF Japanese Crude Cocktail (JCC) Price, 2000 - 2008



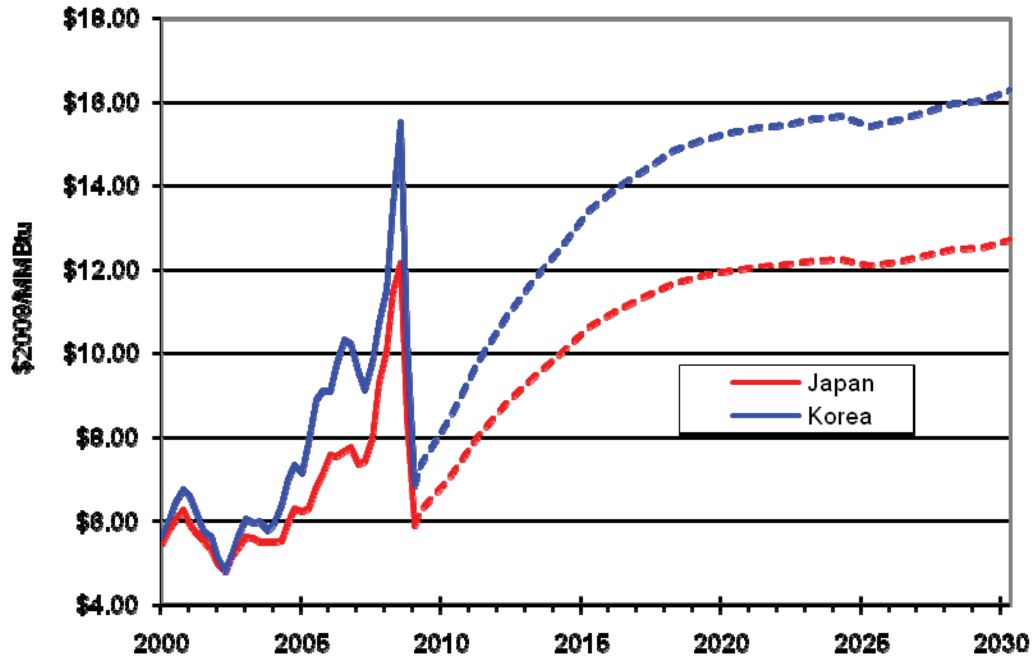
Source: SAIC, derived from Japanese Customs office and Korean Customs office data

The above figure shows that Korean LNG prices are typically higher than Japanese LNG prices at every crude price level and that that the differential increases as the price of crude increases. This implies that the differential is likely not due to different shipping and insurance costs to Korea vs. Japan. The differential is more likely due to Korean pricing formulas that are tied more strongly to crude oil or, potentially, to a greater portion of LNG purchases on the spot market.

Future LNG prices in East Asia can be extrapolated using the inferred pricing formulae from the above figure and forecasts for crude oil prices from Energy Information Administration's Annual Energy Outlook. This forecast method assumes that the LNG pricing formulae that have prevailed in East Asia from 2000 to 2008 will continue to determine future LNG prices. This assumes that LNG contracts will not be significantly renegotiated and that the Japanese-Korean differential continues to be a factor.

Figure 2 shows actual Japanese and Korean CIF LNG prices from the first quarter of 2000 through the second quarter of 2008 and estimated LNG prices based on actual crude prices from the third quarter of 2008 through the first quarter of 2009. Beyond the first quarter of 2009 and through 2030, LNG prices are forecast based on the EIA's projections of future crude prices. All prices are shown in real dollars as of June 2009.

Figure 2. Historical and Forecast LNG Prices in Japan and Korea



Source: SAIC, derived from Japanese Customs office, Korean Customs office, and EIA data

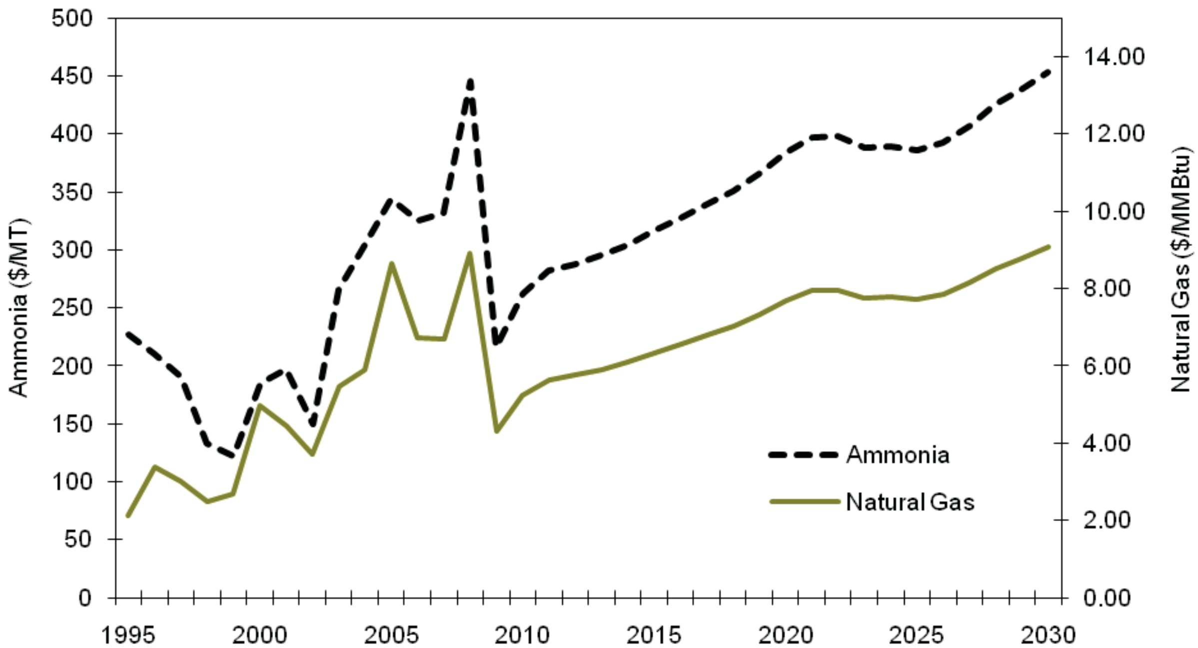
The figure above shows that East Asian LNG prices peaked in the third quarter of 2008 at more than $12 per MMBtu in Japan and more than $15 per MMBtu in Korea. Estimated average LNG prices fell sharply along with crude prices in the fourth quarter of 2008, reaching lows in the first quarter of 2009 of below $6 per MMBtu in Japan and below $7 per MMBtu in Korea. Based on EIA's reference case forecast for crude oil prices, Japanese LNG price are projected to grow by 3.43% per year from 2009 to 2030 and Korean LNG prices are expected to grow by 3.85% per year over the same period. For the purposes of the NPV analysis of LNG facilities conducted in this report, average forecast prices between 2019 and 2030 were applied.

These forecasts assume that the Korean LNG prices continue to be higher than Japanese LNG prices and that the Asian Premium persists over the forecast period. In reality, contract renegotiations may narrow the gap between Korean and Japanese LNG prices and the emergence of an LNG spot market may narrow the gap between East Asian LNG prices and those in the United States and Europe. The forecasted prices in this analysis should serve as one potential scenario for how East Asian LNG prices will evolve. Other price scenarios, such as a convergence of LNG prices across the Atlantic and Pacific basins, should also be considered.

2 Ammonia/ Urea Price Forecast

Forecast product prices for the fertilizer industry was modeled based on the historical relationship with natural gas. The low. mid, and high forecast prices for natural gas were used to project low, mid, and high ammonia prices based on the rough relationship of the price of one metric ton (MT) equal to 50 times the price of natural gas per MMBtu. Historical and projected natural gas and ammonia prices are shown in Figure 3.

Figure 3. Historical and Forecast Ammonia and Natural Gas Prices



Source: SAIC, derived from Japanese Customs office, Korean Customs office, and EIA data

For the purposes of the NPV analysis of an Alaskan fertilizer industry, average projected feedstock and product prices between 2019 and 2030 were applied.

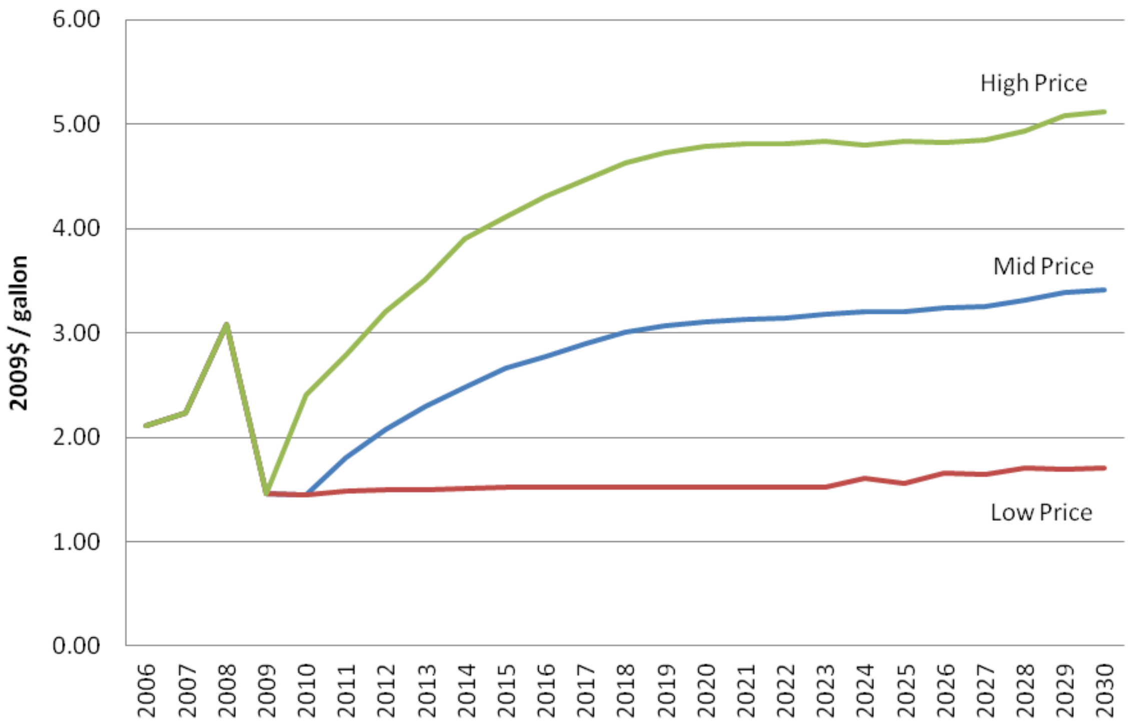
3 Jet Fuel Price Forecast

The modeled product for the GTL complex assessed in this study is jet fuel. The primary market for the GTL product is assumed to be Alaska. It is further assumed that the price of liquid petroleum products in Alaska is linked to the Lower 48. The jet fuel forecast applied in this study was developed using the National Energy Modeling System (NEMS), which forecasts a variety of petroleum-based fuels. The scenarios conducted were the same as those described in Appendix E, Fuel Price Forescasts.

As stated in Appendix E, for liquid fuel prices, the AEO2009 (without ARRA) "low price" forecast appears to set price floors of approximately $46.45/bbl for imported crude, and $50.28/bbl for low sulfur light crude (i.e., the average prices from 2024 to 2030, each with a standard deviation of 0.04). The low price crude forecast in this study was developed based on reducing the mid price forecast by the difference between the high price and mid price forecast until similar floors were reached. For the high price forecast of crude oil and other petroleum products, the high price NEMS run was retained unaltered.

Liquid fuels price forecasts under the AEO2009 "reference case" and "no Alaska pipeline" case were not significantly different, hence the same liquid fuel price forecasts were used for the Valdez pipeline scenario as for the Alberta pipeline scenario. Figure 4 shows low, mid, and high forecasts for Lower 48 jet fuel prices.

Figure 4. Projected Price of Jet Fuel in the Lower 48



Source: SAIC

Jet fuel price differentials between the Lower 48 and Alaska are assumed to be entirely due to transportation costs, allowing direct use of the average projected Lower 48 price between 2019 and 2030 for the purposes of the NPV analyses of a GTL complex conducted in this report.

Appendix B

Exhibit A
In-State Gas Demand Study Submission Letter

Appendix B
Exhibit A

TransCanada
In business to deliver

TransCanada PipeLines Limited
450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1

tel 403.920.2035
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January 12, 2010

Alaska Department of Natural Resources
550 W. 7th Avenue, Suite 1400
Anchorage, Alaska 99501

Attn: Thomas E. Irwin
Commissioner of Natural Resources;

Attn: Patrick S. Galvin
Commissioner of Revenue

Dear Sirs:

Re: State of Alaska Approval of In-State Gas Demand Study (the "Study")

TransCanada Alaska Company, LLC ("TransCanada") has completed a study of gas consumption needs and prospective points of delivery within the State of Alaska which is being delivered to you concurrently with this letter. The Study has been prepared in accordance with the Federal Energy Regulatory Commission's ("FERC") regulations for Open Seasons for Alaska Natural Gas Transportation Projects. It is TransCanada's intention to file this study on January 29, 2010 as part of the Licensee's open season package filing.

TransCanada requests written approval of the Study by the Commissioners. In order to meet the schedule for the filing of the open season package for the project, we kindly ask that you provide your written approval on or before January 22, 2010.

In conjunction with this request, and further to our previous discussion on this matter, we have attached a copy of a document confirming the State's intention to treat the Study as confidential until it is filed publicly with FERC on January 29, 2010. Please execute this document and return it to us as soon as possible

Yours truly,

TransCanada Alaska Company, LLC

Tony Palmer

DEPARTMENT OF
NATURAL RESOURCES

JAN 12 2010

COMMISSIONER'S OFFICE
ANCHORAGE

Appendix B

Exhibit B
In-State Gas Demand Study Approval Letter

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES
DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONERS

SEAN PARNELL, GOVERNOR

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January 22, 2010

Mr. Anthony (Tony) M. Palmer
Vice President Alaska Development
TransCanada PipeLines Limited
450 - 1st Street S.W.
Calgary, Alberta, T2P-5H1
Canada

RE: January 2010 In-State Gas Demand Study

Dear Mr. Palmer:

The Commissioner of Revenue and the Commissioner of Natural Resources of the State of Alaska are in receipt of the January 2010 In-State Gas Demand Study ("Study"), prepared by Northern Economics in association with the University of Alaska Institute of Social and Economic Research and the Science Applications International Corporation. Your letter indicates the Study was prepared at the request of TransCanada Alaska Company, LLC ("TC Alaska") in connection with the Federal Energy Regulatory Commission's ("FERC") regulations governing open seasons for Alaska natural gas transportation projects. As you are aware, both the U.S. Congress and FERC have recognized that Alaska's in-state natural gas consumption needs must be given important consideration in connection with the development of an Alaska natural gas pipeline project.

FERC's regulations specifically require that any prospective applicant for a certificate of public convenience and necessity for an Alaskan gas pipeline project must "conduct or adopt a study of gas consumption needs and prospective points of delivery within the State of Alaska…." 18 C.F.R. § 157.34(b) (2009). If practicable, such study must be "conducted, approved, or otherwise sanctioned by an appropriate governmental agency office or commission of the State of Alaska." *Id.*

In your January 12, 2010 letter, you request that we approve the use of the Study in TC Alaska's FERC open season notice. After due consideration, we hereby approve the use of the Study by TC Alaska and other Alaska gas pipeline sponsors as a reasonable assessment of in-state natural gas consumption needs based on the facts currently available. It is important to note that we have not independently verified and do not expressly endorse any or each of the specific projections set forth in the Study. Nor do we believe that the study necessarily provides the only reasonable assessment of in-state needs. However, the Study appears to rely on timely, comprehensive data, and a sound methodology concerning the data that form the basis of the study.

We therefore consider the study to be reasonable and useful in connection with Alaska gas pipeline open seasons at this time.

The Study correctly acknowledges the difficulty in predicting in-state gas demand in the relatively small Alaska market over a long period of time. Certain assumptions about potential industrial use of natural gas, including, for example, the continuation of existing liquefied natural gas ("LNG") exports from Cook Inlet gas supplies during the forecast period, or the construction of other large scale industrial projects, do not seem assured from our vantage point today. However, in recognition of these uncertainties, the Study takes reasonable steps to describe the broad range of potential in-state demand. In our view, it is less important to focus on any specific source of natural gas demand than on a reasonable assessment of the potential demand from any combination of sources. As a result of the Study and in light of numerous aspects of the TC Alaska pipeline project, including the number of proposed delivery points in Alaska, we conclude that the TC Alaska project would likely be capable of meeting any reasonable assessment of future in-state natural gas demands.

For the reasons discussed above, the Commissioner of Revenue and the Commissioner of Natural Resources of the State of Alaska hereby approve the Study. We appreciate TC Alaska's efforts in taking the lead on commissioning this study of in-state gas consumption needs and prospective points of delivery within the State.

Sincerely,

Thomas E. Irwin
Commissioner of Natural Resources

Patrick S. Galvin
Commissioner of Revenue

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
TransCanada Alaska Company LLC	**)**	**Docket No. PF09-11-001**
	)	

OPEN SEASON PLAN DOCUMENTS SUBMITTED IN CONNECTION WITH REQUEST FOR COMMISSION APPROVAL OF DETAILED PLAN FOR CONDUCTING AN OPEN SEASON

VOLUME III OF III
(includes Information required by 18 C.F. R. §157.34 (c))

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Counsel for TransCanada Alaska Company LLC and Alaska Pipeline Project

Date: January 29, 2010

<u>OPEN SEASON PLAN DOCUMENTS</u> <u>(submitted separately in three volumes)</u>

<u>Volume I</u>

Proposed Open Season Notice with:

Appendix A: Proposed Precedent Agreement

Exhibit A: Bid Forms for the Alaska-Canada Pipeline and Valdez Pipeline

Exhibit B: Creditworthiness

Exhibit C: Additional Shipper Conditions Precedent

Exhibit D: Illustrative Annual Negotiated Rate Calculation

<u>Volume II</u>

Appendix B: In-State Needs Study required by 18 C.F.R. § 157.34 (b)

Exhibit A: In-State Gas Demand Study Submission Letter

Exhibit B: In-State Gas Demand Study Approval Letter

<u>Volume III</u>

Appendix C: Information required by 18 C.F. R. §157.34 (c)

Item 1: Pipeline Routes

Item 2: Project Design and Capacities

Item 3: Operating Pressures

Item 4: Delivery Pressures

Item 5: In-Service Date

Item 6: Transportation and Treating Rates

Item 7: Cost of Service

Item 8: In-State Transportation Rates

Item 9: Negotiated and Other Rates

Exhibit L: Definitions

Appendix C

Information Required by 18 C.F.R. § 157.34(c)

Table of Contents

Pursuant to the requirements of 18 C.F.R. §157.34(c), additional information regarding the Alaska Pipeline Project ("APP") Open Season is provided below. Unless otherwise specified, the information provided applies to both the Alaska-Canada Pipeline and the Valdez Pipeline systems.

Item 1 - Pipeline Routes

18 C.F.R. §157.34(c)(1): The general route of the proposed project, including receipt and delivery points, and any alternative routes under consideration; delivery points must include those within the State of Alaska as determined by the In-State Study in (b) above.

__General Route__

The Alaska Pipeline Project will consist of:

- A FERC jurisdictional gas treatment plant ("GTP") near Prudhoe Bay, Alaska, which will treat North Slope gas for pipeline transportation;
- A FERC jurisdictional gas transmission pipeline from the outlet of the Point Thomson plant in Alaska to the GTP and from there, subject to shipper confirmation during the Open Season process, to either:
    - The Alaska/Canada border for onward delivery to Alberta, Canada (the "Alaska-Canada Pipeline"); or
    - Valdez, Alaska (the "Valdez Pipeline").

With the Alaska-Canada Pipeline, shippers would have the ability to deliver gas to North American markets through the Alberta Hub or other existing off-take capacity at or near the British Columbia/Alberta border. With the Valdez Pipeline, shippers would have the ability to deliver into a liquefied natural gas ("LNG") facility (to be developed by third parties), for onward delivery to global LNG markets. The Alaska-Canada Pipeline and the Valdez Pipeline are alternative proposals. Depending on customer interest as evidenced in the Open Season, APP will proceed with either the Alaska-Canada Pipeline or the Valdez Pipeline, but not both.

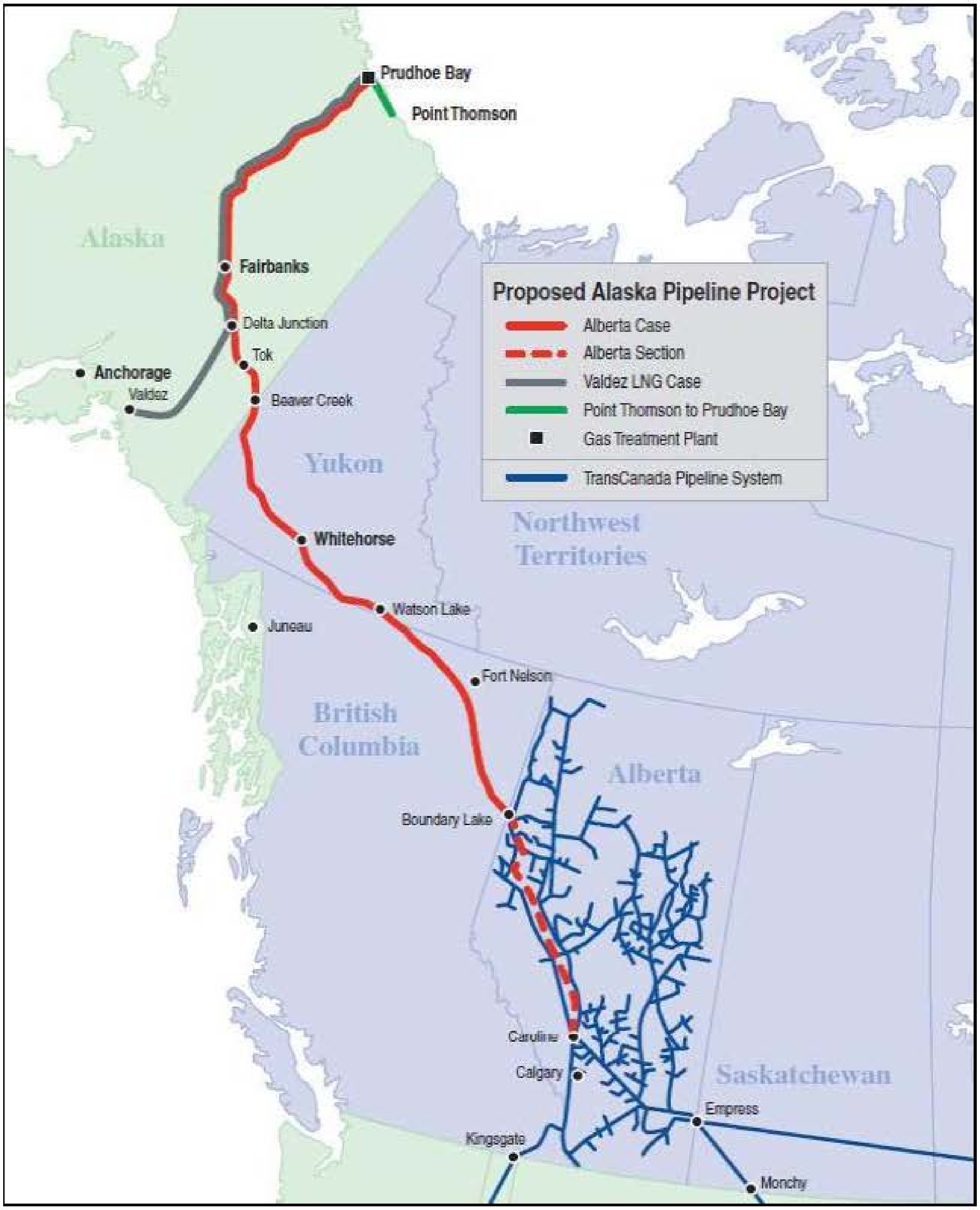
The proposed pipeline segment from the outlet of the Point Thomson plant to the inlet to the GTP will generally run parallel to (offset to the south) the future above-ground Point Thomson to Badami oil pipeline and the existing Badami to Endicott oil pipeline. As the route approaches the West Channel of the Sagavanirktok River and Prudhoe Bay facilities, the pipeline will cross the Endicott pipeline and head directly to the GTP site.

The remainder of the proposed Alaska-Canada Pipeline would extend from the outlet of the GTP past points near Fairbanks, and Delta Junction and then to the Alaska-Canada border where it would interconnect to a new pipeline that APP plans to design, permit and construct ("Canadian Pipeline"). The proposed Canadian Pipeline would head past Whitehorse, and extend to Boundary Lake, Alberta.

The remainder of the proposed Valdez Pipeline would follow a similar route from the outlet of the GTP to Delta Junction before heading to an interconection point with LNG facilities near Valdez.

These proposed general routes are shown in the Figure 1 below. Additional route maps are provided in Exhibits A to E of this Appendix C.

Figure 1: Proposed Pipeline Route



Receipt Points

Receipt points will be provided at the inlet and outlet of the GTP for North Slope Shippers seeking entry into the line. There will also be a receipt point at the inlet of the Point Thomson plant. Other tie-in and receipt points will be provided at various intervals along the pipeline route as determined by the results of the Open Season and as requested by shippers.

Delivery Points

There will be a delivery point at the inlet of the GTP for the Point Thomson pipeline segment and at either the Canadian border or Valdez, depending on which alternative route is selected. In addition, a minimum of five (5) delivery points in the State of Alaska for local demand will be provided on a firm or interruptible basis. For purposes of the Open Season, Exhibit A to the Precedent Agreement specifies the following delivery points, which were identified by the In-State Needs Study as the most likely off-take points based on expected demand.

Table 1: Potential Alaska In-State Delivery Points

Location	Alaska-Canada Pipeline Route	Valdez Pipeline Route
Livengood	√	√
Fairbanks	√	√
Parks Highway spur	√	√
Delta Junction area/Richardson Highway spur	√	√
Tok	√	n/a
Glennallen	n/a	√
Valdez	n/a	√

The final determination of the locations that will be served will depend on which alternative route is selected, the results of the Open Season and input from potential shippers. APP will make provision for delivery along the pipeline at the points finally selected through the installation of tees and blind flanges.

For information, the Northern Pipeline Act ("NPA") also requires a minimum of eight (8) off-takes in Canada in the event the Alaska-Canada Pipeline alternative is selected. In that case, the interconnected Canadian Pipeline will have, in addition to delivery to existing facilities at Boundary Lake in Canada, offtake points near Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction, Whitehorse, Teslin, and Upper Liard/Watson Lake as identified in the NPA.

Item 2 - Project Design And Capacities

18 C.F.R. §157.34(c)(2): Size and design capacity (including proposed certificate capacity at the delivery points named in (1) above to the extent that it differs from design capacity), a description of possible designs for expanded capacity beyond initial capacity, together with any estimated date when such expansions designs may be considered;

<u>**Size and Design Capacity**</u>

The proposed Project will have the size and design capacities summarized in Table 2 below.

Table 2: Proposed Size and Design Capacities

Section Of The Proposed Project	Design Parameter	Value
Point Thomson Pipeline	Pipeline diameter (inches)	32
	Pipeline grade	X65
	Pipeline length (miles)	58
	Pipeline capacity (base design – Bcf/d)	1.1
	Pipeline capacity (with max compression – Bcf/d)	1.5
	Inlet gas receipt temperature (°F)	30
	Minimum design outlet gas delivery temperature (°F)	2
GTP For The Alaska-Canada Pipeline	Processing capacity – inlet raw gas (Bcf/d)	5.3
	Processing capacity – CO_2 (Bcf/d)	0.6
	Delivery capacity – outlet sales gas to pipeline (Bcf/d)	4.5
	Inlet gas average receipt temperature (°F)	60
	Outlet gas delivery temperature (°F)	< 30
	Outlet CO_2 temperature (°F)	100+

Table 2: Proposed Size and Design Capacities (Continued)

Section Of The Proposed Project	Design Parameter	Value
GTP For The Valdez Pipeline	Processing capacity – inlet raw gas (Bcf/d)	3.6
	Processing capacity – CO_2 (Bcf/d)	0.44
	Delivery capacity – outlet sales gas to pipeline (Bcf/d)	3.0
	Inlet gas average receipt temperature (°F)	60
	Outlet gas delivery temperature (°F)	< 30
	Outlet CO_2 temperature (°F)	100+
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Pipeline diameter (inches)	48
	Pipeline grade	X80
	Pipeline length – Alaska (miles)	734
	Pipe capacity (base design – Bcf/d)	4.5
	Pipe capacity (with max compression – Bcf/d)	5.9
	Inlet gas receipt temperature (°F)	< 30
	Minimum design outlet gas delivery temperature (°F)	26
	Outlet gas delivery point capacity – Livengood (MMcf/d)	No less than the In-State Needs Study value of 9
	Outlet gas delivery point capacity – Fairbanks (MMcf/d)	No less than the In-State Needs Study value of 55
	Outlet gas delivery point capacity – Parks Highway Spur (MMcf/d)	Included in Fairbanks capacity

Table 2: Proposed Size and Design Capacities (Continued)

Section Of The Proposed Project	Design Parameter	Value
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Outlet gas delivery point capacity – Delta Junction/Richardson Highway Spur (MMcf/d)	No less than the In-State Needs Study value of 272
	Outlet gas delivery point capacity – Tok (MMcf/d)	No less than the In-State Needs Study value of 0.4
	Outlet gas delivery point capacity – Alaska-Canada Border (Bcf/d)	4.370 – 4.570 (seasonal capacity)
Pipeline Segment Downstream Of The GTP - Valdez Pipeline	Pipeline diameter (inches)	48
	Pipeline grade	X80
	Pipeline length – Alaska (miles)	803
	Pipe capacity (base design – Bcf/d)	3.0
	Pipe capacity (with max compression – Bcf/d)	As per future requirements
	Inlet gas receipt temperature (°F)	< 30
	Minimum Design outlet gas delivery temperature (°F)	26
	Outlet gas delivery point capacity - Livengood (MMcf/d)	No less than the In-State Needs Study value of 9
	Outlet gas delivery point capacity - Fairbanks (MMcf/d)	No less than the In-State Needs Study value of 55
	Outlet gas delivery point capacity - Delta Junction Area/Richardson Highway Spur (MMcf/d)	No less than the In-State Needs Study value of 1.4

Table 2: Proposed Size and Design Capacities (Continued)

Section Of The Proposed Project	Design Parameter	Value
Pipeline Segment Downstream Of The GTP - Valdez Pipeline	Outlet gas delivery point capacity – Parks Highway Spur (MMcf/d)	Included in Fairbanks capacity
	Outlet gas delivery point capacity - Glennallen (MMcf/d)	No less than the In-State Needs Study value of 270
	Outlet gas delivery point capacity – Valdez (MMcf/d)	No less than the In-State Needs Study value of 7
	Outlet gas delivery point capacity - Valdez LNG Terminal (Bcf/d)	2.775

Designs for Initial and Possible Expanded Capacity

1. The gas transmission pipeline segment between the outlet of the Point Thomson plant and the inlet of the GTP consists of a single 32-inch pipeline traversing a distance of approximately 58 miles with a base case capacity of 1.1 Bcf/d and a maximum operating pressure of 1130 psig. A system capacity of 1.5 Bcf/d could be accommodated by designing to a higher maximum operating pressure. The pipeline system will be designed to maintain flowing gas temperatures below 32°F. Maintaining these gas temperatures recognizes the presence of permafrost soils along the route and will support stable operation from a geotechnical perspective. Base case design assumes that gas will be delivered to the GTP at 670 psig.

2. The gas transmission pipeline segment between the outlet of the GTP and Boundary Lake (Alaska-Canada Pipeline and Canadian Pipeline) consists of a single 48-inch pipeline traversing a distance of approximately 1700 miles (734 miles in Alaska and 966 miles in Canada). The base capacity assumes that 4.5 Bcf/d will be received into the pipeline at the outlet of the GTP and that 0.336 Bcf/d of this throughput will be delivered at various locations within the state. For this system, 17 compressor stations will be installed on the pipeline system (6 in Alaska and 11 in Canada). With additional compression, pipeline capacity is expandable to 5.9 Bcf/d. The maximum operating pressure will be 2500 psig. From the outlet of the GTP to a location approximately 867 miles downstream, the pipeline system will be designed to maintain flowing gas temperatures at 32°F or lower. The remainder of the pipeline system to the Alberta border will be designed to generally maintain flowing gas temperatures above 32°F. Maintaining these gas temperatures recognizes the presence of permafrost soils along the route and will support stable operation from a geotechnical perspective. The delivery pressure at the Alberta border will be approximately 1225 psig.

3. The gas transmission pipeline segment from the outlet of the GTP to the LNG terminal facilities near Valdez (i.e. the Valdez Pipeline) consists of a single 48-inch pipeline traversing a distance of approximately 803 miles. Base case capacity assumes that 3.0 Bcf/d will be received into the pipeline at the outlet of the GTP and 0.342 Bcf/d will be delivered at various locations within the state. For this case, two compressor stations will be installed. Pipeline capacity is expandable with additional compression. The maximum operating pressure will be 2500 psig. From the outlet of the GTP to a location approximately 730 miles downstream, the pipeline system will be designed to maintain flowing gas temperatures at 32°F or lower. The remainder of the pipeline system to the LNG terminal will be designed to generally maintain flowing gas temperatures above 32°F. Maintaining these gas temperatures recognizes the presence of permafrost soils along the route and will support stable operation from a geotechnical perspective. The delivery pressure at the LNG terminal is designed to be approximately 900 psig.

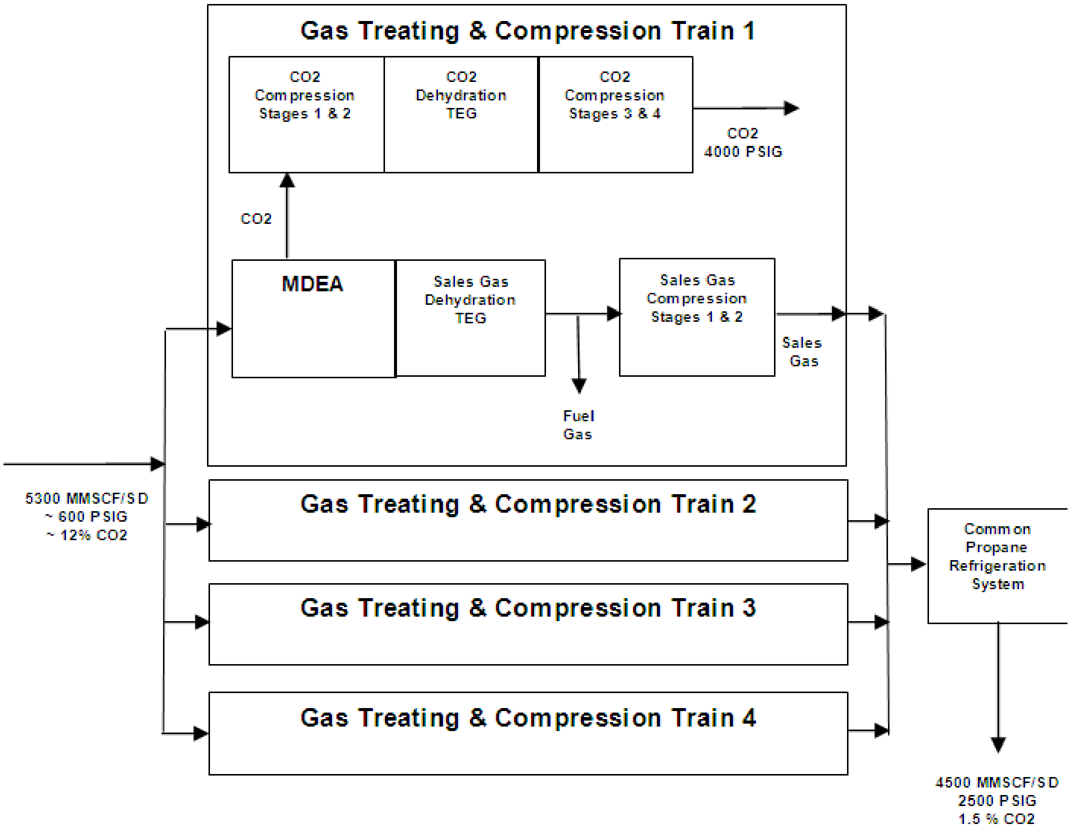
4. The GTP will be designed to handle raw gas with an inlet pressure of about 600 psi, and an average inlet temperature of 60°F, and can be expanded to treat additional gas. It will operate in conjunction with and is necessary to deliver pipeline quality gas into either the Alaska-Canada Pipeline or the Valdez Pipeline. Shippers will be required to meet the gas quality specifications in TC Alaska's FERC Gas Tariff, attached as Exhibit I to Appendix C, but will not be required to have their gas treated at the GTP. The outlet sales gas from the GTP will have a pressure and temperature of approximately 2500 psi and 30°F respectively.

    - The proposed GTP design for the Alaska-Canada Pipeline will treat approximately 5.3 Bcf/d of inlet gas, and deliver approximately 4.5 Bcf/d of pipeline quality gas with a CO_2 content between 1.5% and 2%. The GTP is expected to remove approximately 0.6 Bcf/d of acid gas and consume approximately 0.2 Bcf/d of fuel gas.

    - The GTP design for the Valdez Pipeline will treat approximately 3.6 Bcf/d of inlet gas, and deliver approximately 3.0 Bcf/d of pipeline quality gas with a CO_2 content of ≤50 ppm. The GTP is expected to remove approximately 0.44 Bcf/d of acid gas and consume approximately 0.17 Bcf/d of fuel gas.

    Figure 2 summarizes the GTP design configuration.

Figure 2: Simplified Block Flow Diagram of Gas Treating Trains



5. APP will assess the market demand for additional capacity every two years through public nonbinding solicitations or similar means. Based on the results of the current and future Open Seasons, APP will add capacity to accommodate demonstrated market needs unless such needs cannot be accomodated due to economic, engineering, design, capacity, or operational constraints, or unless the addition of capacity would adversely impact the timely development of the Project.

   APP will first make use of compression to add capacity, consistent with the requirements of AGIA. As the use of additional compression was preplanned in the initial design, such expansions will be relatively inexpensive and will be considered ahead of other options such as looping. To achieve the capacity addition, the use of more compressor stations and line heaters will be needed.

   Without expansion, the initial Alaska-Canada Pipeline and Canadian Pipeline design makes use of up to 17 compressor stations – 7 chilled and 10 unchilled. Of the 7 chilled, 6 are planned for Alaska and 1 in the Yukon, spaced roughly at equal intervals along the pipeline. The design is for Arctic service and suitable for installation on permafrost. The 10 unchilled compressor stations will be all located in Canada and also spaced at roughly equal intervals along the pipeline. One of the 10 will be a double unit station.

The initial pipeline design also includes 3 heater stations, 1 in the Yukon and 2 in British Columbia. A seasonal variation in duty at these heater stations is anticipated and the typical design uses four 20 million Btu/h line heaters.

By adding 16 intermediate compressor stations, the pipeline capability is expandable to approximately 5.9 Bcf/d. Of these 16 intermediate stations, 8 will be chilled stations - 7 in Alaska and 1 in the Yukon. The remaining 8 unchilled stations will be in Canada and 1 of these will be a two unit station.

This expanded design will therefore make use of a total of 33 stations - 15 chilled and 18 unchilled. Of the unchilled, 10 stations will require aerial coolers to control the temperature - 5 of the original stations and 5 of the incremental stations. For the 5.9 Bcf/d volume, two additional line heaters will also be required at an existing British Columbia site. As with the Alaska-Canada pipeline design, the Valdez pipeline may also make use of additional compressors and heaters for future expansion.

The GTP capacity can be expanded by approximately 0.45 Bcf/d by debottlenecking the gas treating trains. Helper motors will be required for both the sales gas and CO_2 compressors as well as for additional plant processing loads. An additional 80,000 BHP is envisioned for this expansion scenario and necessitates the addition of a fifth turbine power generator rated at about 73 MW or 100,000 BHP.

More significant GTP capacity expansion of approximately 1.125 Bcf/d is available through the addition of a gas treatment train, which would be comprised of acid gas removal, dehydration, sales gas compression and CO_2 compression equipment. The utilities and infrastructure (sales gas chilling, heat medium, flares/vents, water treatment, etc.) will also be required to be expanded in order to support the additional train. To supply the additional sales gas chilling refrigeration power load, an additional turbine power generator is anticipated to be required for this alternative also.

Item 3 - Operating Pressures

18 C.F.R. §157.34(c)(3): Maximum allowable operating pressure and expected actual operating pressure;

Maximum allowable operating pressures and actual operating pressures are summarized in Table 3 below.

Table 3: Expected Maximum Allowable And Expected Operating Pressures

Section Of Proposed Project	Location	Maximum Allowable Operating Pressure (psig)	Expected Actual Operating Pressure (psig)
Point Thomson Pipeline	Gas inlet	1130	1030
	Gas outlet	1130	670
GTP For The Alaska-Canada Pipeline	Gas inlet	705	600
	Gas outlet (treated gas)	2500	2450
	CO_2 outlet	4380	4000
GTP For The Valdez Pipeline	Gas inlet	705	600
	Gas outlet (treated gas)	2500	2450
	CO_2 outlet	4380	4000
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Gas inlet (from the GTP and Other points as required)	2500	2450
	Outlet gas delivery point – Livengood	2500	2160
	Outlet gas delivery point – Fairbanks	2500	2296
	Outlet gas delivery point – Parks Highway Spur	2500	2296
	Outlet gas delivery point – Delta Junction/Richardson Highway Spur	2500	2397

Table 3: Expected Maximum Allowable And Expected Operating Pressures (Continued)

Section Of Proposed Project	Location	Maximum Allowable Operating Pressure (psig)	Expected Actual Operating Pressure (psig)
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Outlet gas delivery point – Tok	2500	2412
	Outlet gas delivery point – Alaska-Canada Border	2500	2053
Pipeline Segment Downstream Of The GTP – Valdez Pipeline	Gas inlet (from the GTP and Other points as required)	2500	2450
	Outlet gas delivery point – Livengood	2500	2131
	Outlet gas delivery point – Fairbanks	2500	1979
	Outlet gas delivery point - Parks Highway Spur	2500	1979
	Outlet gas delivery point – Delta Junction/Richardson Highway Spur	2500	1771
	Outlet gas delivery point – Glennallen	2500	1312
	Outlet gas delivery point – Valdez	2500	950
	Outlet gas delivery point – Valdez LNG Terminal	2500	900

Item 4 - Delivery Pressures

18 C.F.R. §157.34(c)(4): Delivery pressure at all delivery points named in (1) above;

Delivery pressures for all proposed delivery points are summarized in Table 4 below.

Table 4: Proposed Delivery Pressures

Section	Delivery Point	Pressure (pisg)
Point Thomson Pipeline	Gas to GTP inlet	600
GTP – For The Alaska-Canada Pipeline	Outlet Gas (to pipeline)	2450
	CO_2 outlet	4000
GTP – For The Valdez Pipeline	Outlet Gas (to pipeline)	2450
	CO_2 outlet	4000
Pipeline Downstream Of The GTP - Alaska-Canada Pipeline	Livengood	2160
	Fairbanks	2296
	Parks Highway Spur	2296
	Delta Junction/Richardson Highway Spur	2397
	Tok	2412
	Alaska-Canada Border	2053
Pipeline Downstream Of The GTP - Valdez Pipeline	Livengood	2131
	Fairbanks	1979
	Parks Highway Spur	1979
	Delta Junction/Richardson Highway Spur	1771
	Glennallen	1312

Table 4: Proposed Delivery Pressures (Continued)

Section	Delivery Point	Pressure (pisg)
Pipeline Downstream Of The GTP - Valdez Pipeline	Valdez	950
	Valdez LNG Terminal	900

Item 5 - In-Service Date

18 C.F.R. §157.34(c)(5): Projected in-service date;

The estimated in-service date for the Alaska-Canada Pipeline and the Valdez Pipeline is 2020 for initial gas and 2021 for full gas.

Item 6 - Transportation And Treating Rates

18 C.F.R. §157.34(c)(6): An estimated unbundled transportation rate for each delivery point named in (1) above, stated on a volumetric or thermal basis, for each service offered, including reservation rates for pipeline capacity, interruptible transportation rates, usage rates, fuel retention percentages, and other applicable charges, or surcharges, such as ACA; (if rates are estimated on a volumetric basis then the notice must inform bidders that final pro forma service agreements and the sponsor's proposed FERC tariff will have to be submitted with rates based on a thermal basis.)

Rates shown below are for a 25-year recourse rate firm transportation and gas treatment contract. The derivation of the rates is explained in Item 7. Additional information is provided in Exhibits J and K.

Rates are established by Zones as follows:

Zone 1: Comprising Transporter's facilities from the Point Thomson plant outlet to the inlet of the GTP, with a receipt point at Point Thomson and delivery points at or near the inlet of the GTP.

Zone 2: Comprising the GTP, providing firm gas treatment service, with a receipt point at the GTP inlet and a delivery point at the GTP outlet into Zone 3 of Transporter's facilities.

Zone 3 – Alaska-Canada Pipeline Alternative: Comprising the pipeline downstream of the outlet of the GTP and proceeding to the Alaska-Canada border, with a receipt point or points downstream of the GTP and delivery points at points within Alaska (In-State Delivery) and at the Alaska-Canada border (Export Delivery) for further transport on the Canadian Pipeline.

Zone 3 – Valdez Pipeline Alternative: Comprising the pipeline downstream of the outlet of the GTP and proceeding to near Valdez, with a receipt point or points downstream of the GTP and delivery points at points within Alaska (In-State Delivery) and at the LNG liquefaction facility at Valdez (Export Delivery).

ESTIMATE OF RECOURSE RATES

Rate Schedule	Base Tariff Rate Range: Alaska-Canada Pipeline	Base Tariff Rate Range: Valdez Pipeline
FT-1		
Zone 1: Point Thomson		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$8.45 - $11.19	$8.43 - $11.07
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$0.28 - $0.37	$0.28 - $0.36
Zone 2: GTP		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$57.62 - $74.72	$73.02 - $93.66
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$1.89 - $2.46	$2.40 - $3.08
Zone 3: In-State Delivery		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$29.28 - $38.72	$55.11 - $72.35
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$0.96 - $1.27	$1.81 - $2.38
Zone 3: Export Delivery		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$40.91 - $54.10	$63.18 – $82.95
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$1.35 - $1.78	$2.08 - $2.73

ESTIMATE OF RECOURSE RATES

Rate Schedule	Base Tariff Rate Range: Alaska-Canada Pipeline	Base Tariff Rate Range: Valdez Pipeline
IT-1		
Zone 1: Point Thomson		
Commodity Rate (per MMBtu)		
Maximum	$0.28 - $0.37	$0.28 - $0.36
Minimum	$0.00	$0.00
Zone 2: GTP		
Commodity Rate (per MMBtu)		
Maximum	$1.89 - $2.46	$2.40 - $3.08
Minimum	$0.00	$0.00
Zone 3: In-State Delivery		
Commodity Rate (per MMBtu)		
Maximum	$0.96 - $1.27	$1.81 - $2.38
Minimum	$0.00	$0.00
Zone 3: Export Delivery		
Commodity Rate (per MMBtu)		
Maximum	$1.35 - $1.78	$2.08 - $2.73
Minimum	$0.00	$0.00
PAL		
Daily Maximum Commodity Rate per MMBtu	$1.35 - $1.78	$2.08 - $2.73
Daily Minimum Commodity Rate per MMBtu	$0.00	$0.00

Surcharges

Rate per MMBtu	Alaska-Canada Pipeline	Valdez Pipeline
Annual Charge Adjustment (ACA) Rate	$0.0019	$0.0019
Change in Law/Tax/Regulation Surcharge	$0.0000	$0.0000

Fuel (%)	Alaska-Canada Pipeline	Valdez Pipeline
Zone 1: Point Thomson	0.25	0.25
Zone 2: GTP	4.50	5.70
Zone 3: In-State Delivery	0.80	0.40
Zone 3: Export Delivery	1.00	0.80

Item 7 - Cost Of Service

18 C.F.R. §157.34(c)(7): The estimated cost of service (i.e., estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses), and estimated cost allocations, rate design volumes and rate design;

The APP estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses are identified in Exhibits J and K. The cost of service underlying the recourse rates for the Alaska-Canada Pipeline and Valdez Pipeline has been derived using a 4% straight line depreciation rate, a return on equity equal to the 10 year U.S. Treasury Note rate plus 965 basis points, adjusted annually (for illustrative rate purposes assumed to be 14%), a capital structure of 70% debt and 30% equity, estimated operating costs and property taxes, a negative salvage allowance, and corporate income tax rates, utilizing principles of tax normalization.

Cost allocation and rate design volumes are reflected in Exhibits J and K. For cost allocation purposes, APP has utilized the costs contained in or associated with each Zone for developing rates applicable to gas transportation in Zones 1 and 3 and gas treatment service in Zone 2. For illustrative rate design purposes only, Exhibits J and K utilize billing determinants of 1.1 Bcf/d for Zone 1, and for Zones 2 and 3 utilize billing determinants of 4.5 Bcf/d for the Alaska-Canada Pipeline and 3.0 Bcf/d for the Valdez Pipeline. Recourse rates will be designed using billing determinants equal to contracted capacities under non-defaulting contracts. Firm transportation and firm gas treatment reservation rates are designed using the straight fixed-variable methodology. AOS, IT, and PAL rates are designed on a 100% load factor basis. The methodology for deriving rates for deliveries within Alaska is described in Item 8.

Item 8 - In-State Transportation Rates

18 C.F.R. §157.34(c)(8): Based on the In-State Study and the delivery points within the State of Alaska identified in (1) above, there must be an estimated transportation rate for such deliveries, based on the amount of in-state needs shown in the study. Such estimated transportation rate must be based on the costs to make such in-state deliveries and shall not include costs to make deliveries outside the State of Alaska;

A single in-state rate will be developed for all in-state delivery points. The estimated rates for the Alaska-Canada Pipeline and the Valdez Pipeline are shown in Exhibits J and K. The volumes from the *In-State Gas Demand Study* on which those estimated rates are based are shown in Table 5 below.

The estimated rate for in-state deliveries has been developed utilizing a weighted average volume-mile cost allocation and rate design methodology as indicated below.

APP computed aggregate in-state volume-miles by adding the products of

1. the estimated MDQ for each delivery point, as derived from the *In-State Gas Demand Study* and,

2. the miles from the outlet of the GTP to each delivery point.

The resulting sum of in-state volume-miles was then divided by the total volume-miles (similarly computed) associated with firm transportation contracts for all deliveries either within the state or to to the Alaska-Canada border or to the Valdez LNG facility. The resulting percentage was then applied to the total cost of service to determine the costs applicable to in-state deliveries.

The costs applicable to in-state deliveries were then used to design in-state rates, by dividing such costs by in-state aggregate MDQs.

Table 5: Estimated In-State Volumes (Based On In-State Needs Study)

Location	Alaska-Canada Pipeline Route (MMcf/d)	Valdez Pipeline Route (MMcf/d)
Livengood	9	9
Fairbanks	55	55
Parks Highway spur	Alternative to Delta Junction	-
Delta Junction area/Richardson Highway spur	272	1.4
Tok	0.4	n/a

Table 5: Estimated In-State Volumes (Based On In-State Needs Study)(Continued)

Location	Alaska-Canada Pipeline Route (MMcf/d)	Valdez Pipeline Route (MMcf/d)
Glennallen	n/a	270
Valdez	n/a	7

Item 9 - Negotiated And Other Rates

18 C.F.R. §157.34(c)(9): Negotiated rate and other rate options under consideration, including any rate amounts and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process proscribed herein;

In this Open Season, APP is offering shippers the option of negotiated rates, which shall be paid without regard to any action or determination of the FERC with respect to recourse rates. APP has not entered into any precedent agreements with prospective shippers outside this Open Season.

The negotiated rates being offered will be computed and paid in accordance with the principles and process specified in Exhibit A to the proposed Precedent Agreement (Appendix A to Open Season Notice). Additional information is provided in Exhibits J and K to this Appendix C.

The negotiated rate principles from Exhibit A of the Precedent Agreement are as follows:

Negotiated rates shall be based upon, and the Parties intend that they will recover, Transporter's costs as identified in items 1-12 below. The Parties agree that negotiated rates shall be recalculated annually in order to assure that Transporter's rates recover all costs of providing service. The Parties further agree to utilize the following process to revise negotiated rates. On each November 1st following at least 15 months after the Commencement Date, Transporter shall circulate schedules and work papers to all Shippers electing negotiated rates which identify (i) Transporter's cost of service and normalized billing determinants for the twelve months ending the preceding August 31st determined in accordance with the negotiated rate principles set forth below, and (ii) Transporter's revenues collected during such twelve month period, net of any credits or applicable adjustments during such period. Transporter shall also identify revised negotiated rates to be effective beginning January 1st of the following year which shall be based upon the cost of service and normalized billing determinants identified above, adjusted for any difference (positive or negative) between costs and revenues, net of any credits or applicable adjustments, during the twelve month period identified in (i) above. Adjustments in normalized billing determinants shall be made separately by Zone if necessary to recognize different levels of service or service interruption by Zone.

Transporter and all Shippers electing negotiated rates shall meet to discuss the cost of service, billing determinants, schedules, work papers and proposed negotiated rates. Transporter will then file at FERC such negotiated rates, or such other rates which Transporter agrees to file, no later than December 31st and request that the negotiated rates be made effective January 1st. In the event Shipper objects to Transporter's filed negotiated rates, the matter shall be subject to the Dispute Resolution provisions of Transporter's Tariff. If the award of the arbitral Tribunal determines that Shipper's negotiated rates should be lower than the rates in effect for any applicable period, Transporter shall refund the difference between such lower rates and the rates charged.

Negotiated firm transportation reservation rates will be stated on an MMBtu (thermal) basis to provide for recovery by the Transporter of all fixed costs of providing firm transportation service. Shipper will also pay a commodity or usage charge for MMBtus actually transported, and provide volumes for Fuel. The negotiated firm reservation rate for gas treatment services will be calculated and stated on an MMBtu basis to provide for recovery by Transporter of all fixed costs of providing firm gas treatment services at Transporter's GTP. Shippers will also pay commodity charges per MMBtu and provide volumes for Fuel, as applicable, for gas treatment services.

The major elements in determining the cost of service and the methodology for the rate design of negotiated rates, are set forth below. Exhibit D sets forth an illustrative rate calculation.

1. Upon the approval of the final costs by FERC, the target capital structure will be 75% debt and 25% equity. The final capital structure used for setting the negotiated rates shall be equal to Transporter's actual capital structure, provided, that the capital structure utilized in determining negotiated rates shall include no less than 25% equity and subject to A.S. 43.90.130(10), as amended from time to time. For expansions and maintenance capital the capital structure for rate making purposes shall be 70% debt and 30% equity.

2. The actual weighted average cost of Transporter's debt calculated using an interest rate equal to the weighted average of the interest rate(s) on such debt. Any payments made to secure or reduce the cost of debt financing will be added to rate base. Changes in the actual weighted average cost of Transporter's debt will be reflected in negotiated rates for the Initial Service Term and any extension of the initial term of the FTSA.

3. Rate of return on equity will be 12% on an after-tax basis.

4. Income taxes will be calculated on a normalized basis, utilizing the federal and state corporate income tax rates for the Initial Service Term and any extension of the initial term of the FTSA. Changes in the federal and state corporate income tax rates will be reflected in the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

5. For the Initial Service Term and any extension of that term, depreciation on transmission and gas treatment plant used for purposes of deriving rates will be calculated annually. An FTSA with an Initial Service Term of 20 to 25 years will recover 80% of the Shipper's proportional share of capital costs approved by FERC for Recourse Rates, and AFUDC and property tax paid during construction ("Approved Capital Costs"), during the Initial Service Term, with Shipper's proportional share equal to Shipper's MDQ divided by aggregate MDQs as of the Commencement Date. Such Shipper's proportional share of the remaining 20% shall be recovered in an additional period of five years following the Initial Service Term, with Shipper's proportional share equal to Shipper's MDQ divided by aggregate MDQs as of the last month in the Initial Service Term. An FTSA with an Initial Service Term exceeding 25 years shall recover 80% of Shipper's proportional share of such costs in the first 25 years and the remaining 20% shall be recovered in an additional period of not less than five years, with Shipper's proportional share based on Shipper's MDQ divided by aggregate MDQs as of the last month in the Initial Service Term.

6. Rates will include a reasonable estimate of negative salvage costs to fund the net costs of abandoning the APP U.S. Facilities and restoring the affected properties at the end of the system's service life. Changes in the negative salvage costs will be reflected in the revenue requirement of the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

7. The rate base will include, among other things, (i) debt service reserve, (ii) cost of line pack, inventory, and spare parts, (iii) payments made to secure or reduce the cost of debt financing, (iv) working capital up to one-eighth of annual operating expenses, (v) prepayments, and (vi) Approved Capital Costs utilizing the weighted average cost of debt in principle No. 2 and the 12% return on equity, and be reduced by the cumulative depreciation and cost reimbursement received pursuant to the Alaska Gasline Inducement Act.

8. The negotiated reservation rates will be calculated based upon billing determinants equal to the sum of all firm contracted capacities under non-defaulting service agreements, normalized for any billing determinants attributable to in-state rates designed on a distance basis and adjusted for any reductions associated with service disruptions or changes in Shippers' MDQ or MTQ, for both the Initial Service Term and any extension of that term.

9. During the Initial Service Term and any extension of that term,

   (a) Shipper shall continue to pay full reservation charges during any period of reduction of firm transportation service or firm gas treatment service, including an Interruption; provided that, reservation charges during a GTP Turnaround or Phase-In Period will be charged with respect to a reduced capacity for firm gas treatment and firm gas transportation services;

   (b) There will be a commodity or usage charge which will recover costs which vary with volumes actually shipped (the commodity charge is estimated to be minimal);

   (c) Fuel will be recovered on the basis of actual quantities of fuel consumed or utilized in operations and fuel lost and unaccounted for;

   (d) Rates will reflect changes in Transporter's taxes (other than income taxes), fees assessed by any governmental entity, and all other operating costs;

   (e) In addition to changes reflected elsewhere in these rate principles, negotiated rates will reflect changes in (i) billing determinants reflecting contracted capacities and (ii) rate base;

   (f) Transporter will credit to Shippers and other shippers that have secured firm transportation service, on a pro rata basis according to firm transportation shippers' MDQ, 75 percent of the revenue received by Transporter for the provision of AOS service, IT service, and PAL service.

10. Negotiated rates shall be adjusted to ensure that they are not inconsistent with A.S. 43.90.130(7)(A)-(D), as amended from time to time.

11. Foundation Shipper shall be entitled to elect the same negotiated rate principles, in their entirety, as offered prior to the Commencement Date and accepted by any other shipper.

12. Negotiated rate shippers shall pay the recourse rate for AOS and any other non FT-1 service.

Item 10 - Quality Specifications

18 C.F.R. §157.34(c)(10): Quality specifications and any other requirements applicable to gas to be delivered to the project; provided that a prospective applicant shall not require that potential shippers process or treat their gas at any designated plant or facility;

The quality specifications and other requirements applicable to gas to be delivered to the Point Thomson Pipeline segment and GTP, and the downstream segments of the Alaska-Canada Pipeline and Valdez Pipeline are set forth in Section 5 of the General Terms and Conditions of TC Alaska's indicative FERC Gas Tariff, attached as Exhibit I to this Appendix. Potential shippers are not required to process or treat their gas at any designated plant or facility.

Item 11 - Terms And Conditions

18 C.F.R. §157.34(c)(11): Terms and conditions for each service offered;

TC Alaska's indicative FERC Gas Tariff, attached as Exhibit I to this Appendix, sets forth the terms and conditions for each service to be offered.

Item 12 - Creditworthiness Standards

18 C.F.R. §157.34(c)(12): Creditworthiness standards to be applied to, and any collateral requirements for, prospective shippers;

The APP creditworthiness requirements are set forth in Exhibit B to the proposed Precedent Agreement (Appendix A to Open Season Notice) and will be applicable to all shippers.

The creditworthiness standards apply for purposes of the Precedent Agreement, including Section III(c), Section IV(a)(4), and Section V(a) of the Precedent Agreement, and for evaluating requests for provision of service. Due to the requirements to finance a project of this magnitude, these creditworthiness standards shall continue to apply to shippers (or assignees) under the terms of the Firm Transportation Service Agreement ("FTSA") during the Initial Service Term and any extension of that term. TC Alaska shall not be required to continue to perform its obligations under the Precedent Agreement or an FTSA, or to commence or continue service, on behalf of any shipper that fails to establish and maintain creditworthiness. TC Alaska shall determine shipper's creditworthiness, at any time in its sole discretion, in accordance with Exhibit B of the Precedent Agreement.

Item 13 - Precedent Agreement Execution Date

18 C.F.R. §157.34(c)(13): The date, if any, by which potential shippers and the prospective applicant must execute precedent agreements;

Potential shippers must submit an executed Precedent Agreement in the form included in Appendix A of the Notice prior to the close of the Open Season. TC Alaska intends to execute the Precedent Agreements as soon as reasonably practicable after December 31, 2010.

Item 14 - Bid Evaluation

18 C.F.R. §157.34(c)(14): A detailed methodology for determining the value of bids for deliveries within the State of Alaska and for deliveries outside the State of Alaska;

Due to the magnitude of this project and the associated financing requirement, APP will require a long-term firm commitment of 20 years or more from all bidders during this Open Season. Since bidders will be required to make a long-term firm commitment, APP will value all acceptable bids for firm transportation service received in this Open Season, whether for deliveries in the State of Alaska or deliveries outside the State of Alaska, on an equal basis. (See response to 18 C.F.R. §157.34(c)(15) for over-subscription allocation.)

Item 15 - Oversubscription Allocations

18 C.F.R. §157.34(c)(15): The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, except that if any capacity is acquired through pre-subscription agreements as provided in §157.33(b) and the prospective applicant does not redesign the project to accommodate all capacity requests, only that capacity that was acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any one of the pre-subscription agreements shall be allocated on a pro rata basis and no other capacity acquired through the open season shall be allocated;

The APP Parties intend to design the Project, within certain economic and engineering design increments, to accommodate all capacity requests on a not unduly discriminatory basis from acceptable bids received during the Open Season.

In the event qualifying bids from shippers for firm services received during the Open Season exceed the design capacity determined by APP, APP reserves the right to reduce the bidders' MDQs and MTQs indicated on Exhibit A to the Precedent Agreements pro rata based solely on each bidder's proportion of the total quantity of firm transportation capacity and firm treatment capacity reflected in bids received by APP, without regard to whether a shipper would qualify as a Foundation Shipper, has selected recourse rates or negotiated rates, or has specified in-state or export deliveries.

In the event that a bidder's transportation MDQ in Zone 3 downstream of the GTP is reduced, as stated above, the bidder's Zone 2 MTQ will be reduced by a corresponding amount. In the event that a bidder's Zone 2 MTQ is reduced, as stated above, the bidder's transportation MDQ in Zone 3 downstream of the GTP will be reduced by a corresponding amount.

Item 16 - Bid Requirements

18 C.F.R. §157.34(c)(16): Required bid information, whether bids are binding or non-binding, receipt and delivery point requirements, the form of a precedent agreement and time of execution of the precedent agreement, definition and treatment of non-conforming bids;

This Open Season is being held to solicit the submission and execution of binding Precedent Agreements (the form of which is attached as Appendix A to the Open Season Notice) for firm interstate natural gas transportation service and optional firm gas treatment service provided by TC Alaska's Alaska Pipeline Project.

An acceptable bid for this Open Season shall consist of an executed Precedent Agreement for either or both of the Alaska-Canada Pipeline or the Valdez Pipeline. Parties interested in contracting for firm capacity, regardless of which route is selected, must complete Exhibit A to the Precedent Agreement. At a minimum, bidders must provide the following information on Exhibit A to the Precedent Agreement:

- Maximum Daily Quantity ("MDQ") and optional Maximum Treatment Quantity ("MTQ"), exclusive of Fuel, by requested primary receipt and delivery points that bidders must indicate on Exhibit A to the Precedent Agreement.
- Whether the party intends to pay recourse rates or negotiated rates.
- Requested primary term of 20-25, 30 or 35 years for shippers selecting negotiated rates and 25 years for shippers selecting recourse rates (shippers selecting negotiated rates will also be entitled to a one-time, five-year extension of the initial service term).

To be considered a bona fide bid, the Precedent Agreement must be signed by an authorized representative of the bidding company. Each bidder must return the completed Precedent Agreement before the end of the Open Season to APP at the address specified in the Precedent Agreement Submittal section of the Open Season Notice. Additional guidance for parties submitting bids is set forth at pp. 5-6 in the Open Season Notice.

APP reserves the right to reject, on a not unduly discriminatory basis, any bid that does not conform to these requirements or that modifies the substantive terms set forth in the Precedent Agreement.

APP recognizes that bidders may desire to include certain conditions precedent ("CPs") to their bids that are outside the control of APP. Notwithstanding the bidders' execution of the Precedent Agreement during the Open Season, bidders will be allowed to negotiate CPs acceptable to the APP Parties and will have until December 31, 2010, to secure all necessary board approvals and internal authorizations necessary to undertake the obligations required by the Precedent Agreement. CPs that modify substantive terms in the Precedent Agreement may not be accepted.

Shippers will be notified, as soon as reasonably practical following the completion of the Open Season, whether APP will proceed to seek to design, permit and construct the Alaska-Canada Pipeline and GTP, or will proceed to seek to design, permit and construct the Valdez Pipeline and GTP. APP will make this determination in its sole discretion, and is entitled to delay provision of this notification if it determines that commercial circumstances justify a later notification. Upon shippers' receipt of such notification, all terms of the Precedent Agreement are binding with respect to each shipper's elections on Exhibit A to the Precedent Agreement for service on the selected pipeline, and the shipper's service elections on Exhibit A to the Precedent Agreement with respect to the pipeline alternative that is not selected for development are thereafter without effect and are not enforceable by the shipper or by TC Alaska.

After awarding capacity and (i) receipt of winning bidders' sufficient written evidence of creditworthiness, as stipulated in Exhibit B to the Precedent Agreement, (ii) resolution of any outstanding commercial issues, and (iii) receipt of bidders' board approvals, TC Alaska will execute each binding Precedent Agreement previously submitted by a bidder and will return one copy to the bidder. If the amount of capacity awarded differs from the amount contained in the initial bid offer as a result of over-subscription, TC Alaska and the winning bidders will execute amended Precedent Agreements reflecting the final award of capacity. The Precedent Agreement will bind the bidder to execute a firm transportation service agreement ("FTSA") before Project construction commences, and will condition the provision of service on satisfaction or express waiver of the transporter Conditions Precedent stipulated in the Precedent Agreement.

Item 17 - Project Certificate Application Date

18 C.F.R. §157.34(c)(17): The projected date for filing an application with the Commission;

TC Alaska intends to file its certificate application by October 31, 2012.

Item 18 - Information Disclosures And Data Room Procedures

18 C.F.R. §157.34(c)(18): All information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;

The Alaska Pipeline Project is establishing a series of data rooms to hold material supplemental to the information contained in the APP Open Season Notice itself.

The data rooms will be made available to potential shippers and certain other interested stakeholders as well as interested U.S., Canada, and State of Alaska regulatory agencies upon issuance of the Open Season Notice, on April 30, 2010.

The data rooms will contain the information that the Alaska Pipeline Project has in its possession relating to the proposed service being offered, projected pipeline design and capacity, the proposed tariff provisions, and cost projections. In addition, the data rooms will contain the information that APP has made available to, or obtained from, any potential shipper, including affiliates of the APP Parties, prior to the issuance of the Open Season Notice.

Due to the commercially and competitively sensitive nature of the information, all information contained in the data rooms that is not in the public domain shall be treated as confidential information. Any person wishing to access such confidential information will be required to sign a confidentiality undertaking in the form attached hereto as Exhibit G and comply with the data room procedures, attached hereto as Exhibit H.

The data rooms will be set up on a hierarchical basis, as follows:

- All data room information in the public domain will be accessible through APP's internet website, www.thealaskapipelineproject.com and available for review by anyone interested in accessing that data.

- Data contained in the physical data rooms will be broken into three levels of confidentiality.

    - The first level ("Tier 1") will contain confidential project information, not in the public domain, but which is of relatively lower commercial and competitive risk to the Project. All interested stakeholders granted access to the data rooms will have access to Tier 1 data.

    - The second level ("Tier 2") will contain high risk, commercially sensitive, data, such as project component cost projections, land access cost projections and the like. Such information will be made available only to potential shippers and regulatory agencies with Project oversight responsibilities.

    - In addition, certain information ("Tier 3") contained in the data rooms is subject to third party confidentiality restrictions. Anyone seeking access to Tier 3 data will need to secure a release from such third parties in order to view such Tier 3 data.

The data rooms will be located in the following locations:

- Houston, Texas – Main data room containing all required project information in electronic format or hard copy.
- Anchorage, Alaska – Adjunct data room containing all required information available in electronic format.
- Whitehorse, Yukon – Adjunct data room containing all required information available in electronic format.
- Calgary, Alberta – Adjunct data room containing all required information available in electronic format.

Item 19 - Applicant Affiliates

18 C.F.R. §157.34(c)(19): A list of the names and addresses of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska. Affiliated unit means "Affiliate" as applicably defined in section 358.3(b) of the Commission's Regulations. Energy Affiliate means "Energy Affiliate" as applicably defined in section 358.3(d) of the Commission's Regulations;

The project applicant is TransCanada Alaska Company LLC ("TC Alaska"). TC Alaska has no divisions or business operations other than the Alaska Pipeline Project. Neither TC Alaska nor its parent, TransCanada Corporation, has any affiliates involved in the production of natural gas in the State of Alaska or the marketing or sales of natural gas from the State of Alaska.

As a participant in the Alaska Pipeline Project, ExxonMobil provides below the names and addresses of the three affiliated organizational units of Exxon Mobil Corporation actively involved in the production of natural gas in the State of Alaska and the marketing or sales of natural gas from the State of Alaska:

ExxonMobil Production Company ("EMPC")
a division of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

EMPC has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the production and processing of petroleum and natural gas in all parts of the world. Within EMPC, the Americas unit has the aforementioned responsibilities in the State of Alaska.

ExxonMobil Gas and Power Marketing Company ("EMGPM")
a division of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

EMGPM has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the commercialization of natural gas and related products and electric power in all parts of the world. Within EMGPM, the Americas unit has the aforementioned responsibilities for natural gas and related products, including the marketing or sales thereof, in the State of Alaska.

ExxonMobil Development Company ("EMDC")
a wholly-owned subsidiary of Exxon Mobil Corporation
5 Greenspoint Plaza
17001 Northchase Dr.
Houston, TX 77060

EMDC has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the development of facilities required for the production and processing of petroleum and natural gas in all parts of the world. Within EMDC, the Arctic unit has the aforementioned responsibilities for the development of the Point Thomson field, support activities related to the Prudhoe Bay Unit and for other related upstream production activities in the State of Alaska.

Additionally, listed below are the names and addresses of four ExxonMobil entities that own or control mineral leases providing the rights to produce and process petroleum and natural gas from lands located in the State of Alaska. In each instance, the day to day stewardship of these mineral leases is the responsibility of the EMPC Americas Unit.

Exxon Mobil Corporation
5959 Las Colinas Blvd.
Irving, TX 75039

ExxonMobil Oil Corporation ("EMOC")
an indirect wholly-owned subsidiary of Exxon Mobil Corporation
5959 Las Colinas Blvd.
Irving, TX 75039

ExxonMobil Alaska Production Inc. ("EMAP")
an indirect wholly-owned subsidiary of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

Mobil Exploration and Producing North America Inc. ("MEPNA")
an indirect wholly-owned subsidiary of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

Item 20 - Organization Charts

18 C.F.R. §157.34(c)(20): A comprehensive organizational chart showing:

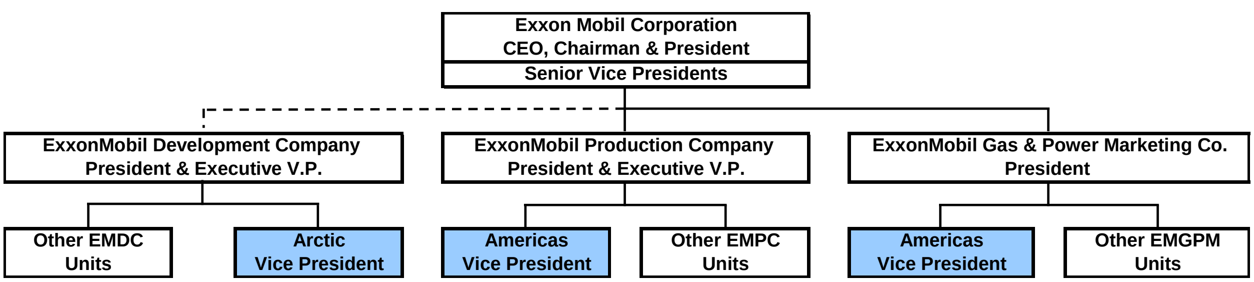
(i) The organizational structure of the prospective applicant's parent corporation(s) with the relative position in the corporate structure of marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska.

(ii) The job titles and descriptions, and chain of command for all officers and directors of the prospective applicant's marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska;

TC Alaska's parent company is TransCanada Corporation. There are no affiliated organizational units of TransCanada Corporation involved in the production of natural gas in the State of Alaska or the marketing or sales of natural gas from the State of Alaska.

As a participant in the Alaska Pipeline Project, ExxonMobil provides below (see Figure 3) an organizational chart illustrating the relevant portion of ExxonMobil's corporate structure and the relative position and reporting relationships (i.e. chain of command) within said structure of the three affiliated organizational units that are actively involved in the production of natural gas in the State of Alaska and the marketing or sales of natural gas from the State of Alaska (highlighted in blue).

Figure 3: Exxon Mobil Corporation and Affiliated Companies



Note:
- Organizational units involved in the production of natural gas in the State of Alaska or marketing/sales of natural gas from the State of Alaska
Dashed lines represent Functional guidance/stewardship/service relationships

Exxon Mobil Corporation and its affiliated companies are organized functionally, with day-to-day control over the business activities of the various organizational units exercised one level below the Office of the President of the affiliated companies. Typically this is a Vice President who has been appointed as an Officer of the affiliated company.

The job titles and descriptions for those positions with day-to-day responsibility for the business activities of Exxon Mobil Corporation's affiliated organizational units that are actively involved in the production of natural gas in the State of Alaska and the marketing or sales of natural gas from the State of Alaska are listed below. The relative position and reporting relationship for these positions is shown on the aforementioned organizational chart.

1. ExxonMobil Production Company ("EMPC") - Vice President, Americas

   The EMPC, Vice President, Americas has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the production and processing of petroleum and natural gas in the Americas region of the world, which includes the State of Alaska.

2. ExxonMobil Gas and Power Marketing Company ("EMGPM") - Vice President, Americas

   The EMGPM, Vice President, Americas has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the commercialization of natural gas and related products, including the marketing and sales thereof, in the Americas region of the world, which includes the State of Alaska.

3. ExxonMobil Development Company ("EMDC") - Vice President, Arctic

   The EMDC, Vice President, Arctic has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the development of facilities required for the production and processing of petroleum and natural gas in the Arctic region of the world, which includes the development of the Point Thomson field, support activities related to the Prudhoe Bay Unit and for any other related upstream production activities in the State of Alaska.

Item 21 - Officer And Director Statement

18 C.F.R. §157.34(c)(21): A statement that any officers and directors of the of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska named in (19) above will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season.

TC Alaska has no divisions or business operations other than the Alaska Pipeline Project. Neither TC Alaska nor its parent, TransCanada Corporation, has any affiliates involved in the production of natural gas in the State of Alaska or the marketing or sales of natural gas from the State of Alaska.

As a particpant in the Alaska Pipeline Project, ExxonMobil has instituted a comprehensive set of Order No. 2005 Compliance Procedures and Standards of Conduct that ensure full functional separation between the participants in APP and those ExxonMobil organizational units engaged in the production of natural gas in the State of Alaska and the marketing or sales of natural gas from the State of Alaska.

Officers and directors with day-to-day responsibility for ExxonMobil's production of natural gas in the State of Alaska and marketing or sales of natural gas from the State of Alaska are and will be prohibited from obtaining information about the conduct of the APP Open Season or APP's allocation of capacity that is not posted on APP's internet website (www.thealaskapipelineproject.com) or that is not otherwise also available to other participants in the Open Season.

Appendix C

Exhibit A
Route Map - Point Thomson Pipeline Segment to GTP

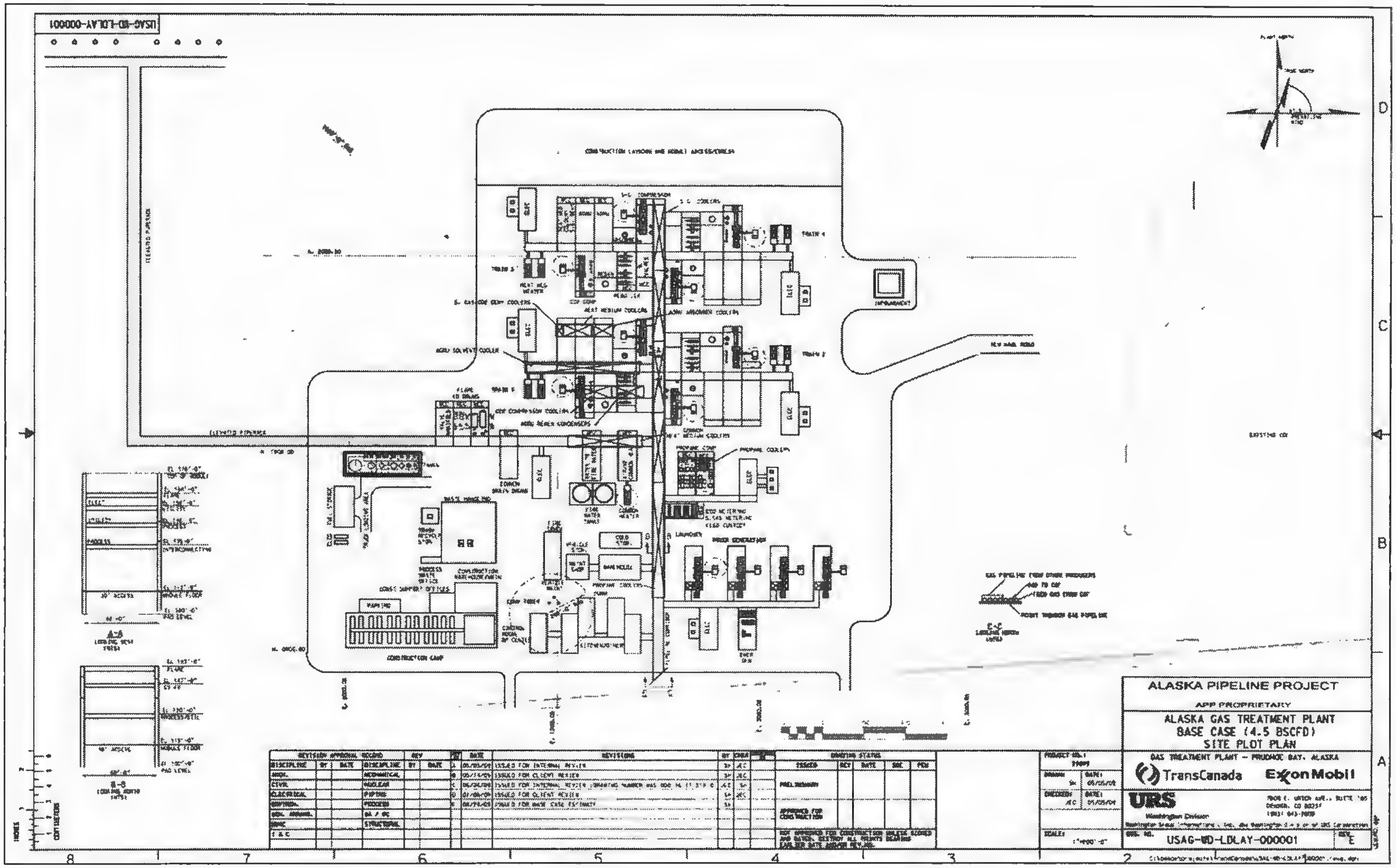
Appendix C
Exhibit A

Point Thomson Pipeline
Segment to GTP

Appendix C

Exhibit B
Route Map - GTP Site Layout

Appendix C
Exhibit B



GTP Site Layout

<u>Appendix C</u>

Exhibit C
Route Map - Alaska-Canada Pipeline, GTP to Canadian Border

Alaska-Canada Pipeline, GTP to Canadian Border

Appendix C

Exhibit D
Route Map - Canadian Pipeline, Canadian Border to Alberta

Canadian Pipeline, Canadian Border to Alberta

Appendix C
Exhibit D

Appendix C

Exhibit E
Route Map - Valdez Pipeline, GTP to Valdez

Appendix C
Exhibit E

Valdez Pipeline, GTP to Valdez

Appendix C

Exhibit F
Preliminary Finance Plan

Preliminary Finance Plan

This Preliminary Finance Plan (the "Plan") presents the base-case view of the financing structure and costs associated with the Alaska Pipeline Project ("Project") at the time of the Project's Open Season regulatory filing. In developing this Plan, the Project has reviewed current financial market conditions, consulted with representatives of the banking community, and held discussions with various relevant government agencies. The specific credit terms, tenor, and rates associated with the Project's contemplated debt financing will depend upon financial market conditions at the time the debt is raised. Moreover, as issues associated with each element of the Plan continue to be progressed, modifications to the Plan may be required.

The Plan contemplates financing the entire project including the gas transmission system from Point Thomson to Prudhoe Bay, the gas treatment plant ("GTP"), the pipeline system from the outlet of the GTP to the Alaska-Canada border, or alternatively, to Valdez, and the pipeline system from the Alaska-Canada border to the B.C.-Alberta border near Boundary Lake. At this stage, no distinction is made between financing the U.S. and the Canadian portions of the project. The Plan assumes the Project will be 'project-financed' and the debt will have limited recourse to the Sponsors.

In order to maximize the capital available to the Project while minimizing costs, the Plan targets a Project credit rating of at least A-/A3. A key element in achieving the target rating will be the credit provisions for Foundation Shippers who will be required to maintain a credit rating equal to or greater than A-/A3 and meet an acceptable tangible net worth threshold. For other shippers whose commitment is less than 200,000 MMBtu/d, a BBB/Baa2 credit rating plus an acceptable tangible net worth threshold will be required.

The Alaska Natural Gas Pipeline Act of 2004 ("ANGPA") provides for the issuance of Federal Loan Guarantees ("FLG") by the U.S. Department of Energy ("DOE") to the holders of certificates for the construction and operation of the Alaska pipeline (Section 116). The Project recognizes that there are potential benefits and costs associated with securing FLGs. One of the primary objectives of the Project is to work with DOE to clarify the terms and conditions of the FLG.

The Project has identified capital cost overrun credit support as one of the possible uses of the FLG. At this early stage, it is premature to estimate the amount of capital cost overrun provision that might be required. For the purpose of determining the indicative tolls, 100% of the FLG at the current legislated amount of $18 billion (2004$) is assumed to be available for providing credit support to the base capital cost. As the project plans are refined and updated over time, and subject to the U.S. Government approval and the debt market capacity and availability, the viability and amount of FLG allocated for supporting the potential capital cost overruns will be evaluated and determined.

Amendments to the ANGPA provisions have been proposed and are currently working their way through the legislative process. Notably, it is proposed that the maximum amount of any outstanding guarantees be raised to $30 billion (2004$) and that application of the guarantees be made more flexible to accommodate the complexity of the anticipated financing.

Equity contributions from Sponsors will finance project development during the period up to Project Sanction and, thereafter, pro-rata with debt to fund the capital expenditures to provide an overall target debt equity ratio of 70/30 during the construction phase. Upon completion of the entire Project, including the GTP, the equity ratio will be reduced to 25% through a corresponding take-out financing in the debt market.

Indications from financial institutions suggest that bank debt will be limited in terms of capacity and tenor. Bank commitments will be secured upfront and will be available during the construction phase to supplement the bond debt program. Once the Project is operational and financial completion has been achieved, the bank loan is assumed to be taken out by further issuances of bond debt.

Financing will rely heavily on the depth and capacity of the bond market. As such, a multi-year bond program – consisting of numerous tranches of various tenors – is likely during the construction phase in order to minimize negative carry. The program will be structured such that the bonds will have laddered bullet maturities to match the tariff depreciation profile. The majority of bonds will carry the backing of the FLGs ("Covered Bonds"), but, based on the limited capacity associated with the currently legislated FLG, a portion will not ("Uncovered Bonds").

Interest rate assumptions in the Plan are:

- Debt with FLG support – 10-year U.S. Treasury rate + 75 bps
- Debt without FLG support – 10-year U.S. Treasury rate + 300 bps

Appendix C

Exhibit G
Data Room Confidentiality Undertaking

CONFIDENTIALITY UNDERTAKING

To: ExxonMobil Alaska Midstream Gas Investments, LLC ("**EMAMGI**"),
TransCanada Alaska Development Inc. ("**TC Development**"),
or any of their respective Affiliates
(individually or collectively referred to as "**APP**")

I, ______________________("Reviewer") acknowledge that during my review of data room materials associated with the Open Season being conducted by APP on behalf of TransCanada Alaska Company, LLC ("Open Season Review"), I will have access, directly and indirectly, to Alaska Pipeline Project Confidential Information. For the purposes of this Undertaking, defined terms shall have the meaning as assigned in Annex A attached hereto or as otherwise specified in this Undertaking.

1. Ownership and Confidentiality of Information

A. I acknowledge that none of the Confidential Information obtained by me in the course of the Open Season Review is my property or the property of the company or companies I represent, specifically ________________________________ ("Stakeholder").

B. I will hold all Confidential Information I obtain in the course of my data room review strictly confidential for a period of ten (10) years from the date hereof, and shall not disclose Confidential Information to anyone except the Stakeholder without the prior written consent of APP, except I may disclose Confidential Information if I demonstrate it is publicly available as of the date of this Undertaking other than as a result of a disclosure in violation of this Undertaking.

C. Unless authorized in writing by APP, I will use Confidential Information only for purposes of evaluating Stakeholder's possible participation in the Open Season being conducted by APP on behalf of TransCanada Alaska Company, LLC.

D. I will keep the terms of this Undertaking confidential.

2. Competitive Advantage

I acknowledge that Confidential Information which I obtain may comprise confidential business and technical information which enables APP and TransCanada Alaska Company, LLC to obtain or maintain a competitive position. If I am unsure if any information is subject to this Undertaking, I will ask APP for a determination as to the applicability of this Undertaking to the information, and I will abide by the advice given by APP.

3. Breach of Confidentiality

Confidential Information is a valuable asset that is difficult or not possible to value. Accordingly, APP may seek to enforce the confidentiality provisions of this Undertaking by injunctive action or specific performance, and I waive any requirement for the posting of a bond in connection with any such equitable relief.

4. **Disclaimer of Warranties**

REVIEWER ACKNOWLEDGES THAT TC DEVELOPMENT AND EMAMGI RESPECTIVELY, AS DISCLOSING PARTIES, MAKE NO REPRESENTATIONS OR WARRANTIES, EXPRESS OR IMPLIED, TO REVIEWER OR TO STAKEHOLDER, AS TO (A) THE QUALITY, ADEQUACY, RELIABILITY, ACCURACY, OR COMPLETENESS OF THE INFORMATION DISCLOSED UNDER OR IN CONNECTION WITH THIS UNDERTAKING; OR (B) WHETHER SUCH INFORMATION CAN OR CANNOT BE USED BY REVIEWER OR STAKEHOLDER WITHOUT INFRINGING ANY THIRD PARTY PATENTS OR COPYRIGHTS. NEITHER TC DEVELOPMENT, EMAMGI NOR THE OFFICERS, DIRECTORS, OR EMPLOYEES OF TC DEVELOPMENT AND EMAMGI OR THEIR RESPECTIVE AFFILIATES SHALL HAVE ANY LIABILITY TO REVIEWER OR STAKEHOLDER NOR ANY OTHER PERSON RESULTING FROM THE USE OF CONFIDENTIAL INFORMATION DISCLOSED PURSUANT TO THIS UNDERTAKING. EXPLANATIONS, DISCUSSIONS, OR OTHER COMMUNICATIONS BETWEEN TC DEVELOPMENT, EMAMGI, REVIEWER OR STAKEHOLDER CONCERNING THE CONFIDENTIAL INFORMATION, AND ANY SUBSEQUENT JOINT USE OF THE CONFIDENTIAL INFORMATION SHALL NOT CONSTITUTE, AND SHOULD NOT BE CONSTRUED AS, A REPRESENTATION OR WARRANTY BY TC DEVELOPMENT AND EMAMGI THAT THE CONFIDENTIAL INFORMATION IS ACCURATE, COMPLETE OR SUITABLE FOR THE LIMITED PURPOSE OR FOR ANY OTHER USE. ANY ASSESSMENTS, CONCLUSIONS, AND APPLICATIONS REVIEWER OR STAKEHOLDER DERIVES FROM THE CONFIDENTIAL INFORMATION ARE AT REVIEWER'S AND STAKEHOLDER'S SOLE RISK.

5. **Further Undertaking**

During the course of my data room review I agree to be bound by and to conduct my review in accordance with the Data Room Guidelines and Procedures, attached hereto as Annex B.

______________________________ _________________________

Date

Annex A

"**Affiliate**" means, in relation to the specified Person, a Person which:

A. directly or indirectly, through one or more intermediaries or otherwise, controls the specified Person;

B. is directly or indirectly controlled by the specified Person; or

C. is directly or indirectly under common control by a Person that directly or indirectly controls the specified Person; where "control" means:

   1. with respect to the entity in question, the right to exercise votes attaching to more than fifty percent (50%) of its voting stock (capital stock of that entity having general voting power under ordinary circumstances to appoint or elect the directors, managers, or trustees, or persons with management authority to perform similar functions, of that entity, irrespective of whether or not at the time other capital stock or other securities of that entity of any class, classes, or series has or might have voting power by reason of the happening of any contingency); or

   2. the power to direct or cause the direction of the management or policies of the specified Person, whether through the ownership of securities, by contract, or otherwise.

"**Alaska Pipeline Project**" includes the following elements:

A. A FERC jurisdictional gas treatment plant ("GTP") near Prudhoe Bay, Alaska, which will treat North Slope gas for pipeline transportation;

B. A FERC jurisdictional gas transmission pipeline connecting the Point Thomson field in Alaska to the GTP and from there either (1) to the Alaska/Canada border for onward delivery to Alberta, Canada; or (2) to Valdez, Alaska;

C. Any other elements described as being part of the Alaska Pipeline Project by APP.

"**Confidential Information**" means any information, technology, data, results of tests or studies, reports, books, operating manuals, maintenance manuals, technical manuals, drawings, plans, schedules, or records related to the Alaska Pipeline Project, including the strategies, methods, and business relationships of APP.

"**Person**" means any natural person, entity, estate, labor union, or governmental authority.

"**Third Party**" means any Person other than the parties hereto or any Affiliate of any of them.

Appendix C

Exhibit H
Open Season Data Room Guidelines and Procedures

Data Room Guidelines and Procedures

1. Access to data rooms shall be conditioned on reviewing person's signing the Confidentiality Undertaking, including agreeing to comply with these data room guidelines and procedures. Pro-forma copies of both documents shall be available in the data room for reference.

2. Hours of Operation are 8 a.m. to 12 p.m. and 1 p.m. to 5 p.m., local time, Monday through Friday, excluding holidays recognized in the respective data room's location.

3. APP shall designate a data room Coordinator for each data room it will make available who shall manage the data room on behalf of APP and who shall be the point person with reviewing persons regarding use of that data room. APP shall provide reviewing persons with contact information for each such data room Coordinator.

4. Requests by reviewing persons for an appointment to visit a data room shall be made through the respective data room's Coordinator. Each respective data room Coordinator shall schedule data room visits so as to reasonably accommodate the requirements of each reviewing person, subject to ensuring that all reviewing persons interested in visiting the respective data room in question are accommodated. The reviewing person or persons representing an individual stakeholder and that stakeholder's affiliates shall have exclusive access to the visited data room during a scheduled data room review session.

5. The data room Coordinator shall arrange that a data room monitor is available to monitor the data room on behalf of APP at all times during a reviewing person's visit. Reviewing persons shall cooperate with the data room Coordinator in addressing reasonable requests to reschedule or otherwise adjust visiting hours to ensure full time monitoring of the data rooms during visits.

6. Personal portable computers and Dictaphones are permitted in the data rooms for use by reviewing persons for the purposes of taking notes only. However, no other electronic equipment including cell phones, portable faxes, photocopiers, scanners and cameras will be permitted in the data rooms, nor shall any visiting person use any such technology that may be included in that reviewing person's portable computers at any time during such reviewing person's data room visit. APP will provide a secure site at each data room location for visiting persons to store any such prohibited technology during a data room visit.

7. Copies of data room material will be provided at APP sole discretion, following a written request, directed to the respective data room Coordinator. APP reserves the right, to the extent it, in its sole discretion, grants any copying requests, to impose any additional confidentiality obligations it deems appropriate to protect the confidentiality of APP data, including requiring a supplemental confidentiality undertaking.

8. <u>No documents or materials in the data rooms may be marked or altered in any way or removed from the data rooms.</u>

9. No briefcases, personal folders, etc. will be allowed in the data rooms.

10. No white page documents will be allowed into or out of the data rooms without prior review by the data room monitor.

11. Reviewing persons shall submit any questions relating to the documents and information in the data rooms using the form attached hereto as Attachment A. The data room Coordinator shall provide a response on behalf of APP as soon as reasonably practicable. APP reserves the right not to answer any questions in its sole discretion. Questions and the corresponding APP response, if any, shall be logged and made available for review by all interested stakeholders in the APP data rooms. As a matter of convenience, question forms will be available in the data rooms and may be submitted to the data room monitor for onward submission to and consideration by the data room Coordinator.

Attachment A

APP Open Season Data Room
ExxonMobil Data Room Question and Answer Sheet

Question:

Printed Name	Signature	Date
Company	Phone	Email

Answer:

Printed Name	Signature	Date

Appendix C

Exhibit I
Indicative FERC Gas Tariff

TransCanada Alaska Company LLC

INDICATIVE FERC GAS TARIFF

Communications Concerning This Tariff
Should Be Addressed To:

[insert]
Agent and Attorney-in-Fact

Telephone:
Facsimile:

TransCanada Alaska Company LLC
[address]

TABLE OF CONTENTS

Sheet Nos. 2 and 3
have not been issued and are
being reserved for future use.

PRELIMINARY STATEMENT

TransCanada Alaska Company LLC (TransCanada Alaska) is a natural gas Transporter primarily engaged in the business of transporting and treating natural gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission").

TransCanada Alaska is organized and existing under the laws of Delaware and provides service to Shippers that have executed Agreements in the forms contained in this Tariff or other Agreements approved by FERC.

TransCanada Alaska's transportation facilities commence from production facilities at Point Thomson, extend to a gas treatment plant near Prudhoe Bay and continue to an interconnection with Foothills Pipe Lines (South Yukon) Ltd. at the Alaska/Yukon border.

The currently effective rates, rate schedules, general terms and conditions, and forms of agreements applicable to the services performed by TransCanada Alaska are contained herein.

[insert map]

STATEMENT OF RECOURSE RATES[1/] [2/]

Rate Schedule	Base Tariff Rate
FT-1	
Zone 1	
Reservation Rate ($ per MMBtu of contractual entitlements)	
Maximum	[$]
Minimum	[$]
Commodity Rate ($ per MMBtu)	
Maximum	[$]
Minimum	[$]
Authorized Overrun Commodity Rate ($ per MMBtu)	[$]
Zone 2: Treatment Quantities	
Reservation Rate ($ per MMBtu of contractual entitlements)	
Maximum	[$]
Minimum	[$]
Commodity Rate ($ per MMBtu)	
Maximum	[$]
Minimum	[$]
Authorized Overrun Commodity Rate ($ per MMBtu)	[$]

[1/]Transporter's Recourse Rates shall be adjusted annually to reflect a return on equity equal to the U.S. 10-year Treasury Note rate plus 965 basis points and may also be adjusted pursuant to Section 4 of the Natural Gas Act.

[2/]All Shippers shall provide Transporter Fuel and Lost and Unaccounted for Gas under Section 41 of the General Terms and Conditions.

STATEMENT OF RECOURSE RATES[1/] [2/] (Continued)

Rate Schedule	Base Tariff Rate
FT-1	
Zone 3: In-State Deliveries	
Reservation Rate ($ per MMBtu of contractual entitlements)	
Maximum	[$]
Minimum	[$]
Commodity Rate ($ per MMBtu)	
Maximum	[$]
Minimum	[$]
Authorized Overrun Commodity Rate ($ per MMBtu)	[$]
Zone 3: Export Deliveries	
Reservation Rate ($ per MMBtu of contractual entitlements)	
Maximum	[$]
Minimum	[$]
Commodity Rate ($ per MMBtu)	
Maximum	[$]
Minimum	[$]
Authorized Overrun Commodity Rate ($ per MMBtu)	[$]

[1/] Transporter's Recourse Rates shall be adjusted annually to reflect a return on equity equal to the U.S. 10-year Treasury Note rate plus 965 basis points and may also be adjusted pursuant to Section 4 of the Natural Gas Act.

[2/] All Shippers shall provide Transporter Fuel and Lost and Unaccounted for Gas under Section 41 of the General Terms and Conditions.

STATEMENT OF RECOURSE RATES[1/] [2/]

Rate Schedule	Base Tariff Rate
IT-1	
Maximum	[$]
Minimum	[$]
Treatment Quantities per MMBtu	[$]
PAL	
Daily Maximum Reservation Rate per MMBtu	[$]
Daily Minimum Reservation Rate per MMBtu	[$]
Daily Maximum Commodity Rate per MMBtu	[$]
Daily Minimum Commodity Rate per MMBtu	[$]

[1/]Transporter's Recourse Rates shall be adjusted annually to reflect a return on equity equal to the U.S. 10-year Treasury Note rate plus 965 basis points and may also be adjusted pursuant to Section 4 of the Natural Gas Act.

[2/]All Shippers shall provide Transporter Fuel and Lost and Unaccounted for Gas under Section 41 of the General Terms and Conditions.

STATEMENT OF RECOURSE RATES

Rates per MMBtu

	Commodity Rate
Annual Charge Adjustment ("ACA") Rate[1/]	[$]
Change in Law/Tax/Regulation Surcharge[1/]	[$]

[1/] Rates are charged in accordance with Section 16 of the General Terms and Conditions.

STATEMENT OF NEGOTIATED RATES[1/] [2/] [3/]

Shipper Name	Agreement Number	Rate Schedule	Maximum Contractual [MMBtu or Mcf/d]	Reservation Rate	Commodity Rate	Authorized Overrun Rate[4/]	Receipt Point ------------- Name	Delivery Point -------------- Name	Contract Term

[1/]Unless otherwise noted, Negotiated Rate service agreements do not deviate in any material respect from the applicable Form of Service Agreement set forth in Transporter's FERC Gas Tariff.

[2/]Unless otherwise noted, this Tariff sheet reflects the essential elements of the Negotiated Rates, including a specification of all consideration.

[3/]All Shippers shall provide Transporter Fuel and Lost and Unaccounted for Gas under Section 41 of the General Terms and Conditions.

[4/]The negotiated Authorized Overrun Rate shall be set at the 100% load factor Recourse Rate.

Sheet Nos. 11 through 99
have not been issued and are
being reserved for future use.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

1. AVAILABILITY

This Rate Schedule is available to any Person (hereinafter referred to as Shipper) desiring the transportation of natural gas on a firm basis, provided the capacity is or will be available on a firm basis on Transporter's facilities for the term of service requested and provided further that Shipper has made arrangements acceptable to Transporter on upstream and downstream facilities.

2. QUALIFICATION FOR SERVICE

2.1 Requests for firm transportation service under this Rate Schedule shall be subject to Section 30 of the General Terms and Conditions.

2.2 Requests for firm service under this Rate Schedule shall satisfy the creditworthiness provisions under Section 41 of the General Terms and Conditions.

2.3 Requests for firm service under this Rate Schedule and qualifying for service shall execute a Rate Schedule FT-1 Service Agreement with Transporter prior to the Billing Commencement Date.

3. APPLICABILITY AND CHARACTER OF SERVICE

3.1 This Rate Schedule shall apply to firm transportation of natural gas provided pursuant to the terms of Shipper's Rate Schedule FT-1 Service Agreement. This service shall be provided to any Shipper, on a non-discriminatory basis, to the extent Transporter determines firm capacity is available.

3.2 Except as otherwise required by law, Transporter shall not be required to modify, install, operate, or maintain any facilities on its pipeline system in order to provide transportation service under this Rate Schedule. However, Transporter may modify, install, operate, or maintain facilities on its pipeline system in accordance with Section 19 of the General Terms and Conditions.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

4. RATES

4.1 Applicable Rates and Charges

The applicable rates for service under this Rate Schedule are set forth on the currently effective Statement of Rates of this Tariff and are incorporated herein. For all service hereunder, Shipper shall pay Transporter each month the sum of the applicable charges listed in this Section 4.

4.2 Transportation Rates and Charges

Shipper shall pay Transporter each month the sum of the charges listed below:

4.2.1 Reservation Charge - The product of 1) the applicable reservation rate per MMBtu for transportation or treatment in accordance with Exhibit A of the Rate Schedule FT-1 Service Agreement and 2) Shipper's Maximum Delivery Quantity as set forth on Exhibit A of Shipper's Rate Schedule FT-1 Service Agreement. Reservation Charges shall be reduced for amounts received from Replacement Shippers. Except as provided in Section 4.7.2, Reservation Charges shall not be reduced during periods of interruption of firm service.

4.2.2 Commodity Charge - The daily Maximum Commodity Rate set forth on the Statement of Rates for Rate Schedule FT-1 multiplied by the quantity of gas delivered on an MMBtu basis or treated by Transporter under Rate Schedule FT-1 for Shipper.

4.3 Gas Treatment Service Charges

Shipper shall pay Transporter the Gas Treatment Service Charges in Section 4.2 if

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

4. RATES (Continued)

4.3 Gas Treatment Service Charges (continued)

Shipper elects to have natural gas tendered to Transporter under this Rate Schedule treated in Transporter's jurisdictional facilities.

4.4 Other Rates and Charges

4.4.1 Annual Charge Adjustment ("ACA")and Change in Law/Regulation Surcharge

Shipper shall pay Transporter the ACA and other surcharges as defined and computed in accordance with Section 16 of the General Terms and Conditions.

4.4.2 Other Charges

Transporter reserves the right to seek authorization to collect various surcharges and other types of rates other than those identified in this Section 4. Shipper shall pay Transporter for any other applicable FERC approved charges that apply to service under this Rate Schedule.

4.4.3 Third Party Charges

Shipper may, on a non-discriminatory basis, be required to pay Transporter, if applicable, any Third Party Charges for off-system service in accordance with Subsection 39.2 of the General Terms and Conditions. In no event shall such Third Party Charges paid by Shipper exceed the amount incurred and paid by Transporter for the applicable off-system services.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

4. RATES (Continued)

4.4.4 Backhaul Charge

For any Backhaul, Shipper shall pay Transporter the applicable rates and charges set forth in Subsections 4.2 and 4.3 herein plus the lost and unaccounted for component of the Transporter Fuel and Lost and Unaccounted for Gas Percentage, as set forth in Section 41 of the General Terms and Conditions.

4.5 Discounted Rates

Notwithstanding the foregoing provisions of this Section 4, Transporter may agree to discounted rates for service hereunder in accordance with Section 38 of the General Terms and Conditions.

In the event secondary points are utilized which impact the directional flow of a discounted Backhaul transaction, such Backhaul discount shall not be applicable to such secondary points unless otherwise expressly agreed to in writing by Transporter. Utilization of such secondary points shall be billed the applicable Maximum Commodity Rate under Rate Schedule IT-1 set forth on the currently effective Statement of Rates.

4.6 Negotiated Rates

Notwithstanding the foregoing provisions of this Section 4, Transporter and Shipper may mutually agree to Negotiated Rates for service hereunder as provided in Section 38 of the General Terms and Conditions.

4.7 Shipper's Obligation to Pay

In accordance with Section 6 of the General Terms and Conditions, Shipper shall be obligated to pay to Transporter its respective monthly billing invoice effective on the Billing Commencement Date of the respective Service Agreement.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

5. TRANSPORTER FUEL AND LOST AND UNACCOUNTED FOR GAS

Shipper shall provide Transporter Fuel and Lost and Unaccounted for Gas associated with rendering transportation service pursuant to this Rate Schedule. The applicable Transporter Fuel and Lost and Unaccounted for Gas Percentage shall be posted on Transporter's public Internet website in accordance with Section 41 of the General Terms and Conditions. Separate Transporter Fuel and Lost and Unaccounted for Gas quantities will be identified for Shippers electing Transporter's gas treatment services.

6. AUTHORIZED OVERRUN SERVICE ("AOS")

Quantities of gas Shipper desires to transport in excess of Shipper's Maximum Delivery Quantity shall be scheduled in accordance with General Terms and Conditions Section 10.5.1 and shall be subject to the Maximum AOS Rate, unless a rate is otherwise agreed to by Transporter, in a not unduly discriminatory manner.

7. RIGHT OF FIRST REFUSAL

A right of first refusal shall be applicable to a Shipper receiving service in accordance with Section 18 of the General Terms and Conditions.

8. RELEASE OF FIRM CAPACITY

Any Shipper receiving service under this Rate Schedule FT-1 shall have the right to release its firm capacity rights on a permanent or temporary basis in accordance with Section 27 of the General Terms and Conditions or the applicable Service Agreement, provided, however, that Transporter may refuse to allow a release if it has a reasonable basis to conclude that it will not be financially or economically indifferent to the release.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

9. UNIFORM QUANTITIES

As nearly as practical, Shipper shall deliver and receive gas in uniform hourly quantities during any day. However, Transporter shall use its reasonable efforts, as operational conditions permit, to allow a Shipper to deliver or receive gas in non-uniform hourly quantities during any day.

10. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff are applicable to this Rate Schedule and service hereunder and are made a part hereof to the extent that such terms and conditions are not contradicted by any provision herein. To the extent any terms and conditions specified in this Rate Schedule are inconsistent with the General Terms and Conditions, the Rate Schedule shall govern. To the extent that any terms and conditions in this Rate Schedule or in the General Terms and Conditions are inconsistent with the Rate Schedule FT-1 Firm Transportation Agreement, the terms of the Rate Schedule FT-1 Firm Transportation Agreement shall govern.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

11. OPTIONAL FIRM GAS TREATMENT SERVICE

11.1 AVAILABILITY

This Service is available to any Person which has executed a Rate Schedule FT-1 Firm Transportation Service Agreement (hereinafter referred to as Shipper) desiring the treatment of natural gas on a firm basis provided the capacity is or will be available on a firm basis on Transporter's gas treatment plant facilities for the term of service requested.

11.2 QUALIFICATION FOR SERVICE

Requests for firm gas treatment service shall be subject to Section 30 of the General Terms and Conditions.

11.3 APPLICABILITY AND CHARACTER OF SERVICE

11.3.1 This service shall be provided to any Shipper, on a non-discriminatory basis, to the extent Transporter determines firm gas treatment service capacity is available.

11.3.2 Except as required by law, Transporter shall not be required to modify, install, operate, or maintain any facilities on its pipeline system in order to provide gas treatment service. However, Transporter may modify, install, operate, or maintain facilities on its pipeline system in accordance with Section 19 of the General Terms and Conditions.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

11. OPTIONAL FIRM GAS TREATMENT SERVICE (Continued)

11.3 APPLICABILITY AND CHARACTER OF SERVICE (Continued)

11.3.3 Gas Treatment Service shall include the removal of acid gas (CO_2 and sulfur), and the dehydration and compression of both acid gas and gas delivered at the outlet of the Gas Treatment Plant ("GTP") for downstream transportation. Acid gas removal and the refrigeration, dehydration and compression of gas will allow Shipper to meet the gas quality specifications applicable to downstream facilities.

11.4 RATES

11.4.1 Applicable Rates and Charges

The applicable rates for gas treatment service are set forth on the currently effective Statement of Rates of this Tariff and are incorporated herein. For all service hereunder, Shipper shall pay Transporter each month the sum of the applicable charges listed in this Section 11.4.

11.4.2 Gas Treatment Service Rates and Charges

Shipper shall pay Transporter each month the applicable charges listed below:

11.4.2.1 The product of the Gas Treatment Reservation Rate and Shipper's Maximum Treatment Quantity.

RATE SCHEDULE FT-1

FIRM TRANSPORTATION SERVICE

11. OPTIONAL FIRM GAS TREATMENT SERVICE (Continued)

11.4. RATES (Continued)

11.4.2 Gas Treatment Service Rates and Charges (Continued)

11.4.2.2 The product of the Maximum Gas Treatment Commodity Rate set forth on the Statement of Rates multiplied by the quantity of gas treated.

11.4.3 Other Rates and Charges

Transporter reserves the right to seek authorization to collect various other surcharges and other types of rates other than those identified in this Section 11.4. Shipper shall pay Transporter for any other applicable FERC approved charges that apply to gas treatment service.

11.5 Discounted Rates

Notwithstanding the foregoing provisions of this Section 11.4, Transporter may agree to discounted rates for gas treatment service in accordance with Section 38 of the General Terms and Conditions.

11.6 Negotiated Rates

Notwithstanding the foregoing provisions of this Section 11.4, Transporter and Shipper may mutually agree to Negotiated Rates for gas treatment service as provided in Section 37 of the General Terms and Conditions.

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE

11. OPTIONAL FIRM GAS TREATMENT SERVICE (Continued)

11.7 TRANSPORTER FUEL AND LOST AND UNACCOUNTED FOR GAS

Shipper shall provide Transporter Fuel and Lost and Unaccounted for Gas associated with rendering gas treatment service. The applicable Transporter Fuel and Lost and Unaccounted for Gas Quantities Percentage shall be posted on Transporter's public Internet website in accordance with Section 42 of the General Terms and Conditions.

11.8 AUTHORIZED OVERRUN

Quantities of gas Shipper desires to treat in excess of Shipper’s Maximum Treatment Quantity shall be scheduled in accordance with General Terms and Conditions Section 10.5.1 and shall be subject to the Maximum AOS gas treatment charge unless a rate is otherwise agreed to by Transporter, in a not unduly discriminatory manner.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

1. AVAILABILITY

This Rate Schedule is available to any Person (hereinafter referred to as Shipper) desiring the transportation of natural gas on an interruptible basis.

2. QUALIFICATION FOR SERVICE

2.1 Requests for interruptible transportation service under this Rate Schedule shall be subject to Section 30 of the General Terms and Conditions.

2.2 Shippers requesting interruptible service under this Rate Schedule shall satisfy the creditworthiness provisions under Section 40 of the General Terms and Conditions. Demonstration of creditworthiness will be required upon Transporter's receipt of each nomination pursuant to Section 10 of the General Terms and Conditions.

2.3 Shippers qualifying for service under this Rate Schedule shall execute a Rate Schedule IT-1 Interruptible Transportation Agreement with Transporter prior to commencement of service.

3. APPLICABILITY AND CHARACTER OF SERVICE

3.1 This Rate Schedule shall apply to the interruptible transportation of natural gas up to the Total Interruptible Delivery Quantity set forth on Exhibit A of Shipper's Rate Schedule IT-1 Interruptible Transportation Agreement. This service shall be provided to any Shipper, on a non-discriminatory basis, and shall be allocated in accordance with Section 10 of the General Terms and Conditions.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

3. APPLICABILITY AND CHARACTER OF SERVICE (Continued)

3.2 Transporter shall not be required to modify, install, operate, or maintain any facilities on its pipeline system in order to provide transportation service under this Rate Schedule. However, Transporter may modify, install, operate, or maintain facilities on its pipeline system in accordance with Section 19 of the General Terms and Conditions.

4. RATES

4.1 Applicable Rates and Charges

The applicable rates for service under this Rate Schedule are set forth on the currently effective Statement of Rates of this Tariff and are incorporated herein. For all service rendered hereunder, Shipper shall pay Transporter each month the sum of the applicable charges listed in this Section 4.

4.2 Transportation Rates and Charges

Shipper shall pay Transporter each month the applicable charges listed below:

4.2.1 Commodity Charge - The daily Maximum Commodity Rate set forth on the Statement of Rates for Rate Schedule IT-1 multiplied by the quantity of gas delivered by Transporter under Rate Schedule IT-1 for Shipper.

4.2.2 Gas Treatment Service Charges

Shipper shall pay Transporter's Gas Treatment Service Charges if Shipper elects to have natural gas tendered to Transporter under this Rate Schedule treated in Transporter's gas treatment plant facilities.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

4. RATES (Continued)

4.2 Transportation Rates and Charges (Continued)

4.2.3 Annual Charge Adjustment ("ACA") Shipper shall pay Transporter the ACA and other surcharges as defined and computed in accordance with Section 16 of the General Terms and Conditions.

4.2.4 Other Charges

Transporter reserves the right to seek authorization to collect various surcharges and other types of rates under this Section 4. Shipper shall pay Transporter for any other applicable FERC approved charges that apply to service under this Rate Schedule.

4.2.5 Third Party Charges

Shipper may, on a non-discriminatory basis, be required to pay Transporter, if applicable, any Third Party Charges in accordance with Subsection 39.2 of the General Terms and Conditions. In no event shall such Third Party Charges paid by Shipper exceed the amount incurred and paid by Transporter for the applicable services.

4.2.6 Backhaul Charge

For any Backhaul, Shipper shall pay Transporter the applicable rates and charges set forth in Subsections 4.2 and 4.3 herein plus the lost and unaccounted for component of the Transporter Fuel and Lost and Unaccounted for Gas Percentage, as set forth in Section 41 of the General Terms and Conditions

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

4. RATES (Continued)

4.3 Discounted Rates

Notwithstanding the foregoing provisions of this Section 4, Transporter may agree to discounted rates for service hereunder in accordance with Section 38 of the General Terms and Conditions.

In the event secondary points are utilized which impact the directional flow of a discounted Backhaul transaction, such Backhaul discount shall not be applicable to such secondary points unless otherwise expressly agreed to in writing by Transporter. Utilization of such secondary points shall be billed the applicable Maximum Commodity Rate under Rate Schedule IT-1 set forth on the currently effective Statement of Rates.

4.4 Negotiated Rates

Notwithstanding the foregoing provisions of this Section 4, Transporter and Shipper may mutually agree to Negotiated Rates for service hereunder as provided in Section 37 of the General Terms and Conditions.

5. TRANSPORTER FUEL AND LOST AND UNACCOUNTED FOR GAS

Shipper shall provide Transporter Fuel and Lost and Unaccounted for Gas associated with rendering Forwardhaul transportation service pursuant to this Rate Schedule. The applicable Transporter Fuel and Lost and Unaccounted for Gas Quantities Percentage shall be posted on Transporter's public Internet website in accordance with Section 41 of the General Terms and Conditions.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

6. UNIFORM QUANTITIES

As nearly as practical, Shipper shall deliver and receive gas in uniform hourly quantities during any day. However, Transporter shall use its reasonable efforts, as operational conditions permit, to allow a Shipper to deliver or receive gas in non-uniform hourly quantities during any day.

7. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff are applicable to this Rate Schedule and service hereunder and are made a part hereof to the extent that such terms and conditions are not contradicted by any provision herein. To the extent any terms and conditions specified in this Rate Schedule are inconsistent with the General Terms and Conditions, this Rate Schedule shall govern.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

8. OPTIONAL INTERRUPTIBLE GAS TREATMENT SERVICE

8.1 Availability

This service is available to any Person which has executed an Interruptible Transportation Service Agreement (hereinafter referred to as Shipper) desiring the treatment of natural gas on an interruptible basis.

8.2 Qualification For Service

8.2.1 Requests for interruptible gas treatment service shall be subject to Section 30 of the General Terms and Conditions.

8.2.2 Shippers requesting interruptible gas treatment service shall satisfy the creditworthiness provisions under Section 40 of the General Terms and Conditions. Demonstration of creditworthiness will be required upon Transporter's receipt of each nomination pursuant to Section 10 of the General Terms and Conditions.

8.3. Applicability And Character Of Service

8.3.1 This service shall be provided to any Shipper, on a non-discriminatory basis, and shall be allocated in accordance with Section 10 of the General Terms and Conditions.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

8. OPTIONAL INTERRUPTIBLE GAS TREATMENT SERVICE (Continued)

8.3 Applicability And Character Of Service (Continued)

8.3.2 Transporter shall not be required to modify, install, operate, or maintain any facilities on its pipeline system in order to provide interruptible gas treatment service. However, Transporter may modify, install, operate, or maintain facilities on its pipeline system in accordance with Section 19 of the General Terms and Conditions.

8.4 Charges

8.4.1 Applicable Rates and Charges

The applicable charges for gas treatment service are set forth on the currently effective Statement of Rates of this Tariff and are incorporated herein. For all service rendered hereunder, Shipper shall pay Transporter each month the sum of the applicable charges listed in this Section 8.4.

8.4.2 Gas Treatment Plant Charges

Shipper shall pay Transporter each month the applicable charge listed below:

8.4.2.1 Commodity Charges - The daily Maximum Gas Treatment Charge multiplied by the quantity of gas treated on an MMBtu basis by Transporter.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

8. OPTIONAL INTERRUPTIBLE GAS TREATMENT SERVICE (Continued)

8.4. Charges (Continued)

8.4.3 Other Rates and Charges

8.4.3.2 Other Charges

Transporter reserves the right to seek authorization to collect various surcharges and other types of rates other than those set forth in this Section 8.4. Shipper shall pay Transporter any other applicable FERC approved charges that apply to service under this Rate Schedule.

8.4.3.3 Third Party Charges

Shipper may, on a non-discriminatory basis, be required to pay Transporter, if applicable, any Third Party Charges for off-system services in accordance with Subsection 39.2 of the General Terms and Conditions. In no event shall such Third Party Charges paid by Shipper exceed the amount incurred and paid by Transporter for the applicable off-system services.

RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION SERVICE

8. OPTIONAL INTERRUPTIBLE GAS TREATMENT SERVICE (Continued)

8.5 Discounted Rates

Notwithstanding the foregoing provisions of Section 8.4, Transporter may agree to discounted rates for service hereunder in accordance with Section 38 of the General Terms and Conditions.

8.6 Negotiated Rates

Notwithstanding the foregoing provisions of Section 8.4, Transporter and Shipper may mutually agree to Negotiated Rates for service hereunder as provided in Section 37 of the General Terms and Conditions.

8.7. Transporter Fuel and Lost and Unaccounted for Gas

Shipper shall provide Transporter Fuel and Lost and Unaccounted for Gas associated with rendering gas treatment service. The applicable Transporter Fuel and Lost and Unaccounted for Gas quantities shall be posted on Transporter's public Internet website in accordance with Section 41 of the General Terms and Conditions.

Sheet Nos. 119 through 131
have not been issued and are
being reserved for future use.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

1. AVAILABILITY

1.1 Availability of Service

This Rate Schedule is available to any Person desiring interruptible park and loan (“PAL”) service from Transporter which has executed a PAL Agreement under this Rate Schedule (a "Shipper" for purposes of this Rate Schedule). Transporter shall provide PAL service on a non-discriminatory basis: (1) subject to Transporter's ability to provide such service and (2) at the sole discretion of Transporter.

1.2 Limits on Service

1.2.1 Existing Facilities and Services

Transporter shall not be required to provide service under this Rate Schedule that would require Transporter to construct or acquire any new facilities, or prevent Transporter from providing any other firm or interruptible service.

1.2.2 Creditworthiness

Transporter shall not be required to execute a PAL Agreement under this Rate Schedule prior to determining the creditworthiness of Shipper. Furthermore, Transporter shall not be required to perform service under this Rate Schedule on behalf of any Shipper who fails to satisfy the creditworthiness provisions under Section 40 of the General Terms and Conditions.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

1. AVAILABILITY (Continued)

1.3 Use of Third Party Storage Services

Transporter may contract for storage services offered by third party service providers for use in providing PAL service. Shipper may, on a non-discriminatory basis, be required to pay Transporter, if applicable, any Third Party Charges in accordance with Subsection 40.2 of the General Terms and Conditions. In no event shall such Third Party Charges paid by Shipper exceed the amount incurred and paid by Transporter for the applicable off-system services.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Applicability of Service

This Rate Schedule shall apply to all PAL services offered by Transporter for Shipper.

2.2 Character of Service

2.2.1 Park Service

Park service is an interruptible service that provides for:

(a) The receipt by Transporter of gas quantities that have been delivered by Shipper at a Park Point(s);

(b) Transporter holding the parked gas quantities; and

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

2. APPLICABILITY AND CHARACTER OF SERVICE (Continued)

2.2 Character of Service (Continued)

2.2.1 Park Service (Continued)

(c) The subsequent return of parked gas quantities to the Shipper at such Park Point(s), or a mutually agreeable alternative Park Point(s), subject to Subsection 4.2 of this Rate Schedule.

2.2.2 Loan Service

Loan service is an interruptible service that provides for:

(a) The receipt of gas quantities by Shipper from Transporter at a Loan Point(s),

(b) The subsequent return of the loaned gas quantities to the Transporter at such Loan Point(s), or a mutually agreeable alternative Loan Point(s), subject to Subsection 4.2 of this Rate Schedule.

Transporter shall attempt to park a quantity of gas provided by Shipper or loan a quantity of gas to Shipper up to the Maximum PAL Quantity stated in Mcf or MMBtu as specified in the effective Rate Schedule PAL Agreement. All PAL service shall be subject to confirmation by Transporter prior to being scheduled.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

2. APPLICABILITY AND CHARACTER OF SERVICE (Continued)

2.3 Term of Service

Service under this Rate Schedule shall be provided for a minimum of one (1) day and a maximum term set forth in the effective Rate Schedule PAL Agreement between Shipper and Transporter.

In the event parked quantities remain in Transporter's pipeline system and/or loaned quantities have not been returned to Transporter's pipeline system by the expiration of a Rate Schedule PAL Agreement, Transporter and Shipper may mutually agree to an extended time frame and/or modified terms, including the rate, of such PAL Agreement, to permit Shipper to return such quantities to Transporter or to permit Transporter to return such quantities to Shipper.

2.4 Nominations for Service

Shipper shall nominate PAL services under this Rate Schedule in accordance with the nomination deadlines set forth in Subsection 10.2 of the General Terms and Conditions.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

2. APPLICABILITY AND CHARACTER OF SERVICE (Continued)

2.5 Confirmation and Scheduling of Service

Service under this Rate Schedule shall be confirmed and scheduled, after all Shippers' firm and interruptible transportation services offered by Transporter are confirmed and scheduled.

Existing quantities of gas parked or loaned by Transporter cannot be bumped by new requests for park and/or loan service.

3. RATE AND PAYMENT

3.1 Maximum and Minimum Rates

The applicable daily Maximum Rates and Minimum Rates for service under this Rate Schedule are listed on the Statement of Rates.

Shipper shall pay the applicable daily Maximum Rate for service under this Rate Schedule unless a lower daily rate has been requested by Shipper and approved in writing by Transporter. Transporter is not obligated to accept a rate for services hereunder at less than the daily Maximum Rate.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

3. RATE AND PAYMENT (Continued)

3.2 Discounted Rates

Transporter may from time to time, at its sole discretion, permit Shipper under this Rate Schedule to request a daily PAL rate that is lower than the applicable daily Maximum PAL Rate set forth in the Statement of Rates. However, such discounted rate shall not be less than the applicable daily Minimum PAL Rate.

3.3 Negotiated Rates

Notwithstanding the foregoing provisions of this Section 3, Transporter and Shipper may mutually agree to Negotiated Rates for service specifically identified and for a term reflected on an Exhibit A to an effective Rate Schedule PAL Agreement as provided for in Section 38 of the General Terms and Conditions.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

4. RATE SCHEDULE PAL POINTS OF SERVICE

4.1 Listing of Available Park Points and Loan Points

Transporter shall post the name and location of all Park Points and Loan Points on its public Internet website.

To fully support segmentation of transportation capacity, a Park Point and Loan Point shall be associated with an existing physical point of service on Transporter's pipeline system.

4.2 Addition or Deletion of Points of Service

Transporter may post from time to time additions or deletions to the list of available points for service under this Rate Schedule. If Transporter terminates a point of service where parked quantities are to be returned to Shipper or loaned quantities are to be returned to Transporter, such point(s) of service shall remain available for the limited purpose of completing such outstanding transactions unless Shipper and Transporter mutually agree to utilize a different Park Point or Loan Point. In the event Shipper and Transporter mutually agree to utilize a different Park Point or Loan Point for the limited purpose of completing such outstanding transactions, Shipper may be charged a separately stated amount for transportation and associated Transporter Fuel and Lost and Unaccounted for Gas which shall not be less than the Minimum Commodity Rate set forth in the Statement of Rates for Rate Schedule IT-1.

4.3 Use of DRN Numbers

In order to facilitate PAL service under this Rate Schedule, all Park Points and Loan Points shall be assigned nominatable DRN numbers. Such DRN numbers shall be posted on Transporter's website.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

5. NOTIFICATIONS, ALLOCATIONS AND CURTAILMENT

5.1 Shipper may be required, upon notification from Transporter, to suspend or reduce deliveries for the agreed upon park service, or receipts for the agreed upon loan service. Further, Shipper may be required, upon notification from Transporter, to remove quantities of gas previously provided to Transporter under the park service, or return quantities of gas previously loaned to Shipper under the loan service. Such notification shall be by facsimile or confirmed delivery e-mail.

5.2 Should Transporter notify Shipper to remove or return quantities of gas pursuant to Subsection 5.1 herein, Transporter's notification shall specify the time frame within which park service quantities shall be removed, and/or loan service quantities shall be returned. Such notifications shall be consistent with Transporter's operating conditions, but in no event shall the specified time frame be less than three (3) Business Days from the date of Transporter's notification unless Transporter and Shipper mutually agree to a different time frame. The obligation of Shipper to comply with the issued notification shall be monitored until such time as Transporter is able to recommence the park and/or loan services.

5.3 In the event Shipper makes a timely nomination in response to a notification by Transporter pursuant to Subsection 5.1 herein, the obligation of Shipper to comply with that notification shall be suspended until such time as Transporter's operational conditions allow Transporter to schedule the nomination.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

6. FAILURE BY SHIPPER TO RESPOND

6.1 Park Service

(a) In the event any of the following occurs, parked quantities shall become the property of Transporter at no cost to Transporter, free and clear of any adverse claims and Transporter shall have the right to seize Shippers' gas, or reduce Shippers' tenders of gas under other Service Agreements:

(i) Transporter's prevailing operations require Transporter to notify Shipper that receipts of parked quantities must be suspended or be reduced, and Shipper fails to comply with such notification; and/or

(ii) Transporter's prevailing operations require Transporter to notify Shipper that all or part of Shipper's parked quantities must be removed, and Shipper fails to comply within the specified time frame; and/or

(iii) Subject to Subsection 2.4 herein, the PAL account reflects a balance at the termination date of the associated Exhibit A to an executed Rate Schedule PAL Agreement.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

6. FAILURE BY SHIPPER TO RESPOND (Continued)

6.1 Park Service (Continued)

(b) If, pursuant to Subsection 6.1(a)(i) herein, Transporter notifies Shipper that receipts of parked quantities must be suspended or be reduced, only those quantities parked in violation of the notification shall become the property of Transporter at no cost to Transporter, free and clear of any adverse claims.

(c) No penalty will be assessed, pursuant to this Subsection 6.1, on a remaining balance if the Shipper-submitted nominations related to that balance to clear the PAL transaction cannot be scheduled by the Transporter, through no fault of the Shipper.

(d) Penalty amounts received by Transporter, net of administrative costs, shall be allocated using the methodology set forth in Section 48 of the General Terms and Conditions.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

6. FAILURE BY SHIPPER TO RESPOND (Continued)

6.2 Loan Service

(a) In the event any of the following occurs, loaned quantities shall be sold to Shipper on a day determined by Transporter at one hundred fifty percent of the highest price published in the absolute range for the **[insert price point]** during the term of the agreed upon transaction as set forth in the associated Exhibit A to a Rate Schedule PAL Agreement, as reported in **[insert publication]** or any successor publication thereto. If such index ceases to be published or is materially changed, a subsequent, mutually agreeable index will be chosen by Transporter and Shipper.

(i) Transporter's prevailing operations require Transporter to notify Shipper that deliveries of Shipper's loaned quantities must be suspended or be reduced, and Shipper fails to comply with such notification; and/or

(ii) Transporter's prevailing operations require Transporter to notify Shipper that all or part of Shipper's loaned quantities must be returned to Transporter, and Shipper fails to comply within the specified time frame; and/or

(iii) Subject to Subsection 2.4 herein, the PAL account reflects a balance at the termination date of the associated Exhibit A to an executed Rate Schedule PAL Agreement.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

6. FAILURE BY SHIPPER TO RESPOND (Continued)

6.2 Loan Service

(b) If, pursuant to Subsection 6.2(a)(i) herein, Transporter notifies Shipper that deliveries of Shipper's loaned quantities must be suspended or be reduced, only those quantities loaned in violation of the notification are subject to Subsection 6.2(a) herein.

RATE SCHEDULE PAL
PARK AND LOAN SERVICE

6. FAILURE BY SHIPPER TO RESPOND (Continued)

6.2 Loan Service (Continued)

(c) No penalty will be assessed, pursuant to this Subsection 6.2, on a remaining balance if the Shipper-submitted nominations related to that balance to clear the PAL transaction cannot be scheduled by the Transporter, through no fault of the Shipper.

(d) Penalty amounts received by Transporter, net of administrative costs, shall be allocated using the methodology set forth in Section 48 of the General Terms and Conditions.

7. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff are applicable to this Rate Schedule and are incorporated herein by reference and made a part hereof. To the extent any terms and conditions specified in this Rate Schedule are inconsistent with the General Terms and Conditions, the Rate Schedule shall govern.

Sheet Nos. 145 through 199
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS
INDEX

GENERAL TERMS AND CONDITIONS
INDEX (Continued)

GENERAL TERMS AND CONDITIONS
INDEX (Continued)

Sheet Nos. 203 and 204
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS

The following terms, when used in this Tariff or in an Agreement, shall have the following respective meanings:

- The term "Account Holder" shall mean a party using the services of a Title Transfer Tracking Service Provider (TTTSP) under a contract or other arrangement with that Title Transfer Tracking Service Provider.

- The term "Agreement" shall mean an executed agreement for service under this Tariff or any agreement to which these General Terms and Conditions or Applicable Rate Schedule shall apply.

- The term "Backhaul" shall mean any transportation service on Transporter's pipeline system where the Delivery Point is located upstream of the Receipt Point. Backhaul transportation service will be available only to the extent that Forwardhaul volumes are received into Transporter's pipeline system on the same day upstream of or at the designated Delivery Point and are required to be delivered out of Transporter's pipeline system downstream of or at the designated Receipt Point such that the service can be provided.

- The term "Best Bid" shall mean the Bid(s) which is determined to be the best using the applicable evaluation methodology.

- The term "Bid" shall mean the terms pursuant to which a Bidder is willing to acquire services under any of Transporter's Rate Schedules or these General Terms and Conditions.

- The term "Bid Closing Date" shall mean the date and time established by Transporter for each Offer by which a Bid must be received to be a valid Bid and included in the evaluation of the Bid(s).

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- o The term "Billing Commencement Date" shall mean the date of the Gas Day when a Shipper's payment obligation commences as set forth in a Shipper's Service Agreement.

- o The term "Btu" shall mean one (1) British thermal unit, the amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit from fifty-eight and one-half (58.5) degrees Fahrenheit to fifty-nine and one-half (59.5) degrees Fahrenheit. (Btu is measured on a dry basis at 14.73 psia.)

- o The term "Business Day" shall mean Monday through Friday, excluding federal banking holidays for transactions in the United States.

- O The term "Calendar Day" shall mean any day, including federal banking holidays for transactions in the United States.

- o The term "Calendar Month" shall mean one of the twelve named divisions of a calendar year according to the Gregorian calendar which shall commence on the first Calendar Day of such Calendar Month and end on the last Calendar Day of such Calendar Month.

- o The term "CCT" shall mean Central Clock Time.

- o The term "Confirmation Requester" shall mean a Person which is seeking to confirm a quantity of gas with another Person with respect to a nomination at a location.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- The term "Confirming Party" shall mean a Service Provider (including a Point Operator) which provides a confirmation for a quantity of gas to another Service Provider (the Confirmation Requester) with respect to a nomination at a location.

- The term "Confirming Parties" shall mean the Confirmation Requester and the Confirming Party.

- The term "Customer Activities" shall mean the business function categories related to Nominations, Flowing Gas, Invoicing, Capacity Release, Contracts and other business functions on Transporter's secured website.

- The term "Delivery Point" shall mean the location where Transporter delivers gas to or for the account of Shipper pursuant to the terms of the applicable Rate Schedule and Agreement.

- The term "Designated Replacement Shipper" shall mean the Person who has been designated by the Releasing Shipper as the Replacement Shipper for firm capacity being released.

- The term "Elapsed Prorata Capacity" or "EPC" shall mean that portion of the capacity that would have theoretically been available for use prior to the effective time of the intra-day recall based upon a cumulative uniform hourly use of the capacity.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- The term "Electronic Data Interchange" ("EDI") shall mean the electronic communication methodology used to transmit and receive data related to gas transactions. Transporter shall designate an electronic "site" at which Shippers, Interconnected Parties, and Transporter may exchange data electronically. All data provided at such site shall be considered as being delivered to the appropriate party.

- The term "Federal Energy Regulatory Commission" or "FERC" or "Commission" shall mean the Federal Energy Regulatory Commission of the United States of America or any other tribunal or Person which may hereafter exercise the functions now exercised by that Commission with respect to Transporter.

- The term "Forwardhaul" shall mean any transportation service provided on Transporter's pipeline system where the Delivery Point is located downstream from a Receipt Point on Transporter's pipeline system.

- The term "Foundation Shipper" shall mean a Shipper who executed a Firm Transportation Service Agreement for a minimum quantity of 200,000 MMBtu per day for at least a term of 20 years.

- The term "gas" or "natural gas" shall mean methane, and such other hydrocarbon constituents or a mixture of two or more of them and other constituents which, in any case, meet the gas quality specifications in the Tariff.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- The term "Gas Day" shall mean a period beginning and ending at 9:00 a.m., Central Clock Time. The reference date for any day shall be the date of the beginning of such day.

- The term "General Terms and Conditions" shall mean, at any time, the effective General Terms and Conditions contained in Transporter's Tariff which may from time to time be amended or supplemented.

- The term "gross heating value", shall mean gross heating value dry as determined by the total calorific (heating) value, in British thermal units, Btu, of the amount of any dry gas which would occupy a volume of one standard cubic foot, based on 14.73 psia and 60 degrees F. The total, or gross, calorific value represents the Btus evolved by the complete combustion, at constant pressure, of one standard cubic foot of any dry gas with air, the temperature of the gas, air, and products of combustion being 60 degrees F, and all water formed by the combustion reaction being condensed to the liquid state.

- The term "Informational Postings" shall mean the common information as required by FERC.

- The term "In-Direction" shall mean a nomination line item that has a nominated flow direction in the same direction as the contracted Transportation Path.

- The term "Interconnected Party" shall mean the Person whose facilities are directly connected to Transporter's facilities at a physical Receipt Point or a physical Delivery Point.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- o The term "Loan Point(s)" shall mean the location(s) referenced on Exhibit A to a Shipper's Rate Schedule PAL Agreement where Shipper can borrow gas quantities on Transporter's pipeline system pursuant to the terms of such Agreement.

- o The term "Maximum Rate" shall mean the sum of the applicable Maximum Reservation Rate, if applicable, and the applicable Maximum Commodity Rate, plus applicable surcharges, as shown on the effective Statement of Rates.

- o The term "Mcf" shall mean 1000 cubic feet of gas.

- O The term "Mcf/day" or "Mcf per day" shall mean 1000 cubic feet of gas per day.

- o The term "Measurement Party" shall mean the Person who is primarily responsible for measurement of gas volumes at a physical Receipt Point into or a physical Delivery Point on Transporter's pipeline system.

- o The term "MMBtu" or “Dth” shall mean a quantity of heating energy which is equivalent to one million (1,000,000) Btus.

- o The term "MMcf" shall mean 1,000,000 cubic feet of gas.

- o The term "MMcf/day" or "MMcf per day" shall mean 1,000,000 cubic feet of gas per day.

- o The term "Minimum Rate" shall mean the minimum commodity rate as shown on the effective Statement of Rates for the applicable Rate Schedules.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

O The term "Netting" shall describe the process of resolving imbalances for a Service Requestor within an Operational Impact Area. There are two types of Netting: summing and offsetting. Summing is the process of accumulation of all imbalances above any applicable tolerance for a Service Requestor or agent. Offsetting is the combination of positive and negative imbalances above any applicable tolerances for Service Requestor or agent.

o The term "Nominating Party" shall mean a Shipper, or its Nominating Agent (one who has been pre-designated in writing by Shipper to serve in such role).

o The term "Nomination Day" shall mean one day prior to Gas Day.

o The term "Non-OBA Point" shall mean a Receipt Point or Delivery Point where no Operational Balancing Agreement is in effect.

o The term "OBA Point" shall mean a Receipt Point or Delivery Point where an Operational Balancing Agreement is in effect between Transporter and Interconnected Party.

o The term "Offer" shall mean the terms pursuant to which a Releasing Shipper is willing to release firm transportation capacity.

o The term "Operational Balancing Agreement" ("OBA") shall mean a contract between two parties which specifies the procedures to manage operating variances at a Point of Interconnection.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- o The term "Operational Flow Order" ("OFO") shall mean an order issued to alleviate conditions, inter alia, which threaten or could threaten the safe operations or system integrity of Transporter's pipeline system or gas treatment plant or to maintain operations required to provide efficient and reliable firm service. Whenever Transporter experiences these conditions, any pertinent order shall be referred to as an OFO.

- o The term "Operational Impact Area" shall mean the largest possible area(s) on Transporter's pipeline system in which imbalances have a similar operational effect.

- o The term "Out-of-Direction" shall mean a nomination line item that has a nominated flow direction opposite of the contracted Transportation Path.

- o The term "Overdelivery" shall mean the quantity of gas that Shipper delivers or causes to be delivered to Transporter which, less Shipper's share of estimated Transporter Fuel and Lost and Unaccounted for Gas, is greater than the quantity of gas delivered out of Transporter's pipeline system for Shipper's account.

- o The term "Park Point(s)" shall mean the location(s) referenced on Exhibit A to Shipper's Rate Schedule PAL Agreement where such Shipper can park quantities of gas on Transporter's pipeline system pursuant to the terms of such Agreement.

- o The term "Pre-Determined Allocation" (PDA) shall mean the allocation method agreed to by the allocating and allocated parties at a point prior to gas flow.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- o The term "Person" shall mean an individual, a corporation, a partnership, an association, a joint venture, a trust, an unincorporated organization or a government or political subdivision thereof, each with the capacity to contract and bring, or be subject to, a legal action; and pronouns shall have a similarly extended meaning.

- o The term "Point of Interconnection" shall mean the location where Transporter's facilities are physically connected to an Interconnected Party.

- o The term "pooling" shall mean 1) the aggregation of gas from multiple physical and/or logical points to a single physical or logical point, and/or 2) the dis-aggregation of gas from a single physical or logical point to multiple physical and/or logical points.

- o The term "Production Month" shall mean the period of actual gas flow beginning at 9:00 a.m., Central Clock Time on the first day of a Calendar Month and ending at 9:00 a.m., Central Clock Time on the first day of the next succeeding Calendar Month.

- o The term "psia" shall mean pounds per square inch, absolute.

- O The term "psig" shall mean pounds per square inch, gauge.

- o The term "Quick Response" shall mean the initial response made by Transporter to recognize the receipt of an EDI-based nomination.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- o The term "Receipt Point" shall mean the location where Transporter receives gas from or for the account of Shipper pursuant to the terms of the applicable Rate Schedule and Agreement.

- o The term "Releasing Shipper" shall mean a Shipper who has firm contractual rights to capacity on Transporter's pipeline or in Transporter's gas treatment plant and offers to release some or all of such firm capacity.

- o The term "Replacement Shipper" shall mean a Person who has obtained the rights to firm capacity from a Releasing Shipper.

- o The term "Service Agreement" shall mean an executed Agreement for service under Transporter's Tariff.

- o The term "Service Requester" shall mean a Nominating Party.

- o The term "Shipper" shall mean the Person as defined in any of the Rate Schedules or Agreements governed by this Tariff. In addition, in a given context, the term Shipper includes a Person seeking to become a Shipper or a Person requesting construction of facilities pursuant to Section 19 of the General Terms and Conditions; and the term "Shippers" shall mean more than one of such Persons. A Person that has been a Shipper, but for which an Agreement between that Person and Transporter has terminated, remains a Shipper for purposes of satisfying their obligations under such Agreement.

- o The term "Shipper Imbalance" shall mean the difference between the quantity of gas received by Transporter for transportation for such Shipper, adjusted for Shipper's share of estimated Transporter Fuel and Lost and Unaccounted for Gas, and the quantity of gas delivered by Transporter for such Shipper's account.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- The term "Tariff" shall mean the compilation on file with FERC of Transporter's Statement of Rates and other rate sheets, Statement of Negotiated Rates, Rate Schedules, General Terms and Conditions, related forms of Agreements, and nonconforming agreements from time to time in effect.

- The term "tender" shall mean the fulfillment of all of the following conditions:

  (1) Shipper has informed Transporter in accordance with applicable contractual and Tariff requirements that it plans to deliver a quantity of gas which such Shipper is entitled to deliver to Transporter pursuant to such Shipper's Agreement at a specified Receipt Point on a specified day;

  (2) either

    (a)(1) relative to an OBA Point, the upstream facilities operator has verified that the quantity of gas Shipper has nominated for delivery to Transporter is in fact the quantity of gas that can be delivered to Transporter at such Receipt Point or

    (a)(2) relative to a Non-OBA Point such Shipper in fact could cause delivery of such quantity to Transporter at such Receipt Point on such day, or

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

(b) to the extent Transporter refuses to receive such gas in the quantity described in (2)(a)(1) or (2)(a)(2) above at such Receipt Point on such day, such Shipper is in fact ready, willing and able to so deliver the quantity so refused or would have been able to do so had Transporter not so refused; and

(3) such Shipper is in fact, ready, willing and able to accept delivery from Transporter on such day of the related quantity of gas in accordance with such Shipper's Agreement. The term "tendered" shall have a corresponding meaning.

o The term "Third Party Account Administrator" is a Title Transfer Tracking Service Provider other than Transporter.

o The term "Title" shall mean the term used to identify the ownership of gas.

o The term "Title Transfer" shall mean the change of title to gas between parties at a location.

o The term "Title Transfer Agreement" shall mean an executed Title Transfer Agreement for service under this Tariff made between Transporter and Account Holder and specifically shall include the form of agreement included herein.

o The term "Title Transfer Nomination" shall mean a nomination line item requesting the service of Title Transfer Tracking and is sent by an Account Holder to a Title Transfer Tracking Service Provider.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- The term "Title Transfer Tracking" shall be the process of accounting for the progression of Title changes from party to party that does not affect a physical transfer of gas.

- The terms "trade" or "trading" shall describe the process of resolving Shipper Imbalances between two or more Shippers or their agents within an Operational Impact Area.

- The term "Transfer Point" shall mean a point on Transporter's pipeline system where, for purposes of nominating and scheduling, transfers of gas from one Agreement to another shall occur. All Receipt Points and Delivery Points on Transporter's pipeline system will have associated Transfer Points. Transfer Points for Forwardhaul transportation purposes are deemed to exist immediately downstream of all Receipt Points and immediately upstream of all Delivery Points. Transfer Points for Backhaul transportation purposes are deemed to exist immediately upstream of all Receipt Points and immediately downstream of all Delivery Points. Transfer Points are considered secondary points for scheduling purposes.

- The term "Transportation Path" shall mean the pipeline path and flow direction from and including the most upstream Receipt Point to and including the most downstream Delivery Point a Shipper has contracted for on Transporter's pipeline system as set forth on Exhibit A of Shipper's Agreement.

GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

- o The term "Transporter" shall mean TransCanada Alaska Company LLC, a "Transportation Service Provider".

- O The term "Underdelivery" shall mean the quantity of gas Shipper receives or causes to be received from Transporter for its account which is less than the quantity of gas tendered by Shipper to Transporter less Shipper's share of estimated Transporter Fuel and Lost and Unaccounted for Gas.

- o The term "WGQ" shall mean the Wholesale Gas Quadrant which is an accredited standards organization under the auspices of the American National Standards Institute.

Sheet Nos. 219 through 222
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

2. PRESSURE AND TEMPERATURE

2.1 Receipt Pressure

Shipper shall deliver gas to Transporter at each of Shipper's Receipt Point(s) at a pressure sufficient to cause such gas to flow into Transporter's facilities, provided that Shipper shall not be required to deliver gas to Transporter at any Receipt Point at a pressure in excess of the maximum pressure specified for such Receipt Point.

2.2 Delivery Pressure

Transporter shall deliver gas to Shipper at each of Shipper's Delivery Point(s) at the pressure existing in Transporter's pipeline at such Delivery Point, provided that Shipper shall not be required to receive gas from Transporter at any Delivery Point at a pressure less than the minimum pressure specified for such Delivery Point.

2.3 Maximum Receipt Temperature

The temperature of gas delivered by Shipper to Transporter at a Receipt Point shall not exceed the maximum receipt temperature specified for such Receipt Point.

2.4 Minimum Delivery Temperature

The temperature of gas delivered by Transporter to Shipper at a Delivery Point shall not be below the minimum delivery temperature specified for such Delivery Point.

2.5 Operating Conditions

Subject to the provisions of Subsections 2.1, 2.2, 2.3 and 2.4 herein, the temperature and pressure of gas delivered to Transporter by Shipper, and of gas delivered to Shipper by Transporter, shall, at each of Shipper's Receipt Point(s) and Delivery Point(s), be consistent with the overall operating conditions of Transporter's pipeline system. Transporter shall use reasonable efforts to deliver gas to Shipper at such uniform pressure as is consistent with the operating conditions of Transporter's pipeline system.

Sheet Nos. 224 and 225
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

3. MEASURING EQUIPMENT

3.1 Transporter's Measuring Equipment

Unless otherwise agreed by Transporter and Interconnected Party, Transporter shall cause to be furnished, installed, maintained, and operated all equipment, devices and material necessary to determine gas volume, pressure, temperature, gross heating value, quality, specific gravity and supercompressibility at each Receipt Point and at each Delivery Point of Interconnected Party.

3.1.1 Multi-Path Ultrasonic Meters

Multi-path ultrasonic meters may be installed and operated and computations made as prescribed in Transmission Measurement Committee Report No. 9 of the American Gas Association, as such report may be amended or revised from time to time.

3.1.2 Turbine Meters

Turbine meters may be used for the measurement of low flow and, if used, will be installed and operated and computations made as prescribed in Transmission Measurement Committee Report No. 7 of the American Gas Association, as such report may be amended or revised from time to time.

3.1.3 Other Measuring Equipment

Measuring equipment other than ultrasonic or turbine meters shall be of a type acceptable to Transporter. The manufacture, installation, operation, and maintenance of such meters shall be consistent with the appropriate industry accepted recommendations and specifications at the time the meters are manufactured and installed.

GENERAL TERMS AND CONDITIONS

3. MEASURING EQUIPMENT (Continued)

3.1 Transporter's Measuring Equipment (Continued)

3.1.4 Measurement Installation

All measurement installations shall include the use of flange connections and straightening vanes or by other measuring methods approved by Transporter. Approval of such methods shall not be unreasonably withheld.

3.1.5 Gas Flow Computer

Computation of volumes shall be made using an on-line gas flow computer ("GFC"). Temperature, pressure, and volumetric measurements shall be input to the GFC at least once per second. The computational method and averaging technique shall meet the minimum requirements of "Flow Measurement Using Electronic Metering Systems", Chapter 21 of the Manual of Petroleum Standards, published by the American Petroleum Institute.

3.1.6 Gas Analysis

Gas analysis shall be determined using an on-line gas chromatograph acceptable to Transporter. Gas density and compressibility shall be determined by the methods described in American Gas Association Transmission Measurement Committee Report No. 8, "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases", gross method, latest revision.

GENERAL TERMS AND CONDITIONS

3. MEASURING EQUIPMENT (Continued)

3.1 Transporter's Measuring Equipment (Continued)

3.1.6 Gas Analysis (Continued)

The total heating value of the gas shall be computed from the same on-line chromatographic analysis.

3.2 Check Measuring Equipment

At each Receipt Point and Delivery Point of an Interconnected Party, the Interconnected Party or Shippers affected, at its or their own expense, may cause to be furnished, installed, maintained and operated check measuring equipment, provided, however, that such equipment does not interfere with the operations of the measuring equipment caused to be installed by Transporter.

3.3 Right of Access

Transporter and the Interconnected Party or Shipper(s) affected, in the presence of each other, shall each have access to the other's measuring equipment at all reasonable times, but the reading, calibrating and adjusting thereof shall be done only by the Person which has installed such equipment, unless otherwise agreed upon. Both Transporter and the Interconnected Party or Shipper(s) affected shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment. The records from such measuring equipment shall remain the property of the Person installing such equipment, but, upon request, each will submit to the other its measurement records, together with calculations therefrom, for inspection, subject to return within thirty (30) days after receipt thereof.

GENERAL TERMS AND CONDITIONS

3. MEASURING EQUIPMENT (Continued)

3.4 Reasonable Care

Transporter shall exercise reasonable care in the installation, maintenance and operation of its measuring equipment so as to avoid any inaccuracy in the determination of the volume and other attributes of gas received and delivered.

3.5 Testing Measuring Equipment

Transporter shall conduct tests to verify the accuracy of its measuring equipment using means and methods acceptable to Transporter and the Interconnected Party or Shipper(s) affected, at least once each quarter, or at such other interval as may be mutually agreed upon and at other times upon request of the Interconnected Party or Shipper(s) affected. Notice of the time and nature of each test shall be given by Transporter to such Interconnected Party or Shipper(s) affected in advance to permit reasonable arrangement for the presence of the other's representatives. If, after notice, an Interconnected Party fails to have a representative present, the results of the test shall nevertheless be considered accurate until the next test. All tests of such measuring equipment shall be made at the expense of the Transporter, except that Interconnected Party or Shipper(s) affected requesting a test shall bear the expense of such test if the inaccuracy is found not to exceed [ ] percent, at a reading corresponding to the average hourly rate of flow.

GENERAL TERMS AND CONDITIONS

3. MEASURING EQUIPMENT (Continued)

3.6 Correction and Adjustment

If, upon test, any measuring equipment is found to be registering inaccurately by not more than two (2) percent, at a reading corresponding to the average hourly rate of flow, then readings of such equipment since the time of the last test thereof shall be considered accurate in computing deliveries of gas. If, upon test, any measuring equipment is found to be registering inaccurately by more than two (2) percent, at a reading corresponding to the average hourly rate of flow, then readings of such equipment shall be corrected to zero error for any past period definitely known, or agreed, to have been inaccurate, or if the inaccuracy during all or part of the period of time since the last test of such equipment is not so known or agreed upon, for a period of sixteen (16) days, or one-half of the elapsed time since such last test, whichever is the shorter period. Any recording equipment found to be registering inaccurately shall be immediately adjusted to register accurately. Parties may mutually agree in writing to a more restricted standard of error than the two (2) percent provided herein.

3.7 Failure of Measuring Equipment

If Transporter's measuring equipment at any Receipt Point or Delivery Point of an Interconnected Party is out of service for any period, the measurement determinants for such Receipt Point or Delivery Point during such period shall be determined:

(a) By using the data recorded by any check measuring equipment accurately registering; or

(b) If such check measuring equipment is not registering accurately but the percentage of error is ascertainable by a calibration test, by using the data recorded, corrected to zero error; or

GENERAL TERMS AND CONDITIONS

3. MEASURING EQUIPMENT (Continued)

3.7 Failure of Measuring Equipment (Continued)

(c) If neither of the methods provided in Subsections 3.7(a) and 3.7(b) above can be used, by estimating the necessary determinants by reference to receipts or deliveries under similar conditions.

3.8 Preservation of Records

Both Transporter and the Interconnected Party shall preserve for a period of at least three years, or such longer period as may be required by FERC or other public authority, all test data and measurement records related to matters covered by Section 3 of these General Terms and Conditions.

3.9 MEASUREMENT OF FLOWING GAS

The measurement information statement is designed to provide information on actual or estimated physical flow moving through a Point of Interconnection at which Transporter has measurement responsibility and does not include data elements utilized to verify the calculation of measured flow. The measurement information statement is posted on the secured non-public Internet website on or before five (5) Business Days after the business month.

For treatment of measurement prior period adjustments, Transporter shall treat the adjustment by taking it back to the Production Month. A meter adjustment becomes a prior period adjustment after the fifth Business Day following the business month.

Measurement data corrections shall be processed within six (6) months of the Production Month with a three (3) month rebuttal period. This standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard.

Sheet Nos. 232 and 233
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

4. MEASUREMENT REPORTING

4.1 Physical Volume

4.1.1 Standard Reference Conditions

The standardized reporting basis for gas volumes is cubic foot at standard conditions of 14.73 psia, 60 degrees F, and dry. For gas volumes reported in cubic meters, the standard conditions are 101.325 kPa, 15 degrees C, and dry.

4.1.2 Reporting/Calculation Accuracy

For reporting purposes, pressure base conversion factors shall be reported to not less than 6 decimal places. For calculation purposes, not less than 6 decimal places shall be used.

4.1.3 Volumetric Unit of Measurement

The standard reporting unit for natural gas volume used by Transporter will be thousands of cubic feet (Mcf) of gas at standard reference conditions.

4.1.4 Metric Conversion for Volumes

The Metric reporting unit for natural gas volume is thousands of cubic meters (10E3 M3) at standard reference temperature and pressure conditions of 15 degrees C and an absolute pressure of 101.325 kPa respectively. The conversion factor to convert cubic feet (at standard reference conditions) to cubic meters is:

(cubic feet) X 0.02832784 = (cubic meters)

GENERAL TERMS AND CONDITIONS

4. MEASUREMENT REPORTING (Continued)

4.2 Energy Quantity

4.2.1 Standard Reference Conditions

The standardized reporting basis for Btu is 14.73 dry psia and 60 degrees F(101.325 kPa and 15 degrees C, and dry). The standardized reporting basis for gigacalorie is 1.035646 Kg/cm2 and 15.6 degrees C and dry.

4.2.2 Calculation of Energy Quantity

The energy quantity, based on standard reference conditions, is the product of the physical volume measured, in thousands of cubic feet (Mcf) and the gross heating value of the measured gas (Btu/cf).

4.2.3 Energy Unit of Measurement

The reporting unit for energy quantity used by Transporter will be MMBtu at standard reference conditions.

4.2.4 Data Elements

All records of energy quantities of natural gas provided to or from Transporter shall be reported using the current measurement standard data elements adopted by FERC.

4.2.5 Metric Conversion for Energy

The metric reporting unit for energy quantity is gigajoules (GJ) at standard reference conditions of 15 degrees C, an absolute pressure of 101.325 kPa, dry, and Btu 58.5 degrees F/59.5 degrees F. The conversion factor to convert MMBtu (at standard reference conditions) to gigajoules is:

(MMBtu) X 1.055056 = (gigajoules)

GENERAL TERMS AND CONDITIONS

4. MEASUREMENT REPORTING (Continued)

4.3 Atmospheric Pressure

For purposes of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be assumed to be the pressure corresponding to the elevation at such station, and shall be stated in pounds per square inch.

Sheet Nos. 237 and 238
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS

5.1 Quality Standards of Gas Received by Transporter at **the Gas Treatment Plant ("GTP") inlet (Zone 2) and at Receipt Points on gas transmission lines delivering gas to the GTP inlet (Zone 1).**

Transporter may refuse to accept gas which does not conform to the following specifications:

5.1.1 Objectionable Substances

The gas shall not contain sand, dust, gums, crude oil, contaminants, impurities or other objectionable substances which may, as determined by Transporter, render the gas unmerchantable, cause injury, cause damage to or interfere with the operations of Transporter's or downstream facilities, or interfere with the transmission of the gas.

5.1.2 Cricondentherm Hydrocarbon Dew Point

The gas shall have a cricondentherm hydrocarbon dew point less than 10 degrees F with composition adjusted to 1.5 mole% CO_2.

5.1.3 Hydrogen Sulphide

The gas shall not contain more than 100 ppm of hydrogen sulphide.

5.1.4 Total Sulphur

The gas shall not contain sulphur species, other than H_2S, with a total concentration of more than 4.75 grains of total sulphur per Ccf, measured on an elemental sulphur basis, with composition adjusted to 1.5 mole% CO_2.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS (Continued)

5.1 Quality Standards of Gas Received by Transporter (Continued)

5.1.5 Methyl Mercaptan Sulphur

The gas shall contain not more than 0.22 grains of methyl mercaptan sulphur per Ccf, or such higher content as, in Transporter's judgment, will not result in deliveries by Transporter to Shipper(s) of gas containing more than 0.22 grains of methyl mercaptan sulphur per Ccf with composition adjusted to 1.5% CO_2.

5.1.6 Carbon Dioxide

The gas shall not contain more than 12 percent by volume of carbon dioxide.

5.1.7 Water Vapor

The gas shall not have a water vapor content in excess of 0.2 pounds per MMcf.

5.1.8 Oxygen

The gas shall be as free of oxygen as it can be kept through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 mole% percent of oxygen with composition adjusted to 1.5 mole% CO_2.

5.1.9 Gross Heating Value (HHV)

The gas shall have a gross heating value of not less than 975 Btu per cf with composition adjusted to 1.5 mole% CO_2.

5.1.10 Temperature

The gas shall not exceed 84 degrees F in temperature.

5.1.11 Inerts

The gas shall not contain more than 3 mole% of total inerts with composition adjusted to 1.5 mole% CO_2.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS (Continued)

5.2 **[Alberta alternative] Quality Standards of Gas Received into the APP pipeline from the GTP or other Zone 3 Receipt Points.**

5.2.1 Objectionable Substances

The gas shall not contain sand, dust, gums, crude oil, contaminants, impurities or other objectionable substances which may, as determined by Transporter, render the gas unmerchantable, cause injury, cause damage to or interfere with the operations of Transporter's or downstream facilities, or interfere with the transmission of the gas.

5.2.2 Cricondentherm Hydrocarbon Dew Point

The gas shall have a cricondentherm hydrocarbon dew point less than 14 degrees F.

5.2.3 Water Dew Point

The gas shall have a water dew point less than -10 degrees F at 2500 psia and less than -33 degrees F at 650 psia.

5.2.4 Hydrogen Sulphide

The gas shall not contain more than 4 ppmv of hydrogen sulphide.

5.2.5 Total Sulphur

The gas shall not contain more than 5 grains of total sulphur per Ccf measured on an elemental sulphur basis.

5.2.6 Methyl Mercaptan Sulphur

The gas shall contain not more than 0.22 grains of methyl mercaptan sulphur per Ccf, or such higher content as, in Transporter's judgment, will not result in deliveries by Transporter to Shipper(s) of gas containing more than 0.22 grains of methyl mercaptan sulphur per Ccf.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS (Continued)

5.2.7 Carbon Dioxide

The gas shall not contain more than 2% percent by volume of carbon dioxide.

5.2.8 Water Vapor

The gas shall not have a water vapor content in excess of 0.8 pounds per MMcf.

5.2.9 Oxygen

The gas shall be as free of oxygen as it can be kept through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 mole% of oxygen.

5.2.10 Gross Heating Value (HHV)

The gas shall have a gross heating value of not less than 967 Btu per cf.

5.2.10 Temperature

The gas shall not exceed 30°F in temperature.

5.2.11 Inerts

The gas shall not contain more than 3 mole% of total inerts.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS (Continued)

5.2 **[Valdez alternative] Quality Standards of Gas Received into the APP Pipeline from the GTP or other Zone 3 Receipt Points.**

5.2.1 Objectionable Substances

The gas shall not contain sand, dust, gums, crude oil, contaminants, impurities or other objectionable substances which may, as determined by Transporter, render the gas unmerchantable, cause injury, cause damage to or interfere with the operations of Transporter’s or downstream facilities, or interfere with the transmission of the gas.

5.2.2 Cricondentherm Hydrocarbon Dew Point

The gas shall have a cricondentherm hydrocarbon dew point of less than 14 degrees F.

5.2.3 Water Dew Point

The gas shall have a water dew point less than -10 degrees F at 2500 psia and less than -33 degrees F at 650 psia.

5.2.4 Hydrogen Sulphide

The gas shall not contain more than 4 ppmv of hydrogen sulphide.

5.2.5 Total Sulphur

The gas shall not contain more than 5 grains of total sulphur per Ccf measured on an elemental sulphur basis.

5.2.6 Methyl Mercaptan Sulphur

The gas shall contain not more than 0.22 grains of methyl mercaptan sulphur per Ccf, or such higher content as, in Transporter's judgment, will not result in deliveries by Transporter to Shipper(s) of gas containing more than 0.22 grains of methyl mercaptan sulphur per Ccf.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS (Continued)

5.2.7 Carbon Dioxide

The gas shall not contain more than 50 parts per million of carbon dioxide.

5.2.8 Water Vapor

The gas shall not have a water vapor content in excess of 0.8 pounds per MMcf.

5.2.9 Oxygen

The gas shall be as free of oxygen as it can be kept through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 mole% of oxygen.

5.2.10 Gross Heating Value (HHV)

The gas shall have a gross heating value of not less than 967 Btu per cf.

5.2.10 Temperature

The gas shall not exceed 30 degrees F in temperature.

5.2.11 Inerts

The gas shall not contain more than 3 mole% of total inerts.

GENERAL TERMS AND CONDITIONS

5. QUALITY OF GAS (Continued)

5.3 Quality Tests.

At each Receipt Point, Transporter shall cause tests to be made, by approved or acceptable methods in the gas industry or other tests Transporter determines to be acceptable, to determine whether the gas conforms to the quality specifications set out herein. Such tests shall be made at such intervals as Transporter may deem reasonable, and at other times, but not more often than once per day, at the request of any Shipper.

5.4 Quality Standards of Gas Transported by Transporter

Transporter shall use reasonable diligence to deliver gas under a Shipper's Agreement which shall meet the quality specifications set out herein, but shall only be obligated to deliver gas of the quality which results from the commingling of the gas received by Transporter from all Shippers.

Sheet Nos. 246 through 250
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

6. BILLING AND PAYMENT

6.1 General

For purposes of this Section 6, Customer shall be defined as any Person, including a Shipper, who is liable for payment in accordance with the terms and conditions of this Tariff.

6.2 Billing and Invoice

6.2.1 Posting of Invoices

On or before the ninth Business Day after the end of the Production Month, Transporter shall post customer's invoice for such Production Month on its secured non-public Internet website. Such invoice shall include, but is not limited to, reservation and/or usage charges, applicable taxes and other surcharges, measurement fees, facility charges, interest, penalty charges or credits to customer. Such charges shall be separately stated on customer's invoice.

6.2.2 Quantity

Invoices should be based on actual (if available) or best available data. Quantities at points where OBAs exist will be invoiced based on scheduled quantities.

6.2.3 Statement of Account

The statement of account shall be used by Transporter to indicate the payment status of customer's invoice(s), and when provided to customer, shall summarize the amounts Transporter has invoiced, the amounts customer has paid, prior period adjustments that have been made, and the remaining amounts owed.

GENERAL TERMS AND CONDITIONS

6. BILLING AND PAYMENT (Continued)

6.3 Imbalance Statement

Imbalance statements shall also be posted on Transporter's secured non-public Internet website at the same time or prior to posting invoices in accordance with Subsection 6.2.1 herein.

If information is required from customer, or its designee, to identify quantities or allocations or other information, customer shall furnish the required information or cause it to be furnished to Transporter, in writing, on or before the tenth Business Day of each Production Month.

6.4 Payment and Disputes

6.4.1 Payment

Customer shall make payment to Transporter by electronic funds transfer to a bank designated by Transporter within ten (10) Calendar Days of the issuance of such invoice, for service billed by Transporter pursuant to the provisions of this Tariff. Customer's payments shall be made in immediately available U.S. funds on or before the due date.

The effective payment due date of an invoice when such date does not fall upon a Business Day shall be the first Business Day following the due date.

If the effective payment due date falls on a day that the designated bank is not open in the normal course of business to receive customer's payment, then customer's payment shall be made on or before the first Business Day after the effective payment date that such bank is available.

GENERAL TERMS AND CONDITIONS

6. BILLING AND PAYMENT (Continued)

6.4 Payment and Disputes (Continued)

6.4.1 Payment (Continued)

Customer shall not be entitled to any abatement or set off of such payments due Transporter including, but not limited to, abatement or set-off due or alleged to be due by reason of any past, present or future claims of customer against Transporter under customer's Agreement or otherwise.

6.4.2 Disputes

If an invoice is in dispute, customer shall pay the undisputed portion of the invoice and provide documentation identifying the basis for the dispute.

If a customer disputes an invoice, a statement shall be sent to Transporter which shall 1) provide details of the dispute, 2) include the appropriate supporting documentation, and 3) reference the invoice code and invoice detail line numbers of the items disputed.

6.5 Remedies for Failure to Pay Invoice

If customer fails to pay in full the undisputed amount of any invoice rendered by Transporter by the payment due date, Transporter may provide customer with a ten (10) day notice of suspension of service, provided, however, that any such suspension shall not relieve Shipper from any obligation to pay any further rates, charges, or other amounts payable to Transporter under the Tariff. If after the ten (10) day notice of service suspension, customer has not paid in full the undisputed amount due, Transporter may give notice to customer and FERC that if full payment of the invoice amount due is not received within fifteen (15) days, Transporter may terminate the Agreement. Transporter may terminate the Agreement with customer, subject to the terms of the applicable Service Agreement.

GENERAL TERMS AND CONDITIONS

6. BILLING AND PAYMENT (Continued)

6.6 Delinquency Charge

Should customer fail to pay all of the amount of any invoice when such amount is due, interest on the unpaid portion of such amount shall accrue at the rate of interest set forth in Section 154.501 of FERC's regulations from the date when the payment was due until the date payment is made. Interest applicable to such bill will be invoiced to customer, in accordance with Subsection 6.2 herein, to the extent that the amount of interest is $25 or more.

If any portion of an amount paid to Transporter by customer is finally determined to be repayable to customer, Transporter shall pay or credit such amount to customer, together with interest thereon computed at the rate of interest set forth in Section 154.501 of FERC's regulations and accrued from the date payment thereof was made by customer to Transporter to the date payment or credit thereof is made by Transporter.

6.7 Late Billing

If the rendering of an invoice to customer is delayed beyond the date provided in Subsection 6.2 herein, then the time for payment shall be extended correspondingly unless customer is responsible for such delay.

GENERAL TERMS AND CONDITIONS

6. BILLING AND PAYMENT (Continued)

6.8 Billing Error/Prior Period Adjustments

In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within thirty (30) days of Transporter's determination thereof. Prior period adjustment time limits shall be twelve (12) months from the date of the initial transportation invoice with a three (3) month rebuttal period, excluding government required rate changes. This standard shall not apply in the case of the use of estimates, deliberate omission or misrepresentation, or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard.

GENERAL TERMS AND CONDITIONS

6. BILLING AND PAYMENT (Continued)

6.9 Audits

All financial settlements, billings, or reports rendered by Transporter or any customer as defined in Section 6.1 and any amendments thereto will, to the best of the knowledge and belief of the party rendering such settlement, billing, or report, properly reflect the facts about all activities and transactions, which data may be relied upon as being complete and accurate in any further recording and reporting made by such other party for whatever purpose. Each party shall promptly notify the other party at any time it has reason to believe that the above-mentioned data is no longer accurate and complete.

Each party and its agents and contractors agree to preserve and maintain available for at least two (2) full calendar years (defined as January to December) all books, records, correspondence, expense account records, plans, receipts, vouchers, data stored in computers, and memoranda of every description pertaining to this Section 6 for the purpose of auditing and verifying compliance with this Section 6. Either party shall have access at all reasonable times to such records of the other party, its agents, and contractors for the purpose of such a compliance audit, and such right of access shall remain in effect after the statement provided in accordance with Section 6.4.2 for a period of two (2) years. The auditing party's representatives shall have the right to reproduce any of the aforesaid documents, and each party shall continue to preserve the records while the audit is in progress.

Sheet No. 257
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

7. REQUEST FOR OPERATING INFORMATION

Upon request of Transporter, Shipper shall from time to time give Transporter written notice, as far in advance as operating conditions will permit, of the estimated daily, monthly and annual quantities of gas Shipper intends to deliver to Transporter pursuant to an Agreement.

Transporter shall from time to time give Shipper written notice, as far in advance as operating conditions will permit, of the estimated daily, monthly and annual quantities of gas Transporter expects to be able to receive and deliver pursuant to Shipper's Agreement.

Shipper and Transporter shall use reasonable judgment and experience in arriving at such estimates, but shall not be bound thereby nor limited to the quantities thereof. Each shall promptly notify the other or others of any significant known or reasonably anticipated modification to the estimates last furnished, provided such estimates covered periods during which a modification was known or reasonably anticipated to occur.

Sheet Nos. 259 and 260
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

8. LIABILITY AND INDEMNIFICATION

8.1 The party that is the titleholder to gas lost or the source of harm to the other party or to third parties shall bear responsibility for such loss or harm and shall hold harmless and indemnify the non-titleholding party against any claim, liability, loss or damage whatsoever suffered by the non-titleholding party or by any third party.

8.2 No party shall pursue a claim for liability, loss, or damage against the other party for harm to that party and its facilities caused by acts of third parties or by acts of nature or for the cost of repair of damage to such facilities caused by such acts.

8.3 Each party shall bear responsibility for all its own tortious acts or tortious omissions connected in any way with an Agreement or the provision or acceptance of service and causing damage or injuries of any kind to the other party or to any third party. The tortfeasor party shall hold harmless and indemnify the other party against any claim, liability, loss or damage whatsoever suffered by that party or by any third party.

8.4 Transporter shall have no liability in damages to Shipper in respect of failure for any reason whatsoever to accept receipt of, receive or deliver gas pursuant to the provisions of an Agreement (or any applicable provisions of the Tariff), and Shipper shall, notwithstanding any failure, for any reason whatsoever, to accept receipt of, receive, or deliver gas, make payment to Transporter in the amounts, in the manner, and at the times provided in the Agreement (and any applicable provisions of the Tariff).

8.5 In no case addressed by this Section 8 shall one party be required to make payments to the other party for consequential losses suffered by that other party.

8.6 Nothing in this Section 8 shall alter the implementation or applicability of any rate principles governing Negotiated Rates or Transporter's ability to recover any costs in its Recourse Rates.

Sheet Nos. 262 and 263
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

9. FORCE MAJEURE

9.1 Neither Transporter nor Shipper shall be liable in damages to the other for any act, omission or circumstance which shall be caused, in whole or substantial part, by a Force Majeure Event. Force Majeure Event means any acts of God, strikes, lockouts or other labor disputes or industrial disturbances, terrorist acts or acts of a public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, other storms, floods, washouts or other act of nature, civil disturbances, explosions, breakage, accident or repairs to machinery or lines of pipe, freezing or cratering of pipe, inability to obtain or unavoidable delay in obtaining pipe, materials or other equipment, acts or binding orders of any court or other governmental authority whether or not having jurisdiction, and any other cause, whether similar or dissimilar to any above enumerated, not reasonably within the control of the Person claiming relief from liability and which such Person was or would have been unable to prevent by the exercise of due diligence. Failure to prevent or settle any strike or strikes or any dispute leading to a lockout shall not be considered to be matter within the control of the Person claiming relief.

9.2 Force majeure affecting the performance by either Shipper or Transporter of any of its obligations shall not relieve

GENERAL TERMS AND CONDITIONS

9. FORCE MAJEURE(Continued)

the Person seeking relief from liability in respect of any period when the continuance of its inability to perform such obligations is due to its failure to use reasonable efforts to remedy the situation in a reasonable manner and with reasonable dispatch, nor shall force majeure, regardless of the circumstances thereof, affect in any way the obligations of Transporter or Shipper to make payments (and a Force Majeure Event shall not include Shipper’s inability to meet its obligation to pay for reasons related to the unavailability of reserves, and any interruption or other impairment of the operation of Transporter’s facilities or facilities upstream or downstream of Transporter’s facilities including impairment due to circumstances beyond Shipper’s control). The Person claiming relief from liability by reason of force majeure shall give notice as soon as reasonably practical to the other of the occurrence and cessation of such Force Majeure Event.

Sheet Nos. 266 and 267
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING

10.1 Nomination Procedures

Whenever Shipper desires service under its Agreement, Shipper shall furnish a nomination for such Agreement. A nomination shall include, at a minimum, the following information:

(a) Daily quantity of gas to be transported (expressed in MMBtu or Mcf where applicable); and

(b) Valid Receipt Point(s) and Delivery Point(s); and

(c) Begin and end date.

Transporter shall not accept nominations in excess of Shipper's Maximum Delivery Quantity, provided, however, Shipper shall nominate at each Receipt Point a quantity sufficient to include Transporter Fuel and Lost and Unaccounted for Gas, if applicable, that Shipper is required to tender to Transporter in accordance with Section 41 of these General Terms and Conditions. The begin and end date shall be within the term of Shipper's Agreement.

When a nomination for a date range is received, each day within that range is considered an original nomination. When a subsequent nomination is received for one or more days within that range, the previous nomination is superseded by the subsequent nomination only to the extent of the days specified. The days of the previous nomination outside the range of the subsequent nomination are unaffected. Nominations have a prospective effect only.

10.1.1 Nomination Principles/Standards

For purposes of this Section 10, "provide" shall mean send or post.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.1 Nomination Procedures (Continued)

10.1.2 Transporter Supported Nomination Classifications

(a) Timely Nominations

A timely nomination is a nomination, effective for an upcoming Gas Day(s), that is received on the Nomination Day prior to the timely nomination deadline for the first effective Gas Day nominated.

If a timely nomination does not meet the definition of a nomination because it contains an identifiable error or an element is missing, such timely nomination will be voided by Transporter.

(b) Intra-day

Transporter shall allow for intra-day nominations.

An intra-day nomination is a nomination submitted after the (timely) nomination deadline whose effective time is no earlier than the beginning of the Gas Day and runs through the end of that Gas Day.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.1 Nomination Procedures (Continued)

10.1.2 Transporter Supported Nomination Classifications (Continued)

For services that provide for intra-day nomination and scheduling, there is no limitation as to the number of intra-day nominations which a Service Requester may submit at any one standard nomination cycle or in total across all standard nomination cycles.

Intra-day nominations can be made at any Receipt Point or Delivery Point on Transporter's pipeline system.

Intra-day nominations do not rollover (i.e. intra-day nominations span one day only). Intra-day nominations do not replace the remainder of a standing nomination. There is no need to re-nominate if an intra-day nomination modifies an existing nomination.

An intra-day nomination which requests an effective period for more than one Gas Day will be voided in its entirety by Transporter.

Intra-day nominations can be used to request increases or decreases in total flow, changes in Receipt Point(s), or changes to Delivery Point(s) of scheduled gas.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.1 Nomination Procedures (Continued)

10.1.2 Transporter Supported Nomination Classifications (Continued)

Intra-day nomination shall include an effective date and time.

The interconnected parties (Transporter and Interconnected Party) shall agree on the hourly flows of the intra-day nomination, if not otherwise addressed in Transporter's contract or tariff.

(c) Emergency Intra-day Requests

In addition to the grid-wide intra-day nomination opportunities, Transporter shall accept, process, and attempt to schedule emergency intra-day requests on a best efforts basis.

To be classified as an emergency intra-day request, such requests must: 1) not impact grid scheduled activity, 2) not result in a bumping event, and 3) not require a formal confirmation process with the Interconnected Party.

10.1.3 Transporter Supported Grid-Wide Intra-day Nomination Cycles

No bumping shall occur at the final grid-wide intra-day nomination opportunity of the Gas Day.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.1 Nomination Procedures (Continued)

10.1.3 Transporter Supported Grid-Wide Intra-day Nomination Cycles (Continued)

Scheduled quantities resulting from intra-day 1 nominations shall be effective at 5:00 p.m. CCT on Gas Day.

Scheduled quantities resulting from intra-day 2 nominations shall be effective at 9:00 p.m. on Gas Day.

10.2 Nomination and Scheduling Timeline

10.2.1 Timely Nominations

(a) Shipper Delivery of Timely Nominations

The deadline for nominations leaving control of the Nominating Party is 11:30 a.m. CCT on the day prior to flow.

(b) Transporter Receipt of Timely Nominations

The time for receipt of nominations by Transporter is 11:45 a.m. CCT on the day prior to flow.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.1 Timely Nominations (Continued)

(c) Quick Response to Timely Nominations

Transporter shall send Quick Response by noon CCT on the day prior to flow.

(d) Confirmation of Timely Nominations

The deadline for receipt of completed confirmations by Transporter from upstream and downstream connected parties (Interconnected Party) is 3:30 p.m. CCT on the day prior to flow.

(e) Scheduled Timely Nominations Quantity Summary - Nominating Party

Nominating Party shall receive a scheduled nomination summary by 4:30 p.m. CCT on the day prior to flow.

(f) Scheduled Timely Nominations Quantity Summary - Interconnected Party/Point Operator

Interconnected Party/Point Operator shall receive a scheduled nomination summary by 4:30 p.m. CCT on the day prior to flow.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.1 Timely Nominations (Continued)

(g) Day End Summary

At the end of each Gas Day Transporter shall provide the final scheduled quantities for the just completed Gas Day. With respect to the implementation of this process via 1.4.X scheduled quantity related standards, Transporter shall send an end of Gas Day Scheduled Quantity document. Receivers of the end of Gas Day Scheduled Quantity document can waive the sender's sending of the end of Gas Day Scheduled Quantity document.

10.2.2 Evening Nomination Cycle

(a) Nominating Party Delivery of Evening Nominations

The deadline for nominations leaving control of the Nominating Party is 6:00 p.m. CCT on the day prior to flow.

The effective time of an Evening Nomination shall be no earlier than 9:00 a.m. CCT, the start of the Gas Day.

All intra-day nominations for the upcoming Gas Day received during the period from the timely nomination deadline to the Evening Nomination deadline will be batched and treated by Transporter as if they were received contemporaneously.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.2 Evening Nomination Cycle (Continued)

(b) Transporter Receipt of Evening Nominations

The time for receipt of nominations by Transporter is 6:15 p.m. CCT on the day prior to flow.

(c) Quick Response to Evening Nominations

Transporter shall send Quick Response by 6:30 p.m. CCT on the day prior to flow.

(d) Confirmation of Evening Nominations

The deadline for receipt of completed confirmations by Transporter from the upstream and downstream connected parties is 9:00 p.m. CCT on the day prior to flow.

(e) Scheduled Evening Nominations Quantity Summary - Affected Nominating Party

Transporter shall provide an affected Nominating Party a scheduled quantity summary by 10:00 p.m. CCT on the day prior to flow.

(f) Scheduled Evening Nominations Quantity Summary - Affected Interconnected Party/Point Operator

Transporter shall provide an affected Interconnected Party/Point Operator a scheduled quantity summary by 10:00 p.m. CCT on the day prior to flow.

ENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.2 Evening Nomination Cycle (Continued)

(g) Scheduled Evening Nominations Quantity Summary - Bumped Parties (Notice to Bumped Parties)

A Bumped Party shall be provided a scheduled quantity summary by 10:00 p.m. CCT on the day prior to flow.

10.2.3 Intra-day 1 Nomination Cycle

(a) Nominating Party Delivery of Intra-day 1 Nominations

The deadline for nominations leaving control of the Nominating Party is 10:00 a.m. CCT on the Gas Day.

The effective time of an intra-day 1 nomination shall be no earlier than 5:00 p.m. CCT on the Gas Day.

All intra-day 1 nominations for the current Gas Day received during the period from the Evening Nomination deadline to the intraday 1 nomination deadline will be batched and treated by Transporter as if they were received contemporaneously.

(b) Transporter Receipt of Intra-day 1 Nominations

The time for receipt of nominations by Transporter is 10:15 a.m. CCT on the Gas Day.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.3 Intra-day 1 Nomination Cycle (Continued)

(c) Quick Response to Intra-day 1 Nominations

Transporter shall send Quick Response by 10:30 a.m. CCT on the Gas Day.

(d) Confirmation of Intra-day 1 Nominations

The deadline for receipt of confirmations by Transporter from the upstream and downstream connected parties is 1:00 p.m. CCT on the Gas Day.

(e) Scheduled Intra-day 1 Quantity Summary - Affected Nominating Party

Transporter shall provide an affected Nominating Party a scheduled quantity summary by 2:00 p.m. CCT on the Gas Day.

(f) Scheduled Quantity Summary - Affected Interconnected Party/Point Operator

Transporter shall provide an affected Interconnected Party/Point Operator a scheduled quantity summary by 2:00 p.m. CCT on the Gas Day.

(g) Scheduled Intra-day 1 Quantity Summary - Bumped Parties (Notice to Bumped Parties)

A bumped party shall be provided a scheduled quantity summary by 2:00 p.m. CCT on the Gas Day.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.4 Intra-day 2 Nomination Cycle

(a) Nominating Party Delivery of Intra-day 2 Nominations

The deadline for intra-day 2 nominations leaving control of the Nominating Party is 5:00 p.m. CCT on the Gas Day.

The effective time of an intra-day 2 nomination shall be no earlier than 9:00 p.m. CCT on the Gas Day.

All intra-day 2 nominations for the current Gas Day received during the period from the intra-day 1 nomination deadline to the intra-day 2 nomination deadline will be batched and treated by Transporter as if they were received contemporaneously.

Bumping is not allowed during the intra-day 2 nomination cycle.

(b) Transporter Receipt of Intra-day 2 Nominations

The time for receipt of nominations by Transporter is 5:15 p.m. CCT on the Gas Day.

(c) Quick Response to Intra-day 2 Nominations

Transporter shall send Quick Response by 5:30 p.m. CCT on the Gas Day.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.4 Intra-day 2 Nomination Cycle (Continued)

(d) Confirmation of Intra-day 2 Nominations

The deadline for receipt of completed confirmations by Transporter from the upstream and downstream connected parties is 8:00 p.m. CCT on the Gas Day.

(e) Scheduled Intra-day 2 Nominations Quantity Summary - Affected Nominating Party

Transporter shall provide an affected Nominating Party a quantity summary by 9:00 p.m. CCT on the Gas Day.

(f) Scheduled Intra-day 2 Nominations Quantity Summary - Affected Interconnected Party/Point Operator

Transporter shall provide an affected Interconnected Party/Point Operator a scheduled quantity summary by 9:00 p.m. CCT on the Gas Day.

10.2.5 Departure from Nomination and Scheduling Deadlines

The sending party shall adhere to the nomination, confirmation, and scheduling deadlines. The party receiving the request has the right to waive the deadline.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.6 Emergency Intra-day Requests

A majority of the time period in which an emergency intra-day request can be submitted to Transporter is outside of non-traditional business hours of 8 a.m. to 5 p.m. CCT. Consequently, it is the responsibility of the Nominating Party to see that Transporter has been notified that an emergency intra-day nomination has been transmitted.

Emergency intra-day requests will be processed using first come, first served, and will be confirmed and scheduled, if capacity is available on Transporter's pipeline system, on a best efforts basis. If an emergency intra-day request can be accepted and processed, Transporter will produce a Quick Response on a timely basis.

Scheduled quantity summaries reflecting scheduled emergency intra-day requests will be generated and delivered to the appropriate parties on a timely basis.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.2 Nomination and Scheduling Timeline (Continued)

10.2.7 Accessibility of Scheduling Staff

All parties, including Transporter, shall support a seven-day a week, twenty-four (24) hours a day nominations process. It is recognized that the success of seven (7) days a week, twenty-four hours a day nomination process is dependent on the availability of affected parties' scheduling personnel on a similar basis. Party contacts (including Transporter's scheduling personnel) need not be at their ordinary work sites but shall be available by telephone or beeper.

Instructions on how to reach Transporter's scheduling staff are posted on Transporter's public Internet website.

10.3 Firm Transportation Nomination Line Items

A nomination line item that has 1) its Receipt Point and its Delivery Point within the Transportation Path and 2) its nominated flow direction is in the Transportation Path direction shall be referred to as an In-Path, In-Direction (“IPID”) nomination line item.

A nomination line item that has 1) its Receipt Point and its Delivery Point within the Transportation Path and 2) its nominated flow direction is opposite of the Transportation Path direction shall be referred to as an In-Path, Out-of-Direction (“IPOD”) nomination line item.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.4 Nomination Validation

Transporter shall validate all nominations once they are received. Such validation will include verifying the nomination elements that are part of the Quick Response, verifying the existence of Agreements and amendments, and verifying that creditworthiness has been established to provide such nominated service.

A nomination which cannot be validated shall be voided by Transporter.

10.5 Allocation of Capacity

10.5.1 Allocation of Mainline and Gas Treatment Plant Capacity

In those instances in which the aggregate quantity of all validated nominations exceeds the physical capacity of Transporter's pipeline system at a specific pipeline location or segment, Transporter will allocate capacity to the validated nominations at the constrained pipeline location in the following order:

(a) IPID Rate Schedule FT-1 Nominations

Pro rata allocation of capacity based on Shipper's Maximum Delivery Quantity.

(b) IPOD Rate Schedule FT-1 Nominations

Pro rata allocation of capacity is based on Shipper's Maximum Delivery Quantity.

(c) Rate Schedule FT-1 Deferred Nominations

Pro Rata allocation of capacity is based on Shipper’s Maximum Delivery Quantity.

(d) AOS Nominations

Pro Rata allocation of capacity is based on Shipper’s Maximum Delivery Quantity.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.5 Allocation of Capacity (Continued)

10.5.1 Allocation of Mainline Capacity (Continued)

(e) Rate Schedule IT-1 Nominations

Allocation is based upon contracted rate with the highest interruptible transportation rate receiving a higher queue position than a lower interruptible transportation rate. For Shippers paying the same interruptible rate, capacity shall be allocated pro rata based on Shipper's validated nomination quantity.

For purposes of allocating interruptible nominations based on contracted rate, a negotiated rate Shipper paying a rate higher than the maximum recourse rate will be deemed to be paying a rate equal to such maximum recourse rate.

(f) Rate Schedule PAL Nominations

Allocation is based upon contracted rate with the highest PAL rate receiving a higher queue position than a lower PAL rate. For Shippers paying the same PAL rate, capacity shall be allocated pro rata based on Shipper's validated nomination quantity.

10.5.2 Allocation of Point Capacity

In those instances in which the aggregate net quantity of all validated nominations exceeds Transporter's physical capacity to receive gas at a specific Receipt Point or deliver gas at a specific Delivery Point, Transporter will allocate capacity to the validated nominations at the constrained point location in the following order:

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.5 Allocation of Capacity (Continued)

10.5.2 Allocation of Point Capacity (Continued)

(a) Primary Capacity Scheduling Rights Firm Nominations

Pro rata allocation of capacity within this nomination class is based on Shipper's primary scheduling rights at such point.

(b) Secondary In-Path ("SIP") Firm Nominations

Pro rata allocation of capacity within this nomination class is based on Shipper's secondary scheduling rights at such point.

(c) Secondary Out-of-Path ("SOP") Firm Nominations

Pro rata allocation of capacity within this nomination class is based on Shipper's secondary scheduling rights at such point.

(d) Deferred Firm Nominations

Pro rata allocation of capacity within this nomination class is based on Shipper's Deferred Firm scheduling rights.

(e) AOS Nominations

Pro rata allocation of capacity within this nomination class is based on Shipper's AOS scheduling rights.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.5 Allocation of Capacity (Continued)

10.5.2 Allocation of Point Capacity (Continued)

(f) Interruptible Nominations

Allocation of capacity for Interruptible Transactions Service is based upon rate paid by Shipper with the highest rate receiving a higher queue position than a lower rate.

Pro rata allocation of capacity within nomination classes (f) for two or more Shippers at an equal rate, if necessary, will be based on Shipper's validated nominated quantity.

(g) Nominations Under Any PAL Service Agreement

Allocation of capacity for PAL Service is based upon rate paid by Shipper with the highest rate receiving a higher queue position than a lower rate.

Pro rata allocation of capacity within nomination class (g) for two or more Shippers at an equal rate, if necessary, will be based on Shipper's validated nominated quantity.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.6 Confirmation Process

10.6.1 Confirmation Principles/Standards

With respect to the timely nomination/ confirmation process at a Receipt Point or Delivery Point, in the absence of agreement to the contrary, the lesser of the confirmation quantities shall be the confirmed quantity. If there is no response to a request for confirmation or an unsolicited confirmation response, the lesser of the confirmation quantity or the previously scheduled quantity shall be the new confirmed quantity.

With respect to the processing of requests for increases during the intra-day nomination/ confirmation process, in the absence of agreement to the contrary, the lesser of the confirmation quantities shall be the new confirmed quantity. If there is no response to a request for confirmation or an unsolicited confirmation response, the previously scheduled quantity shall be the new confirmed quantity.

With respect to the processing of requests for decreases during the intra-day nomination/ confirmation process, in the absence of an agreement to the contrary, the lesser of the confirmation quantities shall be the new confirmed quantity, but in any event no less that the elapsed-prorated-scheduled quantity. If there is no response to a request for confirmation or an unsolicited confirmation response, the greater of the confirmation quantity or the elapsed-prorated-scheduled quantity shall be the new confirmed quantity.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.6 Confirmation Process (Continued)

10.6.1 Confirmation Principles/Standards (Continued)

With respect to the above confirmation rules, if there is no response to a request for confirmation or an unsolicited confirmation response, Transporter shall provide the Nominating Party with the following information to explain why the nomination failed, as applicable:

(i) Transporter did not conduct the confirmation;

(ii) The upstream Confirming Party did not conduct the confirmation;

(iii) The upstream Service Requester did not have the gas or submit the nomination;

(iv) The downstream Confirming Party did not conduct the confirmation;

(v) The downstream Service Requester did not have the market or submit the nomination.

This information shall be imparted to the Nominating Party on the scheduled quantity document.

Ranking shall be included in the list of data elements. Transporter shall use Nominating Party provided rankings when making reductions during the scheduling process when this does not conflict with tariff-based rules.

GENERAL TERMS AND CONDITIONS

10. NOMINATIONS/ALLOCATION OF CAPACITY/CONFIRMATIONS/SCHEDULING (Continued)

10.6 Confirmation Process (Continued)

10.6.2 Timing of Confirmation

When a Confirmation Requester receives a confirmation response document from a Confirming Party by the conclusion of a given quarter hour period, the Confirmation Requester will send to the Confirming Party's designated site a corresponding Confirmation Response Quick Response document by the conclusion of the subsequent quarter hour period.

10.7 Scheduling

Once Transporter and Interconnected Party have completed the confirmation process, and both parties agree to the confirmation results, the confirmed nominations are deemed scheduled. The scheduling results will be communicated to both the Interconnected Party and Nominating Party.

Sheet No. 289
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS

11.1 Circumstances Warranting OFO

Transporter shall have the right to issue an OFO that requires actions by Shipper(s) and/or Interconnected Party(ies) in order (i) to alleviate conditions that threaten the integrity of Transporter's pipeline system, or (ii) to maintain pipeline operations at the pressures required to provide efficient and reliable transportation services, or (iii) to have adequate gas supplies in the pipeline system, or (iv) to maintain service to all firm Shippers, or (v) to maintain adequate Transporter Fuel and Lost and Unaccounted for Gas, or (vi) to balance the pipeline system for the foregoing purposes.

For purposes of this Section, the operational integrity of Transporter's pipeline system shall encompass the integrity of its physical pipeline system, the gas treatment plant, and the preservation of all other physical assets and their performance, the overall operating performance of the entire physical system as an entity (or any portion thereof), and the maintenance (on a reliable and operationally sound basis) of total system deliverability and the quality of gas delivered.

11.1.1 Specific Conditions

Specific conditions that could prompt Transporter to issue an OFO include, but are not limited to, the following situations:

(a) Inability of Transporter to receive scheduled gas at a Receipt Point or to deliver scheduled gas at a Delivery Point due to either operational or weather related conditions.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.1 Circumstances Warranting OFO (Continued)

11.1.1 Specific Conditions (Continued)

(b) Failure of Shipper(s) and/or Interconnected Party(ies) to comply with the provisions of this Tariff that adversely affects the operations of Transporter's pipeline system including, but not limited to, failure of Shipper(s) and/or Interconnected Party(ies) to adhere to the gas quality specifications set forth in Section 5 of these General Terms and Conditions.

(c) Receipt or delivery of gas in non-uniform hourly quantities resulting in pressure transients on Transporter's pipeline facilities which could jeopardize service to other Shipper(s) and/or pose a threat to the operational integrity of Interconnected Party(ies).

11.1.2 Contacts

Each Shipper and Interconnected Party must designate one (1) or more Persons, but not more than three (3) Persons, for Transporter to contact on operating matters at any time, on a twenty-four (24) hours a day, three hundred sixty-five (365) days a year basis. Such contact Persons must have adequate authority and expertise to deal with operating matters.

If Transporter is unable to make contact with the designated Person(s) of affected Shipper(s)/Interconnected Party(ies) because the contact Person is unavailable, the affected Shipper(s)/Interconnected Party(ies) shall remain subject to the terms and conditions of this Section 11. Transporter shall make all reasonable efforts to notify the affected Shipper(s)/ Interconnected Party(ies).

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.2 Net Pipeline Position ("NPP")

Shortly after the end of each Gas Day, Transporter shall calculate its NPP. The NPP is the sum of the total positive and negative cumulative imbalances at all Points of Interconnection, based on Supervisory Control and Data Acquisition ("SCADA") data. A positive NPP indicates that gas is due others. A negative NPP indicates gas that is due Transporter. Once the NPP has been calculated, Transporter shall post on its public Internet website, under Informational Postings, the NPP for the previous Gas Day as well as any operational conditions and anticipated events on Transporter's pipeline system.

11.3 Actions Taken by Transporter Prior to Issuance of an OFO

Transporter shall first attempt to isolate the impact of the operational problem by utilizing an OBA(s) at or in the area of Transporter's pipeline system where the problem is occurring, to the extent possible. However, if Transporter efforts are unsuccessful, Transporter shall issue an OFO watch.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.4 Issuance of OFO Watch

Transporter shall attempt to localize any operational problems as is reasonably practicable such that the issuance of an OFO watch will be directed to the Shipper(s) and/or Interconnected Party(ies) causing the operational problem. Notwithstanding the foregoing, if Transporter is unable to identify specific Shipper(s) and/or Interconnected Party(ies) whose action(s) require issuance of an OFO watch, the OFO watch will be applicable to all Shipper(s)/Interconnected Party(ies) on Transporter's pipeline system.

When Transporter issues an OFO watch, the affected Shipper(s) and/or Interconnected Party(ies) will be directly notified at the time of issuance, which will subsequently be followed by a critical notice to be posted, as soon as practicable, on Transporter's public Internet website under Informational Postings. Such OFO watch will state a period of time the affected Shipper(s) and/or Interconnected Party(ies)has to address the operational problems causing the issuance of the OFO watch.

If the operational problems necessitating the issuance of the OFO watch have been alleviated during the stated period of time, Transporter shall notify affected Shipper(s) and/or Interconnected Party(ies) of the termination of the OFO watch which subsequently will be followed by a critical notice to be posted, as soon as practicable, on Transporter's public Internet website under Informational Postings.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.5 Issuance of OFO

If the Transporter determines that the operational problems detailed in Subsection 11.4 have not been adequately addressed within the time period specified in the OFO watch, Transporter shall have the right to issue an OFO.

11.5.1 Notification

The affected Shipper(s) and/or Interconnected Party(ies) will be notified directly of the issuance of the OFO followed by a subsequent critical notice posting, as soon as practicable, on Transporter's public Internet website under Informational Postings. The OFO will set forth (i) the time and date of issuance, (ii) the actions required of the affected Shipper(s) and/or Interconnected Party(ies), (iii) the time by which the Shipper(s) and/or Interconnected Party(ies) must be in compliance with the OFO, (iv) the anticipated duration of the OFO, and (v) any other terms that Transporter may reasonably require to ensure the effectiveness of the OFO. The actions required in the OFO will directly correlate to the severity of the operational problem.

11.5.2 Actions

The issuance of an OFO may include, but is not limited to, any of the following actions:

(a) Curtailment of interruptible and firm services;

(b) Forced balancing at a Point of Interconnection to assure that the total scheduled nomination equals current flows;

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.5 Issuance of OFO (Continued)

11.5.2 Actions (Continued)

(c) Flow control at a Transporter operated pressure controlled Point of Interconnection to assure that the total scheduled nomination equals current flows.

11.6 Affected Shipper and/or Interconnected Party Compliance

Affected Shipper(s) and/or Interconnected Party(ies) must comply with an OFO within the time period set forth therein unless the affected Shipper(s) and/or Interconnected Party(ies) is able to demonstrate that such compliance (i) is not within their physical control or capability; (ii) is prevented by operating conditions on a third party system that are beyond the Shipper(s) and/or Interconnected Party(ies) control; (iii) is precluded by contractual restrictions or the lack of any contract with persons other than Transporter; and/or (iv) is prevented due to a force majeure event as defined in Subsection 9.2 of Transporter's General Terms and Conditions. The affected Shipper(s) and/or Interconnected Party(ies) shall notify Transporter immediately if it believes that it is excused from compliance with the OFO for any of the above stated reasons and shall provide Transporter with documentation sufficient to support its basis for non-compliance. Upon receipt of notification, Transporter will respond in writing in a timely manner advising Shipper(s) and/or Interconnected Party(ies) if it will be excused from compliance.

11.7 Treatment of Shipper Imbalances

At the time an OFO is issued, affected Shipper(s) and/or Interconnected Party(ies) will be notified of any imbalances that require immediate resolution pursuant to one of Transporter's imbalance resolution methods as detailed in Section 23 of these General Terms and Conditions.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.7 Treatment of Shipper Imbalances (Continued)

Quantities parked and loaned under Rate Schedule PAL may be utilized by affected Shipper(s) and/or Interconnected Party(ies) to net or trade against their respective imbalances to facilitate the immediate elimination of such imbalances.

11.8 Failure to Respond to OFO

11.8.1 Actions

In the event that the affected Shipper(s) and/or Interconnected Party(ies) does not respond to an OFO, or the actions taken are insufficient to correct the operational problems for which the OFO was issued, or there is insufficient time to carry out the procedures with respect to OFO's, Transporter may take unilateral action, including the curtailment of interruptible and firm service, to maintain the operational integrity of Transporter's pipeline system (or any portion thereof).

If a full interruption, partial curtailment, or reduction of service due to an OFO shall become necessary, Transporter shall immediately notify the affected Shipper(s) and/or Interconnected Party(ies), followed by a subsequent critical notice posting, as soon as practicable, on Transporter's public Internet website under Informational Postings. The posting shall contain information regarding the status of the operational variables that prompted such service interruption, and the estimated effective period of the service interruption. Additionally, Transporter shall post routine status updates throughout the service interruption period.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.8 Failure to Respond to OFO (Continued)

11.8.1 Actions (Continued)

Except in situations where the curtailment of interruptible services would not alleviate the causes and conditions necessitating the issuance of the OFO, Transporter shall curtail interruptible services prior to curtailing firm service required to alleviate the causes and conditions of the OFO.

11.8.2 Responsibility

Transporter shall not be responsible for any damages that result from any interruption in Shipper(s) and/or Interconnected Party(ies) service that is a result of Shipper(s) and/or Interconnected Party(ies) failure to comply with the OFO.

Non-complying Shipper(s) and/or Interconnected Party(ies) shall indemnify Transporter against any and all claims which result from their non-compliance.

11.9 OFO Penalty

If an affected Shipper and/or Interconnected Party fails to comply with an OFO and has not been excused in writing by Transporter from compliance pursuant to Subsection 11.6 of Transporter's General Terms and Conditions, it will be subject to an OFO penalty for each MMBtu of gas by which it deviated from the requirements of the OFO. The OFO penalty shall be computed based on a price per MMBtu equal to three times the highest price published in the absolute range for **[insert price point]** for the Gas Day on which the OFO is issued, as reported in **[insert publication]**, or any successor publication thereto.

GENERAL TERMS AND CONDITIONS

11. OPERATIONAL FLOW ORDERS (Continued)

11.9 OFO Penalty (Continued)

All amounts invoiced and collected by Transporter as payment of OFO penalties under this Subsection 11.9, net of incremental administrative charges, shall be allocated by Transporter to Shippers using the methodology set forth in Section 48 of the General Terms and Conditions.

11.10 Termination of OFO

Once the operational problems necessitating the issuance of the OFO have been alleviated, Transporter shall advise the affected Shipper(s) and/or Interconnected Party(ies) of the termination of the OFO and shall post a critical notice on its public Internet website, as soon as practicable, regarding the termination of the OFO.

Sheet Nos. 299 and 300
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

12. SEPARATE LIABILITY OF SHIPPER AND TITLE TO GAS

The execution of an Agreement by Shipper shall result in Shipper undertaking obligations of a separate nature, and shall not be deemed to cause a joint, or joint and several, obligation vis a vis any one or more other Shippers.

Shipper shall maintain ownership and Title to all gas transported. Shipper shall retain Title while the natural gas, including acid gas and gas lost or otherwise unaccounted for, is in the custody of Transporter. Shipper will be in exclusive control and possession of the gas, including acid gas, gas lost or otherwise unaccounted for and gas to be transported, prior to receipt by Transporter and after delivery by Transporter.

Sheet Nos. 302 and 303
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

13. CURTAILMENT

Transporter shall have the right to curtail service on any portion of its pipeline system at any time for reasons of force majeure, maintenance, repairs, operating conditions or other causes, whether similar or dissimilar. Transporter shall exercise this curtailment provision only at affected point(s) or segment(s) of the pipeline system.

Transporter shall provide notice on its public Internet website of any curtailment as soon as practicable.

During the period of the curtailment, scheduled capacity shall be curtailed in reverse allocation order of priority classification as detailed in Subsection 10.5 of these General Terms and Conditions.

Sheet Nos. 305 and 306
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

14. SHIPPER DELIVERY RIGHT AND WARRANTIES

Shipper shall have the right to transport or treat natural gas pursuant to the terms and conditions of Shipper's Agreement. Shipper warrants that it 1) shall have Title to all gas tendered to Transporter and 2) shall indemnify and save harmless Transporter against claims, liability, loss or damage which Transporter may incur or suffer as a result of the lack of such right or other breach of such warranty or any claim made against Transporter by any Person asserting an interest in such gas.

Sheet Nos. 308 and 309
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

15. CUSTODY OF GAS

15.1 Receipt Point

The point of custody transfer at each Receipt Point shall be on the inlet side of the measurement station at such Receipt Point or at such other point as may be agreed between Transporter and Shipper, or all Shippers who utilize such Receipt Point.

15.2 Delivery Point

The point of custody transfer at each Delivery Point shall be on the outlet side of the measurement station at such Delivery Point or at such other point as may be agreed upon between Transporter and Shipper, or all Shippers who utilize such Delivery Point.

Sheet Nos. 311 and 312
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

16. FERC ANNUAL CHARGE PROVISION AND CHANGE IN LAW/TAX/ REGULATION SURCHARGES

16.1 Purpose

Pursuant to Sections 154.402 and 154.403 of FERC's Regulations, Transporter intends to recover the annual charges assessed by FERC under Part 382 of FERC's Regulations and surcharges to recover costs associated with changes in law, tax and regulation through the terms contained in this Section 16 and not through Natural Gas Act ("NGA") Section 4(e) rate filing.

16.2 Annual Charge Adjustment ("ACA") Unit Rate Adjustment

Changes to the ACA unit rate shall be filed annually by Transporter to reflect the annual charge unit rate assessed by FERC on Transporter. The ACA unit rate shall be set forth in the Statement of Rates. Transporter shall file to effectuate the ACA unit rate at least thirty (30) days prior to its proposed effective date, as permitted under Section 4 of the NGA.

The ACA unit rate is not a discountable rate component.

16.3 Changes in Law/Tax/Regulation

Surcharges may be assessed and collected from Shippers related to changes in law or taxes, or regulation, to include, but not be limited to, any law, regulation, or governmental policy which imposes fees or costs upon Transporter related to climate change, greenhouse gas regulation, pipeline safety, or the security of Transporter's facilities. Surcharges may also be imposed to recover costs associated with repairs necessary to restore service levels following an incident of force majeure. Surcharges under this Section 16.3 are not a discountable rate component.

GENERAL TERMS AND CONDITIONS

16. FERC ANNUAL CHARGE PROVISION AND CHANGE IN LAW/TAX/ REGULATION SURCHARGES (Continued)

16.4 Applicability

The ACA unit rate and Section 16.3 surcharges shall apply to all transportation and gas treatment services.

Sheet No. 315
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

17. RECEIPT POINT AND DELIVERY POINT FLEXIBILITY/SEGMENTATION

17.1 Flexible Point Rights

Shipper may nominate any Receipt Point or Delivery Point (physical, logical or Transfer Point) on Transporter's pipeline system, unless otherwise specifically excluded in the Rate Schedule or underlying Agreement.

All Receipt Point(s) and Delivery Point(s) within a firm Shipper's Transportation Path are granted a higher capacity allocation priority than Receipt Point(s) and Delivery Point(s) outside a Shipper's Transportation Path.

17.2 Point Capacity Scheduling Rights Under Firm Transportation Service Agreements

17.2.1 Primary Point Capacity Scheduling Rights

Shipper's primary point capacity scheduling rights will be initially located at the Receipt Point and Delivery Point establishing Shipper's Transportation Path set forth on Exhibit A of Shipper's Service Agreement.

Shipper shall receive primary capacity scheduling rights for a quantity of gas equal to Shipper's Maximum Delivery Quantity set forth on Exhibit A of Shipper's Service Agreement.

17.2.2 Reassignment of Primary Point Capacity Scheduling Rights

Subject to the availability of firm point capacity on Transporter's pipeline system, Shipper shall have the ability to reassign its primary point capacity scheduling rights to one or more Receipt Point(s) or Delivery Point(s) within its Transportation Path.

GENERAL TERMS AND CONDITIONS

17. RECEIPT POINT AND DELIVERY POINT FLEXIBILITY/SEGMENTATION (Continued)

17.2 Point Capacity Scheduling Rights Under Firm Transportation Service Agreements (Continued)

17.2.2 Reassignment of Primary Point Capacity Scheduling Rights (Continued)

The reassignment of primary point capacity scheduling rights within Shipper's Transportation Path shall not result in an increase or decrease in Shipper's contracted rights. The sum of the quantities reassigned to the Receipt Point(s) and Delivery Point(s) shall not exceed Transporter's obligation set forth in Shipper's Service Agreement. Shipper may submit a request to Transporter to reassign its primary point capacity scheduling rights within its Transportation Path. The term of the reassignment period will be included in the request. Such request must be made to Transporter no later than 1:00 p.m. CCT on the day before nominations are due.

If more than one Shipper desires to reassign its primary point capacity scheduling rights to the same point and insufficient firm capacity exists to accommodate the requests, the available capacity at the requested point will be allocated pro rata based upon the requested quantity at such point. Transporter shall notify Shippers of its ability or inability to reassign primary scheduling rights. Such notification shall be made at least one (1) hour before the timely cycle nominations are due and will detail the reason for the request not being implemented, if applicable.

Shipper retains the option to return to its initial primary capacity scheduling rights position at the end of the reassignment period.

GENERAL TERMS AND CONDITIONS

17. RECEIPT POINT AND DELIVERY POINT FLEXIBILITY/SEGMENTATION (Continued)

17.2 Point Capacity Scheduling Rights Under Firm Transportation Service Agreements (Continued)

17.2.2 Reassignment of Primary Point Capacity Scheduling Rights (Continued)

During the term of Shipper's reassignment of primary point capacity scheduling rights, Transporter reserves the right to sell any available capacity resulting from such reassignment.

17.2.3 Shipper's Obligations Under Reassignment of Primary Point Capacity Scheduling Rights

During the term of the reassignment period, a firm Shipper subject to a reservation charge will continue to be billed a reservation charge based upon the Transportation Path set forth on Exhibit A of Shipper's Service Agreement. Shipper shall be required to pay a commodity charge and provide Transporter Fuel and Lost and Unaccounted for Gas based upon the Transportation Path actually scheduled.

If a Shipper requests a permanent reassignment of primary point capacity scheduling rights outside of its currently effective Transportation Path, such a requested permanent change in primary point capacity scheduling rights is subject to available capacity, execution of an amendment to the Service Agreement and compliance with the requirements under Transporter's Tariff in order to effectuate a permanent change in its Transportation Path. Shipper shall be subject to any resulting additional transportation charges associated with the permanent reassignment.

GENERAL TERMS AND CONDITIONS

17. RECEIPT POINT AND DELIVERY POINT FLEXIBILITY/SEGMENTATION (Continued)

17.2 Point Capacity Scheduling Rights Under Firm Transportation Service Agreements (Continued)

17.2.3 Shipper's Obligations Under Reassignment of Primary Point Capacity Scheduling Rights (Continued)

The Receipt Point(s) and Delivery Point(s) within a Shipper's Transportation Path that do not have primary capacity scheduling rights are automatically assigned SIP capacity scheduling rights by Transporter.

The Receipt Point(s) and Delivery Point(s) outside of a Shipper's Transportation Path are automatically assigned SOP capacity scheduling rights by Transporter.

Under no circumstances shall a Shipper’s Primary Receipt or Delivery Point change request result in the payment of reservation and commodity charges that are less than that paid for the original primary path.

17.3 Segmentation Rights

17.3.1 Segmentation via Nomination Process

A Shipper may segment its Transportation Path into separate parts through the nomination process, to the extent such segmentation is operationally feasible.

Shipper may not segment capacity via the nomination process when the nominations by such party exceed the Maximum Delivery Quantity of the underlying Service Agreement at a pipeline location. However, a segmented nomination by a Shipper

GENERAL TERMS AND CONDITIONS

17. RECEIPT POINT AND DELIVERY POINT FLEXIBILITY/SEGMENTATION (Continued)

17.3 Segmentation Rights (Continued)

17.3.1 Segmentation via Nomination Process (Continued

consisting of a Forwardhaul and Backhaul to the same Receipt Point or Delivery Point for a given nomination cycle may exceed the Maximum Delivery Quantity of the underlying Service Agreement.

GENERAL TERMS AND CONDITIONS

17. RECEIPT POINT AND DELIVERY POINT FLEXIBILITY/SEGMENTATION (Continued)

17.3 Segmentation Rights (Continued)

17.3.2 Segmentation via Capacity Release

Shipper may segment its Transportation Path for the purpose of releasing capacity in accordance with Section 27 of these General Terms and Conditions to the extent such segmentation is operationally feasible.

Any secondary scheduling rights resulting from a segmented capacity release may be elevated to primary scheduling rights to the extent firm capacity exists at the requested Receipt Point(s) or Delivery Point(s) within the Transportation Path up to the Releasing Shipper's or Replacement Shipper's Maximum Delivery Quantity.

Shipper may submit a request to Transporter to elevate its scheduling rights no later than 1:00 p.m. CCT on the day before nominations are due.

Transporter shall notify Replacement/ Releasing Shipper of its ability or inability to elevate the scheduling rights. Such notification shall be made at least one hour before the timely cycle nominations are due and will detail the reason for the request not being implemented, if applicable.

17.3.3 Contractual Rights

The use of segmentation shall not result in an increase in Shipper's Maximum Delivery Quantity or Maximum Treatment Quantity.

Sheet No 322
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL

18.1 Applicability

A firm Shipper with a Service Agreement for a term of at least twelve (12) consecutive months at the Maximum Rate shall have the right of first refusal regarding continuing service beyond the primary term specified in the Shipper's Service Agreement for all or a portion of Shipper's Maximum Delivery Quantity, provided Shipper satisfies the creditworthiness requirements set forth in Section 40 of these General Terms and Conditions and the Service Agreement and is current with its obligations and otherwise is in compliance with the terms and conditions of Transporter's Tariff. A Shipper may not exercise its right of first refusal for only a geographic portion of its contracted Transportation Path or to off-system services acquired for Shipper under Subsection 39.2 of these General Terms and Conditions.

Unless Transporter and Shipper expressly agree otherwise in Shipper's Service Agreement, a right of first refusal does not apply to any Negotiated Rate Agreement or to any discounted rate Agreement or to off-system services acquired for Shipper under Subsection 39.2 of these General Terms and Conditions.

A limited right of first refusal shall be applicable to an interim Service Agreement for capacity that has been sold pursuant to Subsection 26.4 or Subsection 28.5 of these General Terms and Conditions.

A Service Agreement containing a right of first refusal applicable to off-system service contracted pursuant to Section 39 of these General Terms and Conditions may not be extended beyond the term of Transporter's agreement with a third-party for such off-system service.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.2 Avoidance of Right of First Refusal Process

Subject to Subsection 18.1 herein, Shipper can extend the term of its Service Agreement at anytime and not be subject to the right of first refusal process outlined below if, prior to the receipt of notice in Subsection 18.3 herein, Shipper agrees to any of the following actions: 1) Shipper agrees to amend the term of its Service Agreement for a term of five (5) or more years at the Maximum Rate from the effective date of the amendment or 2) Shipper and Transporter mutually agree to amend the terms of the existing Service Agreement which shall include an extension of the term beyond the termination date of the existing Service Agreement. An amended Service Agreement containing the revised terms also must be executed prior to receipt of notice in Subsection 18.3 herein.

18.3 Notice to Shipper

Transporter shall give notice to Shipper, not less than six (6) months and no more than eighteen (18) months prior to the termination of Shipper's Service Agreement that Shipper's capacity is subject to the right of first refusal.

In the event an expansion project is proposed that would utilize capacity on Transporter's existing facilities, the sizing of such proposed project could be affected by Shipper's plans regarding its continuation of service. Accordingly, Transporter shall have the right to give Shipper notice no more than thirty-six (36) months prior to termination of Shipper's Service Agreement that Shipper's capacity is subject to the right of first refusal. Transporter shall require a response from Shipper no later than ten (10) Business Days from the date the notice is issued.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.4 Shipper's Response to Notice

Shipper's response to Transporter's notice, pursuant to Subsection 18.3 herein, shall include a binding commitment to any of the following options up to the Maximum Delivery Quantity in Shipper's Service Agreement: 1) extend the term of its Service Agreement at the Maximum Rate under the applicable Rate Schedule; 2) terminate its Service Agreement; or 3) exercise its right of first refusal.

Shipper must notify Transporter of its election, within ten (10) Business Days from the date the notice is issued pursuant to Subsection 18.3 herein. In the event that Shipper does not respond to Transporter's notice within such time frame, Transporter shall post all of Shipper's capacity for Bid, without a right of first refusal, in accordance with Subsection 26.1 of these General Terms and Conditions.

18.4.1 Extension of Term of Service Agreement

If Shipper elects to extend the term of its Service Agreement for all or a portion of its Maximum Delivery Quantity under its Service Agreement for a term of five (5) years or more at the Maximum Rate, Shipper shall execute an amendment to the Service Agreement containing such terms within five (5) Business Days from the date such amended Service Agreement is tendered to Shipper. No further action by Shipper shall be required upon receipt by Transporter of the executed Service Agreement.

18.4.2 Termination of Service Agreement

If Shipper elects to terminate its Service Agreement, such Service Agreement shall expire under its own terms and no further action will be required of Shipper.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.4 Shipper's Response to Notice (Continued)

18.4.3 Exercise of Right of First Refusal

If Shipper elects to exercise its right of first refusal, then such capacity shall be subject to the procedures detailed in Subsection 18.5 herein. Shipper shall be required to execute an amendment to its Service Agreement, within five (5) Business Days from the date such amended Service Agreement is tendered to Shipper reflecting the terms matched. No later than one (1) Business Day of receiving notice of Shipper's election under this Subsection 18.4.3, Transporter shall post the capacity in accordance with Subsection 18.5 herein.

18.5 Posting/Bid Procedures

18.5.1 Posting of Available Capacity

Transporter shall post for twenty (20) Business Days a notice of available firm capacity that is subject to the right of first refusal. The posting shall specify the Maximum Delivery Quantity, Transportation Path, Bid evaluation method, and deadline for resolution of Bid contingency(ies) allowed in Subsection 18.5.2(c) herein. The posting shall state that the capacity is subject to the right of first refusal and whether Transporter will consider a negotiated rate Bid.

18.5.2 Bid Procedures

(a) Within one (1) Business Day of receipt of a Bid by Transporter for the posted firm capacity, Transporter will post the Bid. The identity of the bidder shall be kept confidential. Transporter shall not be obligated to accept a Bid at less than the applicable Maximum Rate.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.5 Posting/Bid Procedures (Continued)

18.5.2 Bid Procedures (Continued)

(b) Any Person desiring to submit a Bid for firm capacity in accordance with this Section 18 must satisfy the requirements of the applicable Rate Schedule and execute the associated Service Agreement. A Bid for firm capacity which exceeds a Shipper's qualified level of creditworthiness shall be accepted up to the level of creditworthiness established pursuant to Section 40 of these General Terms and Conditions.

(c) In the event Transporter will allow a contingent Bid, Transporter shall detail in its posting the specific contingency(ies) it will accept and Bidder must specify the details of the contingency in its Bid.

(d) Transporter will not accept a Bid containing contingencies other than those allowed in Subsection 18.5.2(c) above.

(e) A bidder may withdraw its Bid prior to the Bid Closing Date upon written notice to Transporter.

18.5.3 Selection of Best Bid

(a) For purposes of determining the Best Bid(s), Transporter will use Method A as detailed in Subsection 27.6.1(a) or, if applicable, Subsection 37.4 of these General Terms and Conditions for a negotiated rate Bid. The Best Bid must meet or exceed the lowest rate Transporter is willing to accept for such service.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.5 Posting/Bid Procedures (Continued)

18.5.3 Selection of Best Bid (Continued)

Nothing herein shall obligate Transporter to provide service to any Shipper at less than Transporter's applicable Maximum Rates.

(b) Transporter shall evaluate Bid(s) received and notify Shipper in writing within one (1) Business Day after the Bid Close Date of the Best Bid(s) or if no acceptable Bid(s) were received. In those instances where a contingent Bid(s) pursuant to Subsection 18.5.2(c) herein is determined to be the Best Bid, the allocation of capacity may be delayed, without undue discrimination, pending satisfaction of the contingency. If such contingency has not been resolved by ten (10) Business Days after the Bid Closing Date, then such contingent Bid is deemed void.

(c) In order for Shipper to retain its capacity, Shipper shall notify Transporter in writing within ten (10) Business Days of notification pursuant to Subsection 18.5.3(b) herein that Shipper elects to match the Best Bid(s) for all or a percentage of the Maximum Delivery Quantity. A Shipper that has a primary term greater than one (1) year at the Maximum Rate is not required to match a rate higher than the Maximum Rate currently in effect for that Transportation Path in order to retain its contracted capacity.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.5 Posting/Bid Procedures (Continued)

18.5.3 Selection of Best Bid (Continued)

If the Best Bid(s) contains a Negotiated Rate, Shipper may retain all or a portion of its Maximum Delivery Quantity by choosing one of the following options: 1) matching the Best Bid as a Negotiated Rate or 2) matching the Best Bid as a discounted rate that is equivalent to the Negotiated Rate or 3) agreeing to pay the currently effective Maximum Rate. If Shipper timely matches the Best Bid, Transporter shall prepare a Service Agreement setting forth the terms and conditions of the Best Bid for Shipper's execution to be effective on the date the existing Service Agreement expires. If Shipper fails to execute the Service Agreement within five (5) Business Days of Transporter's tender, Shipper will forfeit any claim under its right of first refusal to the subject capacity. Notwithstanding the prior notice of any award of such capacity to Shipper, Transporter shall have the ability to resell the capacity and Shipper will be required to pay Transporter the difference between the matched Best Bid and the price received for the resold capacity multiplied by the quantity of the awarded Bid, in the event the matched Best Bid was above the price ultimately received for the resold capacity.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.5 Posting/Bid Procedures (Continued)

18.5.3 Selection of Best Bid (Continued)

(d) In the event there is capacity remaining after Shipper's election in Subsection 18.5.3(c) herein and there is more than one Best Bid, the firm capacity shall be allocated on a pro rata basis.

(e) Each bidder who submitted a Best Bid, as determined in Subsection 18.5.3(a) herein, will be awarded capacity within one (1) Business Day following receipt of Shipper's notice to Transporter in Subsection 18.5.3(c) herein. Transporter shall prepare a Service Agreement setting forth the terms and conditions of the Best Bid for Shipper's execution. If Shipper fails to execute the Service Agreement within five (5) Business Days of Transporter's tender, Transporter shall have the ability to resell the capacity, notwithstanding the notice of any award, and Shipper will be required to pay Transporter the difference between the Best Bid and the price received for the resold capacity multiplied by the quantity of the awarded Bid, in the event the Best Bid was above the price ultimately received for the resold capacity.

GENERAL TERMS AND CONDITIONS

18. RIGHT OF FIRST REFUSAL (Continued)

18.5 Posting/Bid Procedures (Continued)

18.5.3 Selection of Best Bid (Continued)

(f) The awarded Best Bid(s), including the identity of the bidder(s), will be posted on Transporter's public Internet website within one (1) Business Day of award.

If Transporter does not receive any acceptable Bid(s) for all or part of the capacity in response to a posting pursuant to Subsection 18.5.1 herein, Transporter shall notify Shipper in writing of the results and inform the Shipper that Shipper may continue to receive service if Transporter and Shipper can mutually agree to acceptable terms and execute a Service Agreement to continue all or a portion of Shipper's Service Agreement within five (5) Business Days of such notification. Transporter is under no obligation to provide service at less than the Maximum Rate under any Rate Schedule. If Transporter and Shipper do not execute a Service Agreement by the close of the five (5) Business Day period, Shipper's right of first refusal under the Service Agreement shall expire and on the following Business Day, Transporter shall post the capacity as available without a right of first refusal in accordance with Subsection 26.1 of these General Terms and Conditions.

Sheet Nos. 332 and 333
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

19. FACILITIES POLICY

Transporter shall not be required to build, modify, operate, own, or contribute to the cost of building or operating any facilities including but not limited to pipeline facilities, taps, metering facilities, valves, looping and/or compression facilities, on behalf of Shippers or other Persons, which are not operationally or economically feasible. In the event Transporter agrees to either build, operate, own, or contribute to the cost of building any such facilities, Transporter shall do so on a not unduly discriminatory basis.

19.1 Shipper Reimbursement

Shipper(s) will be required to reimburse Transporter, on mutually agreeable terms, for costs associated with constructing and operating the facilities. Such mutually agreed upon reimbursement may be in the form of an incremental rate, a firm service commitment, an operations fee, a lump sum payment, or a mutually agreed upon method, including reimbursement for any associated income tax effects. Transporter may waive this requirement on a not unduly discriminatory basis.

GENERAL TERMS AND CONDITIONS

19. FACILITIES POLICY (Continued)

19.2 Transporter Contribution

Transporter may pay for or contribute to all or a portion of the cost of building or operating facilities requested by Shippers or other Persons if Transporter determines that such action will result in an economic benefit, or determines that the project is economically neutral to Transporter. Transporter will evaluate each prospective project under this policy based upon the incremental cost of service and the incremental revenues which Transporter estimates will be generated as a result of the project. When estimating incremental revenues to be generated, Transporter will base those revenues upon transportation rates it expects to be able to charge, including any surcharges, the incremental volumes or firm service contracts that will result from the project, and any reduction in revenues for service rendered to other Shippers if the addition of the billing determinants associated with service provided to the Shipper(s) requesting facilities results in a rate reduction for other Shipper(s). Transporter may also consider volumes or firm service contracts to be incremental if the volumes or firm service contracts that will be transported or provided respectively would not otherwise flow through or be contracted for firm service on Transporter's pipeline system.

Sheet Nos. 336 and 337
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

20. CONTRACTUAL NOTICES

Any notice or other communication required to be given or made in writing under an Agreement shall be sufficiently given if reduced to writing and delivered, mailed by prepaid mail, or other mechanical or electronic means of transmitting written messages, to the Person to which it is to be given at the most recent address of such Person provided to Transporter for such Agreement in the manner provided in this Section 20. Any such notice or other communication which is mailed shall be considered to be given or made when it is received by the Person to which it is given or made and, if provided electronically, shall be deemed received by such Person when it is sent.

Sheet Nos. 339 and 340
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

21. DEFAULTS

No default in the performance of any of the obligations of Transporter or Shipper under this Tariff or Shipper's Agreement, nor any action, non-action, concession, waiver or indulgence by Transporter or Shipper shall operate to terminate, cancel, repudiate or surrender either party's rights or obligations under this Tariff or Shipper's Agreement, except as specifically provided in such Agreement, or relieve Transporter or such Shipper from due and timely compliance with its obligations thereunder.

Sheet Nos. 342 and 343
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

22. [RESERVED FOR FUTURE USE]

Sheet Nos. 345 and 346
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

23. IMBALANCE RESOLUTION

For purposes of this Section 23, Party(ies) shall be defined as any Person having an imbalance with Transporter.

23.1 Pre-Determined Allocations (PDA)

PDAs shall be used to manage the variance between actual quantities and scheduled quantities and an OBA is a form of PDA. The upstream or downstream party providing the Point of Interconnection confirmation should submit the PDA to the allocating party after or during confirmation and before the start of the Gas Day, except that no PDAs need to be submitted if an OBA is in effect at a Point of Interconnection.

23.2 Allocation Statements

Allocations are performed by the operator of the affected location, using the PDA method agreed to by the parties involved. The allocation statement is used to communicate the allocation information to the parties involved.

The time limitation for disputes of allocations should be six (6) months from the date of the initial month-end allocation with a three (3) month rebuttal period. This standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard.

23.3 Imbalance Resolution

Resolution to correct an imbalance shall be required.

Party must correct such imbalance within forty-five (45) days from the date it is notified by Transporter of an imbalance under an existing Agreement or an Agreement that has terminated.

GENERAL TERMS AND CONDITIONS

23. IMBALANCE RESOLUTION (Continued)

23.3 Imbalance Resolution (Continued)

Transporter shall support the following methods of imbalance resolution, provided that at the time proposed for such resolution, sufficient capacity is available and all nominations and scheduling processes are satisfied.

23.3.1 In-kind

To resolve an imbalance due Transporter, party may elect to deliver gas into Transporter's pipeline system at any Receipt Point.

To resolve an imbalance due party, a party may elect to accept gas from Transporter's pipeline system at any Delivery Point.

If party creates and resolves an imbalance within the same zone or Operational Impact Area, there will be no associated charge for transportation or Transporter Fuel and Lost and Unaccounted for Gas.

23.3.2 Netting

Transporter shall allow a party to net an imbalance within the same zone or Operational Impact Area on and across Agreements.

23.3.3 Trading

Transporter shall allow a party to trade imbalances within the same zone or Operational Impact Area on and across Agreements.

Transporter shall provide the ability to post and trade imbalances until at least the close of the nineteenth Business Day of the month.

GENERAL TERMS AND CONDITIONS

23. IMBALANCE RESOLUTION (Continued)

23.3 Imbalance Resolution (Continued)

23.3.3 Trading (Continued)

Authorizations to post imbalances that are received by Transporter by 11:45 a.m. CCT shall be effective at 8:00 a.m. CCT the next Business Day. Imbalances previously authorized for posting shall be posted on or before the ninth Business Day of the month.

23.3.4 Underdelivery Cashout

To resolve an imbalance due Transporter, party may elect to reimburse Transporter for such Underdelivery.

Party must provide written notice to Transporter, within the resolution period, of its desire to cashout all or a portion of the Underdelivery quantity. At such time, Transporter will post an offer to buy linepack equal to the Underdelivery quantity specified by party to resolve. Transporter shall select the lowest Bid received from any qualified bidder and will facilitate the delivery of such linepack into its pipeline system. Transporter shall post all Bids received from qualified bidders and select the lowest qualified Bid. If the lowest qualified Bid is not chosen, explanation and justification of the selected Bid also will be posted.

Transporter shall invoice party for the total cost of the linepack purchased to reduce or eliminate the Underdelivery at the time such linepack is received into Transporter's pipeline system.

GENERAL TERMS AND CONDITIONS

23. IMBALANCE RESOLUTION (Continued)

23.3 Imbalance Resolution (Continued)

23.3.4 Underdelivery Cashout (Continued)

To account for any imbalance remaining after cashout, party and Transporter shall agree to designate one of the Shipper's Agreement(s) in the zone or Operational Impact Area where the original imbalance occurred, for such purpose.

23.3.5 Underdelivery Penalty

If a Shipper Imbalance has not been resolved during the resolution period, and the remaining Shipper Imbalance reflects an Underdelivery, Transporter will invoice Shipper an Underdelivery Penalty for an amount equal to the Underdelivery quantity times the higher of one hundred fifty percent of the actual price established at Subsection 23.3.4 herein or the highest price of gas delivered at points within the State of Alaska.

Amounts received by Transporter for the Underdelivery Penalty, net of administrative costs, shall be allocated by Transporter to Shippers using the methodology set forth in Section 48 of these General Terms and Conditions.

23.3.6 Overdelivery Retention

If a Shipper Imbalance has not been resolved during the resolution period, and the remaining Shipper Imbalance reflects an Overdelivery, Transporter shall retain the quantity of gas in excess and use it to reduce Transporter Fuel and Lost and Unaccounted for Gas.

Sheet Nos. 351 and 352
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

24. SEVERABILITY

If any provision of a Shipper's Agreement shall be contrary to or prohibited by applicable law, such provision shall be severable from the remaining provisions of such Agreement and shall be deemed to be deleted therefrom, and all of the provisions of such Agreement which are not contrary to or prohibited by applicable law shall, notwithstanding such deletion, remain in full force and effect. If Subsection 6.6 of these General Terms and Conditions requires the payment of interest at a rate which exceeds the rate which the Person to whom such interest is required to be paid is permitted under applicable law to receive, or which the Person required to pay such interest is permitted under applicable law to pay, such rate shall be reduced to the highest rate which is permitted under applicable law. In no event will Transporter be made liable to make payment, or credit against the cost of service, for any difference between interest otherwise due and owing to Transporter under Subsection 6.6 of these General Terms and Conditions and the amount actually paid by a Shipper to Transporter, which difference arises in whole or in part as the result of the application of this Section 24 of these General Terms and Conditions.

Sheet Nos. 354 and 355
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

25. SURVIVAL OF OBLIGATION

Notwithstanding the termination of Shipper's Agreement, Shipper and Transporter shall have the following obligations as such obligations relate to activities undertaken prior to the date Shipper's Agreement terminates:

(a) Shipper shall remain liable thereafter to pay all invoices rendered by Transporter to it in the manner contemplated, and subject to Shipper's rights in respect of such payments provided in Section 6 of these General Terms and Conditions;

(b) Transporter shall remain liable thereafter to make all payments to Shipper required to be made under Section 6 of these General Terms and Conditions, provided Transporter is paid for obligations owed to it;

(c) Transporter and Shipper shall remain liable thereafter to indemnify each other as provided in Section 8 of these General Terms and Conditions with respect to events taking place prior to such termination;

(d) Shipper and Transporter shall remain liable thereafter to resolve all other obligations to the date of such termination.

With all reasonable dispatch after the giving of a notice of termination as may be required under Shipper's Agreement, Transporter and Shipper shall enter into such arrangements as may be reasonably necessary to ensure performance of the foregoing obligations and otherwise as may be necessary or desirable in connection with such termination.

Sheet Nos. 357 and 358
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

26. POSTING AND AWARDING OF AVAILABLE AND PLANNED PIPELINE CAPACITY

26.1 Posting of Firm Capacity

(a) Transporter will post on its public Internet website available capacity, not subject to Section 18 of these General Terms and Conditions, and planned firm capacity, for the purpose of obtaining competitive Bids.

(b) The bid period shall be a minimum of 1) three (3) Business Days for capacity with a term of greater than a Calendar Month or 2) one (1) hour for capacity with a term of a Calendar Month or 3) fifteen (15) minutes for capacity with a term of less than a Calendar Month.

(c) All postings shall set forth the criteria for an acceptable Bid, the method for awarding capacity, the Bid Closing Date, the method for resolving a tie breaker, any contingencies that Transporter is willing to accept, and the time frame for resolving contingencies.

26.2 Bid Procedures

(a) Any Person desiring to submit a Bid for firm capacity in accordance with this Section 26 must satisfy the requirements of the applicable firm Rate schedule and agree to execute the applicable Service Agreement. A Person's Bid for firm capacity which exceeds its qualified level of creditworthiness shall not be accepted.

(b) Bidder must specify in its Bid the details of the contingency that Transporter is willing to accept pursuant to Subsection 26.1(c) above. In those instances where such a contingent Bid(s) is determined to be the Best Bid, the allocation of capacity may be delayed pending satisfaction of the contingency.

GENERAL TERMS AND CONDITIONS

26. POSTING AND AWARDING OF AVAILABLE AND PLANNED PIPELINE CAPACITY (Continued)

26.2 Bid Procedures (Continued)

(c) If a Bid is received which contains conditions, other than those allowed in Subsection 26.1(c) above, that are not satisfied at the Bid Closing Date, such Bid shall not be accepted.

(d) A bidder may withdraw its Bid prior to the Bid Closing Date upon written notice to Transporter.

26.3 Awarding of Best Bid(s)

Bidders shall submit Bids to Transporter via Transporter's non-public Internet website unless Transporter provides notice of an alternative means of accepting Bids.

All Bids not withdrawn prior to the close of the bid period shall be binding. At the close of the bid period, Transporter shall evaluate the Bids and determine the Best Bid. Unless otherwise specified in the posting, Transporter shall not be required to accept Bids at less than the Maximum Rate or for a Transportation Path shorter than the posted Transportation Path or for a term shorter than the posted term.

GENERAL TERMS AND CONDITIONS

26. POSTING AND AWARDING OF AVAILABLE AND PLANNED PIPELINE CAPACITY (Continued)

26.3 Awarding of Best Bid(s) (Continued)

No later than one (1) Business Day following the Bid Closing Date, except as set forth in Subsection 26.2 above, Transporter will award Best Bid(s) in accordance with Method A detailed in Subsection 27.6.1(a) of these General Terms and Conditions.

If Transporter accepts a Bid(s) that results in a contract term of one Calendar Month or less, Transporter may re-sell any remaining available capacity for such Calendar Month effective at the end of the contract term without implementing a new bid period.

If available capacity remains after the Bid Closing Date, Transporter shall post the available capacity on its public Internet website as available unsubscribed capacity. Transporter may sell such available capacity on a first come-first serve basis to any Person without commencing a new bid period. Best Bids received with the same date and time-stamp will be prorated, if necessary.

GENERAL TERMS AND CONDITIONS

26. POSTING AND AWARDING OF AVAILABLE AND PLANNED PIPELINE CAPACITY (Continued)

26.4 Interim Sales of Capacity

Capacity that has been awarded pursuant to Subsection 26.3 herein with a future Billing Commencement Date shall be made available to Shippers on an interim basis. Where the available interim capacity would otherwise be eligible for the right of first refusal as set forth in the applicable Service Agreement and pursuant to Section 18 of these General Terms and Conditions, Transporter shall limit the right of first refusal for capacity sold on an interim basis such that the term of the interim capacity may not be extended beyond the future Billing Commencement Date of firm capacity sold. If the right of first refusal is limited, the applicable Service Agreement shall note such limitation.

Sheet Nos. 363 and 364
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY

27.1 Rights and Obligations of Shipper

27.1.1 Permanent Release

Unless otherwise specified in a Service Agreement, a Releasing Shipper may release its firm capacity under its Service Agreement, in whole or part, for the remaining term of the Releasing Shipper's Service Agreement to a Person desiring such service and such release shall be referred to as a permanent release. The Replacement Shipper acquiring the capacity under the permanent release shall satisfy Transporter’s creditworthiness requirements and the creditworthiness conditions of the Releasing Shipper’s Service Agreement and execute a Service Agreement which shall contain the terms and conditions of the Releasing Shipper’s Service Agreement, subject to the financial or economic indifference standard noted below.

In order for a Releasing Shipper to effectuate a permanent release of all or part of its contracted capacity, it shall enter into a Service Agreement amendment with Transporter which will provide for the termination of the Releasing Shipper's existing Service Agreement for the permanent released capacity. In such event, the Releasing Shipper shall thereafter be relieved of its obligations for the permanent released capacity under the Service Agreement, subject to the provisions of Section 25 of these General Terms and Conditions.

Transporter may refuse to allow a permanent release if it has a reasonable basis to conclude that it will not be financially or economically indifferent to the release. If Shipper's request to permanently release capacity is denied, Transporter may, if requested by Replacement Shipper, notify the Releasing Shipper and the Replacement Shipper in writing of the reason(s) for such denial.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.1 Rights and Obligations of Shipper (Continued)

27.1.2 Temporary Release

A Shipper may temporarily release its firm capacity, in whole or in part, to a Person desiring such service which shall be referred to as a temporary release. If a Shipper elects to temporarily release its capacity, all obligations associated with the released capacity remain with the original Releasing Shipper. At the end of the term of the temporary release, all contractual rights and obligations remain with the original Releasing Shipper.

A Replacement Shipper acquiring capacity under a temporary release shall be required to enter into the applicable Service Agreement with Transporter for the capacity acquired which shall incorporate the terms and conditions of the Offer and awarded Bid.

27.1.3 Capacity Release Offer Agreement

Prior to posting an Offer, the Releasing Shipper must execute a Capacity Release Offer Agreement available on Transporter's public Internet website, for each Service Agreement from which it intends to release capacity.

27.2 Offer Requirements

A Releasing Shipper who elects to release its firm capacity on either a permanent basis or a temporary basis, must specify the terms and conditions upon which it will release its capacity in an Offer.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.2 Offer Requirements (Continued)

A release of firm capacity is not subject to Bid if 1) the release is at the Maximum Rate for a term of more than one (1) year or 2) the release period is thirty-one (31) days or less and the Releasing Shipper elects not to make the release biddable, or 3) the release is to an asset manager under an Asset Management Arrangement ("AMA") as defined in 18 CFR 284.8(h)(3) or to a marketer participating in a state-regulated retail access program as defined in 18 CFR 284.8(h)(4). Notice of a firm release of capacity herein will be posted on Transporter's public Internet website no later than the first nomination after the capacity release transaction commences.

Except for capacity released to an AMA or marketer participating in a state-regulated access program, a Releasing Shipper may not roll over, extend or in any way continue a release to the same Replacement Shipper that obtained capacity for a term of thirty-one (31) days or less through a release which was not subject to Bid, until a minimum of twenty-eight (28) days after the first release period has ended. However, the twenty-eight (28) day waiting period is not applicable to a re-release of capacity to the same Replacement Shipper if the Releasing Shipper posts such capacity for Bid or the re-release is otherwise exempt from bidding as detailed above.

An Offer must conform to the parameters set forth in Subsection 27.4 herein. The terms and conditions included in the Offer shall be objectively stated and be applicable to all potential bidders on a non-discriminatory basis.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.2 Offer Requirements (Continued)

Releasing Shipper may submit an Offer to Transporter in writing or electronically for posting.

An Offer expires on the Bid Closing Date if no Bid is received.

Offers will be binding until written or electronic notice of withdrawal is received by Transporter.

Upon the award of a successful Bid(s) the Offer underlying the successful Bid(s) will become an addendum to the Capacity Release Offer Agreement.

27.2.1 Withdrawal of Offer

A Releasing Shipper has the right to withdraw its Offer during the bid period, where unanticipated circumstances justify and no minimum Bid has been made.

A notice of withdrawal of an Offer will be posted upon receipt.

27.3 Bid Requirements

27.3.1 Satisfaction of Credit Requirements

Any Person desiring to submit a Bid for firm capacity must have executed a Capacity Release Bid Agreement, available on Transporter's public Internet website, and must have satisfied the requirements of Section 40 of these General Terms and Conditions. A Person's Bid for firm capacity which exceeds its qualified level of creditworthiness shall not be entertained.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.3 Bid Requirements (Continued)

27.3.2 Term of Bid

Transporter shall not accept a Bid for a term longer than the term set forth in the Offer.

27.3.3 Bid Conditions

If a Bid is received which contains conditions other than those allowed in the Offer, such Bid shall not be entertained.

27.3.4 Withdrawal of Bid

Bids shall be binding until written or electronic notice of withdrawal is received by Transporter. Provided however, the bidder may not submit a new Bid at a lower rate for such offered capacity.

Bids cannot be withdrawn after the bid period ends.

27.4 Parameters for Capacity Release Transactions

27.4.1 Quantity

Release quantity shall be expressed as a numeric quantity only.

There is no minimum quantity.

27.4.2 Term

The maximum term for which capacity can be released is the remaining term of Releasing Shipper's firm Service Agreement

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.4 Parameters for Capacity Release Transactions (Continued)

27.4.3 Rate

The rate charged the Replacement Shipper for any release of capacity for a term of more than one (1) year may not exceed the applicable Maximum Rate. There are no rate limitations applicable to any release of capacity for a period of one (1) year or less if the release is to take effect on or before one (1) year from the date on which Transporter is notified of the release.

Payments or other consideration exchanged between the Releasing Shipper and the Replacement Shipper in an AMA Release are not subject to the applicable Maximum Rate.

27.4.4 Right to Recall Capacity on Temporary Release

A Releasing Shipper shall describe fully in its Offer any rights to recall the capacity being released on a temporary basis and under what conditions the capacity shall be reput to the Replacement Shipper following any such recall.

The amount of capacity allocated to the Replacement Shipper(s) shall equal the original released capacity less the recalled capacity.

Reput method and rights shall be specified at the time of the deal. Reput method and rights are individually negotiated between the Releasing Shipper and Replacement Shipper.

When capacity is recalled, it may not be reput for the same Gas Day.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.4 Parameters for Capacity Release Transactions (Continued)

27.4.5 Re-release of Capacity

A Shipper who has obtained capacity under a temporary release may re-release its capacity, in whole or in part, except in those instances where a re-release was prohibited by the prior Releasing Shipper. Transporter shall allow re-releases on the same terms and basis as the original release (except as prohibited by regulations).

A Replacement Shipper acquiring capacity under a temporary release can not re-release such capacity under a permanent release. However, a Replacement Shipper acquiring capacity under a temporary release may re-release such capacity under a temporary release.

27.4.6 Prearranged Release of Capacity

A Releasing Shipper may identify in an Offer a Designated Replacement Shipper for released capacity under a permanent release or a temporary release which shall be referred to as a prearranged release.

If an Offer containing a Designated Replacement Shipper is made biddable by the Releasing Shipper, a Designated Replacement Shipper will, in the event that a "better Bid" for released capacity is received, have the option to match the "better Bid" in accordance with Subsection 27.7 herein and acquire the released capacity.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.4 Parameters for Capacity Release Transactions (Continued)

27.4.6 Prearranged Release of Capacity (Continued)

A Designated Replacement Shipper acquiring capacity pursuant to this Subsection 27.4.6 shall be required to execute the applicable Service Agreement with Transporter for the capacity acquired which shall contain the terms and conditions of the Offer and awarded Bid.

27.4.7 Non-Prearranged Release

In the event the Releasing Shipper does not specify a Designated Replacement Shipper, the Offer submitted by the Releasing Shipper shall be subject to the Bid procedures set forth in Subsection 27.5 herein.

27.4.8 Volumetric Release

The Replacement Shipper acquiring capacity under a volumetric release shall pay the agreed to volumetric rate for all the volumes transported up to the total volume contracted for during a Production Month and shall pay the rate in accordance with the applicable Rate Schedule underlying such capacity release for any gas transported in excess of the total volume contracted for such Production Month.

Re-release by a Replacement Shipper paying a volumetric rate is prohibited.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.4 Parameters for Capacity Release Transactions (Continued)

27.4.9 Releases Involving Integrated Capacity

A Releasing Shipper can submit an Offer to release capacity which is integrated with an Offer to release capacity on another pipeline. It is the responsibility of the Releasing Shipper to design a release for "integrated" capacity under terms acceptable to the Releasing Shipper.

Transporter will allow Bids for capacity which are contingent upon the bidder obtaining capacity on another pipeline(s). However, removal of such contingency shall not conflict with the capacity release timeline observed by Transporter as set forth in Subsection 27.7 herein.

27.5 Posting of Offers, Bids, and Awarded Transactions

Offers and Bids shall comply with the capacity release timeline as set forth in Subsection 27.7 herein.

Transporter shall post a complete Offer upon receipt, as set forth in Subsection 27.7 herein, unless Releasing Shipper requests otherwise. If a Releasing Shipper requests a posting time, the Transporter shall support such request insofar as it comports with the capacity release timeline set forth in Subsection 27.7 herein.

A Releasing Shipper shall not be able to specify an extension of the original bid period or the prearranged deal match period, without posting a new release.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.5 Posting of Offers, Bids, and Awarded Transactions (Continued)

Transporter may invalidate any Bid or Offer subsequent to its posting on Transporter's public Internet website that does not comply with the terms and conditions of Transporter's Tariff.

The Transporter shall post all complete Bids upon receipt.

The identity of the bidder shall be kept confidential until the capacity has been awarded.

No later than the first nomination after a capacity release transaction commences, Transporter shall post all awarded capacity release transactions including the name(s) and Bid information of Replacement Shipper(s).

27.6 Selection of Best Bid

The Best Bid for capacity releases shall be selected by use of one of the methods set forth in Subsection 27.6.1 herein. The Releasing Shipper shall specify the Bid evaluation method in its Offer.

Transporter shall eliminate all Bids which do not satisfy the minimum criteria specified by the Releasing Shipper in its Offer, if any. When an Offer includes a volumetric rate component, only the reservation charge component will be considered in the Bid evaluation and determination of Best Bid. Bids will be assigned a ranking based on the evaluation method specified by the Releasing Shipper.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.6 Selection of Best Bid (Continued)

27.6.1 Transporter's Bid Evaluation Methods

(a) Method A - Present Value of Bids for Capacity

Present Value = [Bid Rate] * [(1 - (1 + i) -n)/i]

Where:

Bid Rate = Reservation Rate in the Bid for firm releases; the volumetric usage charge in the Bid for volumetric releases.

i = FERC's annual discount rate divided by 365 days or 366 days during leap year.

n = Bid term (days) not to exceed the number of days such capacity is available.

The higher the present value, the higher the ranking.

(b) Method B - Highest Rate of Bids for Capacity

Highest Rate = Highest Bid Rate

Where:

Bid Rate = Reservation Rate in the Bid for firm releases; the volumetric usage charge in the Bid for volumetric releases.

The higher the Bid Rate, the higher the ranking.

27. RELEASE OF FIRM CAPACITY (Continued)

27.6 Selection of Best Bid (Continued)

27.6.1 Transporter's Bid Evaluation Methods (Continued)

(c) Method C - Net Revenue of Bids for Capacity

Net Revenue = Q * Bid Rate * n

Where:

Q = Bid Quantity (Mcf)

Bid Rate = Reservation Rate in the Bid for firm releases; the volumetric usage charge in the Bid for volumetric releases.

n = Bid term (days), not to exceed the number of days offered by the Releasing Shipper.

The higher the net revenue, the higher the ranking.

(d) Method D - Releasing Shipper's Bid Evaluation Methodology

The Releasing Shipper may establish a method for evaluation of the Best Bid. The Releasing Shipper must specify the evaluation method and provide an example of the evaluation method with the Offer. In this event, the Transporter shall evaluate the Bids in accordance with the Releasing Shipper's method and allocate the capacity to the Best Bid. The Releasing Shipper's Bid evaluation methodology must be objective and non-discriminatory. In the event the Releasing Shipper does not specify how capacity will be allocated when there are multiple Best Bids, the capacity will be allocated in accordance with Subsection 27.6.1(f) herein.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.6 Selection of Best Bid (Continued)

27.6.1 Transporter's Bid Evaluation Methods (Continued)

(e) Best Bid

When the Transporter makes awards of capacity for which there have been multiple Bids meeting minimum conditions, the Transporter will award Bids, Best Bid first, until all Offered capacity is awarded.

(f) Tie-Breaker of Best Bids

To the extent there is more than one (1) Best Bid for Bids of five (5) months or more, the Offered capacity shall be allocated on a pro rata basis to potential Replacement Shipper(s) submitting a Best Bid, subject to the condition that potential Replacement Shipper(s) must specify when making its Bid whether it is willing to accept a pro rata portion of its Bid capacity. If the Best Bid does not specify the bidder's willingness to accept a pro rata allocation of the capacity and it is necessary to allocate capacity on a pro rata basis, then no capacity will be awarded to such Best Bid. In the event there is more than one (1) Best Bid for Bids of less than five (5) months, the capacity will be awarded on a first-come, first-served basis.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.7 Capacity Release Timeline

The capacity release timeline is applicable to all parties involved in the capacity release process. However, it is only applicable if 1) all information provided by the parties to the transaction is valid, and the acquiring Shipper has been determined to be creditworthy before the capacity release Bid is tendered and 2) there are no special terms or conditions of the release.

The capacity release timeline is as follows:

(a) For biddable capacity releases less than one (1) year:

(i) Offers shall be tendered by 12:00 p.m. CCT on a Business Day;

(ii) open season ends no later than 1:00 p.m. CCT on a Business Day (evaluation period begins at 1:00 p.m. CCT during which contingency is eliminated, determination of Best Bid is made, and ties are broken);

(iii) evaluation period ends and award posted if no match required at 2:00 p.m. CCT;

(iv) match or award is communicated by 2:00 p.m. CCT;

(v) match response by 2:30 p.m. CCT;

(vi) where match required, award posting by 3:00 p.m. CCT;

(vii) contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.7 Capacity Release Timeline (Continued)

(b) For biddable capacity releases of one (1) year or more:

(i) Offers shall be tendered by 12:00 p.m. CCT four (4) Business Days before award;

(ii) open season ends no later than 1:00 p.m. CCT on the Business Day before timely nominations are due (open season is three (3) Business Days);

(iii) evaluation period begins at 1:00 p.m. CCT during which contingency is eliminated, determination of Best Bid is made, and ties are broken;

(iv) evaluation period ends and awards are posted if no match required at 2:00 p.m. CCT;

(v) match or award is communicated by 2:00 p.m. CCT;

(vi) match response by 2:30 p.m. CCT;

(vii) where match required, award posting by 3:00 p.m. CCT;

(viii) contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nominated cycle for the effective date of the contract.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.7 Capacity Release Timeline (Continued)

(c) For non-biddable releases in the timely cycle:

(i) posting of prearranged deals not subject to bid are due by 10:30 a.m. CCT;

(ii) contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

(d) For non-biddable releases in the evening cycle:

(i) posting of prearranged deals not subject to bid are due by 5:00 p.m. CCT;

(ii) contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

(e) Intra-day 1 cycle:

(i) posting of prearranged deals not subject to bid are due by 9:00 a.m. CCT;

(ii) contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.7 Capacity Release Timeline (Continued)

(f) Intra-day 2 cycle:

(i) posting of prearranged deals not subject to bid are due by 4:00 p.m. CCT;

(ii) contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

(g) Methodologies Supported by Capacity Release Standard Timeline

For the capacity release business process timing model, only the following methodologies are required to be supported by Transporter and provided to Releasing Shippers as choices from which they may select and, once chosen, shall be used in determining the awards from the Bid(s) submitted. They are: 1) highest rate, 2) net revenue, and 3) present value.

(h) Methodologies Not Supported by Capacity Release Standard Timeline

Other choices of bid evaluation methodologies (including other Releasing Shipper defined evaluation methodologies) shall be accorded similar timeline evaluation treatment at the discretion of Transporter. However, Transporter is not required to offer other choices or similar timeline treatment for other choices, nor, is Transporter held to the timeline should the Releasing Shipper elect another method of evaluation.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.8 Standard Recall Notification Periods

Transporter shall support the following recall notification periods for all released capacity subject to recall rights:

(a) Timely Recall Notification

(i) A Releasing Shipper recalling capacity shall provide notice of such recall to Transporter and the first Replacement Shipper no later than 8:00 a.m. CCT.

(ii) Transporter shall provide notification of such recall to affected Replacement Shipper(s) no later than 9:00 a.m. CCT.

(b) Early Evening Recall Notification

(i) A Releasing Shipper recalling capacity shall provide notice of such recall to Transporter and the first Replacement Shipper no later than 3:00 p.m. CCT.

(ii) Transporter shall provide notification of such recall to affected Replacement Shipper(s) no later than 4:00 p.m. CCT.

(c) Evening Recall Notification

(i) A Releasing Shipper recalling capacity shall provide notice of such recall to Transporter and the first Replacement Shipper no later than 5:00 p.m. CCT.

(ii) Transporter shall provide notification of such recall to affected Replacement Shipper(s) no later than 6:00 p.m. CCT.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.8 Standard Recall Notification Periods (Continued)

(d) Intra-day 1 Recall Notification

(i) A Releasing Shipper recalling capacity shall provide notice of such recall to Transporter and the first Replacement Shipper no later than 7:00 a.m. CCT.

(ii) Transporter shall provide notification of such recall to affected Replacement Shipper(s) no later than 8:00 a.m. CCT.

(e) Intra-day 2 Recall Notification

(i) A Releasing Shipper recalling capacity shall provide notice of such recall to Transporter and the first Replacement Shipper no later than 2:30 p.m. CCT.

(ii) Transporter shall provide notification of such recall to affected Replacement Shipper(s) no later than 3:30 p.m. CCT.

For recall notifications provided to Transporter prior to the recall notification deadlines above and received between 7:00 a.m. and 5:00 p.m. CCT, Transporter shall provide notification to affected Replacement Shipper(s) no later than one hour after receipt of such recall notification.

For recall notification provided to Transporter after 5:00 p.m. and prior to 7:00 a.m. CCT, Transporter shall provide notification to affected Replacement Shipper(s) no later than 8:00 a.m. CCT after receipt of such recall notification.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.8 Standard Recall Notification Periods (Continued)

The Releasing Shipper shall provide capacity recall notification to its affected Replacement Shipper(s) at the same time it provides notification to Transporter. The mode of notification shall be mutually agreed between the Releasing Shipper and its Replacement Shipper(s).

In the event of an intra-day capacity recall, Transporter shall determine the allocation of capacity between the Releasing Shipper and the Replacement Shipper(s) based upon the Elapsed Prorata Capacity ("EPC"). Variations to the use of EPC may be necessary to reflect the nature of Transporter's Tariff, services, and/or operational characteristics.

27.9 Deadline for Reput

The deadline for notifying Transporter of a reput is 8:00 a.m. CCT to allow for timely nominations to flow on to the next Gas Day.

27.10 Transporter's Right to Terminate a Temporary Capacity Release

Transporter may elect to terminate a temporary capacity release transaction to a Replacement Shipper under the following conditions:

(a) The Replacement Shipper has not executed the respective Service Agreement underlying the awarded Bid prior to the first nomination under such capacity release; or

(b) The Releasing Shipper has failed to maintain credit in accordance with Section 40 of these General Terms and Conditions and Transporter has provided the Replacement Shipper with thirty (30) days written notice of its intent to terminate its capacity release transaction.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.11 Offers to Purchase Capacity Release

A Person desiring released capacity may submit a request to Transporter in writing. Such request for capacity shall specify the terms and conditions pursuant to which capacity will be accepted. Such a request shall be posted on Transporter's public Internet website for twenty (20) Business Days on an informational basis.

27.12 Marketing of Capacity Release

Transporter shall have no obligation to market any capacity available by a Releasing Shipper. Transporter, however, may agree to market capacity for a Releasing Shipper and may negotiate a fee with the Releasing Shipper for such service.

27.13 Reservation Charge Revenue Credits

For releases and re-releases of firm capacity, Transporter shall credit the reservation charge revenue received from a Replacement Shipper to the associated Releasing Shipper whose capacity has been released on a firm basis to such Replacement Shipper, subject to Subsection 27.4 and Subsection 37.8 of these General Terms and Conditions.

27.14 Bankruptcy

In the event a Releasing Shipper, subject to proceedings under any provision of bankruptcy or insolvency law to which Releasing Shipper is subject, rejects its Agreement, the Replacement Shipper will, as of the date the Releasing Shipper ceases payment under such Agreement, be required to meet the creditworthiness requirements applicable to Releasing Shipper and pay a rate that is no lower than the lesser of 1) the Releasing Shipper's rate or 2) the Maximum Rate.

GENERAL TERMS AND CONDITIONS

27. RELEASE OF FIRM CAPACITY (Continued)

27.15 State of Alaska Royalty Gas

Notwithstanding any of the provisions of this Section 27, Transportation of royalty gas by the State of Alaska, its agent or designee, or the purchaser of royalty gas, shall be subject to the following provisions:

[Insert outcome of the Commission proceedings in Docket No. RP10-145.]

Sheet No. 387
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

28. RESERVATION OF CAPACITY FOR EXPANSION PROJECTS

28.1 Applicability

Notwithstanding Sections 18 and 26 of these General Terms and Conditions, Transporter may elect to reserve capacity required for an expansion project out of 1) unsubscribed capacity or 2) capacity under expiring Service Agreement(s) where such Service Agreement(s) do not have a right of first refusal or 3) capacity under expiring Service Agreement(s) where Shipper elects not to exercise its right of first refusal or 4) turnback capacity which Transporter has agreed to accept in response to a direct solicitation from Transporter to serve an expansion project.

28.2 Time Period

Transporter may reserve capacity only for an expansion project for which an open season has been held or will be held within twelve (12) months of the date that Transporter posts such capacity as being reserved. Capacity may be reserved for expansion projects for only a twelve (12) month period prior to Transporter filing for FERC certificate approval for construction of proposed expansion facilities and thereafter until all expansion facilities related to the certificate filing are placed into service.

28.3 Notice to Shippers

If Transporter reserves capacity for an expansion project, it will notify Shippers of its intent via a posting on Transporter's public Internet website. Transporter's posting for reserved capacity for an expansion project shall include the following information: (a) a description of the expansion project for which the capacity will be reserved; (b) the total quantity of capacity to be reserved; (c) the location of the proposed reserved capacity on the pipeline system; (d) whether, and if so when, Transporter anticipates holding an open season for the expansion project or otherwise posting the reserved capacity for Bid in conjunction with the open season for the expansion project; (e) the projected in-service date of the expansion project; and (f) on an ongoing basis, how much of the reserved capacity has been sold on a limited-term, interim basis.

GENERAL TERMS AND CONDITIONS

28. RESERVATION OF CAPACITY FOR EXPANSION PROJECTS (Continued)

28.4 Solicitation of Turnback

If available capacity posted for Bid pursuant to Subsection 26.1 of these General Terms and Conditions remains unsubscribed after the close of the bid period, and if such unsubscribed capacity is insufficient to serve the expansion project, Transporter shall solicit turnback capacity from Transporter's existing Shippers to serve the expansion project. No later than ninety (90) days after the close of an expansion project's open season that is posted in accordance with Section 26 of these General Terms and Conditions, Transporter shall post a solicitation for expansion project related turnback capacity specifying the minimum terms for a response to the solicitation.

28.5 Interim Capacity

Any capacity reserved under this Section 28 will be made available for transportation service on a limited-term basis up to the in-service date of the expansion project. Transporter reserves the right to limit any extension rights provided in such Service Agreement(s), including the right of first refusal set forth in Section 18 of these General Terms and Conditions, commensurate with the proposed in-service date of any expansion project.

28.6 Reposting of Capacity

Any capacity reserved for a project that does not go forward for any reason shall be reposted as generally available within thirty (30) days of the date the capacity becomes available. The previously reserved capacity will become available when the Transporter posts the capacity on its public Internet website pursuant to Section 26 of these General Terms and Conditions.

Sheet Nos. 390 and 391
have not been issued and are
being reserved for future use.

Issued by: ________________
Issued on: Effective on:

GENERAL TERMS AND CONDITIONS

29. SHIPPER FAILURE TO MEET GAS SPECIFICATIONS

If gas delivered or tendered to Transporter hereunder fails at any time to conform to any of the specifications, Transporter shall notify the Shipper responsible for any such failure, and Transporter may suspend all or a portion of the receipt of any such gas which may jeopardize Transporter's ability to meet its obligations to its other Shippers or endanger the safe operation and integrity of Transporter's system. Transporter shall be relieved of its obligations hereunder to the extent of rightful suspension for the duration of such time as such off-specification gas delivered or tendered by such Shipper does not meet the specifications; provided, however, such suspension by Transporter shall not relieve Shipper of its payment obligations hereunder. Upon receipt of notice by Transporter, Shipper shall make a diligent effort to correct such failure by treatment, cooling, or dehydration consistent with prudent operation and by means which are economically feasible in such Shipper's opinion so as to deliver gas conforming to the above specifications. If Transporter elects to accept receipt of any off-specification gas, Transporter shall do so in a ratable and nondiscriminatory manner as between such Shipper and others who may desire to deliver gas to Transporter which does not conform to the specifications and who otherwise may be entitled to transportation service.

Sheet Nos. 393 through 395
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

30. SERVICE REQUESTS

Requests for services on Transporter's pipeline system shall be directed to any of the commercial contacts listed on the contact list contained on Transporter's public Internet website.

Sheet Nos. 397 and 398
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES

If a Person (referred to as Complainant) has a complaint against Transporter, then Complainant may verbally register and/or file a written complaint with Transporter.

31.1 Verbal Complaint

A verbal complaint should be communicated to the Transporter's Chief Compliance Officer (CCO). Transporter shall attempt to respond timely to a verbal complaint on an informal, case specific basis. A verbal complaint which, in Complainant's judgment is not satisfactorily resolved should be submitted in writing pursuant to the written complaint procedures described below.

31.2 Written Complaint

A written complaint should be sent via registered or certified mail, facsimile (Fax No.___________), or hand delivered in accordance with the following:

(a) A written complaint should be directed in writing to the CCO, at [Insert Address]. A written complaint should contain a clear concise statement of the complaint and the manner in which the Complainant alleges to have been aggrieved. Complainant shall also provide its address, fax number, and contact representative(s) along with their telephone numbers.

(b) Upon receipt of the complaint, Transporter shall record and file the complaint in Transporter's service complaint log.

(c) The CCO will be responsible for notifying the appropriate personnel whose services will be utilized in reviewing and formulating a response to the complaint.

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES (Continued)

31.2 Written Complaint (Continued)

(d) Within thirty (30) days of receipt of the complaint, Transporter shall respond to such complaint. However, Transporter's response to such complaint may indicate additional information is needed from the Complainant and/or additional time is needed to complete the review of the allegations in the complaint. In such case, Transporter's response will set forth what information is needed and/or what additional time is required in order to fully respond to the complaint.

(e) Upon completing its review of the complaint, Transporter shall direct a written response to the Complainant which, inter alia, shall demonstrate either (i) that the Complainant has failed to establish any conduct which warrants corrective action or (ii) that corrective action has been determined to be warranted. In the event that corrective action is deemed warranted, Transporter will set forth a remedy.

31.3 Dispute Resolution

Any disputes, controversies, or claims between the Parties arising out of or relating to this Tariff or any agreement for service under this Tariff, or the breach thereof not resolved under Section 31.1 or 31.2(a "Dispute") shall be resolved by means of the following procedure. Transporter and Shipper agree that the dispute resolution procedure described in this Section 31.3 shall not apply to any controversy wherein the FERC has exclusive jurisdiction and (ii) for the avoidance of doubt, shall apply to any dispute concerning Negotiated Rate principles set forth in Exhibit A of any Rate Schedule FT-1 Service Agreement.

(1) Notification. A Party who desires to submit a Dispute for resolution shall commence the dispute resolution process by providing Notice of the Dispute ("Notice of Dispute") to the other Parties. The Notice of Dispute shall contain a reasonably detailed description of the alleged Dispute and the facts and law the Party believes support the same, the relief requested, and shall request negotiations among executives of the Parties with authority to settle the Dispute. The submission of a Notice of Dispute shall toll any applicable statutes of limitation

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES (Continued)

31.3 Dispute Resolution (Continued)

pending the conclusion or abandonment of dispute resolution proceedings under this Section 31.3.

(2) Negotiations. The Parties shall seek to resolve the Dispute by negotiation between executives who have authority to negotiate a settlement of the Dispute on behalf of each Party in Dispute. Within thirty (30) Days after the date of the receipt of the Notice of Dispute, the executives representing each of the Parties in Dispute shall meet in person at a mutually acceptable time and place in an attempt to resolve the Dispute. If an executive intends to be accompanied at the meeting by an attorney, such executive shall give the other Party Notice of such intention at least three (3) Business Days in advance, and the executive(s) representing the other Party(ies) in Dispute may also be accompanied at the meeting by an attorney. Notwithstanding the above, any Party in Dispute may initiate arbitration proceedings pursuant to paragraph (3) below at any time after sixty (60) Days from the date of receipt of the Notice of Dispute.

(3) Arbitration. Any Dispute not finally resolved by negotiation between executives as set forth in paragraph (2) above shall be exclusively and definitively resolved through final and binding arbitration, except as otherwise set forth herein or otherwise agreed by the Parties.

(a) Rules. Disputes shall be resolved by arbitration in accordance with the Rules for Non-Administered Arbitration of International Disputes of the International Institute for Conflict Prevention and Resolution (“CPR Rules”) as in effect on the date of commencement of the arbitration, as modified in these arbitration procedures.

(b) Commencement of Arbitration. An arbitration shall be commenced in the manner set forth in the CPR Rules except as otherwise provided hereafter.

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES (Continued)

31.3 Dispute Resolution (Continued)

(c) Number of Arbitrators. The arbitration shall be conducted by three (3) arbitrators.

(d) Method of Appointment of the Arbitrators.

(i) The Claimant shall appoint one (1) arbitrator in the Notice of arbitration and the Respondent shall appoint one (1) arbitrator within thirty (30) Days after receiving the Notice of arbitration and give Notice of that appointment to the Claimant. If a Party in Dispute fails to appoint its Party-appointed arbitrator within the foregoing deadlines, the CPR shall appoint such arbitrator if requested to do so by a Party in Dispute.

(ii) The two (2) arbitrators appointed in accordance with this paragraph (d) shall appoint a third arbitrator, who shall act as the presiding arbitrator. If the two (2) arbitrators cannot reach an agreement on the presiding arbitrator within thirty (30) Days of the appointment of the second arbitrator, the CPR shall appoint the presiding arbitrator in accordance with the CPR Rules.

(e) Place of Arbitration. Unless otherwise agreed by all Parties in Dispute, the place of arbitration shall be Houston, Texas.

(f) Language. The arbitration proceedings shall be conducted in the English language.

(g) Entry of Judgment. The award of the arbitral Tribunal ("Award") shall be in writing and shall be final and binding upon the Parties. Judgment on the Award may be entered and enforced by any court of competent jurisdiction and the Parties agree to submit to the personal jurisdiction of any such court.

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES (Continued)

31.3 Dispute Resolution (Continued)

(h) Notice. All Notices required for any arbitration proceeding shall be deemed properly given if sent in accordance with Section 20 of the General Terms and Conditions.

(i) Qualifications and Conduct of the Arbitrators. All arbitrators shall be and remain at all times independent and impartial, and no arbitrator shall have any ex parte communications concerning the arbitration or the Dispute with any of the Parties in Dispute, other than communications appropriate under Rule 7.4 of the CPR Rules to determine an arbitrator's willingness and availability to serve or concerning the selection of the presiding arbitrator, where applicable.

(j) Interim Measures. The Parties in Dispute may seek interim measures as provided in Rules 13 and 14 of the CPR Rules. Any such measures granted by the arbitral Tribunal may be immediately enforced by court order. Hearings on requests to the arbitral Tribunal for interim measures may be held in person, by telephone, by video conference or by other means that permit the Parties in Dispute to present evidence and arguments.

(k) Costs and Fees of Arbitration. The arbitral Tribunal is authorized to allocate the costs of the Tribunal, including fees for the arbitrators and hearing room and transcription expenses, between or among the Parties to the Dispute in such proportions as the Tribunal shall determine. Each Party in Dispute shall bear its own attorney's and expert witness fees, its expenses and the expenses of its witnesses, unless otherwise directed by the Tribunal.

(l) Award. The arbitral Award shall be made and payable in U.S. Dollars.

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES (Continued)

31.3 Dispute Resolution (Continued)

(m) Consequential Losses. The Parties waive their rights to claim or recover, and the arbitral Tribunal shall have no authority to award, any Consequential Losses, which for purposes of this Tariff means as to any Person, any damage, cost, expense, or liability (including pass-through claims for indemnification or contribution owed to another Person under a contract, governmental requirement, or other obligation), or loss of any other nature of that Person that is caused (directly or indirectly) by any of the following arising out of, relating to, or in connection with this Tariff or work carried out (or failed to be carried out) in relation to it: loss or deferment of income or profits; loss of use of any asset; loss of business or reputation; loss of business opportunity; loss of labor or management productivity; increases in wage, salary, or other cost of labor; increase in the cost of funds; or other indirect damages or losses, costs, expenses, or liabilities, whether or not similar to the foregoing; in addition, Consequential Loss also includes any exemplary, punitive, special or treble damages.

(n) Waiver of Challenge to Decision or Award. To the extent permitted by law, the Parties waive any right to challenge any arbitral decision or Award, or to oppose enforcement of any such decision or Award, except on the limited grounds for modification or non-enforcement provided by the CPR Rules or any applicable arbitration statute or treaty.

(o) The Tribunal will apply the substantive law of the State of New York to the merits of the case, except that the Tribunal will not apply any choice of law rules that would call for the application of the law of any other jurisdiction.

GENERAL TERMS AND CONDITIONS

31. COMPLAINT AND DISPUTE RESOLUTION PROCEDURES (Continued)

31.3 Dispute Resolution (Continued)

(4) Confidentiality. All negotiations and arbitration proceedings (including a settlement resulting from negotiation or an Award, documents exchanged or produced during an arbitration proceeding, and memorials, briefs, or other documents prepared for the arbitration) are confidential and may not be disclosed by the Parties in Dispute, their respective employees, officers, directors, counsel, consultants, and expert witnesses, except to the extent necessary to enforce this Section 31 or any Award, to enforce other rights of a Party, or as required by law; provided, however, that breach of this confidentiality provision shall not void any settlement or Award.

GENERAL TERMS AND CONDITIONS

32. INTERNET WEBSITES

32.1 Description

Transporter maintains FERC compliant interactive Internet websites which are available for use by Shippers, Interconnected Parties, and other interested parties on a non-discriminatory basis. Transporter has two Internet websites; a non-secure (public) Informational Postings site and a secure (non-public) Customer Activities site. Information of a general nature is included in the public Informational Postings site. Confidential Shipper and interconnect specific data is accessible only through the non-public Customer Activities site which requires a logon and password.

The address for the Transporter's public Internet website where parties can access the Informational Postings site is **[Insert]**. A link to the Customer Activities site is provided on the Informational Postings site.

Transporter is not responsible for problems that result from user's hardware or software, or the Internet Service Provider used to access Transporter's designated website.

32.2 Informational Postings Site

The Informational Postings site is primarily comprised of FERC mandated Informational Postings. The Informational Postings site will be maintained to provide equal and timely access to certain information, including but not limited to: 1) Operationally Available and Unsubscribed Capacity; 2) Information related to standards of conduct for transmission providers; 3) Gas Quality Information; 4) Index of Customers; 5) Non-Discrimination Reporting Requirements; 6) Critical, Non-Critical, and Planned Service Outage Notices; 7) Posted Imbalances; 8) Transporter's FERC Gas Tariff and 9) Transactional Reporting.

GENERAL TERMS AND CONDITIONS

32. INTERNET WEBSITES (Continued)

32.3 Customer Activities Site

The Customer Activities site provides access to Nominations, Flowing Gas/Volume Inquiry Data, Invoicing, Contracting, and Capacity Release Processing.

To initiate the process necessary to gain access to the non-public Customer Activities site, an employee of a given legal entity ("Initial Requesting Party") must complete and forward an Internet access form to Transporter.

The Internet access form is posted in the Customer Activities area of Transporter's Informational Postings site.

As indicated on the Internet access form, establishing legal entity access rights to business specific areas of Transporter's Customer Activities site may require the requesting party to execute Transporter's Electronic Communication Agreement, which is available on Transporter's public Internet website under Informational Postings.

Once Transporter has validated the necessary paperwork submitted by the Initial Requesting Party to authorize legal entity access to the Customer Activities site, Transporter will require the Initial Requesting Party to designate one or more Persons to perform certain security functions for such legal entity ("Local Security Administrator") by completing and submitting for each such Person the Local Security Administration Designation Form.

The Local Security Administration Designation Form is posted in the Customer Activities area of Transporter's Informational Postings site.

Transporter shall require a minimum of two (2) Local Security Administrators be established for a given legal entity.

GENERAL TERMS AND CONDITIONS

32. INTERNET WEBSITES (Continued)

32.3 Customer Activities Site (Continued)

The Local Security Administrator shall, via the Customer Activities site, be responsible for 1) identifying those users who are duly authorized to access one or more of the authorized business specific areas of Transporter's Customer Activities site, 2) providing individual usernames and passwords, 3) maintaining user account information, 4) adding and terminating users immediately upon a change in status requiring such addition or termination, 5) creating or modifying security rights, 6) approving or terminating agency arrangements and 7) ensuring that Transporter's username/password rules, as detailed in Subsection 32.4 herein, are followed. Transporter shall be entitled to rely upon the representation of the Local Security Administrator that the user(s) identified by the Local Security Administrator may 1) transmit information to Transporter via the Customer Activities site and/or 2) view information posted on Transporter's Customer Activities site in accordance with the security rights granted by the Local Security Administrator.

32.4 Username/Password

Usernames are both individual and legal entity-specific. The username and password combination of a user of Transporter's secured Customer Activities site shall not be shared with any other individual other than the Local Security Administrator.

A user shall be solely responsible for any unauthorized or otherwise improper use of usernames and passwords issued by or for its Local Security Administrator, including, but not limited to, the use of such usernames and passwords by users who are not within the legal entity's employment or control.

GENERAL TERMS AND CONDITIONS

32. INTERNET WEBSITES (Continued)

32.4 Username/Password (Continued)

Transporter reserves the right to disable for due cause any username issued to any user. Transporter shall provide notice to the user and/or Local Security Administrator, as applicable, at the time the username is disabled by Transporter. In addition, upon thirty (30) days prior notice to the Local Security Administrator, Transporter will disable any username that has not been used to access Transporter's Customer Activities sited for fifteen (15) consecutive months.

Either the Local Security Administrator or a user shall promptly notify Transporter if there is any indication that a security breach has occurred with regard to a username and password.

A Local Security Administrator shall be responsible for disabling a username for a user that is no longer an employee of the legal entity or is no longer authorized to transact business for that legal entity.

A Local Security Administrator or user shall immediately notify Transporter of the desire to delete a Local Security Administrator by the submission of a revised Local Security Administration Designation Form. Such revised form shall supersede in its entirety any Local Security Administration Designation Form previously submitted to Transporter.

The legal entity shall be solely responsible for any unauthorized actions of a Local Security Administrator due to the failure to so notify Transporter to delete such Local Security Administrator.

GENERAL TERMS AND CONDITIONS

32. INTERNET WEBSITES (Continued)

32.5 Archiving and Retrieval of Archived Information

32.5.1 Archiving

Daily back-up records of information displayed or entered through Transporter's Internet website are archived. Data posted pursuant to Subsection 32.2 herein is made available on Transporter's public Internet website under Informational Postings for the most recent three (3) month calendar period. Historical data is made available in accordance with FERC requirements.

32.5.2 Retrieval of Archived Information

A Person requiring access to archived posted information may electronically submit their request to the following electronic mail address:

[Insert]

Such request must clearly state the requestor's name, address, phone number, information required, and reason for request.

The requested information may be provided by Transporter to requestor by means that is mutually agreeable to both parties. Transporter may charge requestor a reasonable fee for costs incurred in providing the data.

GENERAL TERMS AND CONDITIONS

32. INTERNET WEBSITES (Continued)

32.6 Confidentiality

Certain information contained in Transporter's Customer Activities site is proprietary and confidential. A user shall not reproduce, disclose, or otherwise make available confidential information contained therein to any other Transporter, corporation, individual, or partnership.

32.7 Reliance Upon User Actions

Transporter may act in reliance upon any acts done or performed by user or designated agents on behalf of user and in respect to all matters conducted through Transporter's Internet websites. Transporter may correct errors in information entered into these websites by user promptly after receiving notice of the corrections or may require users to enter the corrections directly into these Internet websites.

Sheet Nos. 409 and 410
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

33. ELECTRONIC TRANSACTIONS CONTRACTING

Electronic transactions contracting as posted on Transporter's Customer Activities site is available to parties provided that such party shall have previously met the requirements of a Rate Schedule, if applicable, and agreed to the terms and conditions of Transporter's Master Electronic Transactions Agreement.

Sheet Nos. 412 and 413
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

34. OPERATIONAL BALANCING AGREEMENT POLICY

34.1 Purpose

The Operational Balancing Agreement is intended to govern the treatment of any differences between the actual quantity of gas received/delivered at a Point of Interconnection with Transporter's pipeline system and the quantity of gas that was scheduled.

Transporter considers an OBA to be a predetermined allocation method.

34.2 Policy

It is Transporter's policy to negotiate and execute, if possible, the Transporter's form of OBA at each Point of Interconnection. However, Transporter shall have no obligation to execute an OBA with any party that is not creditworthy pursuant to Section 40 of these General Terms and Conditions, substituting the term "OBA Party" for "Shipper", where applicable, for this purpose.

If an OBA does not exist at a Point of Interconnection, the imbalance charges, cash-outs, or penalties incurred at such point shall be the responsibility of Shipper(s) that are out of balance.

An acceptable OBA for a Point of Interconnection must include the following provisions:

(a) The OBA must be in energy or volumetric terms with stated bases.

(b) The OBA parties intend that the quantity actually received/delivered each day at the Point of Interconnection will equal the scheduled nominations.

GENERAL TERMS AND CONDITIONS

34. OPERATIONAL BALANCING AGREEMENT POLICY (Continued)

34.2 Policy (Continued)

(c) Any differences between the metered quantity and the scheduled nomination is treated as an OBA imbalance and exists solely between the OBA parties.

(d) The OBA parties will take the necessary steps to ensure that the cumulative daily OBA imbalance is maintained at or tends towards a zero imbalance. No imbalance penalty shall be imposed when a prior period adjustment applied to the current period causes or increases a current month penalty.

(e) The OBA parties will regularly reconcile scheduled nominations during a given Production Month. A mutually agreed upon scheduled nomination summary must be completed as soon as practical after each Production Month end.

(f) The monthly metered flow data for such Point of Interconnection will be determined and communicated by the Measurement Party in writing as soon as possible to the other OBA party.

(g) The OBA parties at such Point of Interconnection may temporarily suspend the OBA in accordance with the terms thereof if either party discovers or anticipates extraordinary circumstances, such as significant interruption of transportation service, severe weather, or some other event which affects the gas supplies available for delivery at the Point of Interconnection.

GENERAL TERMS AND CONDITIONS

34. OPERATIONAL BALANCING AGREEMENT POLICY (Continued)

34.2 Policy (Continued)

(h) A mutually agreeable commencement and termination date, cancellation clause and other specific language applicable to Transporter.

An OBA party is permitted to discharge an operational imbalance at a given Point of Interconnection utilizing one of the Shipper Imbalance methods set forth in Subsection 23.3 of these General Terms and Conditions.

Sheet Nos. 417 and 418
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

35. DATA ELEMENTS

[Transporter will incorporate herein appropriate North American Energy Standards Board ("NAESB") Wholesale Gas Quadrant (WGQ) standards or similar provisions as required by the Commission.]

Sheet Nos. 420 through 423
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

36. PIPELINE MAINTENANCE AND GAS TREATMENT PLANT TURNAROUNDS

36.1 Transporter shall provide Shippers at least six (6) months written notice prior to the commencement of any planned pipeline maintenance and gas treatment plant turnarounds.

36.2 Transporter and Shippers will meet to discuss the Transporter's program of planned pipeline maintenance and gas treatment plant turnarounds. The purpose of such meeting will be to coordinate maintenance and turnaround schedules with the view to minimizing any curtailment of transportation or treatment service to Shippers. Such meeting will take place not less than thirty (30) days following the notice provided in Section 36.1.

36.3 Transporter shall, after giving as much notice to Shippers as is reasonably practicable, be permitted to curtail deliveries of gas without incurring liability to the Shipper to the extent necessary to carry out emergency maintenance.

36.4 Transporter shall communicate with Shippers regarding the schedule for, nature of and expected duration of emergency maintenance and will carry out such emergency maintenance as quickly as possible and use reasonable efforts to conduct such maintenance at the time of likely least interference to Shippers.

36.5 Notices given under this Section 36 shall include the anticipated start and end times and dates for the pipeline maintenance and gas treatment plant turnaround activity and the available pipeline and gas treatment capacity by Receipt Point and Delivery Points on each included Day.

Sheet Nos. 425 through 432
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

37. NEGOTIATED RATES

37.1 Definition

A Negotiated Rate shall mean a rate or formula for service under any applicable Agreement which Transporter and Shipper mutually agree upon which may be less than, equal to, or greater than the applicable Maximum Rate or Minimum Rate and may be based on a rate design other than the rate design used to compute Transporter's currently effective rates set forth on the Statement of Rates and may include a negotiated level of Transporter Fuel and Lost and Unaccounted for Gas established in accordance with Section 41 of these General Terms and Conditions.

A Negotiated Rate shall be set forth on Exhibit A of an Agreement. An Agreement containing a Negotiated Rate shall be referred to herein as a Negotiated Rate Agreement.

37.2 Availability

Shipper and Transporter may agree to a Negotiated Rate for a specific term of service under any Rate Schedule contained in Transporter's Tariff. Shipper shall be required to execute a separate Negotiated Rate Agreement for each Negotiated Rate agreed upon. Shipper may elect not to contract for service at the Negotiated Rate and instead may contract for service at Transporter's applicable Maximum Rate and Transporter Fuel and Lost and Unaccounted for Gas Percentage.

37.3 Applicability

37.3.1 Existing Service

Notwithstanding anything to the contrary contained in Transporter's Tariff, Transporter and Shipper may mutually agree to Negotiated Rates and the term of service for all or any portion of the capacity under any existing Agreement, provided that Shipper has not acquired its capacity through a temporary capacity release under Section 27 of these General Terms and Conditions.

GENERAL TERMS AND CONDITIONS

37. NEGOTIATED RATES (Continued)

37.3 Applicability (Continued)

37.3.2 New Service

Transporter and Shipper may mutually agree to Negotiated Rates and the term of service for any proposed expansion of facilities.

37.4 Best Bid Evaluation

If Transporter posts available capacity for Bid, Transporter shall state in the posting whether it is willing to consider a Bid at a Negotiated Rate. Transporter shall also state in its posting, that a Bid will be evaluated using Method A, as described in Subsection 27.6.1(a). To the extent a Negotiated Rate(s) Bid by a Shipper over the term of the contract would otherwise produce a unit rate in excess of the Maximum Rate over that term, the present value of a Negotiated Rate Bid under Method A pursuant to Subsection 27.6.1(a) of these General Terms and Conditions will be capped at the value of a Maximum Rate Bid under comparable terms, solely for the purpose of evaluating the net present value of the Bid.

37.5 Filing Requirement

Transporter shall file a tariff sheet stating the name of the Shipper, the Negotiated Rate, and the Rate Schedule applicable to any Negotiated Rate Agreement. Such tariff sheet shall be filed no later than the effective date of the Negotiated Rate. Unless Transporter executes and files a non-conforming Agreement, such tariff sheet will contain a statement that the Negotiated Rate Agreement does not deviate in any material aspect from the applicable form of Agreement in the Tariff.

GENERAL TERMS AND CONDITIONS

37. NEGOTIATED RATES (Continued)

37.6 Rate Treatment

In general rate proceedings, Transporter shall have the right to seek discount-type adjustments in the design of its rates related to Negotiated Rate Agreements. In situations where Transporter had granted a market-justified discount to the Maximum Rate and subsequently converted the Agreement to a Negotiated Rate Agreement, Transporter may seek a discount-type adjustment, based on the greater of: (a) the Negotiated Rate revenues received or (b) the discounted rate revenues which otherwise would have been received.

37.7 Accounting Treatment

Transporter will maintain separate and identifiable accounts for volumes transported, billing determinants, rate components, surcharges, depreciation, deferred income taxes, and revenues associated with Negotiated Rate transactions. All transactions originating as a discounted rate Agreement which were subsequently converted to a Negotiated Rate Agreement shall be recorded separately from those originating as Negotiated Rate Agreements.

37.8 Capacity Release

Negotiated Rates applicable to capacity release transactions for a term of more than one (1) year are capped at the Maximum Rates set forth on the Statement of Rates. There is no maximum price cap for Negotiated Rates for capacity release transactions for a term of one (1) year or less. Unless otherwise agreed, the Negotiated Rate Shipper shall be required to pay Transporter any difference by which the Negotiated Rate exceeds the rate paid by the Replacement Shipper. Transporter and Shipper may agree upon payment obligations or credit mechanisms, which would apply when capacity subject to a Negotiated Rate is released.

GENERAL TERMS AND CONDITIONS

37. NEGOTIATED RATES (Continued)

37.9 Surcharges

If Transporter negotiates any applicable surcharge, except for the ACA or Change in Law/Regulation surcharge, at less than the applicable Maximum Rate as part of a Negotiated Rate Agreement, Transporter shall assume any risk of under-recovery of such costs from such Negotiated Rate Agreement Shipper(s) in order to ensure that its Maximum Rate Shipper(s) are not adversely affected.

37.10 Transporter Fuel and Lost and Unaccounted for Gas

If Transporter negotiates a level of Transporter Fuel and Lost and Unaccounted for Gas as part of a Negotiated Rate Agreement, Transporter shall assume any risk of under-recovery or over-recovery of such percentage from such Negotiated Rate Agreement Shipper(s) in order to ensure that its recourse rate Shipper(s) are not adversely affected. Accordingly, Transporter shall apply the established Transporter Fuel and Lost and Unaccounted for Gas Percentage to the transportation quantities of Negotiated Rate Agreements that contain a negotiated level of Transporter Fuel and Lost and Unaccounted for Gas or otherwise treat such Negotiated Rate Agreement Shipper(s) as if they were subject to the established Transporter Fuel and Lost and Unaccounted for Gas Percentage in performing the calculation of the Transporter Fuel and Lost and Unaccounted for Gas Percentage.

37.11 Negotiated Terms and Conditions

Transporter shall seek FERC authority for any negotiated terms and conditions which materially deviate from the form of Agreement contained in Transporter's Tariff.

GENERAL TERMS AND CONDITIONS

37. NEGOTIATED RATES (Continued)

37.12 Disputes

Any disputes concerning Negotiated Rates shall be resolved by the procedures set forth in Section 31 of these General Terms and Conditions.

Sheet No. 438
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

38. DISCOUNTING

38.1 Parameters

In the event Transporter agrees to discount its rate to Shipper below Transporter's applicable Maximum Rate, the discount terms shall be reflected in the applicable Agreement and will apply without the discount constituting a material deviation from Transporter's form of Agreement; provided, however, that any such discounted rate shall not change the underlying rate design and the resulting discounted rate shall be between the Maximum Rate and the Minimum Rate applicable to the service provided under the applicable Rate Schedule.

The Minimum Rate is not a discountable rate component.

38.2 Types of Discounts

Transporter may provide a specific discounted rate applicable to the following:

(a) to certain specified quantities under the Agreement (referred to as quantity rate type); or

(b) if specified quantity levels are actually achieved or with respect to quantities above or below a specified level (referred to as quantity level rate type); or

(c) during specified time periods (referred to as time period rate type or contract rate type); or

(d) to Receipt Point(s) (referred to as point rate type), Delivery Point(s) (referred to as point rate type), Transportation Path(s) (referred to as point to point rate type) or defined geographical areas (referred to as zone rate type); or

GENERAL TERMS AND CONDITIONS

38. DISCOUNTING (Continued)

38.2 Types of Discounts (Continued)

(e) in a specified relationship to the quantities actually transported (i.e., that the rates shall be adjusted in a specified relationship to quantities actually transported) (referred to as relationship rate type); or

(f) to provide that if one (1) rate component which was equal to or within the applicable Maximum Rate and Minimum Rate at the time the discount agreement was executed subsequently exceeds the applicable Maximum Rate or is below the applicable Minimum Rate due to a change in Transporter's Maximum Rates and/or Minimum Rates, so that such rate component must be adjusted downward or upward to equal the new applicable Maximum Rate or Minimum Rate, then other rate components may be adjusted upward or downward to achieve the agreed-upon overall rate, so long as none of the resulting rate components exceed the Maximum Rate or are below the Minimum Rate applicable to the rate component. Such changes to rate components shall be applied prospectively, commencing no sooner than the date a Commission order places in effect the applicable revised Maximum Rates and Minimum Rates. However, nothing contained herein shall be construed to alter a refund obligation under applicable law for any period during which rates which had been charged under a discount agreement exceeded rates which ultimately are found to be just and reasonable (referred to as rate component rate type); or

GENERAL TERMS AND CONDITIONS

38. DISCOUNTING (Continued)

38.2 Types of Discounts (Continued)

(g) based on a formula including, but not limited to published index prices for specific Receipt Point(s) and/or Delivery Point(s) or other agreed-upon published pricing reference points for price determination. Each Agreement entered into pursuant to this Subsection 38.2(g) shall a) not change the underlying rate design; b) not include any minimum bill or minimum take provision that has the effect of guaranteeing revenue; and c) define the rate component to be discounted (referred to as index price differential type); or

(h) to specific production reserves, supplies, or markets committed by Shipper (referred to as commitment rate type).

Sheet Nos. 442 and 443
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

39. OFF-SYSTEM SERVICES

39.1 Off-System Services Acquired for General System Use

Transporter may acquire off-system services from third parties in order to render services on behalf of its Shippers. Such services will be subject to Transporter's Tariff and currently effective rates that are subject to revision from time to time.

39.2 Off-System Services Acquired for Specific Shipper Requests

Transporter may acquire off-system services from third parties at the request of a specific Shipper. Such services shall be subject to the terms and conditions of Transporter's Tariff. For purposes of transactions entered into subject to this Section 39, the "Shipper must hold Title" requirement shall not be applicable to the acquired off-system services.

39.2.1 Rates and Charges

If a Shipper requests and Transporter agrees, to acquire off-system services from a third party to provide services for the benefit of such Shipper on Transporter's pipeline system, Shipper may, on a non-discriminatory basis, be required to pay Transporter, in addition to any applicable rates and charges assessed pursuant to this Tariff, the rates and charges Transporter is obligated to pay such third party for the off-system service and such administrative costs as are incurred to arrange and provide the service. Such charges shall be set forth as separate items on the monthly invoices rendered to Shipper.

GENERAL TERMS AND CONDITIONS

39. OFF-SYSTEM SERVICES

39.2 Off-System Services Acquired for Specific Shipper Requests (Continued)

39.2.2 Secondary Service Availability

Any off-system services acquired by Transporter for the benefit of a specific Shipper which are not being utilized shall be offered on a non-discriminatory basis to Transporter's other Shippers on a secondary or interruptible basis, pursuant to the terms of Transporter's Tariff and subject to any applicable Third Party Charges. Transporter will indicate in its posting of such off-system service whether any Third Party Charges will apply to the use of such off-system service and whether such off-system service is subject to term limitations. In no event, will service under this Section 39 be offered beyond the term during which Transporter has contracted to obtain such off-system service from a third party.

Sheet Nos. 446 and 447
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS

40.1 In evaluating requests for service and certain other purposes under this Tariff, these creditworthiness standards shall apply to all Shippers. Transporter shall not be required to continue to perform its obligations under any Agreement, or to commence or continue service, on behalf of any Shipper that fails to establish and maintain creditworthiness. Transporter shall determine Shipper's creditworthiness, at any time in its sole discretion, in accordance with the following:

40.1 Creditworthiness Standard

(a) Subject to Transporter's analysis of factors set forth below in Section 40.2, Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment in its sole discretion, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 40.1(b) or 40.1(d), as applicable. Nothing herein shall limit Transporter's ability to undertake further analysis of the factors set forth in Section 40.2 in evaluating and making a determination regarding Shipper's creditworthiness. If Shipper is the State of Alaska, is guaranteed by the State of Alaska, or otherwise is supported by the full faith and credit of the State of Alaska, Shipper is deemed to have satisfied the Tangible Net Worth requirement set forth in this Section 40.1(a); provided that Shipper still must satisfy the requirements of Section 40.1(b) or 40.1(d), as applicable.

A Shipper's "Capital Cost Share" is its pro rata share (determined based on the aggregate of firm transportation capacity

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.1 Creditworthiness Standard (Continued)

commitments compared to all Shippers' total firm transportation capacity commitments) of the capital costs (net of cumulative depreciation collected and cost reimbursement received under AGIA by Transporter), AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's rates.

(b) A Foundation Shipper will be deemed creditworthy if its long-term unenhanced senior unsecured debt securities are rated at least A- by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least A3 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and it meets the provisions of Section 40.1(a) above. If Foundation Shipper's rating has a negative outlook or is on creditwatch for downgrade, Foundation Shipper's rating will be reduced by one rating level. If Foundation Shipper is rated by both S&P and Moody's, only the lower rating will be taken into account.

(c) Notwithstanding Shipper's commitment of capacity, Shipper must satisfy the standards set forth in Section 40.1(b) if it seeks to use such capacity to ship gas associated with a Person (directly or through affiliates) that has an economic interest in, or directs or arranges the shipment of, at least 200,000 MMBtu/day of gas to be shipped on Transporter's facilities. For the avoidance of doubt, all gas shipped by a Shipper in which the State of Alaska has an economic interest,

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.1 Creditworthiness Standard (Continued)

as the result of its exercise of sovereign powers or otherwise, is associated with a Person for purposes of this subsection. As used in this Section 40.1(c), "Person" means any natural person, Entity, estate, labor union, or government authority or component and includes persons, corporate, partnership, affiliates of any person or corporate affiliated commercial entities and related components of any governmental entity; "Entity" means any foreign or domestic general partnership, limited partnership, limited liability company, corporation, joint enterprise or venture, joint stock company, business or statutory trust, employee benefit plan, cooperative, association, or other legal entity. Transporter shall determine whether gas is associated with a Person in its sole discretion, and Shipper shall provide information requested by Transporter that may be of assistance in making that determination.

(d) If Shipper is not a Foundation Shipper and does not fall within the provisions of Section 40.1(c), it will be deemed creditworthy if its long-term unenhanced senior unsecured debt securities are rated at least BBB by S&P or at least Baa2 by Moody's, in each case with a stable or better outlook, and it meets the provisions of Section 40.1(a). If Shipper's rating has a negative outlook or is on creditwatch for downgrade, Shipper's rating will be reduced by one rating level. If Shipper is rated by both S&P and Moody's, only the lower rating will be taken into account.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.1 Creditworthiness Standard (Continued)

(e) "Tangible Net Worth," for purposes of this Section 40.1, means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations. Intangible assets include, but are not limited to, goodwill, patents, copyrights, and unamortized loan costs. Only actual tangible assets are included for purposes of assessing creditworthiness.

40.2 Determination of Creditworthiness

In evaluating Shipper’s creditworthiness, Transporter may consider, in addition to the factors set forth in Section 40.1, the following additional information and factors:

(a) Opinions, outlooks, watch alerts, and rating actions of S&P and Moody’s and other credit reporting agencies;

(b) The pro forma effect on Shipper’s debt rating of execution by Shipper of a Firm Transportation Service Agreement;

(c) Financial statements and reports;

(d) Whether a petition is filed by or against Shipper, any of its affiliates, or any guarantor of Shipper's obligations hereunder, under any chapter of the bankruptcy code of the United States or under legislation of a similar nature of any other nation;

(e) Whether Shipper is subject to any lawsuits or outstanding judgments which could materially impair its ability to remain solvent;

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.2 Determination of Creditworthiness (Continued)

(f) The nature of Shipper's business and the effect on that business of general economic conditions and economic conditions specific to it, including Shipper's ability to recover the costs of Transporter's services through filings with regulatory agencies or otherwise to pass on such costs to its customers;

(g) Whether Shipper has or has had any delinquent balances outstanding for services provided previously by Transporter and whether Shipper is paying and has paid its account balances according to the terms established in its Agreement(s) (excluding amounts as to which there is a good faith dispute);

(h) Any other information, including any information provided by Shipper or requested by Transporter, that is relevant to Shipper's creditworthiness.

40.3 Assignee Creditworthiness

The creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) or to any permanent release, in whole or part, pursuant to a Firm Transportation Service Agreement.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.4 Failure to Satisfy Creditworthiness -- Alternatives

If Shipper fails or ceases to satisfy the creditworthiness standard or criteria as described above, in order to obtain or continue service Shipper must provide and maintain one or more of the following credit alternatives, in lieu of the creditworthiness standard requirements outlined in Section 40.1:

(a) Guaranty: Shipper may provide a guaranty that is sufficient to cover its contractual obligations to the Transporter in a form satisfactory to Transporter in its sole discretion, from a guarantor which meets the creditworthiness standard or criteria described above.

(b) Collateral:

(i) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in its sole discretion in an amount no greater than Shipper’s contractual obligations to Transporter. If Shipper does not, at least twenty (20) business days prior to the conclusion of the letter of credit’s term, provide the Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Section 40, acceptable to Transporter in its sole discretion, Transporter shall be entitled to draw upon the full value of the letter of credit;

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.4 Failure to Satisfy Creditworthiness - Alternatives (Continued)

(ii) Shipper may provide a cash security deposit acceptable to Transporter in its sole discretion in an amount no greater than Shipper's contractual obligations to Transporter; or

(iii) Shipper may provide any other security or collateral acceptable to Transporter in Transporter's sole discretion.

(c) Upon termination in whole or part of a Firm Transportation Service Agreement, any guarantee or collateral provided by Shipper shall first be applied to meet any obligation of Shipper to Transporter, and any remaining balance shall thereafter be returned to Shipper.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.5 Ongoing Creditworthiness Review

Transporter shall have the right to review a Shipper's creditworthiness and the continued acceptability of any credit alternative provided on an ongoing basis, and Shipper shall provide, within ten (10) business days upon Transporter's request, any requested information in order to determine the continuing creditworthiness of Shipper and acceptability of any credit alternative provided. If Shipper or credit alternative provider is not subject to regulation by the Securities and Exchange Commission, Shipper shall notify Transporter in writing within ten (10) business days of the details of any material adverse change in its or its credit alternative provider’s business, properties, conditions, or results of operations (financial or otherwise). If Shipper does not provide such information and/or notification within ten (10) business days of Transporter's request or occurrence of material adverse change, the Transporter may deem that it cannot determine the Shipper’s or its credit alternative provider’s Tangible Net Worth, and the Transporter may set the Shipper’s or its credit alternative provider’s Tangible Net Worth to zero.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.6 Notification of Failure to Meet Creditworthiness

Upon notification by Transporter that Shipper no longer meets Transporter's creditworthiness standard or criteria, Shipper must within five (5) business days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Section 40.

(a) If Shipper fails to provide one of the credit alternatives within this time period, Transporter has the right to suspend its performance under any Firm Transportation Service Agreement and/or terminate any Firm Transportation Service Agreement with Shipper to pay the amounts set forth in Section 4 of Rate Schedule FT-1. Transporter may, after terminating any Firm Transportation Service Agreement, resell capacity previously secured by Shipper. Nothing in this Subsection limits other remedies, including actions for damages, that Transporter may seek against Shipper.

(b) If Shipper fails to provide one of the credit alternatives within this time period, Transporter may provide Notice to Shipper of its intention to suspend service in five (5) business days, provided however, that any such suspension shall not relieve Shipper from any obligation to pay any further rates, charges or other amounts payable to Transporter. If Shipper does not provide one of the credit alternatives within five (5) business days of suspension of its service, Transporter may initiate termination of service proceedings with the Commission and provide such notice to Shipper and any Replacement Shipper(s).

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.6 Notification of Failure to Meet Creditworthiness

(c) If Shipper at any time fails to provide one of the credit alternatives at the time Transporter initiates termination of service proceedings, Transporter shall immediately be entitled to collect, and Shipper shall be immediately obligated to pay, all amounts due to Transporter from Shipper during the full term of any Firm Transportation Agreement; these rights shall be in addition to other rights of and remedies available to Transporter.

(d) If Shipper has multiple agreements with Transporter and defaults on one Agreement, Transporter may deem a default by Shipper on that one Agreement as a loss of creditworthiness on any other Agreement(s) Shipper has with Transporter.

(e) If a petition is filed, by or against Shipper, any of its affiliates, or any of its credit alternative providers, under any chapter of the bankruptcy code of the United States or under legislation of a similar nature of any other nation, Transporter reserves the right to suspend and terminate service as described in Section 6 of these General Terms and Conditions. Transporter also may exercise any other remedy available to it hereunder, at law or in equity.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.7 Evaluation of Interruptible Services

Transporter's creditworthiness evaluation of interruptible services shall be based on the criteria as described above, for an amount up to the maximum amount of interruptible services that may be provided in any three (3) month period under the terms of the Agreement(s), except as provided for under Rate Schedule IT-1. As provided under Rate Schedule IT-1, the credit requirement shall be the dollar value of each nomination.

40.8 Loaned Gas

For loan services under Rate Schedule PAL, the credit requirement shall include an amount to adequately account for the value of loaned gas and any related fees, charges, etc. The value of loaned gas shall be calculated on Shipper's Maximum PAL Quantity multiplied by the average of the New York Mercantile Exchange ("NYMEX") future prices settlement for the most recent available twelve (12) month period, as reported in Platt's Gas Daily's or any successor publication thereto.

40.9 Imbalances Due Transporter

(a) Transporter has the right to seek security to cover the value of Shipper Imbalances owed Transporter by Shipper.

(i) For existing Shippers, such imbalances shall be valued at Shipper's largest monthly negative imbalance over the most recent twelve (12) month period multiplied by the average of the NYMEX future prices settlement for the most recent available twelve (12) month period, as reported in Platt's Gas Daily, on the day the credit requirement is determined.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.9 Imbalances Due Transporter (Continued)

(ii) For new Shippers, such imbalances shall be valued at ten percent of Shipper's estimated monthly usage (as defined by Transporter) multiplied by the average of the NYMEX future prices settlement for the most recent available twelve (12) month period, as reported in Platt's Gas Daily, on the day the credit requirement is determined. This formula shall be used for the first twelve (12) months of service while a historical record is established; thereafter, security for such Shipper will be determined as specified for an existing Shipper.

(b) Transporter shall require credit support to cover the value of imbalances owed Transporter pursuant to an OBA. The credit requirement for such imbalances shall be five percent of the design capacity of the interconnect facility.

40.10 Construction of New Facilities

In the event Transporter constructs new facilities pursuant to Section 19 of these General Terms and Conditions, to accommodate a specific request from a Party, Transporter may require from such Party collateral in an amount up to the cost of such facilities. As Transporter recovers the cost of such facilities, the collateral required shall be reduced accordingly. Where facilities are constructed to serve multiple Shippers, an individual Shipper's obligation hereunder shall be for no more than its proportionate share of the cost of the facilities. This provision is in addition to and shall not supersede or replace any other rights that Transporter may have regarding the construction and reimbursement of facilities.

GENERAL TERMS AND CONDITIONS

40. CREDITWORTHINESS (Continued)

40.11 Designating Representatives for Creditworthiness Notices

Transporter's and Shipper's authorized creditworthiness representative(s) for Internet E-mail notifications, responses and requests as described in this Section 40 shall be established by initiating a request as prescribed on Transporter's Customer Activities site.

Sheet No. 461
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

41. TRANSPORTER FUEL AND LOST AND UNACCOUNTED FOR GAS

41.1 Definition

Transporter Fuel and Lost and Unaccounted for Gas shall consist of compressor fuel used in its operations and fuel for treatment or other operational purposes, including but not limited to gas used by Transporter as fuel, for testing, and gas lost or otherwise unaccounted for.

41.2 Applicability

The Transporter Fuel and Lost and Unaccounted for Gas Percentage shall apply to all Forwardhaul quantities of gas transported under Transporter's Rate Schedules requiring assessment of Transporter Fuel and Lost and Unaccounted for Gas. The Transporter Fuel and Lost and Unaccounted for Gas Percentage shall include a percentage for lost and unaccounted for gas and shall be separately stated in each posting made pursuant to Subsection 42.5 herein. Backhaul quantities of gas transported on Transporter's pipeline system that do not consume Transporter Fuel and Lost and Unaccounted for Gas will not be assessed the fuel charge component of the Transporter Fuel and Lost and Unaccounted for Gas Percentage; however, such Backhaul transactions shall be assessed the separately stated percentage for lost and unaccounted for gas.

41.3 Derivation

The Transporter Fuel and Lost and Unaccounted for Gas Percentage shall be calculated monthly and adjusted if necessary. The Transporter Fuel and Lost and Unaccounted for Gas Percentage shall be derived by dividing the Estimated Transporter Fuel and Lost and Unaccounted for Gas Requirement by the Estimated Transportation Quantity; whereas

(i) Estimated Transporter Fuel and Lost and Unaccounted for Gas Requirement shall be the total Transporter Fuel and Lost and Unaccounted for Gas estimated by Transporter to be required

GENERAL TERMS AND CONDITIONS

41. TRANSPORTER FUEL AND LOST AND UNACCOUNTED FOR GAS Continued)

41.3 Derivation (Continued)

to transport the Estimated Transportation Quantity, adjusted for any Transporter Fuel and Lost and Unaccounted for Gas Imbalance from a prior period, and any changes that are known and reasonable.

(ii) Estimated Transportation Quantity is the quantity of natural gas estimated by Transporter to be physically received and transported on Transporter's pipeline system for all Shippers subject to the Transporter Fuel and Lost and Unaccounted for Gas Percentage for the upcoming month.

(iii) Transporter Fuel and Lost and Unaccounted for Gas Imbalance shall be the difference between the Actual Transporter Fuel and Lost and Unaccounted for Gas Requirement and the Estimated Transporter Fuel and Lost and Unaccounted for Gas Requirement for the same period.

(iv) Actual Transporter Fuel and Lost and Unaccounted for Gas Requirement is the total actual monthly quantity of natural gas related to all components comprising Transporter Fuel and Lost and Unaccounted for Gas.

41.4 Reimbursement

Transporter Fuel and Lost and Unaccounted for Gas shall be furnished in-kind by Shipper. Shipper's total Receipt Point nominations must include the quantity of gas associated with Transporter Fuel and Lost and Unaccounted for Gas pursuant to the terms of Shipper's Agreement.

GENERAL TERMS AND CONDITIONS

41. TRANSPORTER FUEL AND LOST AND UNACCOUNTED FOR GAS Continued)

41.5 Posting

Transporter Fuel and Lost and Unaccounted for Gas Percentage shall be posted on Transporter's public Internet website six (6) Business Days prior to the end of the month preceding the month to which it is applicable.

41.6 Separate Transporter Fuel and Lost and Unaccounted for Gas shall be established for transportation services and gas extraction and treatment services.

Sheet No. 465
has not been issued and is
being reserved for future use.

GENERAL TERMS AND CONDITIONS

42. NON-CONFORMING AGREEMENTS

Sheet Nos. 467 and 468
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

43. AGENTS

For purposes of this Section 43, Shipper shall be defined as any Person who executes an Agreement.

Shipper may delegate to a third party (Agent), authority to exercise certain or all rights and perform certain or all obligations set forth in one or more Agreement(s) entered into between Shipper and Transporter. Shipper may delegate to Agent, the specific rights and obligations set forth above pursuant to the terms and conditions of an Agency Authorization Agreement, a copy of which is available on Transporter's public Internet website. Shipper may not delegate the same rights and/or obligations of an Agreement to more than one Agent

An Agency Authorization Agreement or any changes to such Agency Authorization Agreement must be submitted to Transporter at least two (2) Business Days prior to the requested effective date. Shipper's delegation to its Agent(s) pursuant to this Section 43 shall not confer to either Shipper or Agent(s) rights outside of or in contravention of the terms and conditions of the Agreement(s).

Transporter shall rely on communications and actions of Agent for all purposes that are within the authority conveyed by the Agency Authorization Agreement. Such communications with, and actions by, Agent that are within the authority conveyed by the Agency Authorization Agreement shall be deemed communications with or actions by Shipper. Shipper shall indemnify and hold Transporter harmless from suits, actions, costs, losses, expenses and damages (including, without limitation, attorney's fees) arising from claims associated with Transporter's reliance on such communications and actions of Agent. Shipper remains bound by its obligations under an Agreement. Commitments made by the Agent on behalf of Shipper are binding on the Shipper as if made by the Shipper. In the event of an inconsistency between communications from Shipper and from Agent, the communications first received by Transporter shall prevail.

GENERAL TERMS AND CONDITIONS

43. AGENTS (Continued)

Agent may administer rights under multiple Agreements for one (1) or more Shippers; provided however, that such Agent (i) shall administer and account for each Agreement separately, and (ii) shall perform the specific service(s) only for the Shipper that has delegated its rights and obligations under the Agreement to Agent, as set forth in the Agency Authorization Agreement.

Sheet Nos. 471 and 472
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

44. RESERVED FOR FUTURE USE

Sheet Nos. 474 and 475
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

45. DEFERRED FIRM TRANSPORTATION SERVICE

During any period of interruption of firm transportation service, Shipper shall continue to pay demand charges. Interruption, for purpose of this Section 45, means an interruption of Transporter's ability to provide firm gas transportation service or firm gas treatment service, including for reasons of a Force Majeure Event, and excludes (i) any failure to provide Service attributable to the actions of Shipper (including failure to tender gas at levels less than Shipper's MDQ or MTQ), (ii) reduced levels of Service associated with the phase-in period of Transporter's gas treatment plant, and (iii) reduced levels of Service associated with gas treatment plant turnarounds.

45.1 During any period of interruption, firm transportation and, if applicable, firm treatment of Shipper's gas will be reduced on a pro rata basis (based on Shipper's MDQ as a percentage of total MDQs and MTQ as a percentage of total MTQs).

45.2 Transporter shall provide Deferred Firm Transportation Service and, if applicable, deferred firm treatment service to Shipper in an amount equivalent to the quantity of gas subject to such a reduction of anticipated Service as a result of an interruption. For purposes of this Section 45, Deferred Firm Transportation service means a firm gas transportation service and, if applicable, a deferred firm gas treatment service provided by Transporter (subject to the terms of a Firm Transportation Service Agreement and any applicable terms of Transporter's Tariff) utilizing all transportation or gas treatment capacity, if any, that is available once Transporter has satisfied Shipper's and other shippers' MDQ and, if applicable, MTQ, and shall be offered on a pro rata basis to all firm transportation and firm gas treatment shippers eligible to receive such service.

GENERAL TERMS AND CONDITIONS

45. DEFERRED FIRM TRANSPORTATION SERVICE (Continued)

45.3 Deferred Firm Transportation Service shall be available to Shipper, when capacity is available and Shipper is eligible to receive such service due to a prior interruption of firm service. Deferred Firm Transportation Service shall have priority as set forth in Section 10.5.

Sheet Nos. 478 and 479
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

46. OPERATIONAL PURCHASES AND SALES OF GAS

46.1 Applicability

Transporter may purchase and/or sell gas to the extent necessary to: (i) balance Transporter Fuel and Lost and Unaccounted for Gas pursuant to Section 41 of these General Terms and Conditions; (ii) maintain system pressure and line pack; (iii) manage imbalance quantities; (iv) perform other operational functions in connection with transportation, treatment and other similar services; and (v) otherwise protect the operational integrity of Transporter's pipeline system. Any sales shall be made on an unbundled basis.

The sale or purchase of natural gas shall occur at any Receipt Point or Delivery Point on Transporter's pipeline system or at points located within any off-system capacity held by Transporter on other systems. Such purchases or sales shall be authorized pursuant to Transporter's blanket certificate and will be made on a non-discriminatory basis.

46.2 Solicitation of Bids

Transporter shall post for Bid its operational purchases and/or sales on its public Internet website. Such posting shall include the following information: 1) the level of daily quantities and whether such purchase and/or sale quantities shall be made on a firm or interruptible basis; 2) the requested effective date and term of the purchase and/or sale; 3) the names of the applicable Receipt Point(s) or Delivery Point(s); 4) method for determining Best Bid(s); 5) time period for accepting and awarding Bid(s); and (6) any additional information as may be required by Transporter.

GENERAL TERMS AND CONDITIONS

46. OPERATIONAL PURCHASES AND SALES OF GAS

46.2 Solicitation of Bids (Continued)

Transporter shall ask prospective bidders to place a Bid on its public Internet website or via fax or electronic mail with such Bid(s) containing the following information: 1) bidder's legal name and the name, title, address, and phone number of individual authorized to purchase or sell natural gas; 2) bidder's price; 3) information addressing all criteria requested by Transporter in its posting; 4) any conditions on the prospective bidder's Offer to purchase and/or sell gas. Transporter shall evaluate Bid(s) and shall award such purchase and/or sale of gas to the prospective bidder having a Bid containing the lowest Bid (if a purchase) or the highest Bid (if a sale) and otherwise matching all terms and conditions requested by Transporter in its posting.

Transporter reserves its right, in its sole discretion, to 1) withdraw its postings; 2)reject all Bids due to operational changes; and 3) reject any Bid which is not complete, which contains modifications to the terms of the posting or which contains terms that are operationally unacceptable.

The above procedures shall not apply in emergency situations. Purchases and sales of natural gas in emergency situations shall be reported in accordance with Subsection 46.3 herein.

46.3 Reporting Requirements

In the event Transporter purchases or sells natural gas in a calendar year pursuant to this section of the Tariff, Transporter shall file a report with the FERC on or before May 1st of the following calendar year. The report will indicate the source of the gas purchased/sold, the date of the purchase/sale, quantity purchased/sold, the cost and/or revenue associated with each transaction, and all entities including affiliates, from which Transporter purchased or sold the operational gas.

Sheet Nos. 482 and 483
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

47. WAIVERS

No waiver by either Transporter or Shipper of any one or more defaults by the other in the performance of any provisions of any Agreement shall operate or be construed as a waiver of any subsequent or other default or defaults, whether of a like or of a different character.

Transporter may waive in writing any rights hereunder or any obligations of Shipper applicable to any specific default that has already occurred, or on a case-by-case basis in advance of any specific, temporary operational problem, on a basis which is not unduly discriminatory; provided that no waiver shall operate or be construed as a waiver of other or future rights or obligations, whether of a like or different character.

Sheet Nos. 485 through 488
have not been issued and are
being reserved for future use.

GENERAL TERMS AND CONDITIONS

48. PENALTY REVENUE CREDITS

48.1 Description

Penalty revenue shall include all amounts collected by Transporter for OFO penalties, Underdelivery Penalties, and Rate Schedule PAL penalties. Any penalty revenue collected shall be used first to compensate Transporter for any expenses incurred to alleviate the conditions that created the violation, such as administrative costs. The remaining penalty revenue (net penalty revenue) shall be refunded ratably to non-offending firm Shippers and Shippers which paid the maximum IT rate through a direct payment or invoice credit as more fully described below. If the annual penalty revenue collected does not exceed the expenses incurred by Transporter, such unreimbursed expenses shall be carried forward to future monthly periods until recouped.

48.2 Distribution

The net penalty revenue collected shall be determined for each annual calendar year period ending December 31st and distributed through a credit to current billings where feasible.

GENERAL TERMS AND CONDITIONS

48. PENALTY REVENUE CREDITS (Continued)

48.3 Refund Allocation Factor

A refund allocation factor for each Shipper shall be calculated by dividing the actual revenues for each non-offending Shipper by the total revenue collected during the reporting period. The revenues used to calculate the refund allocation factor shall be net of all applicable surcharges, including but not limited to ACA and Change in Law/Regulation surcharges. The resulting refund allocation factor shall be multiplied by the net penalty charge revenue to determine the applicable invoice credit or direct payment to each Shipper. This calculation shall be performed on a monthly basis but the distribution of any net penalty revenue shall be made on an annual basis. A Shipper which incurred any of the penalty revenue described in Subsection 48.1 herein shall be excluded from the distribution of all net penalty revenues applicable to each Calendar Month in which the violation occurred.

GENERAL TERMS AND CONDITIONS

49. AOS, IT AND PAL REVENUE CREDITS

Fifty percent of AOS, IT, and PAL revenues collected during any calendar year or partial calendar year period ending December 31st shall be distributed to Firm Shippers on the basis of each Shipper’s MDQ to aggregate MDQ as of December 31st and provided as a credit to such Shippers’ invoices within ninety (90) days after each December 31st.

GENERAL TERMS AND CONDITIONS

50. HEADINGS

The headings appearing in these General Terms and Conditions or in any part of this Tariff are for the purpose of convenient reference only and shall not affect the interpretation thereof.

Sheet Nos. 493 through 510
have not been issued and are
being reserved for future use.

Contract #________

TransCanada Alaska Company LLC
RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

This Agreement (the "Service Agreement") is made and entered into at ________________ as of _____________, 20__, by and between TransCanada Alaska Company LLC, hereinafter referred to as "Transporter", and ________________________, hereinafter referred to as "Shipper".

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's (FERC) Regulations; and

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

Article 1 - Transportation Path Receipt Point

As specified in Exhibit A attached hereto, commencing on Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Transporter, at Shipper's Primary Receipt Point(s), a daily quantity of gas not in excess of the Maximum Delivery Quantity on an MMBtu basis plus the applicable quantity of gas associated with Transporter Fuel and Lost and Unaccounted for Gas.

Article 2 - Transportation Path Delivery Point

Transporter shall deliver to Shipper gas scheduled at the Primary Delivery Point(s) specified in Exhibit A attached hereto, in accordance with Section 10 of the General Terms and Conditions of Transporter's FERC Gas Tariff (Tariff).

Article 3 - Payments

Shipper shall make payments to Transporter in accordance with Section 6 of the General Terms and Conditions of Transporter's Tariff.

Article 4 - Change in Transporter's Tariff Provisions

Upon notice to Shipper, and to the extent not inconsistent with this Service Agreement, Transporter shall have the right to file with the Federal Energy Regulatory Commission any changes in Recourse Rates and terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Transporter may deem necessary, and to make such changes effective at such times as Transporter desires under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

TransCanada Alaska Company LLC
RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

Article 5 - Cancellation of Prior Agreements

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

[PA dated ____________]

Article 6 - Term

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect for _____ years, _____ months, _____ days after the Billing Commencement Date or through ______________. This Service Agreement may continue in effect thereafter in accordance with Section 18 of the General Terms and Conditions of Transporter's Tariff, if applicable. Service rendered pursuant to this Service Agreement shall automatically be abandoned upon termination of this Service Agreement.

Termination of this Service Agreement shall not relieve Transporter and Shipper of the obligation to correct any Shipper Imbalances hereunder, or Shipper to pay money due hereunder to Transporter and shall be in addition to any other remedies that Transporter may have.

Article 7 - Applicable Law and Submission to Jurisdiction

This Service Agreement and the rights and obligations of Transporter and Shipper thereunder are subject to all United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of New York. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of New York and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Transporter from proceeding at its election against the Shipper in the Courts of any other state, Province or country.

TRANSCANADA ALASKA COMPANY LLC
RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

Article 7 - Applicable Law and Submission to Jurisdiction (Continued)

At the Transporter's request, the Shipper shall irrevocably appoint an agent in **[insert]** to receive, for it and on its behalf, service of process in connection with any judicial proceeding in **[insert]** relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within **[insert]** on behalf of Shipper, the Shipper shall appoint a substitute process agent within **[insert]** and deliver to the Transporter a copy of the new agent's acceptance of that appointment within thirty (30) days.

Article 8 - Successors and Assigns

Any Person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Transporter, as the case may be, and which shall assume all obligations under this Service Agreement of Shipper or Transporter, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under this Service Agreement. Either party to this Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign this Service Agreement to any affiliated Person (which for such purpose shall mean any Person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 8 shall, however, operate to release Shipper from its obligations under this Service Agreement unless Transporter shall, in its sole discretion, consent in writing to such release. Transporter shall not release Shipper from its obligations under this Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have any adverse effect upon Transporter. Transporter may refuse to allow an assignment if it has a reasonable basis to conclude that it will not be financially or economically indifferent to the assignment. Shipper shall, at Transporter's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Transporter's rights under this Service Agreement or to give effect to the right of a Person whom the

TransCanada Alaska Company LLC

RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

Article 8 - Successors and Assigns (Continued)

Transporter has specified pursuant to Section 6 of the General Terms and Conditions of Transporter's Tariff as the Person to whom payment of amounts invoiced by Transporter shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Transporter under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Transporter to any Person whom the Transporter has specified pursuant to said Section 6 as the Person to whom payment of amounts invoiced by Transporter shall be made.

Article 9 - Loss of Governmental Authority, Gas Supply, Transportation or Market

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Transporter's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Transporter of the transportation charges as provided for in this Service Agreement.

Article 10 - Other Provisions

(This Article to be utilized when necessary to specify other provisions.)

Article 11 - Exhibit A of Service Agreement, Rate Schedules and General Terms and Conditions

Unless Shipper has elected Negotiated Rates as set forth in an Exhibit A attached hereto, Transporter's Recourse Rates and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement. In the event of an inconsistency between this Service Agreement and Transporter's Rate Schedules and General Terms and Conditions, the provisions of this Service Agreement shall control.

TransCanada Alaska Company LLC
RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

TransCanada Alaska Company LLC

By: ______________________________

Title: ___________________________

By: ______________________________

Title: ___________________________

ATTEST: (NAME OF SHIPPER)

______________________________ By: ______________________________

______________________________ Title: ___________________________

Contract #_________

TransCanada Alaska Company LLC
RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

EXHIBIT A TO SERVICE AGREEMENT

TRANSPORTER - TransCanada Alaska Company LLC

TRANSPORTER'S ADDRESS -

SHIPPER -

SHIPPER'S ADDRESS -

Maximum Delivery Quantity: ______ Mcf/day
Transportation Path:

Receipt Point: ____________ Delivery Point: ____________

Right of First Refusal: Yes _____ No _____

_____ Check if Shipper has elected Transporter’s gas treatment service.

Check Applicable Rate:
Maximum Reservation Rate: 1/_________

Discounted Rate: 1/ _________
Description of Discounted Rate: 2/________________________

Negotiated Rate: 1/ _________
Description of Negotiated Rate: _______________________

1/ Plus the applicable commodity charges and other rates and charges, set forth in Section 4 of Rate Schedule FT-1.
2/ See Section 39 of the General Terms and Conditions of Transporter's Tariff for description of various types of discount rates.

TransCanada Alaska Company LLC
RATE SCHEDULE FT-1
FIRM TRANSPORTATION SERVICE AGREEMENT

EXHIBIT A TO SERVICE AGREEMENT
(Continued)

This Exhibit A is made and entered into as of __________, 20__.

Billing Commencement Date of this Exhibit A is ________________.

TransCanada Alaska Company LLC

By: ___________________________

Title: ________________________

By: ___________________________

Title: ________________________

ATTEST: (NAME OF SHIPPER)

____________________________ By: ___________________________

Title: ________________________

Sheet Nos. 518 through 525
have not been issued and are
being reserved for future use.

Contract #________

TransCanada Alaska Company LLC
RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION AGREEMENT

This Agreement is made and entered into as of ________, 20__, by and between TransCanada Alaska Company LLC, hereinafter referred to as "Transporter" and ______________________________, hereinafter referred to as "Shipper".

WHEREAS, Shipper is desirous of engaging Transporter to provide interruptible transportation service for quantities of natural gas; and

WHEREAS, Transporter is desirous of providing interruptible transportation service for Shipper; and

WHEREAS, the transportation or treatment of natural gas shall be effectuated pursuant to Section 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

NOW, THEREFORE, in consideration of their respective covenants and agreements hereinafter set forth, the parties hereto covenant and agree as follows:

Article 1 - Receipts

If on any day after executing this Agreement, Transporter determines that capacity exists in its pipeline system to transport all or a portion of Shipper's Total Interruptible Delivery Quantity plus the applicable quantity of gas associated with Transporter Fuel and Lost and Unaccounted for Gas, then Shipper shall be entitled to tender to Transporter at each of Shipper's Receipt Point(s), hereinafter specified on Transporter's public Internet website under Informational Postings, the quantity of gas which Transporter has determined as available for transportation at each of the Receipt Point(s) for such days. Creditworthiness under this Agreement will be verified upon receipt of nominations under this Agreement. Transporter shall schedule receipts of gas pursuant to Section 10 of the General Terms and Conditions of Transporter's FERC Gas Tariff (Tariff).

Article 2 - Deliveries

Shipper shall be entitled to nominate deliveries of gas at the Delivery Point(s) specified on Transporter's public Internet website under Informational Postings. Transporter shall schedule deliveries of gas to Shipper in accordance with Section 10 of the General Terms and Conditions of Transporter's Tariff.

TransCanada Alaska Company LLC
RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION AGREEMENT

Article 3 - Payments

Shipper shall make payments to Transporter in accordance with Section 6 of the General Terms and Conditions of Transporter's Tariff.

Article 4 - Change in Tariff Provisions

Upon notice to Shipper, Transporter shall have the right to file and seek FERC approval of any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Rate Schedule IT-1 Transportation Agreement as Transporter may deem necessary, and to make such changes effective at such times as Transporter desires and is possible under applicable law. Shipper may protest any filed changes before the FERC and exercise any other rights it may have with respect thereto.

Article 5 - Fees

Shipper shall pay to Transporter all filing fees required by the FERC or any regulatory body related to service provided hereunder to Shipper.

Article 6 - Cancellation of Prior Agreements

When this Agreement becomes effective, it shall supersede, cancel and terminate the following agreements:

Article 7 - Term

This Agreement shall become effective ____________, and shall continue in full force and effect in accordance with Transporter's Tariff for a term of ____________. Termination of this Agreement shall not relieve Transporter and Shipper of the obligation to correct any Shipper Imbalances hereunder, or Shipper to pay money due hereunder to Transporter.

Article 8 - Applicable Law

This Agreement and Transporter's Tariff, and the rights and obligations of Transporter and Shipper thereunder, are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Agreement shall be governed by and interpreted in accordance with the laws of the State of New York.

TransCanada Alaska Company LLC
RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION AGREEMENT

Article 9 - Exhibit A of Rate Schedule IT-1 Transportation Agreement, Rate Schedule, and General Terms and Conditions

Transporter's Rate Schedule IT-1 and Transporter's General Terms and Conditions which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto, are all applicable to this Agreement and are hereby incorporated in, and made a part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the day and year set forth above.

TransCanada Alaska Company LLC

By: ______________________________

Title: ___________________________

By: ______________________________

Title: ___________________________

ATTEST: (NAME OF SHIPPER)

________________________________ By: ______________________________

Title: ___________________________

Contract #________

TransCanada Alaska Company LLC
RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION AGREEMENT

EXHIBIT A 1/

TRANSPORTER - TransCanada Alaska Company LLC

TRANSPORTER'S ADDRESS -

IT-1 SHIPPER -

IT-1 SHIPPER'S ADDRESS -

FORWARDHAUL _____ OR BACKHAUL _____ (check one)

Total Interruptible Delivery Quantity _______Mcf/day

Check Applicable Rate:
Maximum Commodity Rate: 2/ ______

Discounted Rate: 2/ ______
Description of Discounted Rate: 3/ ________________________

Negotiated Rate: 2/ _____
Description of Negotiated Rate: _________________________

1/ Transporter's Receipt Point(s) and Delivery Point(s) are posted on Transporter's public Internet website under Informational Postings and are hereby incorporated by reference and made part of this Agreement.

2/ Plus the applicable other rates and charges, pursuant to Subsection 4.2 of Rate Schedule IT-1.

3/ See Section 38 of the General Terms and Conditions of Transporter's Tariff for description of various types of discount rates.

TransCanada Alaska Company LLC
RATE SCHEDULE IT-1
INTERRUPTIBLE TRANSPORTATION AGREEMENT

EXHIBIT A (Continued)

This Exhibit A is made and entered into as of _________, 20__.

TransCanada Alaska Company LLC

By: ___________________________

Title: ________________________

By: ___________________________

Title: ________________________

ATTEST: (NAME OF SHIPPER)

____________________________ By: ___________________________

Title: ________________________

Sheet Nos. 531 through 538
have not been issued and are
being reserved for future use.

Contract #________

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT

THIS AGREEMENT (the Agreement) is made and entered into at **[insert]** as of ______________, 20__, by and between TransCanada Alaska Company LLC, hereinafter referred to as "Transporter" and ______________________________, hereinafter referred to as "Shipper".

WHEREAS, Shipper desires to engage Transporter to provide interruptible park and loan service; and

WHEREAS, Transporter desires to provide interruptible park and loan service to Shipper;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

Article 1 - Receipts

Shipper shall be entitled to nominate a quantity of gas up to Shipper's Maximum Park and Loan Quantity at a Park Point as set forth in the Exhibit(s) A attached hereto. Once scheduled by Transporter, Transporter shall receive gas in accordance with the applicable terms and conditions of Rate Schedule PAL.

Article 2 - Deliveries

Shipper shall be entitled to nominate a quantity of gas up to Shipper's Maximum Park and Loan Quantity at a Loan Point as set forth in the Exhibit(s) A attached hereto. Once scheduled by Transporter, Transporter shall deliver gas in accordance with the applicable terms and conditions of Rate Schedule PAL.

Article 3 - Rates

Rates for service under this Agreement shall be at Transporter's Maximum Rate plus all applicable surcharges in effect under Rate Schedule PAL unless otherwise agreed to by the parties and set forth in the Exhibit(s) A attached hereto.

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT

Article 4 - Payments

Shipper shall make payments to Transporter in accordance with the terms and conditions specified on the Exhibit(s) A attached hereto, Rate Schedule PAL, Section 6 of the General Terms and Conditions of Transporter's FERC Gas Tariff (Tariff), and the other applicable terms and provisions of this Agreement.

Article 5 - Change in Tariff Provisions

Upon notice to Shipper, Transporter shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Agreement as Transporter may deem necessary, and to make such changes effective at such times as Transporter desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

Article 6 - Cancellation of Prior Agreements

When this Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

Article 7 - Term

Where no Exhibit(s) A has been executed by Transporter and attached hereto within five (5) years of the date of execution of this Agreement then this Agreement shall automatically terminate. Where one (1) or more Exhibit(s) A have been executed by Transporter and attached hereto, then this Agreement shall automatically terminate five (5) years after the latest Termination of Service Date on such Exhibit(s) A.

Termination of this Agreement shall not relieve Shipper of the obligation to pay money due hereunder to Transporter and shall be in addition to any other remedies that Transporter may have.

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT

Article 8 - Applicable Law and Submission to Jurisdiction

This Agreement and Transporter's Tariff, and the rights and obligations of Transporter and Shipper thereunder are subject to all relevant and lawful United States statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Agreement shall be governed by and interpreted in accordance with the laws of the State of **[insert]**. For purposes of legal proceedings, this Agreement shall be deemed to have been made in the State of **[insert]** and performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Agreement, provided always that nothing herein contained shall prevent Transporter from proceeding at its election against Shipper in the Courts of any other State, Province or Country.

At the Transporter's request, the Shipper shall irrevocably appoint an agent in **[insert]** to receive, for it and on its behalf, service of process in connection with any judicial proceeding in **[insert]** relating to the Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within **[insert]** on behalf of Shipper, the Shipper shall appoint a substitute process agent within **[insert]** and deliver to the Transporter a copy of the new agent's acceptance of that appointment within thirty (30) days.

Article 9 - Successors

Any Person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Transporter, as the case may be, and which shall assume all obligations under Shipper's Agreement of Shipper or Transporter, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Agreement. Either party to a Shipper's Agreement may pledge or charge the same under provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Agreement to any affiliated Person (which for such purpose shall mean any Person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Agreement unless Transporter shall, in its sole discretion, consent in writing to such release. Transporter shall not release any

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT

Article 9 - Successors (Continued)

Shipper from its obligations under its Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have an adverse effect upon Transporter. Shipper shall, at Transporter's request, execute such instrument and take such other action as may be desirable to give effect to any such assignment of Transporter's rights under such Shipper's Agreement or to give effect to the right of a Person whom the Transporter has specified pursuant to Section 6 of the General Terms and Conditions of Transporter's Tariff as the Person to whom payment of amounts invoiced by Transporter shall be made; provided, however, the: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Transporter under this Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Transporter to any Person whom the Transporter has specified pursuant to said Section 6 as the Person to whom payment of amounts invoiced by Transporter shall be made.

Article 10 - Other Operating Provisions

(This Article to be utilized when necessary to specify other operating provisions).

Article 11 - Exhibit A of Agreement, Rate Schedules and General Terms and Conditions

Shipper shall initiate a request for interruptible park and loan service by executing and delivering to Transporter one (1) or more Exhibit(s) A. Upon execution by Transporter, Shipper's Exhibit(s) A shall be incorporated in and made a part hereof.

Transporter's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit(s) A hereto are all applicable to this Agreement and are hereby incorporated in, and made a part of, this Agreement.

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT

IN WITNESS WHEREOF, The parties hereto have caused this Agreement to be duly executed as of the day and year first set forth above.

TransCanada Alaska Company LLC

By: ______________________________

Title: ___________________________

By: ______________________________

Title: ___________________________

ATTEST: (NAME OF SHIPPER)

______________________________ By: ______________________________

Title: ___________________________

Contract #_________

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT
EXHIBIT A TO RATE SCHEDULE PARK AND LOAN (PAL) AGREEMENT

TRANSPORTER - TransCanada Alaska Company LLC

TRANSPORTER'S ADDRESS -

SHIPPER -

SHIPPER'S ADDRESS -

Check Applicable Rate:
Maximum Commodity Rate: ______

Discounted Rate: ______
Description of Discounted Rate:[1/]_________________________

Negotiated Rate: _____

Park and Loan (PAL) Service Options:

Commencement of Service Date	Termination of service Date	Maximum PAL Quantity Acf	Daily Rate Per Mcf	Park Points	Loan Points
_______	_______	_____	______	_____	_____

Maximum Cumulative Tolerance Level: ________Mcf

Description of Negotiated Rate: ______________________________

1/ See Section 39 of the General Terms and Conditions of Transporter's Tariff for description of various types of discount rates.

This Exhibit A is made and entered into as of ________, 20__.

TransCanada Alaska Company LLC
RATE SCHEDULE PARK AND LOAN (PAL)
AGREEMENT

EXHIBIT A TO RATE SCHEDULE PARK AND LOAN (PAL) AGREEMENT (Continued)

TransCanada Alaska Company LLC

By: ______________________________

Title: ___________________________

By: ______________________________

Title: ___________________________

ATTEST: (NAME OF SHIPPER)

______________________________ By: ______________________________

Title: ___________________________

Appendix C

Exhibit J
Alaska-Canada Pipeline – Recourse and Negotiated Rate Details

RECOURSE RATE MODEL OUTPUT

(25 Year Contract Term)
Alaska Canada Pipeline

Alaska Pipeline Project - Alaska Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these outputs. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	5	-	1	0	6
2	2011	6	4	-	1	1	11
3	2012	11	4	-	1	1	17
4	2013	17	5	-	1	2	24
5	2014	24	6	0	1	2	33
6	2015	33	24	0	4	4	65
7	2016	65	13	0	2	6	87
8	2017	87	184	4	33	16	325
9	2018	325	188	4	34	35	586
10	2019	586	9	0	2	48	646
11	2020	646	3	-	1	-	650
12	2021	650	0	-	0	-	650
			446	9	81	115	

Alaska Pipeline Project - Alaska Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these outputs. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	6	-	1	0	7
2	2011	7	5	-	1	1	14
3	2012	14	5	-	1	1	22
4	2013	22	6	-	1	2	31
5	2014	31	7	0	1	3	43
6	2015	43	31	1	6	5	86
7	2016	86	18	0	3	8	115
8	2017	115	241	5	43	22	426
9	2018	426	246	5	44	48	769
10	2019	769	12	0	2	65	849
11	2020	849	5	-	1	-	855
12	2021	855	1	-	0	-	855
			583	11	106	156	

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Cost of Service Details

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Operation and Maintenance Expenses	4	4
2	Negative salvage	0	0
3	Depreciation Expense	26	34
4	Taxes Other Than Income Taxes	12	16
5	Federal Income Taxes	16	20
6	State Income Taxes	4	6
7	Return	49	67
8	Net Cost of Service	112	148
9	Cost of Service – Demand Component	112	148
10	Cost of Service – Commodity Component		
11	Demand Billing Determinants - (1100 MMcf/d*1.000 Btu/cf*12)	13,200	13,200
12	Commodity Billing Determinants		
13	Reservation Rate - ($/MMBtu)	8.45	11.19
14	Commodity Rate ($/MMBtu)		
15	IT/AOS/PAL - 100% Load Factor Rate ($/MMBtu)	0.28	0.37

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Depreciation Expense

		2020	
Line No.	Description	$32B Capex	$41B Capex
1	Basis - Straight Line		
2	Depreciation Rate	4.00%	4.00%
3	Depreciation Expense	26	34

Alaska Pipeline Project - Alaska-Canada Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Income Taxes

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Return	49	67
2	Less: Interest Expense	23	33
3	Net Equity Return	26	35
4	Depreciation of Equity AFUDC	3	3
5	Total Federal Tax Basis	29	38
6	Federal Income Tax Factor	53.85%	53.85%
7	Federal Income Taxes (Tax Factor = .5385)	16	20
8	Total State Taxable Income (Line 3 + Line 7)	42	55
9	State Income Tax Factor	10.38%	10.38%
10	State Income Taxes	4	6
11	Total Income Taxes	20	26

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information.

Numbers may not add due to rounding.

Zone 1 - Point Thomson

US$Millions (Nominal)

Rate Base & Rate of Return

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Gas Plant In Service	646	849
	Additions during the year	4	5
2	Reserve for Depreciation	(26)	(34)
3	Net Plant	624	820
4	Working Capital	1	1
5	Accumulated Deferred Income Taxes	(19)	(25)
6	Rate Base	606	796
7	Rate of Return	7.90%	8.19%
8	Return	49	67

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information.

Numbers may not add due to rounding.

Zone 1 - Point Thomson

US$Millions (Nominal)

Capital Structure & Rate of Return

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Long-Term Debt	70.00%	70.00%
2	Common Equity	30.00%	30.00%
3	Total	100.00%	100.00%
4	Interest rate	5.29%	5.70%
5	ROE	14.00%	14.00%
6	Rate of Return	7.90%	8.19%

Alaska Pipeline Project - Alaska Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	106	-	38	6	150
2	2011	150	113	-	41	18	322
3	2012	322	89	-	32	31	475
4	2013	475	113	-	41	45	673
5	2014	673	291	6	100	71	1,141
6	2015	1,141	888	18	304	142	2,492
7	2016	2,492	2,399	48	821	333	6,092
8	2017	6,092	2,336	47	799	622	9,896
9	2018	9,896	1,954	39	668	916	13,473
10	2019	13,473	1,090	22	373	1,173	16,130
11	2020	16,130	372	-	135	-	16,637
12	2021	16,637	9	-	3	-	16,650
			9,760	179	3,355	3,355	

Alaska Pipeline Project - Alaska Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	139	-	50	8	197
2	2011	197	147	-	53	24	422
3	2012	422	117	-	42	42	623
4	2013	623	148	-	53	61	884
5	2014	884	381	8	130	96	1,499
6	2015	1,499	1,160	23	397	192	3,271
7	2016	3,271	3,135	63	1,072	451	7,992
8	2017	7,992	3,053	61	1,044	842	12,992
9	2018	12,992	2,554	51	874	1,240	17,711
10	2019	17,711	1,424	28	487	1,589	21,239
11	2020	21,239	486	-	176	-	21,902
12	2021	21,902	12	-	4	-	21,918
			12,755	234	4,384	4,545	

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP

US$Millions (Nominal)

Cost of Service Details

Line No.	Description	2020 $32B Capex	 $41B Capex
1	Operation and Maintenance Expenses	312	312
2	Negative salvage	68	68
3	Depreciation Expense	666	877
4	Taxes Other Than Income Taxes	306	403
5	Federal Income Taxes	399	524
6	State Income Taxes	110	145
7	Return	1,251	1,706
8	Net Cost of Service	3,112	4,035
9	Cost of Service – Demand Component	3,112	4,035
10	Cost of Service – Commodity Component		
11	Demand Billing Determinants - (4500 MMcf/d*1.118 Btu/cf*12)	54,000	54,000
12	Commodity Billing Determinants		
13	Reservation Rate - ($/MMbtu)	57.62	74.72
14	Commodity Rate ($/MMbtu)		
15	IT/AOS/PAL - 100% Load Factor Rate ($/MMBtu)	1.89	2.46

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP

US$Millions (Nominal)

Depreciation Expense

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Basis - Straight Line		
2	Depreciation Rate	4.00%	4.00%
3	Depreciation Expense	666	877

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP

US$Millions (Nominal)

Income Taxes

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Return	1,251	1,706
2	Less: Interest Expense	586	831
3	Net Equity Return	665	875
4	Depreciation of Equity AFUDC	76	99
5	Total Federal Tax Basis	740	974
6	Federal Income Tax Factor	53.85%	53.85%
7	Federal Income Taxes (Tax Factor = .5385)	399	524
8	Total State Taxable Income (Line 3 + Line 7)	1,063	1,399
9	State Income Tax Factor	10.38%	10.38%
10	State Income Taxes	110	145
11	Total Income Taxes	509	670

Alaska Pipeline Project - Alaska-Canada Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)

Rate Base & Rate of Return

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Gas Plant In Service	16,130	21,239
	Additions during the year	507	663
2	Reserve for Depreciation	(666)	(877)
3	Net Plant	15,971	21,025
4	Working Capital	26	26
5	Accumulated Deferred Income Taxes	(482)	(635)
6	Rate Base	15,515	20,416
7	Rate of Return	7.90%	8.19%
8	Return	1,251	1,706

Alaska Pipeline Project - Alaska-Canada Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)

Capital Structure & Rate of Return

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Long-Term Debt	70.00%	70.00%
2	Common Equity	30.00%	30.00%
3	Total	100.00%	100.00%
4	Interest rate	5.29%	5.70%
5	ROE	14.00%	14.00%
6	Rate of Return	7.90%	8.19%

Alaska Pipeline Project - Alaska Canada Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	97	-	20	5	122
2	2011	122	97	-	20	14	254
3	2012	254	93	-	19	25	391
4	2013	391	149	-	31	39	609
5	2014	609	151	3	28	57	849
6	2015	849	750	15	140	106	1,860
7	2016	1,860	277	6	52	166	2,359
8	2017	2,359	1,532	31	286	269	4,477
9	2018	4,477	4,648	93	869	591	10,677
10	2019	10,677	1,928	39	360	965	13,969
11	2020	13,969	77	-	16	-	14,062
12	2021	14,062	9	-	2	-	14,073
			9,807	186	1,844	2,237	

Alaska Pipeline Project - Alaska Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	127	-	26	6	160
2	2011	160	127	-	26	19	333
3	2012	333	121	-	25	34	513
4	2013	513	194	-	40	53	800
5	2014	800	197	4	37	77	1,116
6	2015	1,116	980	20	183	144	2,442
7	2016	2,442	361	7	68	224	3,103
8	2017	3,103	2,001	40	374	364	5,883
9	2018	5,883	6,074	121	1,135	801	14,014
10	2019	14,014	2,519	50	471	1,307	18,361
11	2020	18,361	101	-	21	-	18,483
12	2021	18,483	12	-	2	-	18,497
			12,816	243	2,409	3,030	

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Cost of Service Details

Line No.	Description	2020 $32B Capex	 $41B Capex
1	Operation and Maintenance Expenses	85	85
2	Negative salvage	12	12
3	Depreciation Expense	563	740
4	Taxes Other Than Income Taxes	259	339
5	Federal Income Taxes	334	438
6	State Income Taxes	94	123
7	Return	1,072	1,459
8	Net Cost of Service	2,418	3,197
9	Cost of Service – Demand Component (In-State)	132	174
10	Cost of Service – Demand Component (Export)	2,286	3,022
11	Cost of Service – Commodity Component		
12	Demand Billing Determinants - In-State (335 MMcf/d*1.118 Btu/cf*12)	4,500	4,500
13	Demand Billing Determinants - Export (4,165 MMcf/d*1.118 Btu/cf*12)	55,872	55,872
14	Commodity Billing Determinants		
15	Reservation Rate - ($/MMBtu; In-State)	29.28	38.72
16	Reservation Rate - ($/MMBtu; Export)	40.91	54.10
17	Commodity Rate		
18	IT/AOS - 100% Load Factor Rate ($/MMBtu; In-State)	0.96	1.27
19	IT/AOS/PAL - 100% Load Factor Rate ($/MMBtu; Export)	1.35	1.78

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Depreciation Expense

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Basis - Straight Line		
2	Depreciation Rate	4.00%	4.00%
3	Depreciation Expense	563	740

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Income Taxes

Line No.	Description	2020 $32B Capex	 $41B Capex
1	Return	1,072	1,459
2	Less: Interest Expense	502	711
3	Net Equity Return	569	748
4	Depreciation of Equity AFUDC	50	66
5	Total Federal Tax Basis	620	814
6	Federal Income Tax Factor	53.85%	53.85%
7	Federal Income Taxes (Tax Factor = .5385)	334	438
8	Total State Taxable Income (Line 3 + Line 7)	903	1,186
9	State Income Tax Factor	10.38%	10.38%
10	State Income Taxes	94	123
11	Total Income Taxes	427	561

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Rate Base & Rate of Return

Line No.	Description	2020 $32B Capex	2020 $41B Capex
1	Gas Plant In Service	13,969	18,361
	Additions during the year	93	122
2	Reserve for Depreciation	(563)	(740)
3	Net Plant	13,499	17,743
4	Working Capital	56	56
5	Accumulated Deferred Income Taxes	(410)	(538)
6	Rate Base	13,146	17,261
7	Rate of Return	7.90%	8.19%
8	Return	1,072	1,459

Alaska Pipeline Project - Alaska-Canada Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Capital Structure & Rate of Return

Line No.	Description	2020 $32B Capex	 $41B Capex
1	Long-Term Debt	70.00%	70.00%
2	Common Equity	30.00%	30.00%
3	Total	100.00%	100.00%
4	Interest rate	5.29%	5.70%
5	ROE	14.00%	14.00%
6	Rate of Return	7.90%	8.19%

NEGOTIATED RATE MODEL OUTPUT

(20 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	5	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	636
2020	636	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	636	4	(1)	640	1	(15)	626
2	2021	640	1	(4)	635	1	(28)	609
3	2022	635	-	(6)	629	1	(40)	590
4	2023	629	-	(8)	621	1	(53)	570
5	2024	621	-	(10)	612	1	(65)	548
6	2025	612	-	(12)	600	1	(76)	525
7	2026	600	-	(14)	585	1	(87)	499
8	2027	585	-	(17)	569	1	(98)	472
9	2028	569	-	(19)	549	1	(108)	443
10	2029	549	-	(22)	527	1	(117)	411
11	2030	527	-	(25)	502	1	(126)	377
12	2031	502	-	(29)	473	1	(134)	341
13	2032	473	-	(32)	441	1	(141)	301
14	2033	441	-	(36)	406	1	(148)	259
15	2034	406	-	(39)	366	1	(142)	225
16	2035	366	-	(42)	324	1	(125)	200
17	2036	324	-	(45)	279	1	(108)	172
18	2037	279	-	(48)	232	1	(89)	143
19	2038	232	-	(50)	181	1	(69)	113
20	2039	181	-	(53)	128	1	(48)	80
			5	(513)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	(0)	842	1	(19)	824
2	2021	842	1	(5)	837	1	(36)	802
3	2022	837	-	(7)	830	1	(53)	778
4	2023	830	-	(10)	820	1	(69)	752
5	2024	820	-	(12)	808	1	(85)	724
6	2025	808	-	(15)	793	1	(100)	694
7	2026	793	-	(18)	775	1	(115)	661
8	2027	775	-	(21)	754	1	(129)	626
9	2028	754	-	(25)	729	1	(142)	588
10	2029	729	-	(29)	700	1	(154)	547
11	2030	700	-	(33)	667	1	(166)	502
12	2031	667	-	(37)	630	1	(177)	454
13	2032	630	-	(42)	587	1	(187)	402
14	2033	587	-	(47)	540	1	(195)	346
15	2034	540	-	(52)	488	1	(189)	299
16	2035	488	-	(56)	431	1	(167)	265
17	2036	431	-	(60)	371	1	(144)	229
18	2037	371	-	(64)	308	1	(119)	190
19	2038	308	-	(68)	240	1	(92)	149
20	2039	240	-	(72)	168	1	(64)	105
			6	(674)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	1	4	0	12	15	78
2	2021	25	19	4	4	0	12	13	78
3	2022	24	18	6	4	0	12	13	78
4	2023	24	17	8	4	0	12	13	78
5	2024	23	17	10	4	1	11	12	78
6	2025	22	16	12	4	1	11	12	78
7	2026	21	15	14	4	1	11	11	78
8	2027	20	15	17	4	1	11	11	78
9	2028	19	14	19	5	1	10	11	78
10	2029	17	13	22	5	1	10	10	78
11	2030	16	12	25	5	1	10	10	78
12	2031	15	11	29	5	1	9	9	78
13	2032	13	10	32	5	1	9	8	78
14	2033	11	8	36	5	1	9	8	78
15	2034	10	7	39	5	1	8	7	78
16	2035	9	6	42	5	1	8	7	78
17	2036	8	6	45	5	1	8	6	78
18	2037	6	5	48	6	1	7	6	78
19	2038	5	4	50	6	1	7	5	78
20	2039	4	3	53	6	1	6	5	78
		317	236	513	95	12	194	190	1,556

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	27	0	4	0	16	19	102
2	2021	35	24	5	4	0	16	17	102
3	2022	34	24	7	4	0	16	17	102
4	2023	33	23	10	4	0	15	17	102
5	2024	32	22	12	4	1	15	16	102
6	2025	31	21	15	4	1	15	16	102
7	2026	30	20	18	4	1	14	15	102
8	2027	28	19	21	4	1	14	15	102
9	2028	26	18	25	5	1	14	14	102
10	2029	25	17	29	5	1	13	13	102
11	2030	23	16	33	5	1	13	13	102
12	2031	21	14	37	5	1	12	12	102
13	2032	19	13	42	5	1	12	11	102
14	2033	16	11	47	5	1	12	10	102
15	2034	14	10	52	5	1	11	9	102
16	2035	12	8	56	5	1	11	9	102
17	2036	11	7	60	5	1	10	8	102
18	2037	9	6	64	6	1	9	8	102
19	2038	7	5	68	6	1	9	7	102
20	2039	6	4	72	6	1	8	6	102
		448	312	674	95	12	255	251	2,047

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	78	1,100	1.000	0.19
2	2021	78	1,100	1.000	0.19
3	2022	78	1,100	1.000	0.19
4	2023	78	1,100	1.000	0.19
5	2024	78	1,100	1.000	0.19
6	2025	78	1,100	1.000	0.19
7	2026	78	1,100	1.000	0.19
8	2027	78	1,100	1.000	0.19
9	2028	78	1,100	1.000	0.19
10	2029	78	1,100	1.000	0.19
11	2030	78	1,100	1.000	0.19
12	2031	78	1,100	1.000	0.19
13	2032	78	1,100	1.000	0.19
14	2033	78	1,100	1.000	0.19
15	2034	78	1,100	1.000	0.19
16	2035	78	1,100	1.000	0.19
17	2036	78	1,100	1.000	0.19
18	2037	78	1,100	1.000	0.19
19	2038	78	1,100	1.000	0.19
20	2039	78	1,100	1.000	0.19

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	102	1,100	1.000	0.25
2	2021	102	1,100	1.000	0.25
3	2022	102	1,100	1.000	0.25
4	2023	102	1,100	1.000	0.25
5	2024	102	1,100	1.000	0.25
6	2025	102	1,100	1.000	0.25
7	2026	102	1,100	1.000	0.25
8	2027	102	1,100	1.000	0.25
9	2028	102	1,100	1.000	0.25
10	2029	102	1,100	1.000	0.25
11	2030	102	1,100	1.000	0.25
12	2031	102	1,100	1.000	0.25
13	2032	102	1,100	1.000	0.25
14	2033	102	1,100	1.000	0.25
15	2034	102	1,100	1.000	0.25
16	2035	102	1,100	1.000	0.25
17	2036	102	1,100	1.000	0.25
18	2037	102	1,100	1.000	0.25
19	2038	102	1,100	1.000	0.25
20	2039	102	1,100	1.000	0.25

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.1%	0.1%
2	2021	0.7%	0.8%
3	2022	0.9%	1.8%
4	2023	1.2%	3.0%
5	2024	1.5%	4.5%
6	2025	1.9%	6.4%
7	2026	2.2%	8.6%
8	2027	2.6%	11.2%
9	2028	3.0%	14.2%
10	2029	3.5%	17.7%
11	2030	3.9%	21.6%
12	2031	4.5%	26.1%
13	2032	5.0%	31.1%
14	2033	5.6%	36.7%
15	2034	6.1%	42.8%
16	2035	6.6%	49.4%
17	2036	7.0%	56.4%
18	2037	7.4%	63.8%
19	2038	7.9%	71.7%
20	2039	8.3%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.0%	0.0%
2	2021	0.6%	0.6%
3	2022	0.8%	1.5%
4	2023	1.1%	2.6%
5	2024	1.4%	4.0%
6	2025	1.8%	5.8%
7	2026	2.1%	8.0%
8	2027	2.5%	10.5%
9	2028	3.0%	13.5%
10	2029	3.4%	16.9%
11	2030	3.9%	20.8%
12	2031	4.4%	25.2%
13	2032	5.0%	30.2%
14	2033	5.6%	35.8%
15	2034	6.2%	42.1%
16	2035	6.7%	48.7%
17	2036	7.1%	55.9%
18	2037	7.6%	63.4%
19	2038	8.0%	71.5%
20	2039	8.5%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	130	2,467
2016	2,467	2,399	48	821	308	6,042
2017	6,042	2,336	47	799	573	9,798
2018	9,798	1,954	39	668	840	13,299
2019	13,299	1,090	22	373	1,067	15,851
2020	15,851	372	-	135	-	16,358
2021	16,358	9	-	3	-	16,370
		9,760	179	3,355	3,076	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	874
2014	874	381	8	130	88	1,481
2015	1,481	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	776	12,859
2018	12,859	2,554	51	874	1,138	17,475
2019	17,475	1,424	28	487	1,446	20,861
2020	20,861	486	-	176	-	21,524
2021	21,524	12	-	4	-	21,540
		12,755	234	4,384	4,167	

Alaska Pipeline Project - Alaska-Canada Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,851	507	(51)	16,307	26	(368)	15,966
2	2021	16,307	13	(92)	16,227	29	(700)	15,556
3	2022	16,227	-	(135)	16,092	28	(1,024)	15,097
4	2023	16,092	-	(192)	15,900	28	(1,339)	14,589
5	2024	15,900	-	(253)	15,647	27	(1,645)	14,029
6	2025	15,647	-	(315)	15,332	26	(1,940)	13,419
7	2026	15,332	-	(375)	14,957	26	(2,223)	12,761
8	2027	14,957	-	(442)	14,515	26	(2,493)	12,048
9	2028	14,515	-	(512)	14,003	26	(2,749)	11,280
10	2029	14,003	-	(586)	13,417	26	(2,990)	10,453
11	2030	13,417	-	(668)	12,749	26	(3,216)	9,559
12	2031	12,749	-	(749)	12,000	26	(3,424)	8,603
13	2032	12,000	-	(833)	11,167	27	(3,613)	7,582
14	2033	11,167	-	(925)	10,242	28	(3,782)	6,488
15	2034	10,242	-	(1,005)	9,237	28	(3,538)	5,727
16	2035	9,237	-	(1,067)	8,170	29	(3,126)	5,073
17	2036	8,170	-	(1,128)	7,042	29	(2,688)	4,384
18	2037	7,042	-	(1,189)	5,853	30	(2,225)	3,658
19	2038	5,853	-	(1,256)	4,597	31	(1,735)	2,893
20	2039	4,597	-	(1,323)	3,274	31	(1,217)	2,089
			520	(13,096)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,861	663	(44)	21,480	26	(483)	21,022
2	2021	21,480	16	(107)	21,389	29	(921)	20,497
3	2022	21,389	-	(163)	21,226	28	(1,347)	19,907
4	2023	21,226	-	(235)	20,991	28	(1,763)	19,255
5	2024	20,991	-	(313)	20,678	27	(2,166)	18,538
6	2025	20,678	-	(393)	20,285	26	(2,555)	17,755
7	2026	20,285	-	(473)	19,811	26	(2,929)	16,908
8	2027	19,811	-	(563)	19,248	26	(3,287)	15,987
9	2028	19,248	-	(656)	18,593	26	(3,627)	14,992
10	2029	18,593	-	(755)	17,838	26	(3,947)	13,917
11	2030	17,838	-	(866)	16,972	26	(4,246)	12,751
12	2031	16,972	-	(978)	15,994	26	(4,523)	11,498
13	2032	15,994	-	(1,093)	14,901	27	(4,775)	10,153
14	2033	14,901	-	(1,222)	13,679	28	(5,001)	8,706
15	2034	13,679	-	(1,337)	12,342	28	(4,736)	7,635
16	2035	12,342	-	(1,427)	10,915	29	(4,183)	6,761
17	2036	10,915	-	(1,514)	9,401	29	(3,594)	5,837
18	2037	9,401	-	(1,601)	7,800	30	(2,970)	4,860
19	2038	7,800	-	(1,697)	6,102	31	(2,306)	3,827
20	2039	6,102	-	(1,794)	4,308	31	(1,602)	2,737
			679	(17,232)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	627	525	51	312	68	315	369	2,267
2	2021	643	473	92	346	69	309	335	2,267
3	2022	625	460	135	342	71	306	329	2,267
4	2023	605	445	192	331	72	299	322	2,267
5	2024	584	429	253	320	74	293	314	2,267
6	2025	560	412	315	313	75	287	305	2,267
7	2026	534	393	375	312	77	280	296	2,267
8	2027	506	372	442	312	79	271	285	2,267
9	2028	476	350	512	311	80	265	274	2,267
10	2029	443	326	586	310	82	258	261	2,267
11	2030	408	300	668	310	84	249	248	2,267
12	2031	370	272	749	317	86	240	233	2,267
13	2032	330	243	833	323	88	233	217	2,267
14	2033	287	211	925	331	90	224	200	2,267
15	2034	249	183	1,005	338	92	214	185	2,267
16	2035	220	162	1,067	345	94	205	174	2,267
17	2036	193	142	1,128	353	96	192	164	2,267
18	2037	164	121	1,189	361	98	183	152	2,267
19	2038	134	98	1,256	369	100	170	140	2,267
20	2039	102	75	1,323	377	102	161	128	2,267
		8,060	5,992	13,096	6,632	1,675	4,954	4,931	45,341

Alaska Pipeline Project - Alaska-Canada Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	883	691	44	312	68	415	485	2,897
2	2021	905	623	107	346	69	407	441	2,897
3	2022	881	606	163	342	71	403	432	2,897
4	2023	854	587	235	331	72	394	423	2,897
5	2024	824	567	313	320	74	386	414	2,897
6	2025	791	544	393	313	75	378	402	2,897
7	2026	756	520	473	312	77	369	390	2,897
8	2027	717	493	563	312	79	357	376	2,897
9	2028	675	465	656	311	80	349	362	2,897
10	2029	630	434	755	310	82	340	346	2,897
11	2030	581	400	866	310	84	328	328	2,897
12	2031	529	364	978	317	86	315	309	2,897
13	2032	472	325	1,093	323	88	307	289	2,897
14	2033	411	283	1,222	331	90	295	267	2,897
15	2034	356	245	1,337	338	92	282	247	2,897
16	2035	314	216	1,427	345	94	270	232	2,897
17	2036	275	189	1,514	353	96	253	218	2,897
18	2037	233	160	1,601	361	98	241	203	2,897
19	2038	189	130	1,697	369	100	224	187	2,897
20	2039	143	98	1,794	377	102	212	171	2,897
		11,418	7,941	17,232	6,632	1,675	6,524	6,522	57,944

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,267	4,500	1.118	1.23
2	2021	2,267	4,500	1.118	1.23
3	2022	2,267	4,500	1.118	1.23
4	2023	2,267	4,500	1.118	1.23
5	2024	2,267	4,500	1.118	1.23
6	2025	2,267	4,500	1.118	1.23
7	2026	2,267	4,500	1.118	1.23
8	2027	2,267	4,500	1.118	1.23
9	2028	2,267	4,500	1.118	1.23
10	2029	2,267	4,500	1.118	1.23
11	2030	2,267	4,500	1.118	1.23
12	2031	2,267	4,500	1.118	1.23
13	2032	2,267	4,500	1.118	1.23
14	2033	2,267	4,500	1.118	1.23
15	2034	2,267	4,500	1.118	1.23
16	2035	2,267	4,500	1.118	1.23
17	2036	2,267	4,500	1.118	1.23
18	2037	2,267	4,500	1.118	1.23
19	2038	2,267	4,500	1.118	1.23
20	2039	2,267	4,500	1.118	1.23

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,897	4,500	1.118	1.58
2	2021	2,897	4,500	1.118	1.58
3	2022	2,897	4,500	1.118	1.58
4	2023	2,897	4,500	1.118	1.58
5	2024	2,897	4,500	1.118	1.58
6	2025	2,897	4,500	1.118	1.58
7	2026	2,897	4,500	1.118	1.58
8	2027	2,897	4,500	1.118	1.58
9	2028	2,897	4,500	1.118	1.58
10	2029	2,897	4,500	1.118	1.58
11	2030	2,897	4,500	1.118	1.58
12	2031	2,897	4,500	1.118	1.58
13	2032	2,897	4,500	1.118	1.58
14	2033	2,897	4,500	1.118	1.58
15	2034	2,897	4,500	1.118	1.58
16	2035	2,897	4,500	1.118	1.58
17	2036	2,897	4,500	1.118	1.58
18	2037	2,897	4,500	1.118	1.58
19	2038	2,897	4,500	1.118	1.58
20	2039	2,897	4,500	1.118	1.58

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.3%	0.3%
2	2021	0.6%	0.9%
3	2022	0.8%	1.7%
4	2023	1.2%	2.9%
5	2024	1.5%	4.4%
6	2025	1.9%	6.3%
7	2026	2.3%	8.6%
8	2027	2.7%	11.3%
9	2028	3.1%	14.5%
10	2029	3.6%	18.0%
11	2030	4.1%	22.1%
12	2031	4.6%	26.7%
13	2032	5.1%	31.8%
14	2033	5.6%	37.4%
15	2034	6.1%	43.6%
16	2035	6.5%	50.1%
17	2036	6.9%	57.0%
18	2037	7.3%	64.2%
19	2038	7.7%	71.9%
20	2039	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.2%	0.2%
2	2021	0.5%	0.7%
3	2022	0.8%	1.5%
4	2023	1.1%	2.6%
5	2024	1.5%	4.0%
6	2025	1.8%	5.8%
7	2026	2.2%	8.0%
8	2027	2.6%	10.6%
9	2028	3.0%	13.7%
10	2029	3.5%	17.2%
11	2030	4.0%	21.2%
12	2031	4.5%	25.7%
13	2032	5.1%	30.8%
14	2033	5.7%	36.5%
15	2034	6.2%	42.7%
16	2035	6.6%	49.3%
17	2036	7.0%	56.4%
18	2037	7.4%	63.8%
19	2038	7.9%	71.7%
20	2039	8.3%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	52	838
2015	838	750	15	140	97	1,840
2016	1,840	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,420
2018	4,420	4,648	93	869	544	10,573
2019	10,573	1,928	39	360	885	13,785
2020	13,785	77	-	16	-	13,878
2021	13,878	9	-	2	-	13,890
		9,807	186	1,844	2,053	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,057
2017	3,057	2,001	40	374	333	5,806
2018	5,806	6,074	121	1,135	736	13,873
2019	13,873	2,519	50	471	1,199	18,113
2020	18,113	101	-	21	-	18,234
2021	18,234	12	-	2	-	18,249
		12,816	243	2,409	2,781	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,785	93	(19)	13,859	56	(316)	13,600
2	2021	13,859	11	(96)	13,775	57	(599)	13,233
3	2022	13,775	-	(130)	13,645	57	(874)	12,828
4	2023	13,645	-	(170)	13,475	57	(1,141)	12,391
5	2024	13,475	-	(213)	13,263	57	(1,400)	11,920
6	2025	13,263	-	(258)	13,004	57	(1,649)	11,413
7	2026	13,004	-	(308)	12,697	57	(1,888)	10,867
8	2027	12,697	-	(363)	12,334	58	(2,116)	10,276
9	2028	12,334	-	(419)	11,915	58	(2,332)	9,641
10	2029	11,915	-	(480)	11,435	58	(2,536)	8,957
11	2030	11,435	-	(547)	10,887	58	(2,726)	8,220
12	2031	10,887	-	(620)	10,268	58	(2,901)	7,425
13	2032	10,268	-	(695)	9,573	59	(3,060)	6,571
14	2033	9,573	-	(778)	8,795	59	(3,203)	5,651
15	2034	8,795	-	(852)	7,943	59	(3,019)	4,983
16	2035	7,943	-	(911)	7,031	59	(2,673)	4,418
17	2036	7,031	-	(970)	6,061	59	(2,304)	3,817
18	2037	6,061	-	(1,029)	5,032	60	(1,913)	3,179
19	2038	5,032	-	(1,094)	3,938	60	(1,497)	2,501
20	2039	3,938	-	(1,160)	2,778	60	(1,056)	1,782
			104	(11,112)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,113	122	(7)	18,227	56	(415)	17,869
2	2021	18,227	15	(107)	18,135	57	(786)	17,406
3	2022	18,135	-	(152)	17,983	57	(1,148)	16,892
4	2023	17,983	-	(205)	17,777	57	(1,500)	16,335
5	2024	17,777	-	(262)	17,515	57	(1,840)	15,732
6	2025	17,515	-	(324)	17,191	57	(2,169)	15,080
7	2026	17,191	-	(390)	16,802	57	(2,484)	14,375
8	2027	16,802	-	(464)	16,338	58	(2,786)	13,610
9	2028	16,338	-	(540)	15,798	58	(3,072)	12,783
10	2029	15,798	-	(622)	15,176	58	(3,342)	11,892
11	2030	15,176	-	(714)	14,462	58	(3,594)	10,926
12	2031	14,462	-	(812)	13,649	58	(3,827)	9,881
13	2032	13,649	-	(915)	12,734	59	(4,039)	8,754
14	2033	12,734	-	(1,028)	11,706	59	(4,228)	7,537
15	2034	11,706	-	(1,133)	10,573	59	(4,021)	6,612
16	2035	10,573	-	(1,216)	9,357	59	(3,558)	5,858
17	2036	9,357	-	(1,297)	8,060	59	(3,065)	5,055
18	2037	8,060	-	(1,379)	6,681	60	(2,541)	4,200
19	2038	6,681	-	(1,470)	5,212	60	(1,982)	3,290
20	2039	5,212	-	(1,562)	3,650	60	(1,388)	2,322
			136	(14,599)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	540	452	19	85	12	268	316	1,692
2	2021	547	402	96	87	13	262	285	1,692
3	2022	532	391	130	89	13	260	279	1,692
4	2023	514	378	170	91	13	254	272	1,692
5	2024	496	365	213	93	14	249	264	1,692
6	2025	476	350	258	95	14	244	256	1,692
7	2026	454	334	308	97	14	238	247	1,692
8	2027	431	317	363	99	14	230	238	1,692
9	2028	406	299	419	101	15	225	227	1,692
10	2029	379	279	480	103	15	219	216	1,692
11	2030	350	258	547	106	15	211	204	1,692
12	2031	319	235	620	108	16	203	192	1,692
13	2032	285	210	695	110	16	198	178	1,692
14	2033	249	183	778	113	16	190	163	1,692
15	2034	217	160	852	115	17	182	150	1,692
16	2035	192	141	911	118	17	174	139	1,692
17	2036	168	124	970	120	18	163	130	1,692
18	2037	143	105	1,029	123	18	155	119	1,692
19	2038	116	85	1,094	126	18	145	109	1,692
20	2039	87	64	1,160	128	19	136	97	1,692
		6,902	5,132	11,112	2,105	307	4,207	4,080	33,845

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	758	594	7	85	12	352	415	2,223
2	2021	769	529	107	87	13	345	374	2,223
3	2022	748	514	152	89	13	341	366	2,223
4	2023	724	498	205	91	13	334	357	2,223
5	2024	699	481	262	93	14	327	347	2,223
6	2025	672	462	324	95	14	320	337	2,223
7	2026	642	442	390	97	14	313	326	2,223
8	2027	610	420	464	99	14	302	314	2,223
9	2028	575	396	540	101	15	295	300	2,223
10	2029	538	370	622	103	15	288	286	2,223
11	2030	497	342	714	106	15	278	271	2,223
12	2031	454	312	812	108	16	267	254	2,223
13	2032	406	280	915	110	16	260	236	2,223
14	2033	355	244	1,028	113	16	250	216	2,223
15	2034	308	212	1,133	115	17	239	199	2,223
16	2035	272	187	1,216	118	17	229	185	2,223
17	2036	238	164	1,297	120	18	215	172	2,223
18	2037	202	139	1,379	123	18	204	158	2,223
19	2038	163	112	1,470	126	18	190	144	2,223
20	2039	122	84	1,562	128	19	179	128	2,223
		9,752	6,783	14,599	2,105	307	5,528	5,386	44,461

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	92	375	0.67	1,600	4,656	0.94
2	2021	1.118	92	375	0.67	1,600	4,656	0.94
3	2022	1.118	92	375	0.67	1,600	4,656	0.94
4	2023	1.118	92	375	0.67	1,600	4,656	0.94
5	2024	1.118	92	375	0.67	1,600	4,656	0.94
6	2025	1.118	92	375	0.67	1,600	4,656	0.94
7	2026	1.118	92	375	0.67	1,600	4,656	0.94
8	2027	1.118	92	375	0.67	1,600	4,656	0.94
9	2028	1.118	92	375	0.67	1,600	4,656	0.94
10	2029	1.118	92	375	0.67	1,600	4,656	0.94
11	2030	1.118	92	375	0.67	1,600	4,656	0.94
12	2031	1.118	92	375	0.67	1,600	4,656	0.94
13	2032	1.118	92	375	0.67	1,600	4,656	0.94
14	2033	1.118	92	375	0.67	1,600	4,656	0.94
15	2034	1.118	92	375	0.67	1,600	4,656	0.94
16	2035	1.118	92	375	0.67	1,600	4,656	0.94
17	2036	1.118	92	375	0.67	1,600	4,656	0.94
18	2037	1.118	92	375	0.67	1,600	4,656	0.94
19	2038	1.118	92	375	0.67	1,600	4,656	0.94
20	2039	1.118	92	375	0.67	1,600	4,656	0.94

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	121	375	0.89	2,102	4,656	1.24
2	2021	1.118	121	375	0.89	2,102	4,656	1.24
3	2022	1.118	121	375	0.89	2,102	4,656	1.24
4	2023	1.118	121	375	0.89	2,102	4,656	1.24
5	2024	1.118	121	375	0.89	2,102	4,656	1.24
6	2025	1.118	121	375	0.89	2,102	4,656	1.24
7	2026	1.118	121	375	0.89	2,102	4,656	1.24
8	2027	1.118	121	375	0.89	2,102	4,656	1.24
9	2028	1.118	121	375	0.89	2,102	4,656	1.24
10	2029	1.118	121	375	0.89	2,102	4,656	1.24
11	2030	1.118	121	375	0.89	2,102	4,656	1.24
12	2031	1.118	121	375	0.89	2,102	4,656	1.24
13	2032	1.118	121	375	0.89	2,102	4,656	1.24
14	2033	1.118	121	375	0.89	2,102	4,656	1.24
15	2034	1.118	121	375	0.89	2,102	4,656	1.24
16	2035	1.118	121	375	0.89	2,102	4,656	1.24
17	2036	1.118	121	375	0.89	2,102	4,656	1.24
18	2037	1.118	121	375	0.89	2,102	4,656	1.24
19	2038	1.118	121	375	0.89	2,102	4,656	1.24
20	2039	1.118	121	375	0.89	2,102	4,656	1.24

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.1%	0.1%
2	2021	0.7%	0.8%
3	2022	0.9%	1.8%
4	2023	1.2%	3.0%
5	2024	1.5%	4.5%
6	2025	1.9%	6.4%
7	2026	2.2%	8.6%
8	2027	2.6%	11.2%
9	2028	3.0%	14.2%
10	2029	3.5%	17.7%
11	2030	3.9%	21.6%
12	2031	4.5%	26.1%
13	2032	5.0%	31.1%
14	2033	5.6%	36.7%
15	2034	6.1%	42.8%
16	2035	6.6%	49.4%
17	2036	7.0%	56.4%
18	2037	7.4%	63.8%
19	2038	7.9%	71.6%
20	2039	8.4%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.0%	0.0%
2	2021	0.6%	0.6%
3	2022	0.8%	1.5%
4	2023	1.1%	2.6%
5	2024	1.4%	4.0%
6	2025	1.8%	5.8%
7	2026	2.1%	7.9%
8	2027	2.5%	10.5%
9	2028	3.0%	13.4%
10	2029	3.4%	16.8%
11	2030	3.9%	20.8%
12	2031	4.5%	25.2%
13	2032	5.0%	30.2%
14	2033	5.6%	35.9%
15	2034	6.2%	42.1%
16	2035	6.7%	48.7%
17	2036	7.1%	55.8%
18	2037	7.6%	63.4%
19	2038	8.1%	71.4%
20	2039	8.6%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(21 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	5	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	636
2020	636	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	636	4	0	641	1	(15)	627
2	2021	641	1	(3)	638	1	(28)	611
3	2022	638	-	(5)	633	1	(40)	594
4	2023	633	-	(6)	627	1	(53)	575
5	2024	627	-	(8)	619	1	(65)	555
6	2025	619	-	(10)	609	1	(76)	534
7	2026	609	-	(12)	597	1	(88)	510
8	2027	597	-	(14)	583	1	(98)	485
9	2028	583	-	(17)	566	1	(109)	458
10	2029	566	-	(19)	546	1	(118)	429
11	2030	546	-	(22)	524	1	(127)	397
12	2031	524	-	(25)	498	1	(136)	363
13	2032	498	-	(29)	470	1	(144)	327
14	2033	470	-	(32)	437	1	(151)	288
15	2034	437	-	(36)	401	1	(156)	247
16	2035	401	-	(39)	362	1	(141)	223
17	2036	362	-	(42)	321	1	(124)	197
18	2037	321	-	(44)	277	1	(107)	171
19	2038	277	-	(47)	230	1	(89)	142
20	2039	230	-	(50)	180	1	(69)	112
21	2040	180	-	(53)	128	1	(48)	80
			5	(513)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	1	844	1	(19)	825
2	2021	844	1	(3)	840	1	(36)	805
3	2022	840	-	(5)	835	1	(53)	783
4	2023	835	-	(7)	828	1	(69)	760
5	2024	828	-	(10)	818	1	(85)	734
6	2025	818	-	(12)	806	1	(101)	706
7	2026	806	-	(15)	791	1	(115)	676
8	2027	791	-	(18)	772	1	(130)	644
9	2028	772	-	(22)	750	1	(143)	608
10	2029	750	-	(25)	725	1	(156)	570
11	2030	725	-	(29)	696	1	(168)	529
12	2031	696	-	(33)	663	1	(179)	484
13	2032	663	-	(38)	625	1	(190)	436
14	2033	625	-	(43)	583	1	(199)	384
15	2034	583	-	(48)	535	1	(208)	328
16	2035	535	-	(52)	483	1	(188)	296
17	2036	483	-	(56)	427	1	(166)	262
18	2037	427	-	(59)	368	1	(143)	227
19	2038	368	-	(63)	306	1	(118)	188
20	2039	306	-	(67)	239	1	(92)	148
21	2040	239	-	(71)	168	1	(64)	105
			6	(674)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(0)	4	0	12	15	77
2	2021	25	19	3	4	0	12	13	77
3	2022	25	18	5	4	0	12	13	77
4	2023	24	18	6	4	0	12	13	77
5	2024	23	17	8	4	0	11	12	77
6	2025	22	16	10	4	0	11	12	77
7	2026	21	16	12	4	1	11	12	77
8	2027	20	15	14	4	1	11	11	77
9	2028	19	14	17	5	1	10	11	77
10	2029	18	13	19	5	1	10	10	77
11	2030	17	12	22	5	1	10	10	77
12	2031	16	11	25	5	1	9	9	77
13	2032	14	10	29	5	1	9	9	77
14	2033	13	9	32	5	1	9	8	77
15	2034	11	8	36	5	1	8	7	77
16	2035	10	7	39	5	1	8	7	77
17	2036	9	6	42	5	1	8	6	77
18	2037	8	6	44	6	1	7	6	77
19	2038	6	5	47	6	1	7	6	77
20	2039	5	4	50	6	1	6	5	77
21	2040	4	3	53	6	1	6	5	77
		334	248	513	101	12	200	199	1,607

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	27	(1)	4	0	16	19	101
2	2021	36	24	3	4	0	16	17	101
3	2022	35	24	5	4	0	16	17	101
4	2023	34	23	7	4	0	15	17	101
5	2024	33	22	10	4	0	15	16	101
6	2025	31	22	12	4	0	15	16	101
7	2026	30	21	15	4	1	14	15	101
8	2027	29	20	18	4	1	14	15	101
9	2028	27	19	22	5	1	14	14	101
10	2029	26	18	25	5	1	13	14	101
11	2030	24	17	29	5	1	13	13	101
12	2031	22	15	33	5	1	12	12	101
13	2032	20	14	38	5	1	12	12	101
14	2033	18	12	43	5	1	12	11	101
15	2034	16	11	48	5	1	11	10	101
16	2035	14	9	52	5	1	11	9	101
17	2036	12	8	56	5	1	10	9	101
18	2037	11	7	59	6	1	9	8	101
19	2038	9	6	63	6	1	9	7	101
20	2039	7	5	67	6	1	8	7	101
21	2040	6	4	71	6	1	8	6	101
		473	329	674	101	12	263	263	2,115

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	77	1,100	1.000	0.19
2	2021	77	1,100	1.000	0.19
3	2022	77	1,100	1.000	0.19
4	2023	77	1,100	1.000	0.19
5	2024	77	1,100	1.000	0.19
6	2025	77	1,100	1.000	0.19
7	2026	77	1,100	1.000	0.19
8	2027	77	1,100	1.000	0.19
9	2028	77	1,100	1.000	0.19
10	2029	77	1,100	1.000	0.19
11	2030	77	1,100	1.000	0.19
12	2031	77	1,100	1.000	0.19
13	2032	77	1,100	1.000	0.19
14	2033	77	1,100	1.000	0.19
15	2034	77	1,100	1.000	0.19
16	2035	77	1,100	1.000	0.19
17	2036	77	1,100	1.000	0.19
18	2037	77	1,100	1.000	0.19
19	2038	77	1,100	1.000	0.19
20	2039	77	1,100	1.000	0.19
21	2040	77	1,100	1.000	0.19

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	101	1,100	1.000	0.25
2	2021	101	1,100	1.000	0.25
3	2022	101	1,100	1.000	0.25
4	2023	101	1,100	1.000	0.25
5	2024	101	1,100	1.000	0.25
6	2025	101	1,100	1.000	0.25
7	2026	101	1,100	1.000	0.25
8	2027	101	1,100	1.000	0.25
9	2028	101	1,100	1.000	0.25
10	2029	101	1,100	1.000	0.25
11	2030	101	1,100	1.000	0.25
12	2031	101	1,100	1.000	0.25
13	2032	101	1,100	1.000	0.25
14	2033	101	1,100	1.000	0.25
15	2034	101	1,100	1.000	0.25
16	2035	101	1,100	1.000	0.25
17	2036	101	1,100	1.000	0.25
18	2037	101	1,100	1.000	0.25
19	2038	101	1,100	1.000	0.25
20	2039	101	1,100	1.000	0.25
21	2040	101	1,100	1.000	0.25

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.5%	0.4%
3	2022	0.7%	1.1%
4	2023	1.0%	2.1%
5	2024	1.3%	3.3%
6	2025	1.6%	4.9%
7	2026	1.9%	6.8%
8	2027	2.3%	9.1%
9	2028	2.6%	11.7%
10	2029	3.0%	14.7%
11	2030	3.5%	18.2%
12	2031	4.0%	22.2%
13	2032	4.5%	26.7%
14	2033	5.0%	31.7%
15	2034	5.6%	37.3%
16	2035	6.1%	43.4%
17	2036	6.5%	49.9%
18	2037	6.9%	56.8%
19	2038	7.3%	64.1%
20	2039	7.7%	71.8%
21	2040	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.4%	0.2%
3	2022	0.6%	0.8%
4	2023	0.9%	1.7%
5	2024	1.2%	2.9%
6	2025	1.5%	4.3%
7	2026	1.8%	6.1%
8	2027	2.2%	8.3%
9	2028	2.6%	10.9%
10	2029	3.0%	13.9%
11	2030	3.5%	17.3%
12	2031	4.0%	21.3%
13	2032	4.5%	25.7%
14	2033	5.0%	30.8%
15	2034	5.7%	36.5%
16	2035	6.2%	42.6%
17	2036	6.6%	49.2%
18	2037	7.0%	56.2%
19	2038	7.5%	63.7%
20	2039	7.9%	71.6%
21	2040	8.4%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	130	2,467
2016	2,467	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,798
2018	9,798	1,954	39	668	840	13,300
2019	13,300	1,090	22	373	1,068	15,852
2020	15,852	372	-	135	-	16,359
2021	16,359	9	-	3	-	16,371
		9,760	179	3,355	3,077	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,481
2015	1,481	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,860
2018	12,860	2,554	51	874	1,138	17,476
2019	17,476	1,424	28	487	1,447	20,862
2020	20,862	486	-	176	-	21,525
2021	21,525	12	-	4	-	21,541
		12,755	234	4,384	4,168	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,852	507	(19)	16,340	26	(367)	15,999
2	2021	16,340	13	(58)	16,295	29	(700)	15,624
3	2022	16,295	-	(97)	16,198	28	(1,025)	15,201
4	2023	16,198	-	(151)	16,047	28	(1,342)	14,732
5	2024	16,047	-	(209)	15,838	27	(1,650)	14,215
6	2025	15,838	-	(267)	15,571	26	(1,948)	13,649
7	2026	15,571	-	(323)	15,248	26	(2,235)	13,039
8	2027	15,248	-	(386)	14,862	26	(2,510)	12,378
9	2028	14,862	-	(451)	14,411	26	(2,772)	11,664
10	2029	14,411	-	(520)	13,890	26	(3,021)	10,895
11	2030	13,890	-	(598)	13,293	26	(3,254)	10,064
12	2031	13,293	-	(673)	12,620	26	(3,472)	9,174
13	2032	12,620	-	(751)	11,869	27	(3,671)	8,224
14	2033	11,869	-	(837)	11,032	28	(3,853)	7,207
15	2034	11,032	-	(922)	10,110	28	(3,882)	6,256
16	2035	10,110	-	(990)	9,120	29	(3,500)	5,648
17	2036	9,120	-	(1,047)	8,072	29	(3,094)	5,007
18	2037	8,072	-	(1,104)	6,968	30	(2,666)	4,333
19	2038	6,968	-	(1,167)	5,802	31	(2,211)	3,622
20	2039	5,802	-	(1,229)	4,572	31	(1,730)	2,873
21	2040	4,572	-	(1,298)	3,274	32	(1,222)	2,085
			520	(13,097)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,862	663	(2)	21,523	26	(483)	21,066
2	2021	21,523	16	(61)	21,478	29	(920)	20,586
3	2022	21,478	-	(113)	21,365	28	(1,348)	20,045
4	2023	21,365	-	(181)	21,184	28	(1,766)	19,446
5	2024	21,184	-	(254)	20,930	27	(2,172)	18,785
6	2025	20,930	-	(329)	20,602	26	(2,566)	18,062
7	2026	20,602	-	(403)	20,198	26	(2,945)	17,279
8	2027	20,198	-	(487)	19,711	26	(3,310)	16,427
9	2028	19,711	-	(574)	19,137	26	(3,657)	15,506
10	2029	19,137	-	(666)	18,471	26	(3,987)	14,509
11	2030	18,471	-	(770)	17,701	26	(4,298)	13,429
12	2031	17,701	-	(874)	16,827	26	(4,587)	12,266
13	2032	16,827	-	(982)	15,845	27	(4,854)	11,018
14	2033	15,845	-	(1,101)	14,745	28	(5,096)	9,676
15	2034	14,745	-	(1,223)	13,521	28	(5,201)	8,349
16	2035	13,521	-	(1,322)	12,199	29	(4,690)	7,538
17	2036	12,199	-	(1,403)	10,796	29	(4,145)	6,680
18	2037	10,796	-	(1,485)	9,311	30	(3,568)	5,774
19	2038	9,311	-	(1,574)	7,737	31	(2,953)	4,815
20	2039	7,737	-	(1,665)	6,072	31	(2,301)	3,802
21	2040	6,072	-	(1,764)	4,308	32	(1,608)	2,732
			679	(17,233)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	628	525	19	312	64	316	368	2,233
2	2021	645	474	58	346	66	309	334	2,233
3	2022	629	462	97	342	67	306	328	2,233
4	2023	611	449	151	331	69	300	322	2,233
5	2024	591	434	209	320	70	294	315	2,233
6	2025	569	418	267	313	72	287	307	2,233
7	2026	545	400	323	312	73	281	298	2,233
8	2027	519	381	386	312	75	272	288	2,233
9	2028	491	361	451	311	77	265	278	2,233
10	2029	460	338	520	310	78	259	266	2,233
11	2030	428	314	598	310	80	249	254	2,233
12	2031	393	289	673	317	82	240	240	2,233
13	2032	355	261	751	323	84	234	225	2,233
14	2033	315	231	837	331	85	224	209	2,233
15	2034	275	202	922	338	87	215	194	2,233
16	2035	243	179	990	345	89	205	181	2,233
17	2036	217	160	1,047	353	91	193	171	2,233
18	2037	191	140	1,104	361	93	183	161	2,233
19	2038	162	119	1,167	369	95	171	150	2,233
20	2039	133	97	1,229	377	97	161	138	2,233
21	2040	101	74	1,298	385	99	148	126	2,233
		8,499	6,311	13,097	7,017	1,695	5,113	5,154	46,886

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	884	692	2	312	64	416	483	2,853
2	2021	908	625	61	346	66	408	440	2,853
3	2022	886	609	113	342	67	403	432	2,853
4	2023	861	592	181	331	69	395	424	2,853
5	2024	834	573	254	320	70	387	415	2,853
6	2025	803	553	329	313	72	378	405	2,853
7	2026	771	530	403	312	73	370	393	2,853
8	2027	735	506	487	312	75	358	381	2,853
9	2028	696	479	574	311	77	349	367	2,853
10	2029	655	450	666	310	78	341	352	2,853
11	2030	609	419	770	310	80	329	336	2,853
12	2031	560	385	874	317	82	316	319	2,853
13	2032	508	349	982	323	84	308	300	2,853
14	2033	451	310	1,101	331	85	295	279	2,853
15	2034	393	270	1,223	338	87	283	258	2,853
16	2035	346	238	1,322	345	89	270	241	2,853
17	2036	310	213	1,403	353	91	254	229	2,853
18	2037	272	187	1,485	361	93	241	215	2,853
19	2038	231	159	1,574	369	95	225	200	2,853
20	2039	188	129	1,665	377	97	212	185	2,853
21	2040	142	98	1,764	385	99	195	169	2,853
		12,044	8,368	17,233	7,017	1,695	6,733	6,820	59,911

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,233	4,500	1.118	1.22
2	2021	2,233	4,500	1.118	1.22
3	2022	2,233	4,500	1.118	1.22
4	2023	2,233	4,500	1.118	1.22
5	2024	2,233	4,500	1.118	1.22
6	2025	2,233	4,500	1.118	1.22
7	2026	2,233	4,500	1.118	1.22
8	2027	2,233	4,500	1.118	1.22
9	2028	2,233	4,500	1.118	1.22
10	2029	2,233	4,500	1.118	1.22
11	2030	2,233	4,500	1.118	1.22
12	2031	2,233	4,500	1.118	1.22
13	2032	2,233	4,500	1.118	1.22
14	2033	2,233	4,500	1.118	1.22
15	2034	2,233	4,500	1.118	1.22
16	2035	2,233	4,500	1.118	1.22
17	2036	2,233	4,500	1.118	1.22
18	2037	2,233	4,500	1.118	1.22
19	2038	2,233	4,500	1.118	1.22
20	2039	2,233	4,500	1.118	1.22
21	2040	2,233	4,500	1.118	1.22

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,853	4,500	1.118	1.55
2	2021	2,853	4,500	1.118	1.55
3	2022	2,853	4,500	1.118	1.55
4	2023	2,853	4,500	1.118	1.55
5	2024	2,853	4,500	1.118	1.55
6	2025	2,853	4,500	1.118	1.55
7	2026	2,853	4,500	1.118	1.55
8	2027	2,853	4,500	1.118	1.55
9	2028	2,853	4,500	1.118	1.55
10	2029	2,853	4,500	1.118	1.55
11	2030	2,853	4,500	1.118	1.55
12	2031	2,853	4,500	1.118	1.55
13	2032	2,853	4,500	1.118	1.55
14	2033	2,853	4,500	1.118	1.55
15	2034	2,853	4,500	1.118	1.55
16	2035	2,853	4,500	1.118	1.55
17	2036	2,853	4,500	1.118	1.55
18	2037	2,853	4,500	1.118	1.55
19	2038	2,853	4,500	1.118	1.55
20	2039	2,853	4,500	1.118	1.55
21	2040	2,853	4,500	1.118	1.55

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.1%	0.1%
2	2021	0.4%	0.5%
3	2022	0.6%	1.1%
4	2023	0.9%	2.0%
5	2024	1.3%	3.3%
6	2025	1.6%	4.9%
7	2026	2.0%	6.9%
8	2027	2.4%	9.2%
9	2028	2.8%	12.0%
10	2029	3.2%	15.2%
11	2030	3.7%	18.8%
12	2031	4.1%	22.9%
13	2032	4.6%	27.5%
14	2033	5.1%	32.6%
15	2034	5.6%	38.2%
16	2035	6.0%	44.3%
17	2036	6.4%	50.7%
18	2037	6.7%	57.4%
19	2038	7.1%	64.6%
20	2039	7.5%	72.1%
21	2040	7.9%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.0%	0.0%
2	2021	0.3%	0.3%
3	2022	0.5%	0.8%
4	2023	0.8%	1.7%
5	2024	1.2%	2.8%
6	2025	1.5%	4.4%
7	2026	1.9%	6.2%
8	2027	2.3%	8.5%
9	2028	2.7%	11.2%
10	2029	3.1%	14.3%
11	2030	3.6%	17.8%
12	2031	4.1%	21.9%
13	2032	4.6%	26.4%
14	2033	5.1%	31.6%
15	2034	5.7%	37.2%
16	2035	6.1%	43.4%
17	2036	6.5%	49.9%
18	2037	6.9%	56.8%
19	2038	7.3%	64.1%
20	2039	7.7%	71.8%
21	2040	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	52	838
2015	838	750	15	140	97	1,840
2016	1,840	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,420
2018	4,420	4,648	93	869	544	10,574
2019	10,574	1,928	39	360	886	13,786
2020	13,786	77	-	16	-	13,879
2021	13,879	9	-	2	-	13,890
		9,807	186	1,844	2,054	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,806
2018	5,806	6,074	121	1,135	737	13,873
2019	13,873	2,519	50	471	1,200	18,113
2020	18,113	101	-	21	-	18,235
2021	18,235	12	-	2	-	18,250
		12,816	243	2,409	2,782	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,786	93	8	13,887	56	(316)	13,628
2	2021	13,887	11	(66)	13,833	57	(599)	13,291
3	2022	13,833	-	(97)	13,735	57	(875)	12,917
4	2023	13,735	-	(135)	13,601	57	(1,144)	12,514
5	2024	13,601	-	(174)	13,427	57	(1,405)	12,079
6	2025	13,427	-	(217)	13,210	57	(1,657)	11,610
7	2026	13,210	-	(262)	12,947	57	(1,899)	11,105
8	2027	12,947	-	(314)	12,633	58	(2,132)	10,559
9	2028	12,633	-	(367)	12,267	58	(2,354)	9,971
10	2029	12,267	-	(423)	11,844	58	(2,564)	9,338
11	2030	11,844	-	(486)	11,358	58	(2,761)	8,655
12	2031	11,358	-	(553)	10,804	58	(2,945)	7,918
13	2032	10,804	-	(623)	10,181	59	(3,114)	7,126
14	2033	10,181	-	(700)	9,481	59	(3,267)	6,273
15	2034	9,481	-	(779)	8,702	59	(3,308)	5,453
16	2035	8,702	-	(843)	7,859	59	(2,987)	4,931
17	2036	7,859	-	(898)	6,962	59	(2,646)	4,375
18	2037	6,962	-	(953)	6,009	60	(2,284)	3,785
19	2038	6,009	-	(1,013)	4,996	60	(1,899)	3,157
20	2039	4,996	-	(1,075)	3,921	60	(1,490)	2,490
21	2040	3,921	-	(1,143)	2,778	60	(1,056)	1,782
			104	(11,112)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,113	122	29	18,264	56	(415)	17,906
2	2021	18,264	15	(68)	18,211	57	(786)	17,481
3	2022	18,211	-	(110)	18,101	57	(1,150)	17,009
4	2023	18,101	-	(159)	17,943	57	(1,503)	16,496
5	2024	17,943	-	(212)	17,731	57	(1,847)	15,941
6	2025	17,731	-	(268)	17,462	57	(2,179)	15,340
7	2026	17,462	-	(330)	17,133	57	(2,500)	14,691
8	2027	17,133	-	(399)	16,734	58	(2,807)	13,985
9	2028	16,734	-	(470)	16,265	58	(3,101)	13,222
10	2029	16,265	-	(546)	15,719	58	(3,379)	12,398
11	2030	15,719	-	(631)	15,088	58	(3,641)	11,505
12	2031	15,088	-	(723)	14,365	58	(3,885)	10,539
13	2032	14,365	-	(818)	13,547	59	(4,110)	9,496
14	2033	13,547	-	(924)	12,624	59	(4,314)	8,369
15	2034	12,624	-	(1,033)	11,591	59	(4,408)	7,242
16	2035	11,591	-	(1,123)	10,468	59	(3,981)	6,547
17	2036	10,468	-	(1,199)	9,270	59	(3,525)	5,804
18	2037	9,270	-	(1,275)	7,994	60	(3,040)	5,014
19	2038	7,994	-	(1,360)	6,635	60	(2,523)	4,172
20	2039	6,635	-	(1,445)	5,189	60	(1,973)	3,276
21	2040	5,189	-	(1,539)	3,650	60	(1,388)	2,322
			136	(14,600)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	541	453	(8)	85	12	268	316	1,665
2	2021	549	404	66	87	12	263	285	1,665
3	2022	535	393	97	89	12	260	279	1,665
4	2023	519	381	135	91	13	255	272	1,665
5	2024	502	369	174	93	13	249	265	1,665
6	2025	483	355	217	95	13	244	258	1,665
7	2026	464	341	262	97	13	239	250	1,665
8	2027	442	325	314	99	14	231	241	1,665
9	2028	419	308	367	101	14	225	231	1,665
10	2029	394	290	423	103	14	220	221	1,665
11	2030	367	270	486	106	15	212	210	1,665
12	2031	338	249	553	108	15	204	198	1,665
13	2032	307	226	623	110	15	198	185	1,665
14	2033	273	201	700	113	16	190	172	1,665
15	2034	239	176	779	115	16	182	158	1,665
16	2035	212	156	843	118	16	174	146	1,665
17	2036	190	140	898	120	17	164	138	1,665
18	2037	167	122	953	123	17	156	128	1,665
19	2038	142	104	1,013	126	17	145	118	1,665
20	2039	115	85	1,075	128	18	137	107	1,665
21	2040	87	64	1,143	131	18	126	96	1,665
		7,285	5,410	11,112	2,236	311	4,342	4,275	34,971

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	759	595	(29)	85	12	352	414	2,188
2	2021	772	531	68	87	12	345	374	2,188
3	2022	752	517	110	89	12	342	366	2,188
4	2023	731	503	159	91	13	335	358	2,188
5	2024	707	487	212	93	13	328	349	2,188
6	2025	682	469	268	95	13	321	340	2,188
7	2026	655	450	330	97	13	314	329	2,188
8	2027	625	430	399	99	14	303	318	2,188
9	2028	593	408	470	101	14	296	306	2,188
10	2029	559	384	546	103	14	289	293	2,188
11	2030	521	359	631	106	15	278	278	2,188
12	2031	481	331	723	108	15	268	263	2,188
13	2032	437	301	818	110	15	261	246	2,188
14	2033	390	268	924	113	16	250	228	2,188
15	2034	340	234	1,033	115	16	240	209	2,188
16	2035	301	207	1,123	118	16	229	194	2,188
17	2036	269	185	1,199	120	17	215	183	2,188
18	2037	236	162	1,275	123	17	204	170	2,188
19	2038	200	138	1,360	126	17	190	157	2,188
20	2039	162	112	1,445	128	18	180	142	2,188
21	2040	122	84	1,539	131	18	166	127	2,188
		10,295	7,154	14,600	2,236	311	5,705	5,645	45,945

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	91	375	0.66	1,575	4,656	0.93
2	2021	1.118	91	375	0.66	1,575	4,656	0.93
3	2022	1.118	91	375	0.66	1,575	4,656	0.93
4	2023	1.118	91	375	0.66	1,575	4,656	0.93
5	2024	1.118	91	375	0.66	1,575	4,656	0.93
6	2025	1.118	91	375	0.66	1,575	4,656	0.93
7	2026	1.118	91	375	0.66	1,575	4,656	0.93
8	2027	1.118	91	375	0.66	1,575	4,656	0.93
9	2028	1.118	91	375	0.66	1,575	4,656	0.93
10	2029	1.118	91	375	0.66	1,575	4,656	0.93
11	2030	1.118	91	375	0.66	1,575	4,656	0.93
12	2031	1.118	91	375	0.66	1,575	4,656	0.93
13	2032	1.118	91	375	0.66	1,575	4,656	0.93
14	2033	1.118	91	375	0.66	1,575	4,656	0.93
15	2034	1.118	91	375	0.66	1,575	4,656	0.93
16	2035	1.118	91	375	0.66	1,575	4,656	0.93
17	2036	1.118	91	375	0.66	1,575	4,656	0.93
18	2037	1.118	91	375	0.66	1,575	4,656	0.93
19	2038	1.118	91	375	0.66	1,575	4,656	0.93
20	2039	1.118	91	375	0.66	1,575	4,656	0.93
21	2040	1.118	91	375	0.66	1,575	4,656	0.93

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	119	375	0.87	2,069	4,656	1.22
2	2021	1.118	119	375	0.87	2,069	4,656	1.22
3	2022	1.118	119	375	0.87	2,069	4,656	1.22
4	2023	1.118	119	375	0.87	2,069	4,656	1.22
5	2024	1.118	119	375	0.87	2,069	4,656	1.22
6	2025	1.118	119	375	0.87	2,069	4,656	1.22
7	2026	1.118	119	375	0.87	2,069	4,656	1.22
8	2027	1.118	119	375	0.87	2,069	4,656	1.22
9	2028	1.118	119	375	0.87	2,069	4,656	1.22
10	2029	1.118	119	375	0.87	2,069	4,656	1.22
11	2030	1.118	119	375	0.87	2,069	4,656	1.22
12	2031	1.118	119	375	0.87	2,069	4,656	1.22
13	2032	1.118	119	375	0.87	2,069	4,656	1.22
14	2033	1.118	119	375	0.87	2,069	4,656	1.22
15	2034	1.118	119	375	0.87	2,069	4,656	1.22
16	2035	1.118	119	375	0.87	2,069	4,656	1.22
17	2036	1.118	119	375	0.87	2,069	4,656	1.22
18	2037	1.118	119	375	0.87	2,069	4,656	1.22
19	2038	1.118	119	375	0.87	2,069	4,656	1.22
20	2039	1.118	119	375	0.87	2,069	4,656	1.22
21	2040	1.118	119	375	0.87	2,069	4,656	1.22

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.5%	0.4%
3	2022	0.7%	1.1%
4	2023	1.0%	2.1%
5	2024	1.3%	3.3%
6	2025	1.6%	4.9%
7	2026	1.9%	6.8%
8	2027	2.3%	9.0%
9	2028	2.6%	11.7%
10	2029	3.0%	14.7%
11	2030	3.5%	18.2%
12	2031	4.0%	22.2%
13	2032	4.5%	26.7%
14	2033	5.0%	31.7%
15	2034	5.6%	37.4%
16	2035	6.1%	43.4%
17	2036	6.5%	49.9%
18	2037	6.9%	56.7%
19	2038	7.3%	64.0%
20	2039	7.7%	71.8%
21	2040	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.4%	0.2%
3	2022	0.6%	0.8%
4	2023	0.9%	1.7%
5	2024	1.2%	2.8%
6	2025	1.5%	4.3%
7	2026	1.8%	6.1%
8	2027	2.2%	8.3%
9	2028	2.6%	10.9%
10	2029	3.0%	13.9%
11	2030	3.5%	17.3%
12	2031	4.0%	21.3%
13	2032	4.5%	25.8%
14	2033	5.1%	30.8%
15	2034	5.7%	36.5%
16	2035	6.2%	42.6%
17	2036	6.6%	49.2%
18	2037	7.0%	56.2%
19	2038	7.5%	63.6%
20	2039	7.9%	71.6%
21	2040	8.4%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(22 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	6	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	636
2020	636	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	636	4	2	642	1	(15)	629
2	2021	642	1	(2)	640	1	(28)	614
3	2022	640	-	(3)	637	1	(40)	598
4	2023	637	-	(5)	633	1	(53)	581
5	2024	633	-	(6)	626	1	(65)	562
6	2025	626	-	(8)	618	1	(77)	542
7	2026	618	-	(10)	608	1	(88)	521
8	2027	608	-	(12)	595	1	(99)	497
9	2028	595	-	(15)	580	1	(109)	472
10	2029	580	-	(17)	563	1	(119)	445
11	2030	563	-	(20)	544	1	(129)	416
12	2031	544	-	(23)	521	1	(138)	384
13	2032	521	-	(26)	495	1	(146)	350
14	2033	495	-	(29)	466	1	(153)	314
15	2034	466	-	(33)	434	1	(160)	274
16	2035	434	-	(36)	398	1	(155)	244
17	2036	398	-	(39)	359	1	(140)	221
18	2037	359	-	(41)	318	1	(124)	196
19	2038	318	-	(43)	275	1	(107)	169
20	2039	275	-	(46)	229	1	(89)	141
21	2040	229	-	(49)	180	1	(69)	112
22	2041	180	-	(52)	128	1	(49)	80
			5	(513)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	3	845	1	(19)	827
2	2021	845	1	(2)	844	1	(36)	808
3	2022	844	-	(3)	840	1	(53)	788
4	2023	840	-	(5)	835	1	(69)	766
5	2024	835	-	(8)	827	1	(85)	743
6	2025	827	-	(10)	817	1	(101)	717
7	2026	817	-	(13)	804	1	(116)	689
8	2027	804	-	(16)	789	1	(130)	659
9	2028	789	-	(19)	770	1	(144)	627
10	2029	770	-	(22)	748	1	(157)	592
11	2030	748	-	(26)	722	1	(170)	553
12	2031	722	-	(30)	693	1	(182)	512
13	2032	693	-	(34)	659	1	(193)	468
14	2033	659	-	(38)	621	1	(203)	419
15	2034	621	-	(43)	578	1	(212)	367
16	2035	578	-	(48)	531	1	(207)	325
17	2036	531	-	(51)	479	1	(187)	294
18	2037	479	-	(55)	424	1	(165)	260
19	2038	424	-	(58)	366	1	(142)	225
20	2039	366	-	(62)	304	1	(118)	187
21	2040	304	-	(66)	238	1	(92)	148
22	2041	238	-	(71)	168	1	(64)	105
			6	(674)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(2)	4	0	12	15	75
2	2021	25	19	2	4	0	12	13	75
3	2022	25	18	3	4	0	12	13	75
4	2023	24	18	5	4	0	12	13	75
5	2024	23	17	6	4	0	12	12	75
6	2025	23	17	8	4	0	11	12	75
7	2026	22	16	10	4	0	11	12	75
8	2027	21	15	12	4	0	11	11	75
9	2028	20	15	15	5	1	10	11	75
10	2029	19	14	17	5	1	10	10	75
11	2030	18	13	20	5	1	10	10	75
12	2031	16	12	23	5	1	9	10	75
13	2032	15	11	26	5	1	9	9	75
14	2033	14	10	29	5	1	9	8	75
15	2034	12	9	33	5	1	8	8	75
16	2035	11	8	36	5	1	8	7	75
17	2036	10	7	39	5	1	8	7	75
18	2037	9	6	41	6	1	7	6	75
19	2038	7	5	43	6	1	7	6	75
20	2039	6	5	46	6	1	6	6	75
21	2040	5	4	49	6	1	6	5	75
22	2041	4	3	52	6	1	5	5	75
		352	261	513	107	12	205	208	1,659

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	27	(3)	4	0	16	19	99
2	2021	36	25	2	4	0	16	17	99
3	2022	35	24	3	4	0	16	17	99
4	2023	34	23	5	4	0	15	17	99
5	2024	33	23	8	4	0	15	16	99
6	2025	32	22	10	4	0	15	16	99
7	2026	31	21	13	4	0	14	15	99
8	2027	29	20	16	4	0	14	15	99
9	2028	28	19	19	5	1	14	14	99
10	2029	27	18	22	5	1	13	14	99
11	2030	25	17	26	5	1	13	13	99
12	2031	23	16	30	5	1	12	13	99
13	2032	21	15	34	5	1	12	12	99
14	2033	19	13	38	5	1	12	11	99
15	2034	17	12	43	5	1	11	10	99
16	2035	15	10	48	5	1	11	10	99
17	2036	14	9	51	5	1	10	9	99
18	2037	12	8	55	6	1	9	9	99
19	2038	11	7	58	6	1	9	8	99
20	2039	9	6	62	6	1	8	7	99
21	2040	7	5	66	6	1	8	7	99
22	2041	6	4	71	6	1	7	6	99
		499	346	674	107	12	270	275	2,183

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	75	1,100	1.000	0.19
2	2021	75	1,100	1.000	0.19
3	2022	75	1,100	1.000	0.19
4	2023	75	1,100	1.000	0.19
5	2024	75	1,100	1.000	0.19
6	2025	75	1,100	1.000	0.19
7	2026	75	1,100	1.000	0.19
8	2027	75	1,100	1.000	0.19
9	2028	75	1,100	1.000	0.19
10	2029	75	1,100	1.000	0.19
11	2030	75	1,100	1.000	0.19
12	2031	75	1,100	1.000	0.19
13	2032	75	1,100	1.000	0.19
14	2033	75	1,100	1.000	0.19
15	2034	75	1,100	1.000	0.19
16	2035	75	1,100	1.000	0.19
17	2036	75	1,100	1.000	0.19
18	2037	75	1,100	1.000	0.19
19	2038	75	1,100	1.000	0.19
20	2039	75	1,100	1.000	0.19
21	2040	75	1,100	1.000	0.19
22	2041	75	1,100	1.000	0.19

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	99	1,100	1.000	0.25
2	2021	99	1,100	1.000	0.25
3	2022	99	1,100	1.000	0.25
4	2023	99	1,100	1.000	0.25
5	2024	99	1,100	1.000	0.25
6	2025	99	1,100	1.000	0.25
7	2026	99	1,100	1.000	0.25
8	2027	99	1,100	1.000	0.25
9	2028	99	1,100	1.000	0.25
10	2029	99	1,100	1.000	0.25
11	2030	99	1,100	1.000	0.25
12	2031	99	1,100	1.000	0.25
13	2032	99	1,100	1.000	0.25
14	2033	99	1,100	1.000	0.25
15	2034	99	1,100	1.000	0.25
16	2035	99	1,100	1.000	0.25
17	2036	99	1,100	1.000	0.25
18	2037	99	1,100	1.000	0.25
19	2038	99	1,100	1.000	0.25
20	2039	99	1,100	1.000	0.25
21	2040	99	1,100	1.000	0.25
22	2041	99	1,100	1.000	0.25

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.3%	0.0%
3	2022	0.5%	0.5%
4	2023	0.7%	1.3%
5	2024	1.0%	2.3%
6	2025	1.3%	3.6%
7	2026	1.6%	5.2%
8	2027	1.9%	7.1%
9	2028	2.3%	9.4%
10	2029	2.7%	12.1%
11	2030	3.1%	15.1%
12	2031	3.5%	18.7%
13	2032	4.0%	22.7%
14	2033	4.5%	27.2%
15	2034	5.1%	32.3%
16	2035	5.6%	37.9%
17	2036	6.0%	43.9%
18	2037	6.4%	50.3%
19	2038	6.8%	57.0%
20	2039	7.2%	64.2%
21	2040	7.6%	71.8%
22	2041	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.2%	-0.2%
3	2022	0.4%	0.2%
4	2023	0.6%	0.9%
5	2024	0.9%	1.8%
6	2025	1.2%	3.0%
7	2026	1.5%	4.5%
8	2027	1.9%	6.3%
9	2028	2.2%	8.6%
10	2029	2.6%	11.2%
11	2030	3.0%	14.2%
12	2031	3.5%	17.7%
13	2032	4.0%	21.7%
14	2033	4.5%	26.2%
15	2034	5.1%	31.3%
16	2035	5.6%	37.0%
17	2036	6.1%	43.1%
18	2037	6.5%	49.6%
19	2038	6.9%	56.5%
20	2039	7.3%	63.8%
21	2040	7.8%	71.6%
22	2041	8.4%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	131	2,468
2016	2,468	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,798
2018	9,798	1,954	39	668	840	13,300
2019	13,300	1,090	22	373	1,068	15,853
2020	15,853	372	-	135	-	16,360
2021	16,360	9	-	3	-	16,372
		9,760	179	3,355	3,078	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,482
2015	1,482	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,860
2018	12,860	2,554	51	874	1,138	17,476
2019	17,476	1,424	28	487	1,447	20,863
2020	20,863	486	-	176	-	21,526
2021	21,526	12	-	4	-	21,542
		12,755	234	4,384	4,169	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,853	507	10	16,370	26	(367)	16,029
2	2021	16,370	13	(26)	16,356	29	(699)	15,686
3	2022	16,356	-	(63)	16,293	28	(1,025)	15,296
4	2023	16,293	-	(114)	16,180	28	(1,344)	14,863
5	2024	16,180	-	(168)	16,011	27	(1,654)	14,384
6	2025	16,011	-	(223)	15,788	26	(1,955)	13,859
7	2026	15,788	-	(276)	15,513	26	(2,246)	13,293
8	2027	15,513	-	(335)	15,177	26	(2,526)	12,678
9	2028	15,177	-	(396)	14,782	26	(2,794)	12,014
10	2029	14,782	-	(461)	14,321	26	(3,048)	11,298
11	2030	14,321	-	(533)	13,787	26	(3,290)	10,524
12	2031	13,787	-	(604)	13,183	26	(3,515)	9,694
13	2032	13,183	-	(676)	12,507	27	(3,725)	8,809
14	2033	12,507	-	(756)	11,751	28	(3,917)	7,861
15	2034	11,751	-	(842)	10,909	28	(4,091)	6,846
16	2035	10,909	-	(915)	9,993	29	(3,845)	6,178
17	2036	9,993	-	(973)	9,020	29	(3,468)	5,581
18	2037	9,020	-	(1,026)	7,994	30	(3,071)	4,953
19	2038	7,994	-	(1,085)	6,909	31	(2,649)	4,291
20	2039	6,909	-	(1,143)	5,766	31	(2,203)	3,595
21	2040	5,766	-	(1,207)	4,559	32	(1,730)	2,860
22	2041	4,559	-	(1,284)	3,274	33	(1,226)	2,081
			520	(13,098)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,863	663	36	21,562	26	(482)	21,105
2	2021	21,562	16	(19)	21,559	29	(920)	20,667
3	2022	21,559	-	(68)	21,491	28	(1,349)	20,170
4	2023	21,491	-	(131)	21,360	28	(1,769)	19,618
5	2024	21,360	-	(200)	21,159	27	(2,178)	19,008
6	2025	21,159	-	(271)	20,889	26	(2,576)	18,339
7	2026	20,889	-	(340)	20,549	26	(2,960)	17,615
8	2027	20,549	-	(419)	20,130	26	(3,330)	16,825
9	2028	20,130	-	(499)	19,630	26	(3,685)	15,971
10	2029	19,630	-	(586)	19,044	26	(4,024)	15,046
11	2030	19,044	-	(683)	18,361	26	(4,344)	14,043
12	2031	18,361	-	(780)	17,581	26	(4,645)	12,962
13	2032	17,581	-	(880)	16,701	27	(4,925)	11,802
14	2033	16,701	-	(991)	15,710	28	(5,183)	10,555
15	2034	15,710	-	(1,110)	14,599	28	(5,415)	9,212
16	2035	14,599	-	(1,216)	13,383	29	(5,157)	8,254
17	2036	13,383	-	(1,302)	12,081	29	(4,653)	7,457
18	2037	12,081	-	(1,378)	10,703	30	(4,118)	6,615
19	2038	10,703	-	(1,462)	9,241	31	(3,548)	5,724
20	2039	9,241	-	(1,546)	7,695	31	(2,944)	4,782
21	2040	7,695	-	(1,639)	6,057	32	(2,302)	3,787
22	2041	6,057	-	(1,748)	4,308	33	(1,615)	2,727
			679	(17,234)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	629	526	(10)	312	61	316	366	2,201
2	2021	647	476	26	346	63	310	334	2,201
3	2022	633	465	63	342	64	307	328	2,201
4	2023	616	452	114	331	66	301	322	2,201
5	2024	597	439	168	320	67	294	316	2,201
6	2025	577	424	223	313	69	288	308	2,201
7	2026	554	407	276	312	70	282	300	2,201
8	2027	530	390	335	312	72	272	291	2,201
9	2028	504	370	396	311	73	266	281	2,201
10	2029	476	350	461	310	75	259	270	2,201
11	2030	446	327	533	310	76	250	259	2,201
12	2031	413	303	604	317	78	240	246	2,201
13	2032	378	278	676	323	80	234	232	2,201
14	2033	340	250	756	331	82	225	218	2,201
15	2034	300	221	842	338	83	215	202	2,201
16	2035	266	195	915	345	85	206	189	2,201
17	2036	240	176	973	353	87	193	179	2,201
18	2037	215	158	1,026	361	89	184	169	2,201
19	2038	189	139	1,085	369	91	171	159	2,201
20	2039	161	118	1,143	377	93	161	148	2,201
21	2040	132	97	1,207	385	95	149	137	2,201
22	2041	101	74	1,284	393	97	127	125	2,201
		8,944	6,634	13,098	7,411	1,715	5,249	5,380	48,431

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	885	692	(36)	312	61	417	481	2,813
2	2021	911	627	19	346	63	408	439	2,813
3	2022	891	613	68	342	64	404	431	2,813
4	2023	868	597	131	331	66	396	424	2,813
5	2024	843	579	200	320	67	387	416	2,813
6	2025	815	560	271	313	69	379	406	2,813
7	2026	784	539	340	312	70	371	396	2,813
8	2027	751	517	419	312	72	358	384	2,813
9	2028	715	492	499	311	73	350	372	2,813
10	2029	677	465	586	310	75	342	358	2,813
11	2030	635	436	683	310	76	329	343	2,813
12	2031	589	405	780	317	78	317	327	2,813
13	2032	540	371	880	323	80	308	309	2,813
14	2033	488	335	991	331	82	296	290	2,813
15	2034	431	296	1,110	338	83	283	270	2,813
16	2035	381	262	1,216	345	85	271	252	2,813
17	2036	343	236	1,302	353	87	254	238	2,813
18	2037	307	211	1,378	361	89	242	226	2,813
19	2038	269	185	1,462	369	91	225	212	2,813
20	2039	229	158	1,546	377	93	212	198	2,813
21	2040	187	129	1,639	385	95	196	183	2,813
22	2041	142	98	1,748	393	97	167	167	2,813
		12,681	8,803	17,234	7,411	1,715	6,912	7,124	61,880

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,201	4,500	1.118	1.20
2	2021	2,201	4,500	1.118	1.20
3	2022	2,201	4,500	1.118	1.20
4	2023	2,201	4,500	1.118	1.20
5	2024	2,201	4,500	1.118	1.20
6	2025	2,201	4,500	1.118	1.20
7	2026	2,201	4,500	1.118	1.20
8	2027	2,201	4,500	1.118	1.20
9	2028	2,201	4,500	1.118	1.20
10	2029	2,201	4,500	1.118	1.20
11	2030	2,201	4,500	1.118	1.20
12	2031	2,201	4,500	1.118	1.20
13	2032	2,201	4,500	1.118	1.20
14	2033	2,201	4,500	1.118	1.20
15	2034	2,201	4,500	1.118	1.20
16	2035	2,201	4,500	1.118	1.20
17	2036	2,201	4,500	1.118	1.20
18	2037	2,201	4,500	1.118	1.20
19	2038	2,201	4,500	1.118	1.20
20	2039	2,201	4,500	1.118	1.20
21	2040	2,201	4,500	1.118	1.20
22	2041	2,201	4,500	1.118	1.20

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,813	4,500	1.118	1.53
2	2021	2,813	4,500	1.118	1.53
3	2022	2,813	4,500	1.118	1.53
4	2023	2,813	4,500	1.118	1.53
5	2024	2,813	4,500	1.118	1.53
6	2025	2,813	4,500	1.118	1.53
7	2026	2,813	4,500	1.118	1.53
8	2027	2,813	4,500	1.118	1.53
9	2028	2,813	4,500	1.118	1.53
10	2029	2,813	4,500	1.118	1.53
11	2030	2,813	4,500	1.118	1.53
12	2031	2,813	4,500	1.118	1.53
13	2032	2,813	4,500	1.118	1.53
14	2033	2,813	4,500	1.118	1.53
15	2034	2,813	4,500	1.118	1.53
16	2035	2,813	4,500	1.118	1.53
17	2036	2,813	4,500	1.118	1.53
18	2037	2,813	4,500	1.118	1.53
19	2038	2,813	4,500	1.118	1.53
20	2039	2,813	4,500	1.118	1.53
21	2040	2,813	4,500	1.118	1.53
22	2041	2,813	4,500	1.118	1.53

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.2%	0.1%
3	2022	0.4%	0.5%
4	2023	0.7%	1.2%
5	2024	1.0%	2.2%
6	2025	1.4%	3.6%
7	2026	1.7%	5.2%
8	2027	2.0%	7.3%
9	2028	2.4%	9.7%
10	2029	2.8%	12.5%
11	2030	3.3%	15.8%
12	2031	3.7%	19.5%
13	2032	4.1%	23.6%
14	2033	4.6%	28.2%
15	2034	5.1%	33.4%
16	2035	5.6%	39.0%
17	2036	5.9%	44.9%
18	2037	6.3%	51.2%
19	2038	6.6%	57.8%
20	2039	7.0%	64.8%
21	2040	7.4%	72.2%
22	2041	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.1%	-0.1%
3	2022	0.3%	0.2%
4	2023	0.6%	0.8%
5	2024	0.9%	1.8%
6	2025	1.3%	3.0%
7	2026	1.6%	4.6%
8	2027	1.9%	6.6%
9	2028	2.3%	8.9%
10	2029	2.7%	11.6%
11	2030	3.2%	14.8%
12	2031	3.6%	18.4%
13	2032	4.1%	22.5%
14	2033	4.6%	27.1%
15	2034	5.2%	32.2%
16	2035	5.6%	37.9%
17	2036	6.0%	43.9%
18	2037	6.4%	50.3%
19	2038	6.8%	57.1%
20	2039	7.2%	64.3%
21	2040	7.6%	71.9%
22	2041	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	52	838
2015	838	750	15	140	97	1,840
2016	1,840	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,421
2018	4,421	4,648	93	869	544	10,574
2019	10,574	1,928	39	360	886	13,786
2020	13,786	77	-	16	-	13,880
2021	13,880	9	-	2	-	13,891
		9,807	186	1,844	2,055	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,807
2018	5,807	6,074	121	1,135	737	13,874
2019	13,874	2,519	50	471	1,200	18,114
2020	18,114	101	-	21	-	18,236
2021	18,236	12	-	2	-	18,250
		12,816	243	2,409	2,782	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,786	93	33	13,913	56	(316)	13,654
2	2021	13,913	11	(39)	13,885	57	(599)	13,343
3	2022	13,885	-	(68)	13,818	57	(876)	12,998
4	2023	13,818	-	(102)	13,715	57	(1,146)	12,626
5	2024	13,715	-	(139)	13,576	57	(1,409)	12,224
6	2025	13,576	-	(179)	13,397	57	(1,664)	11,790
7	2026	13,397	-	(221)	13,175	57	(1,910)	11,323
8	2027	13,175	-	(270)	12,906	58	(2,147)	10,817
9	2028	12,906	-	(319)	12,587	58	(2,373)	10,272
10	2029	12,587	-	(371)	12,216	58	(2,589)	9,685
11	2030	12,216	-	(430)	11,786	58	(2,793)	9,051
12	2031	11,786	-	(493)	11,293	58	(2,985)	8,367
13	2032	11,293	-	(558)	10,735	59	(3,163)	7,632
14	2033	10,735	-	(630)	10,105	59	(3,326)	6,839
15	2034	10,105	-	(707)	9,398	59	(3,473)	5,984
16	2035	9,398	-	(775)	8,622	59	(3,278)	5,404
17	2036	8,622	-	(831)	7,791	59	(2,962)	4,889
18	2037	7,791	-	(882)	6,909	60	(2,626)	4,342
19	2038	6,909	-	(939)	5,970	60	(2,269)	3,760
20	2039	5,970	-	(997)	4,973	60	(1,890)	3,143
21	2040	4,973	-	(1,060)	3,913	60	(1,487)	2,486
22	2041	3,913	-	(1,135)	2,778	61	(1,056)	1,783
			104	(11,113)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,114	122	61	18,297	56	(414)	17,939
2	2021	18,297	15	(32)	18,279	57	(787)	17,549
3	2022	18,279	-	(71)	18,209	57	(1,151)	17,115
4	2023	18,209	-	(116)	18,092	57	(1,506)	16,643
5	2024	18,092	-	(166)	17,927	57	(1,853)	16,131
6	2025	17,927	-	(218)	17,708	57	(2,189)	15,577
7	2026	17,708	-	(275)	17,433	57	(2,514)	14,977
8	2027	17,433	-	(340)	17,094	58	(2,827)	14,325
9	2028	17,094	-	(405)	16,688	58	(3,127)	13,619
10	2029	16,688	-	(476)	16,212	58	(3,413)	12,857
11	2030	16,212	-	(556)	15,656	58	(3,683)	12,031
12	2031	15,656	-	(641)	15,015	58	(3,938)	11,135
13	2032	15,015	-	(730)	14,285	59	(4,174)	10,169
14	2033	14,285	-	(828)	13,456	59	(4,391)	9,124
15	2034	13,456	-	(934)	12,522	59	(4,588)	7,993
16	2035	12,522	-	(1,030)	11,492	59	(4,370)	7,181
17	2036	11,492	-	(1,108)	10,384	59	(3,949)	6,495
18	2037	10,384	-	(1,180)	9,204	60	(3,500)	5,764
19	2038	9,204	-	(1,259)	7,945	60	(3,021)	4,984
20	2039	7,945	-	(1,339)	6,607	60	(2,512)	4,155
21	2040	6,607	-	(1,427)	5,180	60	(1,970)	3,271
22	2041	5,180	-	(1,530)	3,650	61	(1,388)	2,323
			136	(14,600)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	541	453	(33)	85	11	269	315	1,641
2	2021	551	405	39	87	12	263	284	1,641
3	2022	538	395	68	89	12	261	279	1,641
4	2023	523	384	102	91	12	255	273	1,641
5	2024	507	373	139	93	12	250	266	1,641
6	2025	490	360	179	95	13	245	259	1,641
7	2026	472	347	221	97	13	239	252	1,641
8	2027	452	332	270	99	13	231	244	1,641
9	2028	431	316	319	101	13	226	235	1,641
10	2029	407	299	371	103	14	220	226	1,641
11	2030	383	281	430	106	14	212	215	1,641
12	2031	356	261	493	108	14	204	204	1,641
13	2032	327	240	558	110	15	199	193	1,641
14	2033	295	217	630	113	15	191	180	1,641
15	2034	262	192	707	115	15	183	166	1,641
16	2035	233	171	775	118	16	175	154	1,641
17	2036	210	154	831	120	16	164	145	1,641
18	2037	188	138	882	123	16	156	136	1,641
19	2038	165	122	939	126	17	145	127	1,641
20	2039	141	104	997	128	17	137	117	1,641
21	2040	115	84	1,060	131	17	126	106	1,641
22	2041	87	64	1,135	134	18	107	96	1,641
		7,675	5,694	11,113	2,370	315	4,457	4,473	36,096

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	760	595	(61)	85	11	353	413	2,156
2	2021	774	532	32	87	12	346	373	2,156
3	2022	756	520	71	89	12	342	366	2,156
4	2023	736	506	116	91	12	335	359	2,156
5	2024	715	492	166	93	12	328	351	2,156
6	2025	692	476	218	95	13	321	342	2,156
7	2026	667	458	275	97	13	314	332	2,156
8	2027	639	440	340	99	13	304	322	2,156
9	2028	610	419	405	101	13	297	311	2,156
10	2029	578	397	476	103	14	289	298	2,156
11	2030	543	373	556	106	14	279	285	2,156
12	2031	505	347	641	108	14	268	271	2,156
13	2032	465	320	730	110	15	261	256	2,156
14	2033	421	289	828	113	15	251	239	2,156
15	2034	373	257	934	115	15	240	221	2,156
16	2035	331	228	1,030	118	16	229	205	2,156
17	2036	298	205	1,108	120	16	215	193	2,156
18	2037	267	184	1,180	123	16	205	181	2,156
19	2038	234	161	1,259	126	17	191	169	2,156
20	2039	199	137	1,339	128	17	180	155	2,156
21	2040	162	111	1,427	131	17	166	141	2,156
22	2041	122	84	1,530	134	18	141	127	2,156
		10,848	7,532	14,600	2,370	315	5,857	5,908	47,430

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	89	375	0.65	1,551	4,656	0.91
2	2021	1.118	89	375	0.65	1,551	4,656	0.91
3	2022	1.118	89	375	0.65	1,551	4,656	0.91
4	2023	1.118	89	375	0.65	1,551	4,656	0.91
5	2024	1.118	89	375	0.65	1,551	4,656	0.91
6	2025	1.118	89	375	0.65	1,551	4,656	0.91
7	2026	1.118	89	375	0.65	1,551	4,656	0.91
8	2027	1.118	89	375	0.65	1,551	4,656	0.91
9	2028	1.118	89	375	0.65	1,551	4,656	0.91
10	2029	1.118	89	375	0.65	1,551	4,656	0.91
11	2030	1.118	89	375	0.65	1,551	4,656	0.91
12	2031	1.118	89	375	0.65	1,551	4,656	0.91
13	2032	1.118	89	375	0.65	1,551	4,656	0.91
14	2033	1.118	89	375	0.65	1,551	4,656	0.91
15	2034	1.118	89	375	0.65	1,551	4,656	0.91
16	2035	1.118	89	375	0.65	1,551	4,656	0.91
17	2036	1.118	89	375	0.65	1,551	4,656	0.91
18	2037	1.118	89	375	0.65	1,551	4,656	0.91
19	2038	1.118	89	375	0.65	1,551	4,656	0.91
20	2039	1.118	89	375	0.65	1,551	4,656	0.91
21	2040	1.118	89	375	0.65	1,551	4,656	0.91
22	2041	1.118	89	375	0.65	1,551	4,656	0.91

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	118	375	0.86	2,038	4,656	1.20
2	2021	1.118	118	375	0.86	2,038	4,656	1.20
3	2022	1.118	118	375	0.86	2,038	4,656	1.20
4	2023	1.118	118	375	0.86	2,038	4,656	1.20
5	2024	1.118	118	375	0.86	2,038	4,656	1.20
6	2025	1.118	118	375	0.86	2,038	4,656	1.20
7	2026	1.118	118	375	0.86	2,038	4,656	1.20
8	2027	1.118	118	375	0.86	2,038	4,656	1.20
9	2028	1.118	118	375	0.86	2,038	4,656	1.20
10	2029	1.118	118	375	0.86	2,038	4,656	1.20
11	2030	1.118	118	375	0.86	2,038	4,656	1.20
12	2031	1.118	118	375	0.86	2,038	4,656	1.20
13	2032	1.118	118	375	0.86	2,038	4,656	1.20
14	2033	1.118	118	375	0.86	2,038	4,656	1.20
15	2034	1.118	118	375	0.86	2,038	4,656	1.20
16	2035	1.118	118	375	0.86	2,038	4,656	1.20
17	2036	1.118	118	375	0.86	2,038	4,656	1.20
18	2037	1.118	118	375	0.86	2,038	4,656	1.20
19	2038	1.118	118	375	0.86	2,038	4,656	1.20
20	2039	1.118	118	375	0.86	2,038	4,656	1.20
21	2040	1.118	118	375	0.86	2,038	4,656	1.20
22	2041	1.118	118	375	0.86	2,038	4,656	1.20

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.3%	0.0%
3	2022	0.5%	0.5%
4	2023	0.7%	1.3%
5	2024	1.0%	2.3%
6	2025	1.3%	3.6%
7	2026	1.6%	5.1%
8	2027	1.9%	7.1%
9	2028	2.3%	9.4%
10	2029	2.7%	12.1%
11	2030	3.1%	15.1%
12	2031	3.5%	18.7%
13	2032	4.0%	22.7%
14	2033	4.5%	27.3%
15	2034	5.1%	32.3%
16	2035	5.6%	37.9%
17	2036	6.0%	43.9%
18	2037	6.4%	50.3%
19	2038	6.8%	57.0%
20	2039	7.2%	64.2%
21	2040	7.6%	71.8%
22	2041	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.2%	-0.2%
3	2022	0.4%	0.2%
4	2023	0.6%	0.9%
5	2024	0.9%	1.8%
6	2025	1.2%	3.0%
7	2026	1.5%	4.5%
8	2027	1.9%	6.3%
9	2028	2.2%	8.6%
10	2029	2.6%	11.2%
11	2030	3.0%	14.2%
12	2031	3.5%	17.7%
13	2032	4.0%	21.7%
14	2033	4.5%	26.3%
15	2034	5.1%	31.4%
16	2035	5.6%	37.0%
17	2036	6.1%	43.1%
18	2037	6.5%	49.6%
19	2038	6.9%	56.5%
20	2039	7.3%	63.8%
21	2040	7.8%	71.6%
22	2041	8.4%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(23 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	6	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	636
2020	636	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	636	4	3	643	1	(15)	630
2	2021	643	1	(1)	643	1	(28)	616
3	2022	643	-	(2)	641	1	(40)	601
4	2023	641	-	(3)	637	1	(53)	585
5	2024	637	-	(5)	632	1	(65)	568
6	2025	632	-	(7)	626	1	(77)	550
7	2026	626	-	(9)	617	1	(88)	530
8	2027	617	-	(11)	607	1	(100)	508
9	2028	607	-	(13)	594	1	(110)	485
10	2029	594	-	(15)	579	1	(120)	460
11	2030	579	-	(17)	562	1	(130)	432
12	2031	562	-	(20)	541	1	(139)	403
13	2032	541	-	(23)	518	1	(148)	372
14	2033	518	-	(26)	492	1	(156)	338
15	2034	492	-	(29)	463	1	(163)	301
16	2035	463	-	(33)	430	1	(168)	264
17	2036	430	-	(36)	394	1	(154)	242
18	2037	394	-	(38)	356	1	(139)	219
19	2038	356	-	(40)	316	1	(123)	194
20	2039	316	-	(43)	273	1	(106)	168
21	2040	273	-	(46)	228	1	(88)	140
22	2041	228	-	(49)	179	1	(69)	111
23	2042	179	-	(51)	128	1	(49)	80
			5	(513)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	4	846	1	(19)	828
2	2021	846	1	(0)	846	1	(36)	811
3	2022	846	-	(2)	845	1	(53)	793
4	2023	845	-	(4)	841	1	(70)	772
5	2024	841	-	(6)	835	1	(86)	751
6	2025	835	-	(8)	827	1	(101)	727
7	2026	827	-	(10)	817	1	(117)	701
8	2027	817	-	(13)	804	1	(131)	674
9	2028	804	-	(16)	788	1	(145)	643
10	2029	788	-	(19)	769	1	(159)	611
11	2030	769	-	(22)	746	1	(172)	576
12	2031	746	-	(26)	720	1	(184)	537
13	2032	720	-	(30)	690	1	(195)	496
14	2033	690	-	(34)	656	1	(206)	451
15	2034	656	-	(39)	617	1	(216)	403
16	2035	617	-	(44)	574	1	(224)	351
17	2036	574	-	(48)	526	1	(205)	322
18	2037	526	-	(51)	475	1	(185)	291
19	2038	475	-	(54)	421	1	(164)	258
20	2039	421	-	(57)	364	1	(142)	223
21	2040	364	-	(61)	303	1	(117)	186
22	2041	303	-	(66)	237	1	(92)	147
23	2042	237	-	(69)	168	1	(64)	105
			6	(674)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(3)	4	0	12	14	74
2	2021	25	19	1	4	0	12	13	74
3	2022	25	18	2	4	0	12	13	74
4	2023	24	18	3	4	0	12	13	74
5	2024	24	17	5	4	0	12	12	74
6	2025	23	17	7	4	0	11	12	74
7	2026	22	16	9	4	0	11	12	74
8	2027	21	16	11	4	0	11	11	74
9	2028	20	15	13	5	0	10	11	74
10	2029	19	14	15	5	0	10	11	74
11	2030	18	13	17	5	1	10	10	74
12	2031	17	13	20	5	1	9	10	74
13	2032	16	12	23	5	1	9	9	74
14	2033	15	11	26	5	1	9	9	74
15	2034	13	10	29	5	1	8	8	74
16	2035	12	8	33	5	1	8	8	74
17	2036	10	8	36	5	1	8	7	74
18	2037	9	7	38	6	1	7	7	74
19	2038	8	6	40	6	1	7	6	74
20	2039	7	5	43	6	1	6	6	74
21	2040	6	5	46	6	1	6	6	74
22	2041	5	4	49	6	1	5	5	74
23	2042	4	3	51	6	1	5	5	74
		370	274	513	113	12	211	217	1,710

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	27	(4)	4	0	16	19	98
2	2021	36	25	0	4	0	16	17	98
3	2022	35	24	2	4	0	16	17	98
4	2023	34	23	4	4	0	15	17	98
5	2024	33	23	6	4	0	15	16	98
6	2025	32	22	8	4	0	15	16	98
7	2026	31	21	10	4	0	15	15	98
8	2027	30	21	13	4	0	14	15	98
9	2028	29	20	16	5	0	14	15	98
10	2029	27	19	19	5	0	13	14	98
11	2030	26	18	22	5	1	13	14	98
12	2031	24	17	26	5	1	12	13	98
13	2032	23	16	30	5	1	12	12	98
14	2033	21	14	34	5	1	12	12	98
15	2034	19	13	39	5	1	11	11	98
16	2035	16	11	44	5	1	11	10	98
17	2036	15	10	48	5	1	10	9	98
18	2037	13	9	51	6	1	9	9	98
19	2038	12	8	54	6	1	9	8	98
20	2039	11	7	57	6	1	8	8	98
21	2040	9	6	61	6	1	8	7	98
22	2041	7	5	66	6	1	7	7	98
23	2042	6	4	69	6	1	7	6	98
		524	364	674	113	12	277	287	2,252

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	74	1,100	1.000	0.19
2	2021	74	1,100	1.000	0.19
3	2022	74	1,100	1.000	0.19
4	2023	74	1,100	1.000	0.19
5	2024	74	1,100	1.000	0.19
6	2025	74	1,100	1.000	0.19
7	2026	74	1,100	1.000	0.19
8	2027	74	1,100	1.000	0.19
9	2028	74	1,100	1.000	0.19
10	2029	74	1,100	1.000	0.19
11	2030	74	1,100	1.000	0.19
12	2031	74	1,100	1.000	0.19
13	2032	74	1,100	1.000	0.19
14	2033	74	1,100	1.000	0.19
15	2034	74	1,100	1.000	0.19
16	2035	74	1,100	1.000	0.19
17	2036	74	1,100	1.000	0.19
18	2037	74	1,100	1.000	0.19
19	2038	74	1,100	1.000	0.19
20	2039	74	1,100	1.000	0.19
21	2040	74	1,100	1.000	0.19
22	2041	74	1,100	1.000	0.19
23	2042	74	1,100	1.000	0.19

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	98	1,100	1.000	0.24
2	2021	98	1,100	1.000	0.24
3	2022	98	1,100	1.000	0.24
4	2023	98	1,100	1.000	0.24
5	2024	98	1,100	1.000	0.24
6	2025	98	1,100	1.000	0.24
7	2026	98	1,100	1.000	0.24
8	2027	98	1,100	1.000	0.24
9	2028	98	1,100	1.000	0.24
10	2029	98	1,100	1.000	0.24
11	2030	98	1,100	1.000	0.24
12	2031	98	1,100	1.000	0.24
13	2032	98	1,100	1.000	0.24
14	2033	98	1,100	1.000	0.24
15	2034	98	1,100	1.000	0.24
16	2035	98	1,100	1.000	0.24
17	2036	98	1,100	1.000	0.24
18	2037	98	1,100	1.000	0.24
19	2038	98	1,100	1.000	0.24
20	2039	98	1,100	1.000	0.24
21	2040	98	1,100	1.000	0.24
22	2041	98	1,100	1.000	0.24
23	2042	98	1,100	1.000	0.24

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.4%	-0.4%
2	2021	0.1%	-0.3%
3	2022	0.3%	0.0%
4	2023	0.5%	0.5%
5	2024	0.8%	1.3%
6	2025	1.0%	2.3%
7	2026	1.3%	3.7%
8	2027	1.6%	5.3%
9	2028	2.0%	7.3%
10	2029	2.3%	9.6%
11	2030	2.7%	12.3%
12	2031	3.1%	15.5%
13	2032	3.6%	19.1%
14	2033	4.1%	23.1%
15	2034	4.6%	27.7%
16	2035	5.1%	32.8%
17	2036	5.6%	38.4%
18	2037	5.9%	44.3%
19	2038	6.3%	50.6%
20	2039	6.7%	57.3%
21	2040	7.1%	64.4%
22	2041	7.6%	72.0%
23	2042	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	0.0%	-0.5%
3	2022	0.2%	-0.3%
4	2023	0.4%	0.1%
5	2024	0.7%	0.8%
6	2025	0.9%	1.8%
7	2026	1.2%	3.0%
8	2027	1.6%	4.6%
9	2028	1.9%	6.5%
10	2029	2.3%	8.7%
11	2030	2.7%	11.4%
12	2031	3.1%	14.5%
13	2032	3.5%	18.0%
14	2033	4.1%	22.1%
15	2034	4.6%	26.7%
16	2035	5.2%	31.8%
17	2036	5.7%	37.5%
18	2037	6.0%	43.5%
19	2038	6.4%	49.9%
20	2039	6.8%	56.7%
21	2040	7.3%	64.0%
22	2041	7.8%	71.8%
23	2042	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	131	2,468
2016	2,468	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,799
2018	9,799	1,954	39	668	841	13,301
2019	13,301	1,090	22	373	1,068	15,853
2020	15,853	372	-	135	-	16,360
2021	16,360	9	-	3	-	16,373
		9,760	179	3,355	3,078	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,482
2015	1,482	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,860
2018	12,860	2,554	51	874	1,139	17,477
2019	17,477	1,424	28	487	1,447	20,864
2020	20,864	486	-	176	-	21,526
2021	21,526	12	-	4	-	21,543
		12,755	234	4,384	4,169	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,853	507	36	16,397	26	(366)	16,056
2	2021	16,397	13	2	16,412	29	(699)	15,741
3	2022	16,412	-	(32)	16,379	28	(1,026)	15,382
4	2023	16,379	-	(80)	16,299	28	(1,346)	14,981
5	2024	16,299	-	(132)	16,167	27	(1,658)	14,536
6	2025	16,167	-	(184)	15,983	26	(1,962)	14,048
7	2026	15,983	-	(233)	15,750	26	(2,256)	13,520
8	2027	15,750	-	(289)	15,461	26	(2,540)	12,947
9	2028	15,461	-	(346)	15,114	26	(2,813)	12,328
10	2029	15,114	-	(407)	14,707	26	(3,073)	11,660
11	2030	14,707	-	(476)	14,231	26	(3,321)	10,936
12	2031	14,231	-	(542)	13,689	26	(3,555)	10,161
13	2032	13,689	-	(609)	13,080	27	(3,773)	9,334
14	2033	13,080	-	(684)	12,395	28	(3,975)	8,447
15	2034	12,395	-	(765)	11,631	28	(4,160)	7,498
16	2035	11,631	-	(843)	10,788	29	(4,158)	6,659
17	2036	10,788	-	(906)	9,882	29	(3,808)	6,103
18	2037	9,882	-	(956)	8,926	30	(3,438)	5,518
19	2038	8,926	-	(1,011)	7,915	31	(3,046)	4,900
20	2039	7,915	-	(1,065)	6,850	31	(2,631)	4,250
21	2040	6,850	-	(1,125)	5,725	32	(2,192)	3,565
22	2041	5,725	-	(1,198)	4,527	33	(1,722)	2,837
23	2042	4,527	-	(1,252)	3,275	34	(1,231)	2,077
			520	(13,098)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,864	663	70	21,597	26	(482)	21,141
2	2021	21,597	16	18	21,631	29	(920)	20,740
3	2022	21,631	-	(27)	21,604	28	(1,350)	20,283
4	2023	21,604	-	(87)	21,518	28	(1,772)	19,773
5	2024	21,518	-	(152)	21,366	27	(2,183)	19,209
6	2025	21,366	-	(218)	21,148	26	(2,584)	18,589
7	2026	21,148	-	(283)	20,865	26	(2,973)	17,917
8	2027	20,865	-	(357)	20,508	26	(3,349)	17,184
9	2028	20,508	-	(432)	20,075	26	(3,711)	16,390
10	2029	20,075	-	(514)	19,561	26	(4,057)	15,530
11	2030	19,561	-	(605)	18,957	26	(4,387)	14,596
12	2031	18,957	-	(696)	18,261	26	(4,698)	13,589
13	2032	18,261	-	(789)	17,472	27	(4,990)	12,510
14	2033	17,472	-	(893)	16,580	28	(5,260)	11,347
15	2034	16,580	-	(1,004)	15,576	28	(5,508)	10,096
16	2035	15,576	-	(1,116)	14,459	29	(5,582)	8,906
17	2036	14,459	-	(1,210)	13,250	29	(5,115)	8,164
18	2037	13,250	-	(1,281)	11,969	30	(4,618)	7,381
19	2038	11,969	-	(1,359)	10,609	31	(4,090)	6,551
20	2039	10,609	-	(1,438)	9,171	31	(3,529)	5,674
21	2040	9,171	-	(1,525)	7,646	32	(2,932)	4,746
22	2041	7,646	-	(1,629)	6,018	33	(2,293)	3,758
23	2042	6,018	-	(1,709)	4,309	34	(1,620)	2,722
			679	(17,234)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	630	526	(36)	312	59	317	365	2,173
2	2021	649	477	(2)	346	60	311	333	2,173
3	2022	636	467	32	342	61	307	328	2,173
4	2023	620	455	80	331	63	301	323	2,173
5	2024	603	443	132	320	64	295	317	2,173
6	2025	584	429	184	313	66	288	310	2,173
7	2026	563	414	233	312	67	282	302	2,173
8	2027	541	397	289	312	68	273	294	2,173
9	2028	516	379	346	311	70	266	284	2,173
10	2029	490	360	407	310	71	260	274	2,173
11	2030	462	339	476	310	73	250	264	2,173
12	2031	431	316	542	317	75	241	252	2,173
13	2032	398	292	609	323	76	235	239	2,173
14	2033	363	267	684	331	78	225	225	2,173
15	2034	326	239	765	338	80	216	211	2,173
16	2035	289	212	843	345	81	206	196	2,173
17	2036	261	191	906	353	83	193	185	2,173
18	2037	237	174	956	361	85	184	176	2,173
19	2038	213	156	1,011	369	87	171	167	2,173
20	2039	187	137	1,065	377	89	162	157	2,173
21	2040	160	117	1,125	385	91	149	146	2,173
22	2041	131	96	1,198	393	93	127	136	2,173
23	2042	100	74	1,252	402	95	127	123	2,173
		9,389	6,959	13,098	7,813	1,735	5,385	5,606	49,986

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	886	693	(70)	312	59	417	480	2,776
2	2021	914	628	(18)	346	60	409	438	2,776
3	2022	895	615	27	342	61	405	431	2,776
4	2023	874	601	87	331	63	397	424	2,776
5	2024	851	585	152	320	64	388	417	2,776
6	2025	825	567	218	313	66	380	408	2,776
7	2026	797	548	283	312	67	371	398	2,776
8	2027	766	527	357	312	68	359	388	2,776
9	2028	733	504	432	311	70	351	376	2,776
10	2029	697	479	514	310	71	342	363	2,776
11	2030	657	452	605	310	73	330	350	2,776
12	2031	615	423	696	317	75	317	335	2,776
13	2032	570	391	789	323	76	309	318	2,776
14	2033	521	358	893	331	78	296	300	2,776
15	2034	468	322	1,004	338	80	284	282	2,776
16	2035	415	285	1,116	345	81	271	262	2,776
17	2036	373	256	1,210	353	83	255	247	2,776
18	2037	339	233	1,281	361	85	242	235	2,776
19	2038	304	209	1,359	369	87	225	223	2,776
20	2039	267	183	1,438	377	89	213	210	2,776
21	2040	227	156	1,525	385	91	196	196	2,776
22	2041	186	128	1,629	393	93	167	181	2,776
23	2042	141	97	1,709	402	95	167	165	2,776
		13,319	9,239	17,234	7,813	1,735	7,091	7,428	63,858

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,173	4,500	1.118	1.18
2	2021	2,173	4,500	1.118	1.18
3	2022	2,173	4,500	1.118	1.18
4	2023	2,173	4,500	1.118	1.18
5	2024	2,173	4,500	1.118	1.18
6	2025	2,173	4,500	1.118	1.18
7	2026	2,173	4,500	1.118	1.18
8	2027	2,173	4,500	1.118	1.18
9	2028	2,173	4,500	1.118	1.18
10	2029	2,173	4,500	1.118	1.18
11	2030	2,173	4,500	1.118	1.18
12	2031	2,173	4,500	1.118	1.18
13	2032	2,173	4,500	1.118	1.18
14	2033	2,173	4,500	1.118	1.18
15	2034	2,173	4,500	1.118	1.18
16	2035	2,173	4,500	1.118	1.18
17	2036	2,173	4,500	1.118	1.18
18	2037	2,173	4,500	1.118	1.18
19	2038	2,173	4,500	1.118	1.18
20	2039	2,173	4,500	1.118	1.18
21	2040	2,173	4,500	1.118	1.18
22	2041	2,173	4,500	1.118	1.18
23	2042	2,173	4,500	1.118	1.18

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,776	4,500	1.118	1.51
2	2021	2,776	4,500	1.118	1.51
3	2022	2,776	4,500	1.118	1.51
4	2023	2,776	4,500	1.118	1.51
5	2024	2,776	4,500	1.118	1.51
6	2025	2,776	4,500	1.118	1.51
7	2026	2,776	4,500	1.118	1.51
8	2027	2,776	4,500	1.118	1.51
9	2028	2,776	4,500	1.118	1.51
10	2029	2,776	4,500	1.118	1.51
11	2030	2,776	4,500	1.118	1.51
12	2031	2,776	4,500	1.118	1.51
13	2032	2,776	4,500	1.118	1.51
14	2033	2,776	4,500	1.118	1.51
15	2034	2,776	4,500	1.118	1.51
16	2035	2,776	4,500	1.118	1.51
17	2036	2,776	4,500	1.118	1.51
18	2037	2,776	4,500	1.118	1.51
19	2038	2,776	4,500	1.118	1.51
20	2039	2,776	4,500	1.118	1.51
21	2040	2,776	4,500	1.118	1.51
22	2041	2,776	4,500	1.118	1.51
23	2042	2,776	4,500	1.118	1.51

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.0%	-0.2%
3	2022	0.2%	0.0%
4	2023	0.5%	0.5%
5	2024	0.8%	1.3%
6	2025	1.1%	2.4%
7	2026	1.4%	3.8%
8	2027	1.8%	5.6%
9	2028	2.1%	7.7%
10	2029	2.5%	10.2%
11	2030	2.9%	13.1%
12	2031	3.3%	16.4%
13	2032	3.7%	20.1%
14	2033	4.2%	24.3%
15	2034	4.7%	29.0%
16	2035	5.1%	34.1%
17	2036	5.5%	39.6%
18	2037	5.8%	45.5%
19	2038	6.2%	51.7%
20	2039	6.5%	58.2%
21	2040	6.9%	65.0%
22	2041	7.3%	72.4%
23	2042	7.6%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	-0.1%	-0.4%
3	2022	0.1%	-0.3%
4	2023	0.4%	0.1%
5	2024	0.7%	0.8%
6	2025	1.0%	1.8%
7	2026	1.3%	3.1%
8	2027	1.7%	4.8%
9	2028	2.0%	6.8%
10	2029	2.4%	9.2%
11	2030	2.8%	12.0%
12	2031	3.2%	15.2%
13	2032	3.7%	18.9%
14	2033	4.1%	23.0%
15	2034	4.7%	27.7%
16	2035	5.2%	32.9%
17	2036	5.6%	38.5%
18	2037	5.9%	44.4%
19	2038	6.3%	50.8%
20	2039	6.7%	57.4%
21	2040	7.1%	64.5%
22	2041	7.6%	72.1%
23	2042	7.9%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	52	838
2015	838	750	15	140	97	1,840
2016	1,840	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,421
2018	4,421	4,648	93	869	544	10,574
2019	10,574	1,928	39	360	886	13,787
2020	13,787	77	-	16	-	13,880
2021	13,880	9	-	2	-	13,891
		9,807	186	1,844	2,055	

Alaska Pipeline Project - Alaska-Canada Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,807
2018	5,807	6,074	121	1,135	737	13,874
2019	13,874	2,519	50	471	1,200	18,114
2020	18,114	101	-	21	-	18,236
2021	18,236	12	-	2	-	18,251
		12,816	243	2,409	2,783	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,787	93	56	13,936	56	(315)	13,677
2	2021	13,936	11	(14)	13,933	57	(599)	13,390
3	2022	13,933	-	(41)	13,892	57	(877)	13,071
4	2023	13,892	-	(73)	13,818	57	(1,148)	12,727
5	2024	13,818	-	(108)	13,710	57	(1,413)	12,354
6	2025	13,710	-	(145)	13,565	57	(1,670)	11,952
7	2026	13,565	-	(185)	13,381	57	(1,919)	11,519
8	2027	13,381	-	(230)	13,151	58	(2,160)	11,049
9	2028	13,151	-	(275)	12,876	58	(2,391)	10,542
10	2029	12,876	-	(324)	12,551	58	(2,612)	9,997
11	2030	12,551	-	(379)	12,172	58	(2,822)	9,408
12	2031	12,172	-	(438)	11,734	58	(3,021)	8,771
13	2032	11,734	-	(499)	11,234	59	(3,206)	8,087
14	2033	11,234	-	(567)	10,668	59	(3,379)	7,348
15	2034	10,668	-	(639)	10,029	59	(3,536)	6,552
16	2035	10,029	-	(711)	9,318	59	(3,542)	5,835
17	2036	9,318	-	(771)	8,547	59	(3,249)	5,358
18	2037	8,547	-	(819)	7,728	60	(2,938)	4,850
19	2038	7,728	-	(872)	6,856	60	(2,606)	4,310
20	2039	6,856	-	(926)	5,930	60	(2,254)	3,736
21	2040	5,930	-	(985)	4,945	60	(1,880)	3,126
22	2041	4,945	-	(1,056)	3,890	61	(1,479)	2,472
23	2042	3,890	-	(1,111)	2,778	61	(1,056)	1,783
			104	(11,113)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,114	122	91	18,327	56	(414)	17,969
2	2021	18,327	15	(0)	18,341	57	(787)	17,611
3	2022	18,341	-	(36)	18,305	57	(1,152)	17,210
4	2023	18,305	-	(78)	18,227	57	(1,509)	16,775
5	2024	18,227	-	(124)	18,103	57	(1,858)	16,303
6	2025	18,103	-	(173)	17,930	57	(2,197)	15,790
7	2026	17,930	-	(226)	17,704	57	(2,526)	15,236
8	2027	17,704	-	(286)	17,418	58	(2,844)	14,632
9	2028	17,418	-	(348)	17,070	58	(3,150)	13,978
10	2029	17,070	-	(414)	16,657	58	(3,443)	13,272
11	2030	16,657	-	(488)	16,169	58	(3,722)	12,505
12	2031	16,169	-	(568)	15,601	58	(3,985)	11,674
13	2032	15,601	-	(650)	14,951	59	(4,232)	10,777
14	2033	14,951	-	(743)	14,208	59	(4,462)	9,805
15	2034	14,208	-	(842)	13,366	59	(4,671)	8,754
16	2035	13,366	-	(942)	12,425	59	(4,725)	7,759
17	2036	12,425	-	(1,026)	11,399	59	(4,335)	7,123
18	2037	11,399	-	(1,093)	10,306	60	(3,919)	6,446
19	2038	10,306	-	(1,167)	9,139	60	(3,475)	5,723
20	2039	9,139	-	(1,242)	7,897	60	(3,003)	4,954
21	2040	7,897	-	(1,324)	6,573	60	(2,499)	4,134
22	2041	6,573	-	(1,422)	5,151	61	(1,959)	3,253
23	2042	5,151	-	(1,501)	3,650	61	(1,388)	2,323
			136	(14,600)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	542	453	(56)	85	11	269	314	1,619
2	2021	553	406	14	87	11	264	284	1,619
3	2022	540	397	41	89	11	261	279	1,619
4	2023	527	387	73	91	12	256	273	1,619
5	2024	512	376	108	93	12	250	267	1,619
6	2025	496	365	145	95	12	245	261	1,619
7	2026	479	352	185	97	12	240	254	1,619
8	2027	461	339	230	99	13	231	247	1,619
9	2028	441	324	275	101	13	226	238	1,619
10	2029	420	308	324	103	13	221	230	1,619
11	2030	396	291	379	106	13	213	220	1,619
12	2031	371	273	438	108	14	205	210	1,619
13	2032	344	253	499	110	14	199	199	1,619
14	2033	315	232	567	113	14	191	187	1,619
15	2034	284	208	639	115	15	183	174	1,619
16	2035	253	186	711	118	15	175	162	1,619
17	2036	229	168	771	120	15	164	152	1,619
18	2037	209	153	819	123	16	156	144	1,619
19	2038	187	137	872	126	16	145	135	1,619
20	2039	164	121	926	128	16	137	126	1,619
21	2040	140	103	985	131	17	126	116	1,619
22	2041	114	84	1,056	134	17	108	106	1,619
23	2042	87	64	1,111	137	17	108	94	1,619
		8,066	5,979	11,113	2,507	318	4,573	4,672	37,228

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	761	596	(91)	85	11	354	412	2,127
2	2021	776	534	0	87	11	347	373	2,127
3	2022	760	522	36	89	11	343	366	2,127
4	2023	742	510	78	91	12	336	359	2,127
5	2024	722	496	124	93	12	329	352	2,127
6	2025	700	481	173	95	12	322	344	2,127
7	2026	677	465	226	97	12	315	335	2,127
8	2027	652	448	286	99	13	304	326	2,127
9	2028	624	429	348	101	13	297	315	2,127
10	2029	595	409	414	103	13	290	304	2,127
11	2030	562	387	488	106	13	279	292	2,127
12	2031	528	363	568	108	14	269	278	2,127
13	2032	490	337	650	110	14	262	264	2,127
14	2033	449	309	743	113	14	251	249	2,127
15	2034	405	278	842	115	15	240	232	2,127
16	2035	360	248	942	118	15	230	215	2,127
17	2036	325	223	1,026	120	15	216	202	2,127
18	2037	296	204	1,093	123	16	205	191	2,127
19	2038	266	183	1,167	126	16	191	179	2,127
20	2039	233	160	1,242	128	16	180	167	2,127
21	2040	198	136	1,324	131	17	166	154	2,127
22	2041	161	111	1,422	134	17	141	141	2,127
23	2042	122	84	1,501	137	17	141	125	2,127
		11,404	7,911	14,600	2,507	318	6,008	6,173	48,923

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	88	375	0.64	1,530	4,656	0.90
2	2021	1.118	88	375	0.64	1,530	4,656	0.90
3	2022	1.118	88	375	0.64	1,530	4,656	0.90
4	2023	1.118	88	375	0.64	1,530	4,656	0.90
5	2024	1.118	88	375	0.64	1,530	4,656	0.90
6	2025	1.118	88	375	0.64	1,530	4,656	0.90
7	2026	1.118	88	375	0.64	1,530	4,656	0.90
8	2027	1.118	88	375	0.64	1,530	4,656	0.90
9	2028	1.118	88	375	0.64	1,530	4,656	0.90
10	2029	1.118	88	375	0.64	1,530	4,656	0.90
11	2030	1.118	88	375	0.64	1,530	4,656	0.90
12	2031	1.118	88	375	0.64	1,530	4,656	0.90
13	2032	1.118	88	375	0.64	1,530	4,656	0.90
14	2033	1.118	88	375	0.64	1,530	4,656	0.90
15	2034	1.118	88	375	0.64	1,530	4,656	0.90
16	2035	1.118	88	375	0.64	1,530	4,656	0.90
17	2036	1.118	88	375	0.64	1,530	4,656	0.90
18	2037	1.118	88	375	0.64	1,530	4,656	0.90
19	2038	1.118	88	375	0.64	1,530	4,656	0.90
20	2039	1.118	88	375	0.64	1,530	4,656	0.90
21	2040	1.118	88	375	0.64	1,530	4,656	0.90
22	2041	1.118	88	375	0.64	1,530	4,656	0.90
23	2042	1.118	88	375	0.64	1,530	4,656	0.90

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	116	375	0.85	2,011	4,656	1.18
2	2021	1.118	116	375	0.85	2,011	4,656	1.18
3	2022	1.118	116	375	0.85	2,011	4,656	1.18
4	2023	1.118	116	375	0.85	2,011	4,656	1.18
5	2024	1.118	116	375	0.85	2,011	4,656	1.18
6	2025	1.118	116	375	0.85	2,011	4,656	1.18
7	2026	1.118	116	375	0.85	2,011	4,656	1.18
8	2027	1.118	116	375	0.85	2,011	4,656	1.18
9	2028	1.118	116	375	0.85	2,011	4,656	1.18
10	2029	1.118	116	375	0.85	2,011	4,656	1.18
11	2030	1.118	116	375	0.85	2,011	4,656	1.18
12	2031	1.118	116	375	0.85	2,011	4,656	1.18
13	2032	1.118	116	375	0.85	2,011	4,656	1.18
14	2033	1.118	116	375	0.85	2,011	4,656	1.18
15	2034	1.118	116	375	0.85	2,011	4,656	1.18
16	2035	1.118	116	375	0.85	2,011	4,656	1.18
17	2036	1.118	116	375	0.85	2,011	4,656	1.18
18	2037	1.118	116	375	0.85	2,011	4,656	1.18
19	2038	1.118	116	375	0.85	2,011	4,656	1.18
20	2039	1.118	116	375	0.85	2,011	4,656	1.18
21	2040	1.118	116	375	0.85	2,011	4,656	1.18
22	2041	1.118	116	375	0.85	2,011	4,656	1.18
23	2042	1.118	116	375	0.85	2,011	4,656	1.18

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.4%	-0.4%
2	2021	0.1%	-0.3%
3	2022	0.3%	0.0%
4	2023	0.5%	0.5%
5	2024	0.8%	1.3%
6	2025	1.0%	2.3%
7	2026	1.3%	3.7%
8	2027	1.7%	5.3%
9	2028	2.0%	7.3%
10	2029	2.3%	9.6%
11	2030	2.7%	12.4%
12	2031	3.2%	15.5%
13	2032	3.6%	19.1%
14	2033	4.1%	23.2%
15	2034	4.6%	27.8%
16	2035	5.1%	32.9%
17	2036	5.5%	38.5%
18	2037	5.9%	44.4%
19	2038	6.3%	50.6%
20	2039	6.7%	57.3%
21	2040	7.1%	64.4%
22	2041	7.6%	72.0%
23	2042	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	0.0%	-0.5%
3	2022	0.2%	-0.3%
4	2023	0.4%	0.1%
5	2024	0.7%	0.8%
6	2025	0.9%	1.8%
7	2026	1.2%	3.0%
8	2027	1.6%	4.6%
9	2028	1.9%	6.5%
10	2029	2.3%	8.7%
11	2030	2.7%	11.4%
12	2031	3.1%	14.5%
13	2032	3.6%	18.1%
14	2033	4.1%	22.2%
15	2034	4.6%	26.8%
16	2035	5.2%	31.9%
17	2036	5.6%	37.5%
18	2037	6.0%	43.5%
19	2038	6.4%	49.9%
20	2039	6.8%	56.7%
21	2040	7.3%	64.0%
22	2041	7.8%	71.8%
23	2042	8.2%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(24 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	6	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	637
2020	637	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	637	4	4	644	1	(15)	631
2	2021	644	1	0	645	1	(28)	618
3	2022	645	-	(1)	644	1	(40)	604
4	2023	644	-	(2)	642	1	(53)	590
5	2024	642	-	(4)	638	1	(65)	574
6	2025	638	-	(5)	633	1	(77)	557
7	2026	633	-	(7)	626	1	(89)	538
8	2027	626	-	(9)	617	1	(100)	518
9	2028	617	-	(11)	606	1	(111)	496
10	2029	606	-	(13)	593	1	(121)	473
11	2030	593	-	(15)	578	1	(131)	448
12	2031	578	-	(18)	560	1	(141)	420
13	2032	560	-	(20)	540	1	(150)	391
14	2033	540	-	(23)	517	1	(158)	359
15	2034	517	-	(26)	490	1	(166)	325
16	2035	490	-	(30)	460	1	(173)	288
17	2036	460	-	(33)	427	1	(167)	262
18	2037	427	-	(35)	392	1	(153)	240
19	2038	392	-	(38)	355	1	(138)	217
20	2039	355	-	(40)	315	1	(123)	193
21	2040	315	-	(42)	272	1	(106)	167
22	2041	272	-	(45)	227	1	(88)	140
23	2042	227	-	(48)	179	1	(69)	111
24	2043	179	-	(52)	128	1	(49)	80
			5	(513)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	5	848	1	(19)	830
2	2021	848	1	1	849	1	(36)	814
3	2022	849	-	(0)	849	1	(53)	797
4	2023	849	-	(2)	847	1	(70)	778
5	2024	847	-	(4)	843	1	(86)	758
6	2025	843	-	(6)	837	1	(102)	736
7	2026	837	-	(8)	829	1	(117)	713
8	2027	829	-	(11)	818	1	(132)	687
9	2028	818	-	(14)	804	1	(146)	659
10	2029	804	-	(16)	788	1	(160)	629
11	2030	788	-	(20)	768	1	(173)	596
12	2031	768	-	(23)	745	1	(186)	560
13	2032	745	-	(27)	719	1	(198)	522
14	2033	719	-	(30)	688	1	(209)	480
15	2034	688	-	(35)	654	1	(219)	435
16	2035	654	-	(39)	614	1	(229)	387
17	2036	614	-	(44)	571	1	(223)	349
18	2037	571	-	(47)	524	1	(205)	320
19	2038	524	-	(50)	473	1	(185)	289
20	2039	473	-	(53)	420	1	(164)	257
21	2040	420	-	(57)	363	1	(142)	223
22	2041	363	-	(61)	302	1	(117)	186
23	2042	302	-	(64)	238	1	(92)	147
24	2043	238	-	(70)	168	1	(64)	105
			6	(674)				

Alaska Pipeline Project - Alaska-Canada Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(4)	4	0	12	14	73
2	2021	26	19	(0)	4	0	12	13	73
3	2022	25	18	1	4	0	12	13	73
4	2023	24	18	2	4	0	12	13	73
5	2024	24	17	4	4	0	12	12	73
6	2025	23	17	5	4	0	11	12	73
7	2026	22	16	7	4	0	11	12	73
8	2027	22	16	9	4	0	11	12	73
9	2028	21	15	11	5	0	10	11	73
10	2029	20	15	13	5	0	10	11	73
11	2030	19	14	15	5	0	10	10	73
12	2031	18	13	18	5	0	9	10	73
13	2032	17	12	20	5	1	9	10	73
14	2033	15	11	23	5	1	9	9	73
15	2034	14	10	26	5	1	8	8	73
16	2035	13	9	30	5	1	8	8	73
17	2036	11	8	33	5	1	8	7	73
18	2037	10	8	35	6	1	7	7	73
19	2038	9	7	38	6	1	7	7	73
20	2039	8	6	40	6	1	6	6	73
21	2040	7	5	42	6	1	6	6	73
22	2041	6	5	45	6	1	5	5	73
23	2042	5	4	48	6	1	5	5	73
24	2043	4	3	52	6	1	3	5	73
		389	288	513	120	12	214	227	1,762

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	28	(5)	4	0	16	19	97
2	2021	36	25	(1)	4	0	16	17	97
3	2022	35	24	0	4	0	16	17	97
4	2023	34	24	2	4	0	16	17	97
5	2024	34	23	4	4	0	15	16	97
6	2025	33	22	6	4	0	15	16	97
7	2026	32	22	8	4	0	15	16	97
8	2027	31	21	11	4	0	14	15	97
9	2028	29	20	14	5	0	14	15	97
10	2029	28	19	16	5	0	13	14	97
11	2030	27	18	20	5	0	13	14	97
12	2031	25	17	23	5	0	12	13	97
13	2032	24	16	27	5	1	12	13	97
14	2033	22	15	30	5	1	12	12	97
15	2034	20	14	35	5	1	11	11	97
16	2035	18	12	39	5	1	11	11	97
17	2036	16	11	44	5	1	10	10	97
18	2037	15	10	47	6	1	9	9	97
19	2038	13	9	50	6	1	9	9	97
20	2039	12	8	53	6	1	8	8	97
21	2040	10	7	57	6	1	8	8	97
22	2041	9	6	61	6	1	7	7	97
23	2042	7	5	64	6	1	7	7	97
24	2043	6	4	70	6	1	5	6	97
		550	382	674	120	12	282	300	2,320

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	73	1,100	1.000	0.18
2	2021	73	1,100	1.000	0.18
3	2022	73	1,100	1.000	0.18
4	2023	73	1,100	1.000	0.18
5	2024	73	1,100	1.000	0.18
6	2025	73	1,100	1.000	0.18
7	2026	73	1,100	1.000	0.18
8	2027	73	1,100	1.000	0.18
9	2028	73	1,100	1.000	0.18
10	2029	73	1,100	1.000	0.18
11	2030	73	1,100	1.000	0.18
12	2031	73	1,100	1.000	0.18
13	2032	73	1,100	1.000	0.18
14	2033	73	1,100	1.000	0.18
15	2034	73	1,100	1.000	0.18
16	2035	73	1,100	1.000	0.18
17	2036	73	1,100	1.000	0.18
18	2037	73	1,100	1.000	0.18
19	2038	73	1,100	1.000	0.18
20	2039	73	1,100	1.000	0.18
21	2040	73	1,100	1.000	0.18
22	2041	73	1,100	1.000	0.18
23	2042	73	1,100	1.000	0.18
24	2043	73	1,100	1.000	0.18

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	97	1,100	1.000	0.24
2	2021	97	1,100	1.000	0.24
3	2022	97	1,100	1.000	0.24
4	2023	97	1,100	1.000	0.24
5	2024	97	1,100	1.000	0.24
6	2025	97	1,100	1.000	0.24
7	2026	97	1,100	1.000	0.24
8	2027	97	1,100	1.000	0.24
9	2028	97	1,100	1.000	0.24
10	2029	97	1,100	1.000	0.24
11	2030	97	1,100	1.000	0.24
12	2031	97	1,100	1.000	0.24
13	2032	97	1,100	1.000	0.24
14	2033	97	1,100	1.000	0.24
15	2034	97	1,100	1.000	0.24
16	2035	97	1,100	1.000	0.24
17	2036	97	1,100	1.000	0.24
18	2037	97	1,100	1.000	0.24
19	2038	97	1,100	1.000	0.24
20	2039	97	1,100	1.000	0.24
21	2040	97	1,100	1.000	0.24
22	2041	97	1,100	1.000	0.24
23	2042	97	1,100	1.000	0.24
24	2043	97	1,100	1.000	0.24

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.6%
3	2022	0.1%	-0.5%
4	2023	0.3%	-0.2%
5	2024	0.6%	0.4%
6	2025	0.8%	1.2%
7	2026	1.1%	2.3%
8	2027	1.4%	3.7%
9	2028	1.7%	5.4%
10	2029	2.0%	7.4%
11	2030	2.4%	9.8%
12	2031	2.8%	12.5%
13	2032	3.2%	15.7%
14	2033	3.6%	19.4%
15	2034	4.1%	23.5%
16	2035	4.6%	28.1%
17	2036	5.1%	33.3%
18	2037	5.5%	38.8%
19	2038	5.9%	44.6%
20	2039	6.2%	50.8%
21	2040	6.6%	57.4%
22	2041	7.1%	64.5%
23	2042	7.4%	72.0%
24	2043	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.8%
3	2022	0.0%	-0.8%
4	2023	0.2%	-0.6%
5	2024	0.5%	-0.1%
6	2025	0.7%	0.6%
7	2026	1.0%	1.6%
8	2027	1.3%	2.9%
9	2028	1.6%	4.5%
10	2029	1.9%	6.5%
11	2030	2.3%	8.8%
12	2031	2.7%	11.5%
13	2032	3.1%	14.6%
14	2033	3.6%	18.3%
15	2034	4.1%	22.4%
16	2035	4.7%	27.0%
17	2036	5.2%	32.2%
18	2037	5.6%	37.8%
19	2038	6.0%	43.8%
20	2039	6.3%	50.1%
21	2040	6.7%	56.9%
22	2041	7.2%	64.1%
23	2042	7.6%	71.7%
24	2043	8.3%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	131	2,468
2016	2,468	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,799
2018	9,799	1,954	39	668	841	13,301
2019	13,301	1,090	22	373	1,068	15,854
2020	15,854	372	-	135	-	16,361
2021	16,361	9	-	3	-	16,373
		9,760	179	3,355	3,079	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,482
2015	1,482	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,860
2018	12,860	2,554	51	874	1,139	17,477
2019	17,477	1,424	28	487	1,448	20,864
2020	20,864	486	-	176	-	21,527
2021	21,527	12	-	4	-	21,543
		12,755	234	4,384	4,170	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,854	507	61	16,422	26	(366)	16,081
2	2021	16,422	13	29	16,463	29	(699)	15,792
3	2022	16,463	-	(4)	16,459	28	(1,027)	15,461
4	2023	16,459	-	(49)	16,410	28	(1,348)	15,090
5	2024	16,410	-	(98)	16,312	27	(1,662)	14,677
6	2025	16,312	-	(147)	16,164	26	(1,968)	14,223
7	2026	16,164	-	(194)	15,971	26	(2,265)	13,732
8	2027	15,971	-	(247)	15,724	26	(2,553)	13,197
9	2028	15,724	-	(300)	15,424	26	(2,830)	12,620
10	2029	15,424	-	(358)	15,066	26	(3,096)	11,996
11	2030	15,066	-	(422)	14,644	26	(3,350)	11,320
12	2031	14,644	-	(484)	14,160	26	(3,591)	10,595
13	2032	14,160	-	(547)	13,613	27	(3,818)	9,822
14	2033	13,613	-	(617)	12,995	28	(4,029)	8,994
15	2034	12,995	-	(692)	12,303	28	(4,225)	8,106
16	2035	12,303	-	(773)	11,530	29	(4,403)	7,156
17	2036	11,530	-	(842)	10,689	29	(4,126)	6,592
18	2037	10,689	-	(890)	9,799	30	(3,783)	6,046
19	2038	9,799	-	(941)	8,858	31	(3,418)	5,470
20	2039	8,858	-	(992)	7,865	31	(3,033)	4,864
21	2040	7,865	-	(1,049)	6,817	32	(2,624)	4,225
22	2041	6,817	-	(1,117)	5,699	33	(2,187)	3,545
23	2042	5,699	-	(1,167)	4,532	34	(1,729)	2,836
24	2043	4,532	-	(1,257)	3,275	34	(1,235)	2,074
			520	(13,099)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,864	663	102	21,629	26	(481)	21,174
2	2021	21,629	16	53	21,698	29	(920)	20,807
3	2022	21,698	-	11	21,709	28	(1,351)	20,387
4	2023	21,709	-	(46)	21,664	28	(1,774)	19,917
5	2024	21,664	-	(107)	21,557	27	(2,188)	19,395
6	2025	21,557	-	(169)	21,387	26	(2,592)	18,821
7	2026	21,387	-	(230)	21,157	26	(2,985)	18,198
8	2027	21,157	-	(300)	20,857	26	(3,366)	17,517
9	2028	20,857	-	(371)	20,487	26	(3,734)	16,778
10	2029	20,487	-	(447)	20,040	26	(4,087)	15,978
11	2030	20,040	-	(532)	19,508	26	(4,425)	15,108
12	2031	19,508	-	(617)	18,890	26	(4,746)	14,170
13	2032	18,890	-	(704)	18,186	27	(5,049)	13,164
14	2033	18,186	-	(801)	17,385	28	(5,332)	12,081
15	2034	17,385	-	(905)	16,480	28	(5,594)	10,914
16	2035	16,480	-	(1,017)	15,463	29	(5,833)	9,658
17	2036	15,463	-	(1,117)	14,345	29	(5,547)	8,827
18	2037	14,345	-	(1,190)	13,155	30	(5,087)	8,098
19	2038	13,155	-	(1,264)	11,891	31	(4,597)	7,325
20	2039	11,891	-	(1,338)	10,554	31	(4,076)	6,509
21	2040	10,554	-	(1,419)	9,135	32	(3,522)	5,645
22	2041	9,135	-	(1,517)	7,618	33	(2,928)	4,723
23	2042	7,618	-	(1,591)	6,027	34	(2,303)	3,758
24	2043	6,027	-	(1,718)	4,309	34	(1,625)	2,717
			679	(17,235)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	631	527	(61)	312	56	317	364	2,147
2	2021	651	478	(29)	346	58	311	332	2,147
3	2022	639	469	4	342	59	308	327	2,147
4	2023	624	458	49	331	60	302	323	2,147
5	2024	608	447	98	320	61	295	317	2,147
6	2025	591	433	147	313	63	289	311	2,147
7	2026	571	419	194	312	64	283	304	2,147
8	2027	550	404	247	312	66	273	296	2,147
9	2028	528	387	300	311	67	267	287	2,147
10	2029	503	369	358	310	69	260	278	2,147
11	2030	476	350	422	310	70	251	268	2,147
12	2031	448	329	484	317	72	241	257	2,147
13	2032	417	306	547	323	73	235	245	2,147
14	2033	384	282	617	331	75	225	232	2,147
15	2034	349	256	692	338	76	216	219	2,147
16	2035	312	229	773	345	78	206	204	2,147
17	2036	281	206	842	353	80	194	192	2,147
18	2037	258	190	890	361	82	184	183	2,147
19	2038	235	173	941	369	83	171	174	2,147
20	2039	211	155	992	377	85	162	165	2,147
21	2040	186	136	1,049	385	87	149	155	2,147
22	2041	159	117	1,117	393	89	127	145	2,147
23	2042	130	96	1,167	402	91	127	134	2,147
24	2043	100	74	1,257	411	93	89	123	2,147
		9,844	7,290	13,099	8,224	1,756	5,483	5,837	51,532

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	887	693	(102)	312	56	418	478	2,743
2	2021	916	630	(53)	346	58	410	437	2,743
3	2022	899	618	(11)	342	59	405	431	2,743
4	2023	880	605	46	331	60	397	425	2,743
5	2024	858	590	107	320	61	389	418	2,743
6	2025	834	573	169	313	63	380	410	2,743
7	2026	808	555	230	312	64	372	401	2,743
8	2027	780	536	300	312	66	360	391	2,743
9	2028	749	514	371	311	67	351	380	2,743
10	2029	715	491	447	310	69	343	368	2,743
11	2030	679	466	532	310	70	330	356	2,743
12	2031	639	439	617	317	72	318	342	2,743
13	2032	597	410	704	323	73	309	326	2,743
14	2033	551	379	801	331	75	297	310	2,743
15	2034	502	345	905	338	76	284	292	2,743
16	2035	449	309	1,017	345	78	272	273	2,743
17	2036	404	277	1,117	353	80	255	257	2,743
18	2037	369	254	1,190	361	82	242	245	2,743
19	2038	337	231	1,264	369	83	226	233	2,743
20	2039	302	208	1,338	377	85	213	221	2,743
21	2040	265	182	1,419	385	87	196	208	2,743
22	2041	226	156	1,517	393	89	167	195	2,743
23	2042	185	127	1,591	402	91	167	179	2,743
24	2043	141	97	1,718	411	93	117	165	2,743
		13,972	9,685	17,235	8,224	1,756	7,219	7,739	65,830

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,147	4,500	1.118	1.17
2	2021	2,147	4,500	1.118	1.17
3	2022	2,147	4,500	1.118	1.17
4	2023	2,147	4,500	1.118	1.17
5	2024	2,147	4,500	1.118	1.17
6	2025	2,147	4,500	1.118	1.17
7	2026	2,147	4,500	1.118	1.17
8	2027	2,147	4,500	1.118	1.17
9	2028	2,147	4,500	1.118	1.17
10	2029	2,147	4,500	1.118	1.17
11	2030	2,147	4,500	1.118	1.17
12	2031	2,147	4,500	1.118	1.17
13	2032	2,147	4,500	1.118	1.17
14	2033	2,147	4,500	1.118	1.17
15	2034	2,147	4,500	1.118	1.17
16	2035	2,147	4,500	1.118	1.17
17	2036	2,147	4,500	1.118	1.17
18	2037	2,147	4,500	1.118	1.17
19	2038	2,147	4,500	1.118	1.17
20	2039	2,147	4,500	1.118	1.17
21	2040	2,147	4,500	1.118	1.17
22	2041	2,147	4,500	1.118	1.17
23	2042	2,147	4,500	1.118	1.17
24	2043	2,147	4,500	1.118	1.17

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,743	4,500	1.118	1.49
2	2021	2,743	4,500	1.118	1.49
3	2022	2,743	4,500	1.118	1.49
4	2023	2,743	4,500	1.118	1.49
5	2024	2,743	4,500	1.118	1.49
6	2025	2,743	4,500	1.118	1.49
7	2026	2,743	4,500	1.118	1.49
8	2027	2,743	4,500	1.118	1.49
9	2028	2,743	4,500	1.118	1.49
10	2029	2,743	4,500	1.118	1.49
11	2030	2,743	4,500	1.118	1.49
12	2031	2,743	4,500	1.118	1.49
13	2032	2,743	4,500	1.118	1.49
14	2033	2,743	4,500	1.118	1.49
15	2034	2,743	4,500	1.118	1.49
16	2035	2,743	4,500	1.118	1.49
17	2036	2,743	4,500	1.118	1.49
18	2037	2,743	4,500	1.118	1.49
19	2038	2,743	4,500	1.118	1.49
20	2039	2,743	4,500	1.118	1.49
21	2040	2,743	4,500	1.118	1.49
22	2041	2,743	4,500	1.118	1.49
23	2042	2,743	4,500	1.118	1.49
24	2043	2,743	4,500	1.118	1.49

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.4%	-0.4%
2	2021	-0.2%	-0.5%
3	2022	0.0%	-0.5%
4	2023	0.3%	-0.2%
5	2024	0.6%	0.4%
6	2025	0.9%	1.3%
7	2026	1.2%	2.5%
8	2027	1.5%	4.0%
9	2028	1.8%	5.8%
10	2029	2.2%	8.0%
11	2030	2.6%	10.6%
12	2031	3.0%	13.5%
13	2032	3.3%	16.9%
14	2033	3.8%	20.6%
15	2034	4.2%	24.9%
16	2035	4.7%	29.6%
17	2036	5.1%	34.7%
18	2037	5.4%	40.2%
19	2038	5.7%	45.9%
20	2039	6.1%	52.0%
21	2040	6.4%	58.4%
22	2041	6.8%	65.2%
23	2042	7.1%	72.3%
24	2043	7.7%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.2%	-0.7%
3	2022	-0.1%	-0.8%
4	2023	0.2%	-0.6%
5	2024	0.5%	-0.1%
6	2025	0.8%	0.7%
7	2026	1.1%	1.8%
8	2027	1.4%	3.2%
9	2028	1.7%	4.9%
10	2029	2.1%	7.0%
11	2030	2.5%	9.4%
12	2031	2.9%	12.3%
13	2032	3.3%	15.6%
14	2033	3.7%	19.3%
15	2034	4.2%	23.5%
16	2035	4.7%	28.2%
17	2036	5.2%	33.4%
18	2037	5.5%	38.9%
19	2038	5.9%	44.8%
20	2039	6.2%	51.0%
21	2040	6.6%	57.6%
22	2041	7.0%	64.6%
23	2042	7.4%	72.0%
24	2043	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	52	838
2015	838	750	15	140	97	1,840
2016	1,840	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,421
2018	4,421	4,648	93	869	544	10,575
2019	10,575	1,928	39	360	886	13,787
2020	13,787	77	-	16	-	13,880
2021	13,880	9	-	2	-	13,892
		9,807	186	1,844	2,055	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,807
2018	5,807	6,074	121	1,135	737	13,874
2019	13,874	2,519	50	471	1,200	18,115
2020	18,115	101	-	21	-	18,237
2021	18,237	12	-	2	-	18,251
		12,816	243	2,409	2,783	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,787	93	77	13,957	56	(315)	13,698
2	2021	13,957	11	9	13,977	57	(599)	13,434
3	2022	13,977	-	(16)	13,960	57	(878)	13,139
4	2023	13,960	-	(46)	13,914	57	(1,150)	12,820
5	2024	13,914	-	(79)	13,835	57	(1,417)	12,476
6	2025	13,835	-	(113)	13,722	57	(1,676)	12,103
7	2026	13,722	-	(150)	13,572	57	(1,928)	11,701
8	2027	13,572	-	(192)	13,380	58	(2,172)	11,265
9	2028	13,380	-	(235)	13,145	58	(2,408)	10,795
10	2029	13,145	-	(281)	12,864	58	(2,634)	10,288
11	2030	12,864	-	(332)	12,532	58	(2,849)	9,740
12	2031	12,532	-	(388)	12,144	58	(3,054)	9,148
13	2032	12,144	-	(444)	11,700	59	(3,247)	8,511
14	2033	11,700	-	(508)	11,192	59	(3,428)	7,823
15	2034	11,192	-	(576)	10,616	59	(3,594)	7,081
16	2035	10,616	-	(648)	9,968	59	(3,746)	6,281
17	2036	9,968	-	(712)	9,256	59	(3,518)	5,797
18	2037	9,256	-	(759)	8,497	60	(3,230)	5,327
19	2038	8,497	-	(809)	7,687	60	(2,922)	4,825
20	2039	7,687	-	(859)	6,828	60	(2,595)	4,293
21	2040	6,828	-	(915)	5,913	60	(2,248)	3,726
22	2041	5,913	-	(982)	4,931	61	(1,874)	3,117
23	2042	4,931	-	(1,033)	3,898	61	(1,482)	2,477
24	2043	3,898	-	(1,120)	2,778	61	(1,056)	1,783
			104	(11,113)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,115	122	118	18,354	56	(414)	17,997
2	2021	18,354	15	30	18,399	57	(787)	17,668
3	2022	18,399	-	(3)	18,395	57	(1,153)	17,299
4	2023	18,395	-	(43)	18,353	57	(1,512)	16,898
5	2024	18,353	-	(85)	18,267	57	(1,863)	16,462
6	2025	18,267	-	(131)	18,136	57	(2,205)	15,988
7	2026	18,136	-	(180)	17,956	57	(2,538)	15,475
8	2027	17,956	-	(237)	17,719	58	(2,860)	14,916
9	2028	17,719	-	(294)	17,425	58	(3,172)	14,311
10	2029	17,425	-	(355)	17,070	58	(3,471)	13,657
11	2030	17,070	-	(425)	16,645	58	(3,757)	12,946
12	2031	16,645	-	(500)	16,145	58	(4,030)	12,174
13	2032	16,145	-	(577)	15,568	59	(4,286)	11,341
14	2033	15,568	-	(663)	14,905	59	(4,527)	10,438
15	2034	14,905	-	(756)	14,150	59	(4,749)	9,460
16	2035	14,150	-	(855)	13,295	59	(4,952)	8,403
17	2036	13,295	-	(945)	12,350	59	(4,696)	7,713
18	2037	12,350	-	(1,012)	11,338	60	(4,312)	7,086
19	2038	11,338	-	(1,081)	10,257	60	(3,900)	6,416
20	2039	10,257	-	(1,151)	9,105	60	(3,463)	5,703
21	2040	9,105	-	(1,228)	7,877	60	(2,995)	4,942
22	2041	7,877	-	(1,321)	6,556	61	(2,493)	4,124
23	2042	6,556	-	(1,394)	5,163	61	(1,963)	3,260
24	2043	5,163	-	(1,513)	3,650	61	(1,388)	2,323
			136	(14,601)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	543	454	(77)	85	10	270	313	1,598
2	2021	554	407	(9)	87	11	264	284	1,598
3	2022	543	399	16	89	11	261	279	1,598
4	2023	530	389	46	91	11	256	274	1,598
5	2024	517	379	79	93	11	251	268	1,598
6	2025	502	369	113	95	12	245	262	1,598
7	2026	486	357	150	97	12	240	256	1,598
8	2027	469	344	192	99	12	232	249	1,598
9	2028	451	331	235	101	12	226	242	1,598
10	2029	431	316	281	103	13	221	233	1,598
11	2030	409	300	332	106	13	213	225	1,598
12	2031	386	283	388	108	13	205	215	1,598
13	2032	361	265	444	110	13	199	205	1,598
14	2033	334	245	508	113	14	191	194	1,598
15	2034	305	224	576	115	14	183	182	1,598
16	2035	273	200	648	118	14	175	169	1,598
17	2036	247	181	712	120	15	164	158	1,598
18	2037	227	167	759	123	15	156	150	1,598
19	2038	207	152	809	126	15	146	143	1,598
20	2039	186	137	859	128	16	137	134	1,598
21	2040	164	120	915	131	16	127	125	1,598
22	2041	140	103	982	134	16	108	116	1,598
23	2042	114	84	1,033	137	17	108	105	1,598
24	2043	87	64	1,120	140	17	75	95	1,598
		8,468	6,271	11,113	2,647	322	4,656	4,875	38,352

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	762	596	(118)	85	10	354	411	2,100
2	2021	778	535	(30)	87	11	347	372	2,100
3	2022	763	525	3	89	11	344	366	2,100
4	2023	746	513	43	91	11	336	360	2,100
5	2024	728	500	85	93	11	329	353	2,100
6	2025	708	487	131	95	12	322	346	2,100
7	2026	687	472	180	97	12	315	338	2,100
8	2027	663	456	237	99	12	305	329	2,100
9	2028	638	438	294	101	12	298	319	2,100
10	2029	610	420	355	103	13	290	309	2,100
11	2030	581	399	425	106	13	280	297	2,100
12	2031	548	377	500	108	13	269	285	2,100
13	2032	513	353	577	110	13	262	272	2,100
14	2033	475	327	663	113	14	251	258	2,100
15	2034	434	298	756	115	14	241	242	2,100
16	2035	390	268	855	118	14	230	225	2,100
17	2036	352	242	945	120	15	216	211	2,100
18	2037	323	222	1,012	123	15	205	200	2,100
19	2038	295	203	1,081	126	15	191	190	2,100
20	2039	265	182	1,151	128	16	181	178	2,100
21	2040	232	160	1,228	131	16	166	166	2,100
22	2041	198	136	1,321	134	16	142	154	2,100
23	2042	161	111	1,394	137	17	142	139	2,100
24	2043	122	84	1,513	140	17	99	126	2,100
		11,974	8,301	14,601	2,647	322	6,117	6,445	50,408

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	MMBtu/ Mcf	In-state Revenue requirement	In-state MDQ (MMBtu/d)	In-state Rate - $/MMBtu	Export Revenue requirement	Export MDQ (MMBtu/d)	Export Rate - $/MMBtu
1	2020	1.118	87	375	0.64	1,511	4,656	0.89
2	2021	1.118	87	375	0.64	1,511	4,656	0.89
3	2022	1.118	87	375	0.64	1,511	4,656	0.89
4	2023	1.118	87	375	0.64	1,511	4,656	0.89
5	2024	1.118	87	375	0.64	1,511	4,656	0.89
6	2025	1.118	87	375	0.64	1,511	4,656	0.89
7	2026	1.118	87	375	0.64	1,511	4,656	0.89
8	2027	1.118	87	375	0.64	1,511	4,656	0.89
9	2028	1.118	87	375	0.64	1,511	4,656	0.89
10	2029	1.118	87	375	0.64	1,511	4,656	0.89
11	2030	1.118	87	375	0.64	1,511	4,656	0.89
12	2031	1.118	87	375	0.64	1,511	4,656	0.89
13	2032	1.118	87	375	0.64	1,511	4,656	0.89
14	2033	1.118	87	375	0.64	1,511	4,656	0.89
15	2034	1.118	87	375	0.64	1,511	4,656	0.89
16	2035	1.118	87	375	0.64	1,511	4,656	0.89
17	2036	1.118	87	375	0.64	1,511	4,656	0.89
18	2037	1.118	87	375	0.64	1,511	4,656	0.89
19	2038	1.118	87	375	0.64	1,511	4,656	0.89
20	2039	1.118	87	375	0.64	1,511	4,656	0.89
21	2040	1.118	87	375	0.64	1,511	4,656	0.89
22	2041	1.118	87	375	0.64	1,511	4,656	0.89
23	2042	1.118	87	375	0.64	1,511	4,656	0.89
24	2043	1.118	87	375	0.64	1,511	4,656	0.89

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	MMBtu/ Mcf	In-state Revenue requirement	In-state MDQ (MMBtu/d)	In-state Rate - $/MMBtu	Export Revenue requirement	Export MDQ (MMBtu/d)	Export Rate - $/MMBtu
1	2020	1.118	114	375	0.84	1,986	4,656	1.17
2	2021	1.118	114	375	0.84	1,986	4,656	1.17
3	2022	1.118	114	375	0.84	1,986	4,656	1.17
4	2023	1.118	114	375	0.84	1,986	4,656	1.17
5	2024	1.118	114	375	0.84	1,986	4,656	1.17
6	2025	1.118	114	375	0.84	1,986	4,656	1.17
7	2026	1.118	114	375	0.84	1,986	4,656	1.17
8	2027	1.118	114	375	0.84	1,986	4,656	1.17
9	2028	1.118	114	375	0.84	1,986	4,656	1.17
10	2029	1.118	114	375	0.84	1,986	4,656	1.17
11	2030	1.118	114	375	0.84	1,986	4,656	1.17
12	2031	1.118	114	375	0.84	1,986	4,656	1.17
13	2032	1.118	114	375	0.84	1,986	4,656	1.17
14	2033	1.118	114	375	0.84	1,986	4,656	1.17
15	2034	1.118	114	375	0.84	1,986	4,656	1.17
16	2035	1.118	114	375	0.84	1,986	4,656	1.17
17	2036	1.118	114	375	0.84	1,986	4,656	1.17
18	2037	1.118	114	375	0.84	1,986	4,656	1.17
19	2038	1.118	114	375	0.84	1,986	4,656	1.17
20	2039	1.118	114	375	0.84	1,986	4,656	1.17
21	2040	1.118	114	375	0.84	1,986	4,656	1.17
22	2041	1.118	114	375	0.84	1,986	4,656	1.17
23	2042	1.118	114	375	0.84	1,986	4,656	1.17
24	2043	1.118	114	375	0.84	1,986	4,656	1.17

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.6%
3	2022	0.1%	-0.5%
4	2023	0.3%	-0.2%
5	2024	0.6%	0.4%
6	2025	0.8%	1.2%
7	2026	1.1%	2.3%
8	2027	1.4%	3.7%
9	2028	1.7%	5.4%
10	2029	2.0%	7.4%
11	2030	2.4%	9.8%
12	2031	2.8%	12.6%
13	2032	3.2%	15.8%
14	2033	3.7%	19.4%
15	2034	4.1%	23.6%
16	2035	4.7%	28.2%
17	2036	5.1%	33.4%
18	2037	5.5%	38.8%
19	2038	5.8%	44.7%
20	2039	6.2%	50.8%
21	2040	6.6%	57.4%
22	2041	7.1%	64.5%
23	2042	7.4%	71.9%
24	2043	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.2%	-0.8%
3	2022	0.0%	-0.8%
4	2023	0.2%	-0.6%
5	2024	0.5%	-0.1%
6	2025	0.7%	0.6%
7	2026	1.0%	1.6%
8	2027	1.3%	2.9%
9	2028	1.6%	4.5%
10	2029	1.9%	6.5%
11	2030	2.3%	8.8%
12	2031	2.7%	11.5%
13	2032	3.2%	14.7%
14	2033	3.6%	18.3%
15	2034	4.1%	22.5%
16	2035	4.7%	27.2%
17	2036	5.2%	32.3%
18	2037	5.5%	37.9%
19	2038	5.9%	43.8%
20	2039	6.3%	50.1%
21	2040	6.7%	56.8%
22	2041	7.2%	64.1%
23	2042	7.6%	71.7%
24	2043	8.3%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(25 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	6	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	637
2020	637	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	637	4	4	645	1	(15)	632
2	2021	645	1	1	647	1	(28)	620
3	2022	647	-	0	647	1	(40)	607
4	2023	647	-	(1)	646	1	(53)	594
5	2024	646	-	(2)	643	1	(65)	579
6	2025	643	-	(4)	639	1	(77)	563
7	2026	639	-	(5)	634	1	(89)	546
8	2027	634	-	(7)	627	1	(101)	527
9	2028	627	-	(9)	617	1	(112)	507
10	2029	617	-	(11)	606	1	(122)	485
11	2030	606	-	(13)	593	1	(132)	462
12	2031	593	-	(16)	577	1	(142)	436
13	2032	577	-	(18)	559	1	(151)	409
14	2033	559	-	(21)	538	1	(160)	379
15	2034	538	-	(24)	514	1	(168)	347
16	2035	514	-	(27)	488	1	(176)	313
17	2036	488	-	(30)	457	1	(179)	280
18	2037	457	-	(33)	424	1	(166)	260
19	2038	424	-	(35)	389	1	(152)	238
20	2039	389	-	(37)	352	1	(138)	216
21	2040	352	-	(39)	313	1	(122)	192
22	2041	313	-	(42)	271	1	(106)	166
23	2042	271	-	(45)	226	1	(88)	139
24	2043	226	-	(48)	178	1	(69)	110
25	2044	178	-	(50)	128	1	(49)	80
			5	(513)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	7	849	1	(19)	831
2	2021	849	1	3	852	1	(36)	816
3	2022	852	-	1	853	1	(53)	800
4	2023	853	-	(1)	852	1	(70)	783
5	2024	852	-	(2)	850	1	(86)	765
6	2025	850	-	(4)	846	1	(102)	745
7	2026	846	-	(6)	839	1	(117)	723
8	2027	839	-	(9)	830	1	(133)	699
9	2028	830	-	(11)	819	1	(147)	673
10	2029	819	-	(14)	805	1	(161)	645
11	2030	805	-	(17)	788	1	(175)	614
12	2031	788	-	(20)	768	1	(188)	581
13	2032	768	-	(23)	745	1	(200)	545
14	2033	745	-	(27)	717	1	(212)	507
15	2034	717	-	(31)	686	1	(222)	465
16	2035	686	-	(35)	651	1	(232)	419
17	2036	651	-	(40)	611	1	(239)	373
18	2037	611	-	(44)	567	1	(222)	346
19	2038	567	-	(47)	520	1	(204)	318
20	2039	520	-	(50)	471	1	(184)	288
21	2040	471	-	(53)	418	1	(163)	255
22	2041	418	-	(57)	361	1	(141)	221
23	2042	361	-	(60)	301	1	(117)	185
24	2043	301	-	(65)	236	1	(91)	145
25	2044	236	-	(68)	168	1	(64)	105
			6	(674)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(4)	4	0	12	14	73
2	2021	26	19	(1)	4	0	12	13	73
3	2022	25	18	(0)	4	0	12	13	73
4	2023	25	18	1	4	0	12	13	73
5	2024	24	18	2	4	0	12	12	73
6	2025	23	17	4	4	0	11	12	73
7	2026	23	17	5	4	0	11	12	73
8	2027	22	16	7	4	0	11	12	73
9	2028	21	16	9	5	0	10	11	73
10	2029	20	15	11	5	0	10	11	73
11	2030	19	14	13	5	0	10	11	73
12	2031	18	13	16	5	0	9	10	73
13	2032	17	13	18	5	0	9	10	73
14	2033	16	12	21	5	0	9	9	73
15	2034	15	11	24	5	1	8	9	73
16	2035	14	10	27	5	1	8	8	73
17	2036	12	9	30	5	1	8	8	73
18	2037	11	8	33	6	1	7	7	73
19	2038	10	7	35	6	1	7	7	73
20	2039	9	7	37	6	1	6	7	73
21	2040	8	6	39	6	1	6	6	73
22	2041	7	5	42	6	1	5	6	73
23	2042	6	5	45	6	1	5	5	73
24	2043	5	4	48	6	1	3	5	73
25	2044	4	3	50	6	1	4	4	73
		407	301	513	126	12	219	236	1,814

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	28	(7)	4	0	16	19	96
2	2021	36	25	(3)	4	0	16	17	96
3	2022	35	24	(1)	4	0	16	17	96
4	2023	35	24	1	4	0	16	17	96
5	2024	34	23	2	4	0	15	16	96
6	2025	33	23	4	4	0	15	16	96
7	2026	32	22	6	4	0	15	16	96
8	2027	31	21	9	4	0	14	15	96
9	2028	30	21	11	5	0	14	15	96
10	2029	29	20	14	5	0	13	15	96
11	2030	28	19	17	5	0	13	14	96
12	2031	26	18	20	5	0	12	14	96
13	2032	25	17	23	5	0	12	13	96
14	2033	23	16	27	5	0	12	12	96
15	2034	21	15	31	5	1	11	12	96
16	2035	19	13	35	5	1	11	11	96
17	2036	17	12	40	5	1	10	10	96
18	2037	16	11	44	6	1	9	10	96
19	2038	15	10	47	6	1	9	9	96
20	2039	13	9	50	6	1	8	9	96
21	2040	12	8	53	6	1	8	8	96
22	2041	10	7	57	6	1	7	8	96
23	2042	9	6	60	6	1	7	7	96
24	2043	7	5	65	6	1	5	7	96
25	2044	5	4	68	6	1	6	6	96
		576	399	674	126	12	288	312	2,389

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	73	1,100	1.000	0.18
2	2021	73	1,100	1.000	0.18
3	2022	73	1,100	1.000	0.18
4	2023	73	1,100	1.000	0.18
5	2024	73	1,100	1.000	0.18
6	2025	73	1,100	1.000	0.18
7	2026	73	1,100	1.000	0.18
8	2027	73	1,100	1.000	0.18
9	2028	73	1,100	1.000	0.18
10	2029	73	1,100	1.000	0.18
11	2030	73	1,100	1.000	0.18
12	2031	73	1,100	1.000	0.18
13	2032	73	1,100	1.000	0.18
14	2033	73	1,100	1.000	0.18
15	2034	73	1,100	1.000	0.18
16	2035	73	1,100	1.000	0.18
17	2036	73	1,100	1.000	0.18
18	2037	73	1,100	1.000	0.18
19	2038	73	1,100	1.000	0.18
20	2039	73	1,100	1.000	0.18
21	2040	73	1,100	1.000	0.18
22	2041	73	1,100	1.000	0.18
23	2042	73	1,100	1.000	0.18
24	2043	73	1,100	1.000	0.18
25	2044	73	1,100	1.000	0.18

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	96	1,100	1.000	0.24
2	2021	96	1,100	1.000	0.24
3	2022	96	1,100	1.000	0.24
4	2023	96	1,100	1.000	0.24
5	2024	96	1,100	1.000	0.24
6	2025	96	1,100	1.000	0.24
7	2026	96	1,100	1.000	0.24
8	2027	96	1,100	1.000	0.24
9	2028	96	1,100	1.000	0.24
10	2029	96	1,100	1.000	0.24
11	2030	96	1,100	1.000	0.24
12	2031	96	1,100	1.000	0.24
13	2032	96	1,100	1.000	0.24
14	2033	96	1,100	1.000	0.24
15	2034	96	1,100	1.000	0.24
16	2035	96	1,100	1.000	0.24
17	2036	96	1,100	1.000	0.24
18	2037	96	1,100	1.000	0.24
19	2038	96	1,100	1.000	0.24
20	2039	96	1,100	1.000	0.24
21	2040	96	1,100	1.000	0.24
22	2041	96	1,100	1.000	0.24
23	2042	96	1,100	1.000	0.24
24	2043	96	1,100	1.000	0.24
25	2044	96	1,100	1.000	0.24

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.6%
10	2029	1.7%	5.4%
11	2030	2.1%	7.4%
12	2031	2.5%	9.9%
13	2032	2.8%	12.7%
14	2033	3.3%	16.0%
15	2034	3.7%	19.7%
16	2035	4.2%	23.9%
17	2036	4.7%	28.6%
18	2037	5.1%	33.7%
19	2038	5.5%	39.2%
20	2039	5.8%	45.0%
21	2040	6.2%	51.1%
22	2041	6.6%	57.7%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.8%	-0.8%
2	2021	-0.3%	-1.1%
3	2022	-0.1%	-1.2%
4	2023	0.1%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.5%	-0.4%
7	2026	0.8%	0.4%
8	2027	1.0%	1.4%
9	2028	1.3%	2.8%
10	2029	1.7%	4.4%
11	2030	2.0%	6.4%
12	2031	2.4%	8.8%
13	2032	2.8%	11.6%
14	2033	3.2%	14.8%
15	2034	3.7%	18.5%
16	2035	4.2%	22.7%
17	2036	4.8%	27.5%
18	2037	5.2%	32.7%
19	2038	5.5%	38.2%
20	2039	5.9%	44.1%
21	2040	6.3%	50.4%
22	2041	6.8%	57.1%
23	2042	7.1%	64.2%
24	2043	7.7%	72.0%
25	2044	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	131	2,468
2016	2,468	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,799
2018	9,799	1,954	39	668	841	13,302
2019	13,302	1,090	22	373	1,069	15,855
2020	15,855	372	-	135	-	16,362
2021	16,362	9	-	3	-	16,374
		9,760	179	3,355	3,080	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,482
2015	1,482	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,861
2018	12,861	2,554	51	874	1,139	17,478
2019	17,478	1,424	28	487	1,448	20,865
2020	20,865	486	-	176	-	21,528
2021	21,528	12	-	4	-	21,544
		12,755	234	4,384	4,171	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,855	507	82	16,444	26	(366)	16,104
2	2021	16,444	13	52	16,508	29	(699)	15,838
3	2022	16,508	-	22	16,530	28	(1,027)	15,531
4	2023	16,530	-	(22)	16,508	28	(1,349)	15,187
5	2024	16,508	-	(68)	16,440	27	(1,665)	14,802
6	2025	16,440	-	(115)	16,325	26	(1,973)	14,378
7	2026	16,325	-	(159)	16,166	26	(2,273)	13,919
8	2027	16,166	-	(209)	15,957	26	(2,564)	13,419
9	2028	15,957	-	(259)	15,698	26	(2,846)	12,878
10	2029	15,698	-	(314)	15,384	26	(3,117)	12,294
11	2030	15,384	-	(375)	15,010	26	(3,376)	11,659
12	2031	15,010	-	(433)	14,577	26	(3,624)	10,979
13	2032	14,577	-	(492)	14,085	27	(3,858)	10,254
14	2033	14,085	-	(558)	13,527	28	(4,077)	9,477
15	2034	13,527	-	(629)	12,898	28	(4,282)	8,644
16	2035	12,898	-	(704)	12,194	29	(4,470)	7,753
17	2036	12,194	-	(777)	11,417	29	(4,413)	7,033
18	2037	11,417	-	(831)	10,586	30	(4,093)	6,523
19	2038	10,586	-	(879)	9,707	31	(3,753)	5,984
20	2039	9,707	-	(927)	8,780	31	(3,394)	5,418
21	2040	8,780	-	(980)	7,800	32	(3,012)	4,820
22	2041	7,800	-	(1,045)	6,755	33	(2,604)	4,183
23	2042	6,755	-	(1,091)	5,663	34	(2,177)	3,520
24	2043	5,663	-	(1,177)	4,486	34	(1,715)	2,806
25	2044	4,486	-	(1,212)	3,275	35	(1,238)	2,071
			520	(13,099)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,865	663	131	21,658	26	(481)	21,203
2	2021	21,658	16	84	21,758	29	(920)	20,867
3	2022	21,758	-	45	21,803	28	(1,352)	20,480
4	2023	21,803	-	(9)	21,794	28	(1,776)	20,045
5	2024	21,794	-	(67)	21,727	27	(2,192)	19,561
6	2025	21,727	-	(126)	21,601	26	(2,599)	19,027
7	2026	21,601	-	(183)	21,418	26	(2,996)	18,447
8	2027	21,418	-	(249)	21,169	26	(3,382)	17,813
9	2028	21,169	-	(315)	20,853	26	(3,755)	17,124
10	2029	20,853	-	(387)	20,467	26	(4,115)	16,378
11	2030	20,467	-	(468)	19,999	26	(4,460)	15,565
12	2031	19,999	-	(547)	19,451	26	(4,790)	14,688
13	2032	19,451	-	(629)	18,823	27	(5,102)	13,748
14	2033	18,823	-	(720)	18,103	28	(5,396)	12,734
15	2034	18,103	-	(818)	17,286	28	(5,671)	11,643
16	2035	17,286	-	(922)	16,363	29	(5,924)	10,468
17	2036	16,363	-	(1,029)	15,335	29	(5,938)	9,427
18	2037	15,335	-	(1,109)	14,226	30	(5,510)	8,746
19	2038	14,226	-	(1,178)	13,048	31	(5,054)	8,025
20	2039	13,048	-	(1,247)	11,801	31	(4,569)	7,263
21	2040	11,801	-	(1,324)	10,477	32	(4,054)	6,456
22	2041	10,477	-	(1,416)	9,061	33	(3,500)	5,595
23	2042	9,061	-	(1,485)	7,576	34	(2,917)	4,692
24	2043	7,576	-	(1,606)	5,970	34	(2,285)	3,719
25	2044	5,970	-	(1,661)	4,309	35	(1,630)	2,713
			679	(17,235)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	632	527	(82)	312	54	318	363	2,124
2	2021	653	479	(52)	346	55	312	331	2,124
3	2022	641	471	(22)	342	56	308	327	2,124
4	2023	628	461	22	331	58	302	323	2,124
5	2024	613	450	68	320	59	296	318	2,124
6	2025	596	438	115	313	60	289	312	2,124
7	2026	578	424	159	312	62	283	305	2,124
8	2027	559	410	209	312	63	273	298	2,124
9	2028	538	394	259	311	64	267	290	2,124
10	2029	515	378	314	310	66	261	281	2,124
11	2030	490	359	375	310	67	251	272	2,124
12	2031	463	340	433	317	69	242	262	2,124
13	2032	434	319	492	323	70	235	250	2,124
14	2033	403	296	558	331	72	226	239	2,124
15	2034	370	272	629	338	73	216	226	2,124
16	2035	335	246	704	345	75	207	212	2,124
17	2036	302	222	777	353	77	194	199	2,124
18	2037	277	203	831	361	78	184	189	2,124
19	2038	256	188	879	369	80	172	181	2,124
20	2039	233	171	927	377	82	162	172	2,124
21	2040	209	154	980	385	84	149	163	2,124
22	2041	184	135	1,045	393	85	127	154	2,124
23	2042	157	116	1,091	402	87	127	143	2,124
24	2043	129	95	1,177	411	89	89	134	2,124
25	2044	100	73	1,212	420	91	108	120	2,124
		10,296	7,618	13,099	8,644	1,777	5,598	6,067	53,099

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	888	694	(131)	312	54	419	477	2,713
2	2021	919	631	(84)	346	55	410	436	2,713
3	2022	903	620	(45)	342	56	406	430	2,713
4	2023	885	608	9	331	58	398	425	2,713
5	2024	865	594	67	320	59	389	419	2,713
6	2025	843	579	126	313	60	381	411	2,713
7	2026	818	562	183	312	62	373	403	2,713
8	2027	792	544	249	312	63	360	394	2,713
9	2028	763	524	315	311	64	352	384	2,713
10	2029	731	503	387	310	66	343	373	2,713
11	2030	697	479	468	310	67	331	361	2,713
12	2031	661	454	547	317	69	318	348	2,713
13	2032	621	427	629	323	70	310	333	2,713
14	2033	578	397	720	331	72	297	318	2,713
15	2034	532	366	818	338	73	285	302	2,713
16	2035	483	332	922	345	75	272	284	2,713
17	2036	434	298	1,029	353	77	255	267	2,713
18	2037	397	273	1,109	361	78	243	253	2,713
19	2038	366	252	1,178	369	80	226	242	2,713
20	2039	334	229	1,247	377	82	213	231	2,713
21	2040	300	206	1,324	385	84	197	219	2,713
22	2041	263	181	1,416	393	85	167	207	2,713
23	2042	225	154	1,485	402	87	167	192	2,713
24	2043	184	126	1,606	411	89	117	179	2,713
25	2044	140	96	1,661	420	91	142	162	2,713
		14,620	10,128	17,235	8,644	1,777	7,372	8,048	67,824

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,124	4,500	1.118	1.16
2	2021	2,124	4,500	1.118	1.16
3	2022	2,124	4,500	1.118	1.16
4	2023	2,124	4,500	1.118	1.16
5	2024	2,124	4,500	1.118	1.16
6	2025	2,124	4,500	1.118	1.16
7	2026	2,124	4,500	1.118	1.16
8	2027	2,124	4,500	1.118	1.16
9	2028	2,124	4,500	1.118	1.16
10	2029	2,124	4,500	1.118	1.16
11	2030	2,124	4,500	1.118	1.16
12	2031	2,124	4,500	1.118	1.16
13	2032	2,124	4,500	1.118	1.16
14	2033	2,124	4,500	1.118	1.16
15	2034	2,124	4,500	1.118	1.16
16	2035	2,124	4,500	1.118	1.16
17	2036	2,124	4,500	1.118	1.16
18	2037	2,124	4,500	1.118	1.16
19	2038	2,124	4,500	1.118	1.16
20	2039	2,124	4,500	1.118	1.16
21	2040	2,124	4,500	1.118	1.16
22	2041	2,124	4,500	1.118	1.16
23	2042	2,124	4,500	1.118	1.16
24	2043	2,124	4,500	1.118	1.16
25	2044	2,124	4,500	1.118	1.16

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,713	4,500	1.118	1.48
2	2021	2,713	4,500	1.118	1.48
3	2022	2,713	4,500	1.118	1.48
4	2023	2,713	4,500	1.118	1.48
5	2024	2,713	4,500	1.118	1.48
6	2025	2,713	4,500	1.118	1.48
7	2026	2,713	4,500	1.118	1.48
8	2027	2,713	4,500	1.118	1.48
9	2028	2,713	4,500	1.118	1.48
10	2029	2,713	4,500	1.118	1.48
11	2030	2,713	4,500	1.118	1.48
12	2031	2,713	4,500	1.118	1.48
13	2032	2,713	4,500	1.118	1.48
14	2033	2,713	4,500	1.118	1.48
15	2034	2,713	4,500	1.118	1.48
16	2035	2,713	4,500	1.118	1.48
17	2036	2,713	4,500	1.118	1.48
18	2037	2,713	4,500	1.118	1.48
19	2038	2,713	4,500	1.118	1.48
20	2039	2,713	4,500	1.118	1.48
21	2040	2,713	4,500	1.118	1.48
22	2041	2,713	4,500	1.118	1.48
23	2042	2,713	4,500	1.118	1.48
24	2043	2,713	4,500	1.118	1.48
25	2044	2,713	4,500	1.118	1.48

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.3%	-0.8%
3	2022	-0.1%	-1.0%
4	2023	0.1%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.7%	0.3%
7	2026	1.0%	1.3%
8	2027	1.3%	2.5%
9	2028	1.6%	4.1%
10	2029	1.9%	6.0%
11	2030	2.3%	8.3%
12	2031	2.6%	11.0%
13	2032	3.0%	14.0%
14	2033	3.4%	17.4%
15	2034	3.8%	21.2%
16	2035	4.3%	25.5%
17	2036	4.7%	30.3%
18	2037	5.1%	35.4%
19	2038	5.4%	40.7%
20	2039	5.7%	46.4%
21	2040	6.0%	52.4%
22	2041	6.4%	58.7%
23	2042	6.7%	65.4%
24	2043	7.2%	72.6%
25	2044	7.4%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.4%	-1.0%
3	2022	-0.2%	-1.2%
4	2023	0.0%	-1.2%
5	2024	0.3%	-0.8%
6	2025	0.6%	-0.3%
7	2026	0.9%	0.6%
8	2027	1.2%	1.7%
9	2028	1.5%	3.2%
10	2029	1.8%	5.0%
11	2030	2.2%	7.2%
12	2031	2.5%	9.7%
13	2032	2.9%	12.6%
14	2033	3.3%	16.0%
15	2034	3.8%	19.8%
16	2035	4.3%	24.0%
17	2036	4.8%	28.8%
18	2037	5.1%	34.0%
19	2038	5.5%	39.4%
20	2039	5.8%	45.2%
21	2040	6.1%	51.4%
22	2041	6.6%	57.9%
23	2042	6.9%	64.8%
24	2043	7.5%	72.3%
25	2044	7.7%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	53	838
2015	838	750	15	140	97	1,841
2016	1,841	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,421
2018	4,421	4,648	93	869	544	10,575
2019	10,575	1,928	39	360	886	13,788
2020	13,788	77	-	16	-	13,881
2021	13,881	9	-	2	-	13,892
		9,807	186	1,844	2,056	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,807
2018	5,807	6,074	121	1,135	737	13,875
2019	13,875	2,519	50	471	1,200	18,115
2020	18,115	101	-	21	-	18,237
2021	18,237	12	-	2	-	18,251
		12,816	243	2,409	2,784	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,788	93	95	13,976	56	(315)	13,717
2	2021	13,976	11	29	14,016	57	(599)	13,473
3	2022	14,016	-	6	14,022	57	(879)	13,200
4	2023	14,022	-	(23)	13,999	57	(1,152)	12,904
5	2024	13,999	-	(53)	13,947	57	(1,420)	12,584
6	2025	13,947	-	(85)	13,862	57	(1,682)	12,237
7	2026	13,862	-	(119)	13,742	57	(1,936)	11,863
8	2027	13,742	-	(159)	13,583	58	(2,183)	11,457
9	2028	13,583	-	(199)	13,384	58	(2,422)	11,019
10	2029	13,384	-	(242)	13,142	58	(2,653)	10,547
11	2030	13,142	-	(291)	12,851	58	(2,873)	10,036
12	2031	12,851	-	(343)	12,509	58	(3,084)	9,483
13	2032	12,509	-	(396)	12,113	59	(3,284)	8,888
14	2033	12,113	-	(455)	11,658	59	(3,472)	8,245
15	2034	11,658	-	(519)	11,139	59	(3,647)	7,551
16	2035	11,139	-	(587)	10,551	59	(3,808)	6,803
17	2036	10,551	-	(655)	9,897	59	(3,762)	6,194
18	2037	9,897	-	(705)	9,191	60	(3,494)	5,757
19	2038	9,191	-	(753)	8,439	60	(3,208)	5,291
20	2039	8,439	-	(800)	7,639	60	(2,904)	4,795
21	2040	7,639	-	(852)	6,787	60	(2,580)	4,267
22	2041	6,787	-	(915)	5,872	61	(2,232)	3,700
23	2042	5,872	-	(963)	4,909	61	(1,866)	3,104
24	2043	4,909	-	(1,046)	3,863	61	(1,468)	2,456
25	2044	3,863	-	(1,085)	2,778	61	(1,056)	1,784
			104	(11,114)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,115	122	142	18,379	56	(414)	18,022
2	2021	18,379	15	56	18,450	57	(787)	17,719
3	2022	18,450	-	26	18,476	57	(1,154)	17,378
4	2023	18,476	-	(11)	18,464	57	(1,514)	17,007
5	2024	18,464	-	(51)	18,413	57	(1,867)	16,603
6	2025	18,413	-	(94)	18,320	57	(2,212)	16,165
7	2026	18,320	-	(140)	18,180	57	(2,548)	15,689
8	2027	18,180	-	(193)	17,987	58	(2,875)	15,170
9	2028	17,987	-	(246)	17,741	58	(3,191)	14,608
10	2029	17,741	-	(303)	17,438	58	(3,496)	14,000
11	2030	17,438	-	(369)	17,069	58	(3,789)	13,338
12	2031	17,069	-	(439)	16,630	58	(4,069)	12,620
13	2032	16,630	-	(511)	16,119	59	(4,335)	11,843
14	2033	16,119	-	(592)	15,528	59	(4,585)	11,002
15	2034	15,528	-	(679)	14,849	59	(4,818)	10,090
16	2035	14,849	-	(772)	14,077	59	(5,033)	9,103
17	2036	14,077	-	(866)	13,210	59	(5,024)	8,246
18	2037	13,210	-	(939)	12,271	60	(4,667)	7,664
19	2038	12,271	-	(1,004)	11,267	60	(4,285)	7,042
20	2039	11,267	-	(1,070)	10,198	60	(3,878)	6,380
21	2040	10,198	-	(1,142)	9,055	60	(3,444)	5,672
22	2041	9,055	-	(1,229)	7,826	61	(2,976)	4,910
23	2042	7,826	-	(1,297)	6,529	61	(2,483)	4,107
24	2043	6,529	-	(1,411)	5,118	61	(1,946)	3,233
25	2044	5,118	-	(1,468)	3,650	61	(1,388)	2,323
			136	(14,601)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	543	454	(95)	85	10	270	313	1,580
2	2021	556	408	(29)	87	10	265	283	1,580
3	2022	545	400	(6)	89	10	262	279	1,580
4	2023	534	392	23	91	11	256	274	1,580
5	2024	521	382	53	93	11	251	269	1,580
6	2025	507	372	85	95	11	246	264	1,580
7	2026	493	362	119	97	11	240	258	1,580
8	2027	477	350	159	99	12	232	251	1,580
9	2028	459	337	199	101	12	227	244	1,580
10	2029	441	323	242	103	12	221	237	1,580
11	2030	421	309	291	106	12	213	229	1,580
12	2031	399	293	343	108	13	205	220	1,580
13	2032	376	276	396	110	13	200	210	1,580
14	2033	350	257	455	113	13	192	200	1,580
15	2034	323	237	519	115	13	184	189	1,580
16	2035	293	215	587	118	14	175	177	1,580
17	2036	266	195	655	120	14	165	165	1,580
18	2037	244	179	705	123	14	157	157	1,580
19	2038	226	166	753	126	15	146	149	1,580
20	2039	206	151	800	128	15	138	141	1,580
21	2040	185	136	852	131	15	127	133	1,580
22	2041	163	120	915	134	16	108	124	1,580
23	2042	139	102	963	137	16	108	114	1,580
24	2043	114	83	1,046	140	16	76	105	1,580
25	2044	87	64	1,085	143	17	92	93	1,580
		8,867	6,562	11,114	2,791	326	4,754	5,079	39,492

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	763	596	(142)	85	10	355	410	2,076
2	2021	780	536	(56)	87	10	348	372	2,076
3	2022	766	526	(26)	89	10	344	366	2,076
4	2023	751	516	11	91	11	337	361	2,076
5	2024	734	504	51	93	11	330	354	2,076
6	2025	715	492	94	95	11	323	347	2,076
7	2026	695	478	140	97	11	316	340	2,076
8	2027	674	463	193	99	12	305	332	2,076
9	2028	650	447	246	101	12	298	323	2,076
10	2029	625	429	303	103	12	291	313	2,076
11	2030	597	410	369	106	12	280	303	2,076
12	2031	567	389	439	108	13	270	291	2,076
13	2032	534	367	511	110	13	262	279	2,076
14	2033	499	343	592	113	13	252	266	2,076
15	2034	461	316	679	115	13	241	251	2,076
16	2035	419	288	772	118	14	231	235	2,076
17	2036	379	260	866	120	14	216	220	2,076
18	2037	347	239	939	123	14	206	208	2,076
19	2038	321	221	1,004	126	15	192	199	2,076
20	2039	293	201	1,070	128	15	181	188	2,076
21	2040	263	181	1,142	131	15	167	177	2,076
22	2041	231	159	1,229	134	16	142	166	2,076
23	2042	197	135	1,297	137	16	142	152	2,076
24	2043	160	110	1,411	140	16	99	140	2,076
25	2044	121	83	1,468	143	17	121	124	2,076
		12,542	8,689	14,601	2,791	326	6,246	6,716	51,912

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	86	375	0.63	1,494	4,656	0.88
2	2021	1.118	86	375	0.63	1,494	4,656	0.88
3	2022	1.118	86	375	0.63	1,494	4,656	0.88
4	2023	1.118	86	375	0.63	1,494	4,656	0.88
5	2024	1.118	86	375	0.63	1,494	4,656	0.88
6	2025	1.118	86	375	0.63	1,494	4,656	0.88
7	2026	1.118	86	375	0.63	1,494	4,656	0.88
8	2027	1.118	86	375	0.63	1,494	4,656	0.88
9	2028	1.118	86	375	0.63	1,494	4,656	0.88
10	2029	1.118	86	375	0.63	1,494	4,656	0.88
11	2030	1.118	86	375	0.63	1,494	4,656	0.88
12	2031	1.118	86	375	0.63	1,494	4,656	0.88
13	2032	1.118	86	375	0.63	1,494	4,656	0.88
14	2033	1.118	86	375	0.63	1,494	4,656	0.88
15	2034	1.118	86	375	0.63	1,494	4,656	0.88
16	2035	1.118	86	375	0.63	1,494	4,656	0.88
17	2036	1.118	86	375	0.63	1,494	4,656	0.88
18	2037	1.118	86	375	0.63	1,494	4,656	0.88
19	2038	1.118	86	375	0.63	1,494	4,656	0.88
20	2039	1.118	86	375	0.63	1,494	4,656	0.88
21	2040	1.118	86	375	0.63	1,494	4,656	0.88
22	2041	1.118	86	375	0.63	1,494	4,656	0.88
23	2042	1.118	86	375	0.63	1,494	4,656	0.88
24	2043	1.118	86	375	0.63	1,494	4,656	0.88
25	2044	1.118	86	375	0.63	1,494	4,656	0.88

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	113	375	0.83	1,963	4,656	1.16
2	2021	1.118	113	375	0.83	1,963	4,656	1.16
3	2022	1.118	113	375	0.83	1,963	4,656	1.16
4	2023	1.118	113	375	0.83	1,963	4,656	1.16
5	2024	1.118	113	375	0.83	1,963	4,656	1.16
6	2025	1.118	113	375	0.83	1,963	4,656	1.16
7	2026	1.118	113	375	0.83	1,963	4,656	1.16
8	2027	1.118	113	375	0.83	1,963	4,656	1.16
9	2028	1.118	113	375	0.83	1,963	4,656	1.16
10	2029	1.118	113	375	0.83	1,963	4,656	1.16
11	2030	1.118	113	375	0.83	1,963	4,656	1.16
12	2031	1.118	113	375	0.83	1,963	4,656	1.16
13	2032	1.118	113	375	0.83	1,963	4,656	1.16
14	2033	1.118	113	375	0.83	1,963	4,656	1.16
15	2034	1.118	113	375	0.83	1,963	4,656	1.16
16	2035	1.118	113	375	0.83	1,963	4,656	1.16
17	2036	1.118	113	375	0.83	1,963	4,656	1.16
18	2037	1.118	113	375	0.83	1,963	4,656	1.16
19	2038	1.118	113	375	0.83	1,963	4,656	1.16
20	2039	1.118	113	375	0.83	1,963	4,656	1.16
21	2040	1.118	113	375	0.83	1,963	4,656	1.16
22	2041	1.118	113	375	0.83	1,963	4,656	1.16
23	2042	1.118	113	375	0.83	1,963	4,656	1.16
24	2043	1.118	113	375	0.83	1,963	4,656	1.16
25	2044	1.118	113	375	0.83	1,963	4,656	1.16

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.7%
10	2029	1.7%	5.4%
11	2030	2.1%	7.5%
12	2031	2.5%	10.0%
13	2032	2.8%	12.8%
14	2033	3.3%	16.1%
15	2034	3.7%	19.8%
16	2035	4.2%	24.0%
17	2036	4.7%	28.8%
18	2037	5.1%	33.8%
19	2038	5.4%	39.3%
20	2039	5.8%	45.0%
21	2040	6.1%	51.1%
22	2041	6.6%	57.7%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.8%	-0.8%
2	2021	-0.3%	-1.1%
3	2022	-0.1%	-1.2%
4	2023	0.1%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.5%	-0.4%
7	2026	0.8%	0.4%
8	2027	1.1%	1.4%
9	2028	1.3%	2.8%
10	2029	1.7%	4.5%
11	2030	2.0%	6.5%
12	2031	2.4%	8.9%
13	2032	2.8%	11.7%
14	2033	3.2%	14.9%
15	2034	3.7%	18.6%
16	2035	4.2%	22.9%
17	2036	4.7%	27.6%
18	2037	5.1%	32.8%
19	2038	5.5%	38.3%
20	2039	5.9%	44.1%
21	2040	6.3%	50.4%
22	2041	6.7%	57.1%
23	2042	7.1%	64.2%
24	2043	7.7%	72.0%
25	2044	8.0%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(30 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	6	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	637
2020	637	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	637	4	4	645	1	(15)	632
2	2021	645	1	1	647	1	(28)	620
3	2022	647	-	0	647	1	(40)	607
4	2023	647	-	(1)	646	1	(53)	594
5	2024	646	-	(2)	643	1	(65)	579
6	2025	643	-	(4)	640	1	(77)	563
7	2026	640	-	(5)	634	1	(89)	546
8	2027	634	-	(7)	627	1	(101)	527
9	2028	627	-	(9)	618	1	(112)	507
10	2029	618	-	(11)	606	1	(122)	485
11	2030	606	-	(13)	593	1	(132)	462
12	2031	593	-	(16)	577	1	(142)	436
13	2032	577	-	(18)	559	1	(151)	409
14	2033	559	-	(21)	538	1	(160)	379
15	2034	538	-	(24)	515	1	(168)	347
16	2035	515	-	(27)	488	1	(176)	313
17	2036	488	-	(30)	457	1	(179)	280
18	2037	457	-	(33)	425	1	(166)	260
19	2038	425	-	(35)	390	1	(152)	238
20	2039	390	-	(37)	352	1	(138)	216
21	2040	352	-	(40)	313	1	(122)	192
22	2041	313	-	(42)	271	1	(106)	166
23	2042	271	-	(45)	226	1	(88)	139
24	2043	226	-	(48)	178	1	(69)	110
25	2044	178	-	(50)	128	1	(49)	80
26	2045	128	-	(23)	105	1	(40)	66
27	2046	105	-	(24)	81	1	(31)	51
28	2047	81	-	(26)	55	1	(21)	35
29	2048	55	-	(27)	28	1	(11)	18
30	2049	28	-	(29)	(1)	1	(0)	1
			5	(641)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	7	849	1	(19)	831
2	2021	849	1	3	852	1	(36)	816
3	2022	852	-	1	853	1	(53)	800
4	2023	853	-	(0)	852	1	(70)	783
5	2024	852	-	(2)	850	1	(86)	765
6	2025	850	-	(4)	846	1	(102)	745
7	2026	846	-	(6)	839	1	(117)	723
8	2027	839	-	(9)	830	1	(133)	699
9	2028	830	-	(11)	819	1	(147)	673
10	2029	819	-	(14)	805	1	(161)	645
11	2030	805	-	(17)	788	1	(175)	614
12	2031	788	-	(20)	768	1	(188)	581
13	2032	768	-	(23)	745	1	(200)	546
14	2033	745	-	(27)	718	1	(212)	507
15	2034	718	-	(31)	686	1	(222)	465
16	2035	686	-	(35)	651	1	(232)	419
17	2036	651	-	(40)	611	1	(239)	373
18	2037	611	-	(44)	567	1	(222)	346
19	2038	567	-	(47)	520	1	(204)	318
20	2039	520	-	(50)	471	1	(184)	288
21	2040	471	-	(53)	418	1	(163)	255
22	2041	418	-	(57)	361	1	(141)	221
23	2042	361	-	(60)	301	1	(117)	185
24	2043	301	-	(65)	236	1	(91)	145
25	2044	236	-	(68)	168	1	(64)	105
26	2045	168	-	(30)	138	1	(53)	86
27	2046	138	-	(32)	107	1	(41)	67
28	2047	107	-	(34)	73	1	(28)	46
29	2048	73	-	(36)	37	1	(15)	24
30	2049	37	-	(38)	(1)	1	(0)	1
			6	(843)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(4)	4	0	12	14	72
2	2021	26	19	(1)	4	0	12	13	72
3	2022	25	18	(0)	4	0	12	13	72
4	2023	25	18	1	4	0	12	13	72
5	2024	24	18	2	4	0	12	12	72
6	2025	23	17	4	4	0	11	12	72
7	2026	23	17	5	4	0	11	12	72
8	2027	22	16	7	4	0	11	12	72
9	2028	21	16	9	5	0	10	11	72
10	2029	20	15	11	5	0	10	11	72
11	2030	19	14	13	5	0	10	11	72
12	2031	18	13	16	5	0	9	10	72
13	2032	17	13	18	5	0	9	10	72
14	2033	16	12	21	5	0	9	9	72
15	2034	15	11	24	5	0	8	9	72
16	2035	14	10	27	5	0	8	8	72
17	2036	12	9	30	5	0	8	8	72
18	2037	11	8	33	6	0	7	7	72
19	2038	10	7	35	6	0	7	7	72
20	2039	9	7	37	6	0	6	7	72
21	2040	8	6	40	6	0	6	6	72
22	2041	7	5	42	6	0	5	6	72
23	2042	6	5	45	6	1	5	5	72
24	2043	5	4	48	6	1	3	5	72
25	2044	4	3	50	6	1	4	4	72
26	2045	3	2	23	7	1	4	3	42
27	2046	2	2	24	7	1	3	2	42
28	2047	2	1	26	7	1	3	2	42
29	2048	1	1	27	7	1	3	2	42
30	2049	0	0	29	7	1	3	2	42
		416	308	641	161	13	235	247	2,020

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	28	(7)	4	0	16	19	95
2	2021	36	25	(3)	4	0	16	17	95
3	2022	35	24	(1)	4	0	16	17	95
4	2023	35	24	0	4	0	16	17	95
5	2024	34	23	2	4	0	15	16	95
6	2025	33	23	4	4	0	15	16	95
7	2026	32	22	6	4	0	15	16	95
8	2027	31	21	9	4	0	14	15	95
9	2028	30	21	11	5	0	14	15	95
10	2029	29	20	14	5	0	13	15	95
11	2030	28	19	17	5	0	13	14	95
12	2031	26	18	20	5	0	12	14	95
13	2032	25	17	23	5	0	12	13	95
14	2033	23	16	27	5	0	12	12	95
15	2034	21	15	31	5	0	11	12	95
16	2035	19	13	35	5	0	11	11	95
17	2036	17	12	40	5	0	10	10	95
18	2037	16	11	44	6	0	9	10	95
19	2038	15	10	47	6	0	9	9	95
20	2039	13	9	50	6	0	8	9	95
21	2040	12	8	53	6	0	8	8	95
22	2041	10	7	57	6	0	7	8	95
23	2042	9	6	60	6	1	7	7	95
24	2043	7	5	65	6	1	5	7	95
25	2044	5	4	68	6	1	6	6	95
26	2045	4	3	30	7	1	5	3	52
27	2046	3	2	32	7	1	5	3	52
28	2047	2	2	34	7	1	4	3	52
29	2048	2	1	36	7	1	4	3	52
30	2049	1	0	38	7	1	4	2	52
		589	408	843	161	13	309	326	2,649

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	72	1,100	1.000	0.18
2	2021	72	1,100	1.000	0.18
3	2022	72	1,100	1.000	0.18
4	2023	72	1,100	1.000	0.18
5	2024	72	1,100	1.000	0.18
6	2025	72	1,100	1.000	0.18
7	2026	72	1,100	1.000	0.18
8	2027	72	1,100	1.000	0.18
9	2028	72	1,100	1.000	0.18
10	2029	72	1,100	1.000	0.18
11	2030	72	1,100	1.000	0.18
12	2031	72	1,100	1.000	0.18
13	2032	72	1,100	1.000	0.18
14	2033	72	1,100	1.000	0.18
15	2034	72	1,100	1.000	0.18
16	2035	72	1,100	1.000	0.18
17	2036	72	1,100	1.000	0.18
18	2037	72	1,100	1.000	0.18
19	2038	72	1,100	1.000	0.18
20	2039	72	1,100	1.000	0.18
21	2040	72	1,100	1.000	0.18
22	2041	72	1,100	1.000	0.18
23	2042	72	1,100	1.000	0.18
24	2043	72	1,100	1.000	0.18
25	2044	72	1,100	1.000	0.18
26	2045	42	1,100	1.000	0.10
27	2046	42	1,100	1.000	0.10
28	2047	42	1,100	1.000	0.10
29	2048	42	1,100	1.000	0.10
30	2049	42	1,100	1.000	0.10

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	95	1,100	1.000	0.24
2	2021	95	1,100	1.000	0.24
3	2022	95	1,100	1.000	0.24
4	2023	95	1,100	1.000	0.24
5	2024	95	1,100	1.000	0.24
6	2025	95	1,100	1.000	0.24
7	2026	95	1,100	1.000	0.24
8	2027	95	1,100	1.000	0.24
9	2028	95	1,100	1.000	0.24
10	2029	95	1,100	1.000	0.24
11	2030	95	1,100	1.000	0.24
12	2031	95	1,100	1.000	0.24
13	2032	95	1,100	1.000	0.24
14	2033	95	1,100	1.000	0.24
15	2034	95	1,100	1.000	0.24
16	2035	95	1,100	1.000	0.24
17	2036	95	1,100	1.000	0.24
18	2037	95	1,100	1.000	0.24
19	2038	95	1,100	1.000	0.24
20	2039	95	1,100	1.000	0.24
21	2040	95	1,100	1.000	0.24
22	2041	95	1,100	1.000	0.24
23	2042	95	1,100	1.000	0.24
24	2043	95	1,100	1.000	0.24
25	2044	95	1,100	1.000	0.24
26	2045	52	1,100	1.000	0.13
27	2046	52	1,100	1.000	0.13
28	2047	52	1,100	1.000	0.13
29	2048	52	1,100	1.000	0.13
30	2049	52	1,100	1.000	0.13

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.0%
8	2027	1.1%	2.2%
9	2028	1.4%	3.6%
10	2029	1.7%	5.3%
11	2030	2.1%	7.4%
12	2031	2.5%	9.9%
13	2032	2.8%	12.7%
14	2033	3.3%	16.0%
15	2034	3.7%	19.7%
16	2035	4.2%	23.9%
17	2036	4.7%	28.6%
18	2037	5.1%	33.7%
19	2038	5.5%	39.2%
20	2039	5.8%	45.0%
21	2040	6.2%	51.1%
22	2041	6.6%	57.7%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.2%	95.5%
30	2049	4.5%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.8%	-0.8%
2	2021	-0.3%	-1.1%
3	2022	-0.1%	-1.2%
4	2023	0.1%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.5%	-0.4%
7	2026	0.8%	0.4%
8	2027	1.0%	1.4%
9	2028	1.3%	2.8%
10	2029	1.7%	4.4%
11	2030	2.0%	6.4%
12	2031	2.4%	8.8%
13	2032	2.8%	11.6%
14	2033	3.2%	14.8%
15	2034	3.7%	18.5%
16	2035	4.2%	22.7%
17	2036	4.8%	27.5%
18	2037	5.2%	32.6%
19	2038	5.5%	38.2%
20	2039	5.9%	44.1%
21	2040	6.3%	50.4%
22	2041	6.8%	57.1%
23	2042	7.1%	64.2%
24	2043	7.7%	72.0%
25	2044	8.0%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.3%	95.5%
30	2049	4.5%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	131	2,468
2016	2,468	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,799
2018	9,799	1,954	39	668	841	13,302
2019	13,302	1,090	22	373	1,069	15,855
2020	15,855	372	-	135	-	16,362
2021	16,362	9	-	3	-	16,374
		9,760	179	3,355	3,080	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,482
2015	1,482	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,861
2018	12,861	2,554	51	874	1,139	17,478
2019	17,478	1,424	28	487	1,448	20,865
2020	20,865	486	-	176	-	21,528
2021	21,528	12	-	4	-	21,544
		12,755	234	4,384	4,171	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,855	507	84	16,446	26	(366)	16,106
2	2021	16,446	13	54	16,512	29	(699)	15,842
3	2022	16,512	-	24	16,536	28	(1,027)	15,537
4	2023	16,536	-	(20)	16,516	28	(1,349)	15,194
5	2024	16,516	-	(67)	16,449	27	(1,665)	14,811
6	2025	16,449	-	(113)	16,336	26	(1,974)	14,388
7	2026	16,336	-	(157)	16,179	26	(2,274)	13,931
8	2027	16,179	-	(207)	15,971	26	(2,565)	13,432
9	2028	15,971	-	(258)	15,713	26	(2,847)	12,892
10	2029	15,713	-	(312)	15,401	26	(3,118)	12,309
11	2030	15,401	-	(374)	15,027	26	(3,378)	11,675
12	2031	15,027	-	(432)	14,595	26	(3,626)	10,996
13	2032	14,595	-	(491)	14,104	27	(3,860)	10,271
14	2033	14,104	-	(558)	13,546	28	(4,080)	9,494
15	2034	13,546	-	(628)	12,918	28	(4,285)	8,661
16	2035	12,918	-	(704)	12,214	29	(4,473)	7,769
17	2036	12,214	-	(778)	11,436	29	(4,421)	7,045
18	2037	11,436	-	(832)	10,604	30	(4,100)	6,534
19	2038	10,604	-	(881)	9,723	31	(3,760)	5,994
20	2039	9,723	-	(929)	8,795	31	(3,400)	5,426
21	2040	8,795	-	(982)	7,813	32	(3,018)	4,827
22	2041	7,813	-	(1,047)	6,765	33	(2,609)	4,189
23	2042	6,765	-	(1,094)	5,671	34	(2,180)	3,524
24	2043	5,671	-	(1,181)	4,490	34	(1,717)	2,808
25	2044	4,490	-	(1,216)	3,275	35	(1,238)	2,071
26	2045	3,275	-	(592)	2,682	36	(1,016)	1,702
27	2046	2,682	-	(624)	2,058	37	(782)	1,314
28	2047	2,058	-	(654)	1,405	37	(534)	908
29	2048	1,405	-	(688)	717	38	(273)	482
30	2049	717	-	(717)	(0)	39	-	39
			520	(16,374)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,865	663	132	21,660	26	(481)	21,205
2	2021	21,660	16	86	21,762	29	(920)	20,871
3	2022	21,762	-	47	21,809	28	(1,352)	20,485
4	2023	21,809	-	(7)	21,801	28	(1,776)	20,053
5	2024	21,801	-	(65)	21,736	27	(2,193)	19,570
6	2025	21,736	-	(124)	21,612	26	(2,600)	19,038
7	2026	21,612	-	(182)	21,430	26	(2,997)	18,459
8	2027	21,430	-	(247)	21,183	26	(3,383)	17,826
9	2028	21,183	-	(314)	20,869	26	(3,756)	17,139
10	2029	20,869	-	(386)	20,483	26	(4,116)	16,393
11	2030	20,483	-	(467)	20,016	26	(4,462)	15,580
12	2031	20,016	-	(546)	19,470	26	(4,792)	14,705
13	2032	19,470	-	(628)	18,842	27	(5,104)	13,765
14	2033	18,842	-	(719)	18,123	28	(5,399)	12,751
15	2034	18,123	-	(817)	17,305	28	(5,674)	11,660
16	2035	17,305	-	(922)	16,383	29	(5,927)	10,485
17	2036	16,383	-	(1,029)	15,354	29	(5,946)	9,438
18	2037	15,354	-	(1,110)	14,244	30	(5,518)	8,757
19	2038	14,244	-	(1,179)	13,065	31	(5,061)	8,035
20	2039	13,065	-	(1,249)	11,816	31	(4,576)	7,272
21	2040	11,816	-	(1,326)	10,491	32	(4,059)	6,464
22	2041	10,491	-	(1,419)	9,072	33	(3,504)	5,601
23	2042	9,072	-	(1,488)	7,584	34	(2,920)	4,697
24	2043	7,584	-	(1,610)	5,974	34	(2,287)	3,721
25	2044	5,974	-	(1,665)	4,309	35	(1,630)	2,713
26	2045	4,309	-	(770)	3,539	36	(1,342)	2,232
27	2046	3,539	-	(816)	2,723	37	(1,035)	1,725
28	2047	2,723	-	(860)	1,863	37	(710)	1,191
29	2048	1,863	-	(909)	954	38	(364)	628
30	2049	954	-	(954)	(0)	39	0	39
			679	(21,544)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	632	527	(84)	312	45	318	363	2,113
2	2021	653	479	(54)	346	46	312	331	2,113
3	2022	641	471	(24)	342	47	308	327	2,113
4	2023	628	461	20	331	48	302	323	2,113
5	2024	613	450	67	320	49	296	318	2,113
6	2025	597	438	113	313	50	289	312	2,113
7	2026	579	425	157	312	51	283	306	2,113
8	2027	559	410	207	312	52	273	298	2,113
9	2028	538	395	258	311	54	267	290	2,113
10	2029	515	378	312	310	55	261	282	2,113
11	2030	490	360	374	310	56	251	272	2,113
12	2031	463	340	432	317	57	242	262	2,113
13	2032	435	319	491	323	59	235	251	2,113
14	2033	404	296	558	331	60	226	239	2,113
15	2034	371	272	628	338	61	216	226	2,113
16	2035	336	246	704	345	62	207	212	2,113
17	2036	303	222	778	353	64	194	200	2,113
18	2037	278	204	832	361	65	184	190	2,113
19	2038	256	188	881	369	67	172	182	2,113
20	2039	233	171	929	377	68	162	173	2,113
21	2040	210	154	982	385	70	149	163	2,113
22	2041	184	135	1,047	393	71	127	154	2,113
23	2042	158	116	1,094	402	73	127	143	2,113
24	2043	129	95	1,181	411	74	89	134	2,113
25	2044	100	73	1,216	420	76	108	121	2,113
26	2045	77	57	592	429	78	99	73	1,405
27	2046	62	45	624	439	79	89	67	1,405
28	2047	45	33	654	448	81	83	61	1,405
29	2048	28	21	688	458	83	73	54	1,405
30	2049	11	8	717	468	85	70	46	1,405
		10,530	7,790	16,374	10,887	1,886	6,012	6,374	59,853

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	888	694	(132)	312	45	419	477	2,702
2	2021	919	631	(86)	346	46	410	436	2,702
3	2022	903	620	(47)	342	47	406	430	2,702
4	2023	885	608	7	331	48	398	425	2,702
5	2024	865	594	65	320	49	389	419	2,702
6	2025	843	579	124	313	50	381	411	2,702
7	2026	819	562	182	312	51	373	403	2,702
8	2027	792	544	247	312	52	360	394	2,702
9	2028	763	524	314	311	54	352	384	2,702
10	2029	732	503	386	310	55	343	373	2,702
11	2030	698	480	467	310	56	331	361	2,702
12	2031	661	454	546	317	57	318	348	2,702
13	2032	622	427	628	323	59	310	334	2,702
14	2033	579	398	719	331	60	297	318	2,702
15	2034	533	366	817	338	61	285	302	2,702
16	2035	484	332	922	345	62	272	284	2,702
17	2036	435	299	1,029	353	64	255	267	2,702
18	2037	397	273	1,110	361	65	243	254	2,702
19	2038	367	252	1,179	369	67	226	243	2,702
20	2039	334	230	1,249	377	68	214	231	2,702
21	2040	300	206	1,326	385	70	197	219	2,702
22	2041	263	181	1,419	393	71	167	207	2,702
23	2042	225	154	1,488	402	73	167	192	2,702
24	2043	184	126	1,610	411	74	117	180	2,702
25	2044	140	97	1,665	420	76	142	162	2,702
26	2045	108	74	770	429	78	130	96	1,685
27	2046	86	59	816	439	79	117	88	1,685
28	2047	64	44	860	448	81	109	79	1,685
29	2048	40	27	909	458	83	96	71	1,685
30	2049	15	10	954	468	85	92	61	1,685
		14,944	10,350	21,544	10,887	1,886	7,917	8,448	75,975

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,113	4,500	1.118	1.15
2	2021	2,113	4,500	1.118	1.15
3	2022	2,113	4,500	1.118	1.15
4	2023	2,113	4,500	1.118	1.15
5	2024	2,113	4,500	1.118	1.15
6	2025	2,113	4,500	1.118	1.15
7	2026	2,113	4,500	1.118	1.15
8	2027	2,113	4,500	1.118	1.15
9	2028	2,113	4,500	1.118	1.15
10	2029	2,113	4,500	1.118	1.15
11	2030	2,113	4,500	1.118	1.15
12	2031	2,113	4,500	1.118	1.15
13	2032	2,113	4,500	1.118	1.15
14	2033	2,113	4,500	1.118	1.15
15	2034	2,113	4,500	1.118	1.15
16	2035	2,113	4,500	1.118	1.15
17	2036	2,113	4,500	1.118	1.15
18	2037	2,113	4,500	1.118	1.15
19	2038	2,113	4,500	1.118	1.15
20	2039	2,113	4,500	1.118	1.15
21	2040	2,113	4,500	1.118	1.15
22	2041	2,113	4,500	1.118	1.15
23	2042	2,113	4,500	1.118	1.15
24	2043	2,113	4,500	1.118	1.15
25	2044	2,113	4,500	1.118	1.15
26	2045	1,405	4,500	1.118	0.77
27	2046	1,405	4,500	1.118	0.77
28	2047	1,405	4,500	1.118	0.77
29	2048	1,405	4,500	1.118	0.77
30	2049	1,405	4,500	1.118	0.77

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,702	4,500	1.118	1.47
2	2021	2,702	4,500	1.118	1.47
3	2022	2,702	4,500	1.118	1.47
4	2023	2,702	4,500	1.118	1.47
5	2024	2,702	4,500	1.118	1.47
6	2025	2,702	4,500	1.118	1.47
7	2026	2,702	4,500	1.118	1.47
8	2027	2,702	4,500	1.118	1.47
9	2028	2,702	4,500	1.118	1.47
10	2029	2,702	4,500	1.118	1.47
11	2030	2,702	4,500	1.118	1.47
12	2031	2,702	4,500	1.118	1.47
13	2032	2,702	4,500	1.118	1.47
14	2033	2,702	4,500	1.118	1.47
15	2034	2,702	4,500	1.118	1.47
16	2035	2,702	4,500	1.118	1.47
17	2036	2,702	4,500	1.118	1.47
18	2037	2,702	4,500	1.118	1.47
19	2038	2,702	4,500	1.118	1.47
20	2039	2,702	4,500	1.118	1.47
21	2040	2,702	4,500	1.118	1.47
22	2041	2,702	4,500	1.118	1.47
23	2042	2,702	4,500	1.118	1.47
24	2043	2,702	4,500	1.118	1.47
25	2044	2,702	4,500	1.118	1.47
26	2045	1,685	4,500	1.118	0.92
27	2046	1,685	4,500	1.118	0.92
28	2047	1,685	4,500	1.118	0.92
29	2048	1,685	4,500	1.118	0.92
30	2049	1,685	4,500	1.118	0.92

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.3%	-0.8%
3	2022	-0.1%	-1.0%
4	2023	0.1%	-0.9%
5	2024	0.4%	-0.5%
6	2025	0.7%	0.2%
7	2026	1.0%	1.2%
8	2027	1.3%	2.5%
9	2028	1.6%	4.0%
10	2029	1.9%	5.9%
11	2030	2.3%	8.2%
12	2031	2.6%	10.9%
13	2032	3.0%	13.9%
14	2033	3.4%	17.3%
15	2034	3.8%	21.1%
16	2035	4.3%	25.4%
17	2036	4.8%	30.2%
18	2037	5.1%	35.2%
19	2038	5.4%	40.6%
20	2039	5.7%	46.3%
21	2040	6.0%	52.3%
22	2041	6.4%	58.7%
23	2042	6.7%	65.4%
24	2043	7.2%	72.6%
25	2044	7.4%	80.0%
26	2045	3.6%	83.6%
27	2046	3.8%	87.4%
28	2047	4.0%	91.4%
29	2048	4.2%	95.6%
30	2049	4.4%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.4%	-1.0%
3	2022	-0.2%	-1.2%
4	2023	0.0%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.6%	-0.3%
7	2026	0.8%	0.5%
8	2027	1.1%	1.7%
9	2028	1.5%	3.1%
10	2029	1.8%	4.9%
11	2030	2.2%	7.1%
12	2031	2.5%	9.6%
13	2032	2.9%	12.5%
14	2033	3.3%	15.9%
15	2034	3.8%	19.7%
16	2035	4.3%	24.0%
17	2036	4.8%	28.7%
18	2037	5.2%	33.9%
19	2038	5.5%	39.4%
20	2039	5.8%	45.2%
21	2040	6.2%	51.3%
22	2041	6.6%	57.9%
23	2042	6.9%	64.8%
24	2043	7.5%	72.3%
25	2044	7.7%	80.0%
26	2045	3.6%	83.6%
27	2046	3.8%	87.4%
28	2047	4.0%	91.4%
29	2048	4.2%	95.6%
30	2049	4.4%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	53	838
2015	838	750	15	140	97	1,841
2016	1,841	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,421
2018	4,421	4,648	93	869	544	10,575
2019	10,575	1,928	39	360	886	13,788
2020	13,788	77	-	16	-	13,881
2021	13,881	9	-	2	-	13,892
		9,807	186	1,844	2,056	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,807
2018	5,807	6,074	121	1,135	737	13,875
2019	13,875	2,519	50	471	1,200	18,115
2020	18,115	101	-	21	-	18,237
2021	18,237	12	-	2	-	18,251
		12,816	243	2,409	2,784	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,788	93	95	13,976	56	(315)	13,718
2	2021	13,976	11	29	14,017	57	(599)	13,474
3	2022	14,017	-	6	14,023	57	(879)	13,201
4	2023	14,023	-	(22)	14,001	57	(1,152)	12,905
5	2024	14,001	-	(52)	13,948	57	(1,420)	12,585
6	2025	13,948	-	(85)	13,864	57	(1,682)	12,239
7	2026	13,864	-	(119)	13,744	57	(1,936)	11,866
8	2027	13,744	-	(159)	13,585	58	(2,183)	11,460
9	2028	13,585	-	(199)	13,387	58	(2,423)	11,022
10	2029	13,387	-	(242)	13,145	58	(2,653)	10,550
11	2030	13,145	-	(290)	12,854	58	(2,874)	10,039
12	2031	12,854	-	(342)	12,512	58	(3,085)	9,486
13	2032	12,512	-	(395)	12,117	59	(3,284)	8,891
14	2033	12,117	-	(455)	11,662	59	(3,472)	8,248
15	2034	11,662	-	(519)	11,143	59	(3,647)	7,554
16	2035	11,143	-	(587)	10,555	59	(3,808)	6,806
17	2036	10,555	-	(655)	9,900	59	(3,763)	6,197
18	2037	9,900	-	(706)	9,195	60	(3,495)	5,759
19	2038	9,195	-	(753)	8,442	60	(3,209)	5,293
20	2039	8,442	-	(800)	7,642	60	(2,905)	4,797
21	2040	7,642	-	(852)	6,789	60	(2,581)	4,269
22	2041	6,789	-	(916)	5,874	61	(2,233)	3,702
23	2042	5,874	-	(964)	4,910	61	(1,866)	3,105
24	2043	4,910	-	(1,046)	3,864	61	(1,469)	2,456
25	2044	3,864	-	(1,086)	2,778	61	(1,056)	1,784
26	2045	2,778	-	(491)	2,287	62	(869)	1,480
27	2046	2,287	-	(523)	1,764	62	(671)	1,156
28	2047	1,764	-	(554)	1,211	62	(460)	813
29	2048	1,211	-	(589)	621	62	(236)	448
30	2049	621	-	(621)	(0)	63	0	63
			104	(13,892)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,115	122	142	18,379	56	(414)	18,022
2	2021	18,379	15	57	18,451	57	(787)	17,720
3	2022	18,451	-	26	18,477	57	(1,154)	17,379
4	2023	18,477	-	(11)	18,466	57	(1,514)	17,008
5	2024	18,466	-	(51)	18,415	57	(1,867)	16,605
6	2025	18,415	-	(93)	18,322	57	(2,212)	16,167
7	2026	18,322	-	(139)	18,182	57	(2,548)	15,692
8	2027	18,182	-	(192)	17,990	58	(2,875)	15,173
9	2028	17,990	-	(246)	17,744	58	(3,191)	14,611
10	2029	17,744	-	(303)	17,441	58	(3,496)	14,003
11	2030	17,441	-	(369)	17,072	58	(3,790)	13,341
12	2031	17,072	-	(439)	16,634	58	(4,069)	12,623
13	2032	16,634	-	(511)	16,123	59	(4,335)	11,847
14	2033	16,123	-	(592)	15,531	59	(4,585)	11,005
15	2034	15,531	-	(679)	14,853	59	(4,819)	10,093
16	2035	14,853	-	(772)	14,080	59	(5,034)	9,106
17	2036	14,080	-	(867)	13,214	59	(5,025)	8,248
18	2037	13,214	-	(939)	12,275	60	(4,668)	7,667
19	2038	12,275	-	(1,004)	11,270	60	(4,286)	7,044
20	2039	11,270	-	(1,070)	10,200	60	(3,879)	6,381
21	2040	10,200	-	(1,143)	9,058	60	(3,444)	5,674
22	2041	9,058	-	(1,230)	7,828	61	(2,977)	4,912
23	2042	7,828	-	(1,298)	6,530	61	(2,483)	4,108
24	2043	6,530	-	(1,411)	5,119	61	(1,947)	3,233
25	2044	5,119	-	(1,469)	3,650	61	(1,388)	2,324
26	2045	3,650	-	(641)	3,010	62	(1,145)	1,927
27	2046	3,010	-	(685)	2,325	62	(884)	1,503
28	2047	2,325	-	(728)	1,597	62	(607)	1,052
29	2048	1,597	-	(776)	821	62	(312)	571
30	2049	821	-	(821)	(0)	63	0	63
			136	(18,251)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	543	454	(95)	85	8	270	313	1,578
2	2021	556	408	(29)	87	8	265	283	1,578
3	2022	545	400	(6)	89	9	262	279	1,578
4	2023	534	392	22	91	9	256	274	1,578
5	2024	521	382	52	93	9	251	269	1,578
6	2025	507	372	85	95	9	246	264	1,578
7	2026	493	362	119	97	9	240	258	1,578
8	2027	477	350	159	99	10	232	251	1,578
9	2028	460	337	199	101	10	227	244	1,578
10	2029	441	324	242	103	10	221	237	1,578
11	2030	421	309	290	106	10	213	229	1,578
12	2031	399	293	342	108	10	205	220	1,578
13	2032	376	276	395	110	11	200	210	1,578
14	2033	350	257	455	113	11	192	200	1,578
15	2034	323	237	519	115	11	184	189	1,578
16	2035	294	215	587	118	11	175	177	1,578
17	2036	266	195	655	120	12	165	165	1,578
18	2037	244	179	706	123	12	157	157	1,578
19	2038	226	166	753	126	12	146	149	1,578
20	2039	206	151	800	128	12	138	141	1,578
21	2040	185	136	852	131	13	127	133	1,578
22	2041	163	120	916	134	13	108	124	1,578
23	2042	139	102	964	137	13	108	114	1,578
24	2043	114	83	1,046	140	14	76	105	1,578
25	2044	87	64	1,086	143	14	92	93	1,578
26	2045	67	49	491	146	14	84	56	907
27	2046	54	40	523	150	15	76	51	907
28	2047	40	30	554	153	15	70	45	907
29	2048	26	19	589	156	15	62	40	907
30	2049	10	8	621	160	16	59	33	907
		9,067	6,708	13,892	3,555	346	5,105	5,305	43,978

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	763	596	(142)	85	8	355	410	2,075
2	2021	780	536	(57)	87	8	348	372	2,075
3	2022	766	526	(26)	89	9	344	366	2,075
4	2023	751	516	11	91	9	337	361	2,075
5	2024	734	504	51	93	9	330	354	2,075
6	2025	716	492	93	95	9	323	347	2,075
7	2026	696	478	139	97	9	316	340	2,075
8	2027	674	463	192	99	10	305	332	2,075
9	2028	650	447	246	101	10	298	323	2,075
10	2029	625	429	303	103	10	291	313	2,075
11	2030	597	410	369	106	10	280	303	2,075
12	2031	567	389	439	108	10	270	291	2,075
13	2032	534	367	511	110	11	262	279	2,075
14	2033	499	343	592	113	11	252	266	2,075
15	2034	461	316	679	115	11	241	251	2,075
16	2035	419	288	772	118	11	231	235	2,075
17	2036	379	260	867	120	12	216	220	2,075
18	2037	347	239	939	123	12	206	208	2,075
19	2038	321	221	1,004	126	12	192	199	2,075
20	2039	293	201	1,070	128	12	181	188	2,075
21	2040	263	181	1,143	131	13	167	177	2,075
22	2041	231	159	1,230	134	13	142	166	2,075
23	2042	197	135	1,298	137	13	142	152	2,075
24	2043	160	110	1,411	140	14	99	140	2,075
25	2044	121	83	1,469	143	14	121	124	2,075
26	2045	93	64	641	146	14	110	73	1,141
27	2046	75	51	685	150	15	99	66	1,141
28	2047	56	38	728	153	15	92	59	1,141
29	2048	35	24	776	156	15	82	52	1,141
30	2049	14	10	821	160	16	78	43	1,141
		12,817	8,878	18,251	3,555	346	6,707	7,011	57,566

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	86	375	0.63	1,492	4,656	0.88
2	2021	1.118	86	375	0.63	1,492	4,656	0.88
3	2022	1.118	86	375	0.63	1,492	4,656	0.88
4	2023	1.118	86	375	0.63	1,492	4,656	0.88
5	2024	1.118	86	375	0.63	1,492	4,656	0.88
6	2025	1.118	86	375	0.63	1,492	4,656	0.88
7	2026	1.118	86	375	0.63	1,492	4,656	0.88
8	2027	1.118	86	375	0.63	1,492	4,656	0.88
9	2028	1.118	86	375	0.63	1,492	4,656	0.88
10	2029	1.118	86	375	0.63	1,492	4,656	0.88
11	2030	1.118	86	375	0.63	1,492	4,656	0.88
12	2031	1.118	86	375	0.63	1,492	4,656	0.88
13	2032	1.118	86	375	0.63	1,492	4,656	0.88
14	2033	1.118	86	375	0.63	1,492	4,656	0.88
15	2034	1.118	86	375	0.63	1,492	4,656	0.88
16	2035	1.118	86	375	0.63	1,492	4,656	0.88
17	2036	1.118	86	375	0.63	1,492	4,656	0.88
18	2037	1.118	86	375	0.63	1,492	4,656	0.88
19	2038	1.118	86	375	0.63	1,492	4,656	0.88
20	2039	1.118	86	375	0.63	1,492	4,656	0.88
21	2040	1.118	86	375	0.63	1,492	4,656	0.88
22	2041	1.118	86	375	0.63	1,492	4,656	0.88
23	2042	1.118	86	375	0.63	1,492	4,656	0.88
24	2043	1.118	86	375	0.63	1,492	4,656	0.88
25	2044	1.118	86	375	0.63	1,492	4,656	0.88
26	2045	1.118	49	375	0.36	858	4,656	0.50
27	2046	1.118	49	375	0.36	858	4,656	0.50
28	2047	1.118	49	375	0.36	858	4,656	0.50
29	2048	1.118	49	375	0.36	858	4,656	0.50
30	2049	1.118	49	375	0.36	858	4,656	0.50

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	113	375	0.83	1,961	4,656	1.15
2	2021	1.118	113	375	0.83	1,961	4,656	1.15
3	2022	1.118	113	375	0.83	1,961	4,656	1.15
4	2023	1.118	113	375	0.83	1,961	4,656	1.15
5	2024	1.118	113	375	0.83	1,961	4,656	1.15
6	2025	1.118	113	375	0.83	1,961	4,656	1.15
7	2026	1.118	113	375	0.83	1,961	4,656	1.15
8	2027	1.118	113	375	0.83	1,961	4,656	1.15
9	2028	1.118	113	375	0.83	1,961	4,656	1.15
10	2029	1.118	113	375	0.83	1,961	4,656	1.15
11	2030	1.118	113	375	0.83	1,961	4,656	1.15
12	2031	1.118	113	375	0.83	1,961	4,656	1.15
13	2032	1.118	113	375	0.83	1,961	4,656	1.15
14	2033	1.118	113	375	0.83	1,961	4,656	1.15
15	2034	1.118	113	375	0.83	1,961	4,656	1.15
16	2035	1.118	113	375	0.83	1,961	4,656	1.15
17	2036	1.118	113	375	0.83	1,961	4,656	1.15
18	2037	1.118	113	375	0.83	1,961	4,656	1.15
19	2038	1.118	113	375	0.83	1,961	4,656	1.15
20	2039	1.118	113	375	0.83	1,961	4,656	1.15
21	2040	1.118	113	375	0.83	1,961	4,656	1.15
22	2041	1.118	113	375	0.83	1,961	4,656	1.15
23	2042	1.118	113	375	0.83	1,961	4,656	1.15
24	2043	1.118	113	375	0.83	1,961	4,656	1.15
25	2044	1.118	113	375	0.83	1,961	4,656	1.15
26	2045	1.118	62	375	0.45	1,079	4,656	0.63
27	2046	1.118	62	375	0.45	1,079	4,656	0.63
28	2047	1.118	62	375	0.45	1,079	4,656	0.63
29	2048	1.118	62	375	0.45	1,079	4,656	0.63
30	2049	1.118	62	375	0.45	1,079	4,656	0.63

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.6%
10	2029	1.7%	5.4%
11	2030	2.1%	7.5%
12	2031	2.5%	9.9%
13	2032	2.8%	12.8%
14	2033	3.3%	16.1%
15	2034	3.7%	19.8%
16	2035	4.2%	24.0%
17	2036	4.7%	28.7%
18	2037	5.1%	33.8%
19	2038	5.4%	39.2%
20	2039	5.8%	45.0%
21	2040	6.1%	51.1%
22	2041	6.6%	57.7%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.2%	95.5%
30	2049	4.5%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.8%	-0.8%
2	2021	-0.3%	-1.1%
3	2022	-0.1%	-1.2%
4	2023	0.1%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.5%	-0.4%
7	2026	0.8%	0.4%
8	2027	1.1%	1.4%
9	2028	1.3%	2.8%
10	2029	1.7%	4.4%
11	2030	2.0%	6.5%
12	2031	2.4%	8.9%
13	2032	2.8%	11.7%
14	2033	3.2%	14.9%
15	2034	3.7%	18.6%
16	2035	4.2%	22.9%
17	2036	4.7%	27.6%
18	2037	5.1%	32.7%
19	2038	5.5%	38.2%
20	2039	5.9%	44.1%
21	2040	6.3%	50.4%
22	2041	6.7%	57.1%
23	2042	7.1%	64.2%
24	2043	7.7%	72.0%
25	2044	8.0%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.2%
29	2048	4.3%	95.5%
30	2049	4.5%	100.0%
		100.0%	

NEGOTIATED RATE MODEL OUTPUT

(35 Year Contract Term)
Alaska-Canada Pipeline

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	6
2011	6	4	-	1	1	11
2012	11	4	-	1	1	16
2013	16	5	-	1	1	23
2014	23	6	0	1	2	32
2015	32	24	0	4	4	65
2016	65	13	0	2	6	86
2017	86	184	4	33	15	322
2018	322	188	4	34	33	581
2019	581	9	0	2	44	637
2020	637	3	-	1	-	641
2021	641	0	-	0	-	641
		446	9	81	106	

Alaska Pipeline Project - Alaska-Canada Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	6	-	1	0	7
2011	7	5	-	1	1	14
2012	14	5	-	1	1	22
2013	22	6	-	1	2	31
2014	31	7	0	1	3	43
2015	43	31	1	6	5	85
2016	85	18	0	3	7	113
2017	113	241	5	43	20	422
2018	422	246	5	44	44	762
2019	762	12	0	2	60	837
2020	837	5	-	1	-	842
2021	842	1	-	0	-	843
		583	11	106	144	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	637	4	4	645	1	(15)	632
2	2021	645	1	1	646	1	(28)	620
3	2022	646	-	0	647	1	(40)	607
4	2023	647	-	(1)	646	1	(53)	594
5	2024	646	-	(2)	643	1	(65)	579
6	2025	643	-	(4)	639	1	(77)	563
7	2026	639	-	(6)	634	1	(89)	546
8	2027	634	-	(7)	626	1	(101)	527
9	2028	626	-	(9)	617	1	(112)	507
10	2029	617	-	(11)	606	1	(122)	485
11	2030	606	-	(13)	593	1	(132)	461
12	2031	593	-	(16)	577	1	(142)	436
13	2032	577	-	(18)	559	1	(151)	408
14	2033	559	-	(21)	538	1	(160)	379
15	2034	538	-	(24)	514	1	(168)	347
16	2035	514	-	(27)	487	1	(176)	312
17	2036	487	-	(30)	456	1	(176)	281
18	2037	456	-	(33)	424	1	(164)	261
19	2038	424	-	(35)	389	1	(150)	240
20	2039	389	-	(37)	352	1	(135)	217
21	2040	352	-	(39)	312	1	(120)	194
22	2041	312	-	(42)	270	1	(103)	168
23	2042	270	-	(44)	226	1	(85)	141
24	2043	226	-	(48)	178	1	(66)	112
25	2044	178	-	(50)	128	1	(46)	82
26	2045	128	-	(10)	118	1	(43)	76
27	2046	118	-	(10)	108	1	(39)	69
28	2047	108	-	(11)	97	1	(36)	62
29	2048	97	-	(12)	85	1	(31)	55
30	2049	85	-	(13)	72	1	(27)	47
31	2050	72	-	(13)	59	1	(22)	38
32	2051	59	-	(14)	45	1	(17)	29
33	2052	45	-	(15)	31	1	(12)	20
34	2053	31	-	(15)	15	1	(6)	11
35	2054	15	-	(16)	(1)	1	0	1
			5	(641)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	837	5	7	849	1	(19)	831
2	2021	849	1	3	851	1	(36)	816
3	2022	851	-	1	853	1	(53)	800
4	2023	853	-	(1)	852	1	(70)	783
5	2024	852	-	(2)	850	1	(86)	765
6	2025	850	-	(4)	845	1	(102)	744
7	2026	845	-	(6)	839	1	(117)	722
8	2027	839	-	(9)	830	1	(133)	698
9	2028	830	-	(11)	819	1	(147)	672
10	2029	819	-	(14)	805	1	(161)	644
11	2030	805	-	(17)	788	1	(175)	614
12	2031	788	-	(20)	767	1	(188)	581
13	2032	767	-	(24)	744	1	(200)	545
14	2033	744	-	(27)	717	1	(212)	506
15	2034	717	-	(31)	685	1	(222)	464
16	2035	685	-	(36)	650	1	(232)	418
17	2036	650	-	(40)	610	1	(236)	375
18	2037	610	-	(44)	566	1	(219)	348
19	2038	566	-	(47)	519	1	(201)	320
20	2039	519	-	(50)	470	1	(181)	290
21	2040	470	-	(53)	417	1	(160)	258
22	2041	417	-	(57)	360	1	(138)	224
23	2042	360	-	(60)	300	1	(114)	188
24	2043	300	-	(65)	235	1	(88)	149
25	2044	235	-	(67)	168	1	(61)	108
26	2045	168	-	(12)	156	1	(57)	100
27	2046	156	-	(13)	142	1	(52)	91
28	2047	142	-	(14)	128	1	(47)	82
29	2048	128	-	(16)	112	1	(42)	72
30	2049	112	-	(16)	96	1	(36)	62
31	2050	96	-	(17)	79	1	(29)	50
32	2051	79	-	(18)	60	1	(23)	39
33	2052	60	-	(19)	41	1	(15)	27
34	2053	41	-	(20)	21	1	(8)	14
35	2054	21	-	(21)	(1)	1	0	1
			6	(843)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	25	21	(4)	4	0	12	14	72
2	2021	26	19	(1)	4	0	12	13	72
3	2022	25	18	(0)	4	0	12	13	72
4	2023	25	18	1	4	0	12	13	72
5	2024	24	18	2	4	0	12	12	72
6	2025	23	17	4	4	0	11	12	72
7	2026	23	17	6	4	0	11	12	72
8	2027	22	16	7	4	0	11	12	72
9	2028	21	16	9	5	0	10	11	72
10	2029	20	15	11	5	0	10	11	72
11	2030	19	14	13	5	0	10	11	72
12	2031	18	13	16	5	0	9	10	72
13	2032	17	13	18	5	0	9	10	72
14	2033	16	12	21	5	0	9	9	72
15	2034	15	11	24	5	0	8	9	72
16	2035	13	10	27	5	0	8	8	72
17	2036	12	9	30	5	0	8	8	72
18	2037	11	8	33	6	0	7	7	72
19	2038	10	8	35	6	0	7	7	72
20	2039	9	7	37	6	0	6	7	72
21	2040	8	6	39	6	0	6	6	72
22	2041	7	5	42	6	0	5	6	72
23	2042	6	5	44	6	0	5	5	72
24	2043	5	4	48	6	0	3	5	72
25	2044	4	3	50	6	0	4	5	72
26	2045	3	2	10	7	0	4	2	28
27	2046	3	2	10	7	0	3	2	28
28	2047	3	2	11	7	0	3	2	28
29	2048	2	2	12	7	0	3	2	28
30	2049	2	2	13	7	1	3	2	28
31	2050	2	1	13	7	1	3	2	28
32	2051	1	1	14	8	1	3	1	28
33	2052	1	1	15	8	1	2	1	28
34	2053	1	0	15	8	1	2	1	28
35	2054	0	0	16	8	1	2	1	28
		426	315	641	199	14	248	252	2,095

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	35	28	(7)	4	0	16	19	95
2	2021	36	25	(3)	4	0	16	17	95
3	2022	35	24	(1)	4	0	16	17	95
4	2023	35	24	1	4	0	16	17	95
5	2024	34	23	2	4	0	15	16	95
6	2025	33	23	4	4	0	15	16	95
7	2026	32	22	6	4	0	15	16	95
8	2027	31	21	9	4	0	14	15	95
9	2028	30	21	11	5	0	14	15	95
10	2029	29	20	14	5	0	13	14	95
11	2030	27	19	17	5	0	13	14	95
12	2031	26	18	20	5	0	12	14	95
13	2032	25	17	24	5	0	12	13	95
14	2033	23	16	27	5	0	12	12	95
15	2034	21	15	31	5	0	11	12	95
16	2035	19	13	36	5	0	11	11	95
17	2036	17	12	40	5	0	10	10	95
18	2037	16	11	44	6	0	9	10	95
19	2038	15	10	47	6	0	9	9	95
20	2039	13	9	50	6	0	8	9	95
21	2040	12	8	53	6	0	8	8	95
22	2041	11	7	57	6	0	7	8	95
23	2042	9	6	60	6	0	7	7	95
24	2043	7	5	65	6	0	5	7	95
25	2044	6	4	67	6	0	6	6	95
26	2045	5	3	12	7	0	5	3	35
27	2046	4	3	13	7	0	5	3	35
28	2047	4	3	14	7	0	4	3	35
29	2048	3	2	16	7	0	4	2	35
30	2049	3	2	16	7	1	4	2	35
31	2050	2	2	17	7	1	3	2	35
32	2051	2	1	18	8	1	3	2	35
33	2052	1	1	19	8	1	3	2	35
34	2053	1	1	20	8	1	3	1	35
35	2054	0	0	21	8	1	3	1	35
		603	418	843	199	14	326	333	2,736

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	72	1,100	1.000	0.18
2	2021	72	1,100	1.000	0.18
3	2022	72	1,100	1.000	0.18
4	2023	72	1,100	1.000	0.18
5	2024	72	1,100	1.000	0.18
6	2025	72	1,100	1.000	0.18
7	2026	72	1,100	1.000	0.18
8	2027	72	1,100	1.000	0.18
9	2028	72	1,100	1.000	0.18
10	2029	72	1,100	1.000	0.18
11	2030	72	1,100	1.000	0.18
12	2031	72	1,100	1.000	0.18
13	2032	72	1,100	1.000	0.18
14	2033	72	1,100	1.000	0.18
15	2034	72	1,100	1.000	0.18
16	2035	72	1,100	1.000	0.18
17	2036	72	1,100	1.000	0.18
18	2037	72	1,100	1.000	0.18
19	2038	72	1,100	1.000	0.18
20	2039	72	1,100	1.000	0.18
21	2040	72	1,100	1.000	0.18
22	2041	72	1,100	1.000	0.18
23	2042	72	1,100	1.000	0.18
24	2043	72	1,100	1.000	0.18
25	2044	72	1,100	1.000	0.18
26	2045	28	1,100	1.000	0.07
27	2046	28	1,100	1.000	0.07
28	2047	28	1,100	1.000	0.07
29	2048	28	1,100	1.000	0.07
30	2049	28	1,100	1.000	0.07
31	2050	28	1,100	1.000	0.07
32	2051	28	1,100	1.000	0.07
33	2052	28	1,100	1.000	0.07
34	2053	28	1,100	1.000	0.07
35	2054	28	1,100	1.000	0.07

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	95	1,100	1.000	0.24
2	2021	95	1,100	1.000	0.24
3	2022	95	1,100	1.000	0.24
4	2023	95	1,100	1.000	0.24
5	2024	95	1,100	1.000	0.24
6	2025	95	1,100	1.000	0.24
7	2026	95	1,100	1.000	0.24
8	2027	95	1,100	1.000	0.24
9	2028	95	1,100	1.000	0.24
10	2029	95	1,100	1.000	0.24
11	2030	95	1,100	1.000	0.24
12	2031	95	1,100	1.000	0.24
13	2032	95	1,100	1.000	0.24
14	2033	95	1,100	1.000	0.24
15	2034	95	1,100	1.000	0.24
16	2035	95	1,100	1.000	0.24
17	2036	95	1,100	1.000	0.24
18	2037	95	1,100	1.000	0.24
19	2038	95	1,100	1.000	0.24
20	2039	95	1,100	1.000	0.24
21	2040	95	1,100	1.000	0.24
22	2041	95	1,100	1.000	0.24
23	2042	95	1,100	1.000	0.24
24	2043	95	1,100	1.000	0.24
25	2044	95	1,100	1.000	0.24
26	2045	35	1,100	1.000	0.09
27	2046	35	1,100	1.000	0.09
28	2047	35	1,100	1.000	0.09
29	2048	35	1,100	1.000	0.09
30	2049	35	1,100	1.000	0.09
31	2050	35	1,100	1.000	0.09
32	2051	35	1,100	1.000	0.09
33	2052	35	1,100	1.000	0.09
34	2053	35	1,100	1.000	0.09
35	2054	35	1,100	1.000	0.09

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.7%
10	2029	1.7%	5.4%
11	2030	2.1%	7.5%
12	2031	2.5%	10.0%
13	2032	2.8%	12.8%
14	2033	3.3%	16.1%
15	2034	3.7%	19.8%
16	2035	4.2%	24.0%
17	2036	4.7%	28.7%
18	2037	5.1%	33.8%
19	2038	5.4%	39.3%
20	2039	5.8%	45.1%
21	2040	6.1%	51.2%
22	2041	6.6%	57.8%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.1%
28	2047	1.7%	84.8%
29	2048	1.9%	86.7%
30	2049	2.0%	88.7%
31	2050	2.1%	90.7%
32	2051	2.2%	92.9%
33	2052	2.3%	95.2%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.8%	-0.8%
2	2021	-0.3%	-1.1%
3	2022	-0.1%	-1.2%
4	2023	0.1%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.5%	-0.4%
7	2026	0.8%	0.4%
8	2027	1.1%	1.5%
9	2028	1.3%	2.8%
10	2029	1.7%	4.5%
11	2030	2.0%	6.5%
12	2031	2.4%	8.9%
13	2032	2.8%	11.7%
14	2033	3.2%	14.9%
15	2034	3.7%	18.6%
16	2035	4.2%	22.9%
17	2036	4.8%	27.6%
18	2037	5.2%	32.8%
19	2038	5.5%	38.3%
20	2039	5.9%	44.2%
21	2040	6.3%	50.5%
22	2041	6.7%	57.2%
23	2042	7.1%	64.3%
24	2043	7.7%	72.0%
25	2044	8.0%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.0%
28	2047	1.7%	84.7%
29	2048	1.8%	86.6%
30	2049	2.0%	88.5%
31	2050	2.1%	90.6%
32	2051	2.2%	92.8%
33	2052	2.3%	95.1%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	106	-	38	5	150
2011	150	113	-	41	17	320
2012	320	89	-	32	29	471
2013	471	113	-	41	41	666
2014	666	291	6	100	65	1,128
2015	1,128	888	18	304	131	2,468
2016	2,468	2,399	48	821	308	6,043
2017	6,043	2,336	47	799	574	9,799
2018	9,799	1,954	39	668	841	13,302
2019	13,302	1,090	22	373	1,069	15,855
2020	15,855	372	-	135	-	16,362
2021	16,362	9	-	3	-	16,374
		9,760	179	3,355	3,080	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	139	-	50	7	196
2011	196	147	-	53	23	420
2012	420	117	-	42	39	618
2013	618	148	-	53	56	875
2014	875	381	8	130	88	1,482
2015	1,482	1,160	23	397	177	3,238
2016	3,238	3,135	63	1,072	417	7,925
2017	7,925	3,053	61	1,044	777	12,861
2018	12,861	2,554	51	874	1,139	17,478
2019	17,478	1,424	28	487	1,448	20,865
2020	20,865	486	-	176	-	21,528
2021	21,528	12	-	4	-	21,544
		12,755	234	4,384	4,171	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	15,855	507	84	16,446	26	(366)	16,106
2	2021	16,446	13	54	16,513	29	(699)	15,842
3	2022	16,513	-	24	16,537	28	(1,027)	15,538
4	2023	16,537	-	(20)	16,517	28	(1,349)	15,195
5	2024	16,517	-	(67)	16,450	27	(1,665)	14,812
6	2025	16,450	-	(114)	16,336	26	(1,974)	14,389
7	2026	16,336	-	(158)	16,179	26	(2,274)	13,931
8	2027	16,179	-	(208)	15,971	26	(2,565)	13,431
9	2028	15,971	-	(259)	15,712	26	(2,847)	12,891
10	2029	15,712	-	(313)	15,398	26	(3,118)	12,306
11	2030	15,398	-	(375)	15,023	26	(3,378)	11,671
12	2031	15,023	-	(434)	14,590	26	(3,626)	10,990
13	2032	14,590	-	(493)	14,096	27	(3,860)	10,264
14	2033	14,096	-	(560)	13,536	28	(4,080)	9,484
15	2034	13,536	-	(631)	12,905	28	(4,284)	8,649
16	2035	12,905	-	(707)	12,198	29	(4,473)	7,754
17	2036	12,198	-	(779)	11,419	29	(4,362)	7,087
18	2037	11,419	-	(830)	10,589	30	(4,039)	6,580
19	2038	10,589	-	(879)	9,710	31	(3,696)	6,045
20	2039	9,710	-	(927)	8,783	31	(3,333)	5,481
21	2040	8,783	-	(980)	7,803	32	(2,949)	4,886
22	2041	7,803	-	(1,045)	6,758	33	(2,538)	4,253
23	2042	6,758	-	(1,092)	5,666	34	(2,107)	3,592
24	2043	5,666	-	(1,178)	4,488	34	(1,641)	2,880
25	2044	4,488	-	(1,213)	3,275	35	(1,161)	2,148
26	2045	3,275	-	(274)	3,001	36	(1,067)	1,970
27	2046	3,001	-	(289)	2,712	37	(966)	1,782
28	2047	2,712	-	(301)	2,412	37	(861)	1,588
29	2048	2,412	-	(316)	2,095	38	(748)	1,385
30	2049	2,095	-	(326)	1,769	39	(632)	1,176
31	2050	1,769	-	(337)	1,432	40	(511)	961
32	2051	1,432	-	(344)	1,088	41	(388)	741
33	2052	1,088	-	(355)	733	42	(260)	515
34	2053	733	-	(363)	370	43	(128)	284
35	2054	370	-	(358)	13	44	(0)	56
			520	(16,362)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	20,865	663	133	21,660	26	(481)	21,205
2	2021	21,660	16	86	21,762	29	(920)	20,871
3	2022	21,762	-	46	21,808	28	(1,352)	20,485
4	2023	21,808	-	(8)	21,801	28	(1,776)	20,052
5	2024	21,801	-	(66)	21,735	27	(2,193)	19,569
6	2025	21,735	-	(125)	21,610	26	(2,600)	19,036
7	2026	21,610	-	(183)	21,427	26	(2,997)	18,456
8	2027	21,427	-	(249)	21,179	26	(3,382)	17,822
9	2028	21,179	-	(315)	20,863	26	(3,756)	17,133
10	2029	20,863	-	(387)	20,476	26	(4,116)	16,386
11	2030	20,476	-	(469)	20,007	26	(4,461)	15,571
12	2031	20,007	-	(549)	19,458	26	(4,791)	14,693
13	2032	19,458	-	(631)	18,827	27	(5,104)	13,751
14	2033	18,827	-	(723)	18,105	28	(5,398)	12,734
15	2034	18,105	-	(821)	17,284	28	(5,672)	11,640
16	2035	17,284	-	(927)	16,357	29	(5,925)	10,461
17	2036	16,357	-	(1,030)	15,327	29	(5,866)	9,490
18	2037	15,327	-	(1,107)	14,219	30	(5,435)	8,815
19	2038	14,219	-	(1,177)	13,043	31	(4,975)	8,098
20	2039	13,043	-	(1,246)	11,797	31	(4,487)	7,341
21	2040	11,797	-	(1,322)	10,474	32	(3,968)	6,539
22	2041	10,474	-	(1,415)	9,059	33	(3,410)	5,682
23	2042	9,059	-	(1,484)	7,575	34	(2,824)	4,784
24	2043	7,575	-	(1,606)	5,969	34	(2,188)	3,815
25	2044	5,969	-	(1,660)	4,309	35	(1,530)	2,814
26	2045	4,309	-	(343)	3,965	36	(1,412)	2,589
27	2046	3,965	-	(366)	3,600	37	(1,286)	2,350
28	2047	3,600	-	(385)	3,214	37	(1,151)	2,100
29	2048	3,214	-	(409)	2,805	38	(1,007)	1,836
30	2049	2,805	-	(426)	2,379	39	(855)	1,562
31	2050	2,379	-	(444)	1,934	40	(697)	1,278
32	2051	1,934	-	(459)	1,476	41	(532)	985
33	2052	1,476	-	(478)	998	42	(360)	680
34	2053	998	-	(493)	505	43	(181)	366
35	2054	505	-	(499)	6	44	-	49
			679	(21,538)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	632	527	(84)	312	39	318	363	2,106
2	2021	653	479	(54)	346	39	312	331	2,106
3	2022	641	471	(24)	342	40	308	327	2,106
4	2023	628	461	20	331	41	302	323	2,106
5	2024	613	450	67	320	42	296	318	2,106
6	2025	597	438	114	313	43	289	312	2,106
7	2026	579	425	158	312	44	283	306	2,106
8	2027	559	410	208	312	45	273	298	2,106
9	2028	538	395	259	311	46	267	290	2,106
10	2029	515	378	313	310	47	261	282	2,106
11	2030	490	360	375	310	48	251	273	2,106
12	2031	463	340	434	317	49	242	262	2,106
13	2032	434	319	493	323	50	235	251	2,106
14	2033	404	296	560	331	51	226	239	2,106
15	2034	371	272	631	338	52	216	226	2,106
16	2035	335	246	707	345	54	207	212	2,106
17	2036	303	223	779	353	55	194	200	2,106
18	2037	279	205	830	361	56	184	191	2,106
19	2038	258	189	879	369	57	172	182	2,106
20	2039	236	173	927	377	58	162	174	2,106
21	2040	212	156	980	385	60	149	165	2,106
22	2041	187	137	1,045	393	61	127	155	2,106
23	2042	160	118	1,092	402	62	127	145	2,106
24	2043	132	97	1,178	411	64	89	135	2,106
25	2044	103	75	1,213	420	65	108	122	2,106
26	2045	84	62	274	429	67	99	59	1,073
27	2046	77	56	289	439	68	89	56	1,073
28	2047	69	51	301	448	70	83	52	1,073
29	2048	61	45	316	458	71	73	49	1,073
30	2049	52	38	326	468	73	70	45	1,073
31	2050	43	32	337	479	74	67	41	1,073
32	2051	35	25	344	489	76	67	37	1,073
33	2052	25	19	355	500	77	64	33	1,073
34	2053	16	12	363	511	79	64	29	1,073
35	2054	7	5	358	522	81	64	24	1,059
		10,793	7,983	16,362	13,387	2,004	6,337	6,508	63,374

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	888	694	(133)	312	39	419	477	2,696
2	2021	919	631	(86)	346	39	410	436	2,696
3	2022	903	620	(46)	342	40	406	430	2,696
4	2023	885	608	8	331	41	398	425	2,696
5	2024	865	594	66	320	42	389	419	2,696
6	2025	843	579	125	313	43	381	411	2,696
7	2026	819	562	183	312	44	373	403	2,696
8	2027	792	544	249	312	45	360	394	2,696
9	2028	763	524	315	311	46	352	384	2,696
10	2029	732	503	387	310	47	343	373	2,696
11	2030	698	479	469	310	48	331	361	2,696
12	2031	661	454	549	317	49	318	348	2,696
13	2032	621	427	631	323	50	310	334	2,696
14	2033	578	397	723	331	51	297	318	2,696
15	2034	532	366	821	338	52	285	302	2,696
16	2035	483	332	927	345	54	272	284	2,696
17	2036	436	299	1,030	353	55	255	267	2,696
18	2037	400	275	1,107	361	56	243	255	2,696
19	2038	369	254	1,177	369	57	226	244	2,696
20	2039	337	232	1,246	377	58	214	232	2,696
21	2040	303	208	1,322	385	60	197	220	2,696
22	2041	267	183	1,415	393	61	167	208	2,696
23	2042	229	157	1,484	402	62	167	194	2,696
24	2043	188	129	1,606	411	64	117	181	2,696
25	2044	145	99	1,660	420	65	142	164	2,696
26	2045	118	81	343	429	67	130	76	1,244
27	2046	108	74	366	439	68	117	72	1,244
28	2047	97	67	385	448	70	109	68	1,244
29	2048	86	59	409	458	71	96	64	1,244
30	2049	74	51	426	468	73	92	60	1,244
31	2050	62	43	444	479	74	88	55	1,244
32	2051	49	34	459	489	76	88	50	1,244
33	2052	36	25	478	500	77	84	44	1,244
34	2053	23	16	493	511	79	84	39	1,244
35	2054	9	6	499	522	81	84	33	1,234
		15,315	10,605	21,538	13,387	2,004	8,344	8,626	79,821

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,106	4,500	1.118	1.15
2	2021	2,106	4,500	1.118	1.15
3	2022	2,106	4,500	1.118	1.15
4	2023	2,106	4,500	1.118	1.15
5	2024	2,106	4,500	1.118	1.15
6	2025	2,106	4,500	1.118	1.15
7	2026	2,106	4,500	1.118	1.15
8	2027	2,106	4,500	1.118	1.15
9	2028	2,106	4,500	1.118	1.15
10	2029	2,106	4,500	1.118	1.15
11	2030	2,106	4,500	1.118	1.15
12	2031	2,106	4,500	1.118	1.15
13	2032	2,106	4,500	1.118	1.15
14	2033	2,106	4,500	1.118	1.15
15	2034	2,106	4,500	1.118	1.15
16	2035	2,106	4,500	1.118	1.15
17	2036	2,106	4,500	1.118	1.15
18	2037	2,106	4,500	1.118	1.15
19	2038	2,106	4,500	1.118	1.15
20	2039	2,106	4,500	1.118	1.15
21	2040	2,106	4,500	1.118	1.15
22	2041	2,106	4,500	1.118	1.15
23	2042	2,106	4,500	1.118	1.15
24	2043	2,106	4,500	1.118	1.15
25	2044	2,106	4,500	1.118	1.15
26	2045	1,073	4,500	1.118	0.58
27	2046	1,073	4,500	1.118	0.58
28	2047	1,073	4,500	1.118	0.58
29	2048	1,073	4,500	1.118	0.58
30	2049	1,073	4,500	1.118	0.58
31	2050	1,073	4,500	1.118	0.58
32	2051	1,073	4,500	1.118	0.58
33	2052	1,073	4,500	1.118	0.58
34	2053	1,073	4,500	1.118	0.58
35	2054	1,059	4,500	1.118	0.58

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,696	4,500	1.118	1.47
2	2021	2,696	4,500	1.118	1.47
3	2022	2,696	4,500	1.118	1.47
4	2023	2,696	4,500	1.118	1.47
5	2024	2,696	4,500	1.118	1.47
6	2025	2,696	4,500	1.118	1.47
7	2026	2,696	4,500	1.118	1.47
8	2027	2,696	4,500	1.118	1.47
9	2028	2,696	4,500	1.118	1.47
10	2029	2,696	4,500	1.118	1.47
11	2030	2,696	4,500	1.118	1.47
12	2031	2,696	4,500	1.118	1.47
13	2032	2,696	4,500	1.118	1.47
14	2033	2,696	4,500	1.118	1.47
15	2034	2,696	4,500	1.118	1.47
16	2035	2,696	4,500	1.118	1.47
17	2036	2,696	4,500	1.118	1.47
18	2037	2,696	4,500	1.118	1.47
19	2038	2,696	4,500	1.118	1.47
20	2039	2,696	4,500	1.118	1.47
21	2040	2,696	4,500	1.118	1.47
22	2041	2,696	4,500	1.118	1.47
23	2042	2,696	4,500	1.118	1.47
24	2043	2,696	4,500	1.118	1.47
25	2044	2,696	4,500	1.118	1.47
26	2045	1,244	4,500	1.118	0.68
27	2046	1,244	4,500	1.118	0.68
28	2047	1,244	4,500	1.118	0.68
29	2048	1,244	4,500	1.118	0.68
30	2049	1,244	4,500	1.118	0.68
31	2050	1,244	4,500	1.118	0.68
32	2051	1,244	4,500	1.118	0.68
33	2052	1,244	4,500	1.118	0.68
34	2053	1,244	4,500	1.118	0.68
35	2054	1,234	4,500	1.118	0.67

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.3%	-0.8%
3	2022	-0.1%	-1.0%
4	2023	0.1%	-0.9%
5	2024	0.4%	-0.5%
6	2025	0.7%	0.2%
7	2026	1.0%	1.2%
8	2027	1.3%	2.5%
9	2028	1.6%	4.0%
10	2029	1.9%	6.0%
11	2030	2.3%	8.2%
12	2031	2.6%	10.9%
13	2032	3.0%	13.9%
14	2033	3.4%	17.3%
15	2034	3.9%	21.2%
16	2035	4.3%	25.5%
17	2036	4.8%	30.3%
18	2037	5.1%	35.3%
19	2038	5.4%	40.7%
20	2039	5.7%	46.4%
21	2040	6.0%	52.3%
22	2041	6.4%	58.7%
23	2042	6.7%	65.4%
24	2043	7.2%	72.6%
25	2044	7.4%	80.0%
26	2045	1.7%	81.7%
27	2046	1.8%	83.4%
28	2047	1.8%	85.3%
29	2048	1.9%	87.2%
30	2049	2.0%	89.2%
31	2050	2.1%	91.2%
32	2051	2.1%	93.3%
33	2052	2.2%	95.5%
34	2053	2.2%	97.7%
35	2054	2.2%	99.9%
		99.9%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.4%	-1.0%
3	2022	-0.2%	-1.2%
4	2023	0.0%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.6%	-0.3%
7	2026	0.8%	0.5%
8	2027	1.2%	1.7%
9	2028	1.5%	3.2%
10	2029	1.8%	5.0%
11	2030	2.2%	7.1%
12	2031	2.5%	9.7%
13	2032	2.9%	12.6%
14	2033	3.4%	16.0%
15	2034	3.8%	19.8%
16	2035	4.3%	24.1%
17	2036	4.8%	28.9%
18	2037	5.1%	34.0%
19	2038	5.5%	39.5%
20	2039	5.8%	45.2%
21	2040	6.1%	51.4%
22	2041	6.6%	58.0%
23	2042	6.9%	64.8%
24	2043	7.5%	72.3%
25	2044	7.7%	80.0%
26	2045	1.6%	81.6%
27	2046	1.7%	83.3%
28	2047	1.8%	85.1%
29	2048	1.9%	87.0%
30	2049	2.0%	89.0%
31	2050	2.1%	91.0%
32	2051	2.1%	93.1%
33	2052	2.2%	95.4%
34	2053	2.3%	97.6%
35	2054	2.3%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	97	-	20	4	122
2011	122	97	-	20	13	253
2012	253	93	-	19	23	388
2013	388	149	-	31	36	603
2014	603	151	3	28	53	838
2015	838	750	15	140	97	1,841
2016	1,841	277	6	52	152	2,326
2017	2,326	1,532	31	286	246	4,421
2018	4,421	4,648	93	869	544	10,575
2019	10,575	1,928	39	360	886	13,788
2020	13,788	77	-	16	-	13,881
2021	13,881	9	-	2	-	13,892
		9,807	186	1,844	2,056	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	127	-	26	6	160
2011	160	127	-	26	18	331
2012	331	121	-	25	31	509
2013	509	194	-	40	49	792
2014	792	197	4	37	71	1,101
2015	1,101	980	20	183	132	2,416
2016	2,416	361	7	68	206	3,058
2017	3,058	2,001	40	374	333	5,807
2018	5,807	6,074	121	1,135	737	13,875
2019	13,875	2,519	50	471	1,200	18,115
2020	18,115	101	-	21	-	18,237
2021	18,237	12	-	2	-	18,251
		12,816	243	2,409	2,784	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,788	93	96	13,977	56	(315)	13,718
2	2021	13,977	11	29	14,017	57	(599)	13,475
3	2022	14,017	-	6	14,023	57	(879)	13,202
4	2023	14,023	-	(22)	14,002	57	(1,152)	12,906
5	2024	14,002	-	(52)	13,949	57	(1,420)	12,586
6	2025	13,949	-	(84)	13,865	57	(1,682)	12,241
7	2026	13,865	-	(119)	13,746	57	(1,936)	11,867
8	2027	13,746	-	(159)	13,587	58	(2,184)	11,461
9	2028	13,587	-	(199)	13,389	58	(2,423)	11,024
10	2029	13,389	-	(242)	13,147	58	(2,653)	10,552
11	2030	13,147	-	(290)	12,857	58	(2,874)	10,041
12	2031	12,857	-	(342)	12,515	58	(3,085)	9,488
13	2032	12,515	-	(395)	12,119	59	(3,285)	8,893
14	2033	12,119	-	(455)	11,664	59	(3,472)	8,250
15	2034	11,664	-	(519)	11,145	59	(3,648)	7,557
16	2035	11,145	-	(587)	10,558	59	(3,809)	6,808
17	2036	10,558	-	(655)	9,903	59	(3,764)	6,198
18	2037	9,903	-	(706)	9,197	60	(3,496)	5,761
19	2038	9,197	-	(753)	8,444	60	(3,210)	5,294
20	2039	8,444	-	(800)	7,644	60	(2,906)	4,798
21	2040	7,644	-	(853)	6,791	60	(2,581)	4,270
22	2041	6,791	-	(916)	5,875	61	(2,233)	3,703
23	2042	5,875	-	(964)	4,911	61	(1,867)	3,105
24	2043	4,911	-	(1,047)	3,864	61	(1,469)	2,457
25	2044	3,864	-	(1,086)	2,778	61	(1,056)	1,784
26	2045	2,778	-	(210)	2,568	62	(976)	1,654
27	2046	2,568	-	(227)	2,342	62	(890)	1,513
28	2047	2,342	-	(241)	2,100	62	(798)	1,364
29	2048	2,100	-	(259)	1,842	62	(700)	1,204
30	2049	1,842	-	(272)	1,569	63	(597)	1,035
31	2050	1,569	-	(287)	1,283	63	(488)	858
32	2051	1,283	-	(299)	984	63	(374)	673
33	2052	984	-	(314)	670	64	(255)	479
34	2053	670	-	(328)	342	64	(130)	276
35	2054	342	-	(343)	(1)	64	0	64
			104	(13,893)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	18,115	122	143	18,380	56	(414)	18,022
2	2021	18,380	15	57	18,451	57	(787)	17,721
3	2022	18,451	-	26	18,477	57	(1,154)	17,380
4	2023	18,477	-	(11)	18,467	57	(1,514)	17,009
5	2024	18,467	-	(50)	18,416	57	(1,867)	16,606
6	2025	18,416	-	(93)	18,323	57	(2,212)	16,168
7	2026	18,323	-	(139)	18,184	57	(2,548)	15,693
8	2027	18,184	-	(192)	17,992	58	(2,875)	15,174
9	2028	17,992	-	(246)	17,746	58	(3,191)	14,613
10	2029	17,746	-	(303)	17,443	58	(3,497)	14,005
11	2030	17,443	-	(368)	17,075	58	(3,790)	13,343
12	2031	17,075	-	(439)	16,636	58	(4,070)	12,625
13	2032	16,636	-	(511)	16,125	59	(4,335)	11,849
14	2033	16,125	-	(592)	15,534	59	(4,586)	11,007
15	2034	15,534	-	(679)	14,855	59	(4,819)	10,095
16	2035	14,855	-	(772)	14,083	59	(5,034)	9,108
17	2036	14,083	-	(867)	13,216	59	(5,026)	8,250
18	2037	13,216	-	(939)	12,277	60	(4,669)	7,668
19	2038	12,277	-	(1,005)	11,273	60	(4,287)	7,046
20	2039	11,273	-	(1,070)	10,202	60	(3,880)	6,383
21	2040	10,202	-	(1,143)	9,059	60	(3,445)	5,675
22	2041	9,059	-	(1,230)	7,829	61	(2,977)	4,913
23	2042	7,829	-	(1,298)	6,531	61	(2,484)	4,108
24	2043	6,531	-	(1,412)	5,119	61	(1,947)	3,234
25	2044	5,119	-	(1,469)	3,650	61	(1,388)	2,324
26	2045	3,650	-	(269)	3,381	62	(1,286)	2,157
27	2046	3,381	-	(292)	3,089	62	(1,175)	1,976
28	2047	3,089	-	(312)	2,777	62	(1,056)	1,783
29	2048	2,777	-	(337)	2,440	62	(928)	1,574
30	2049	2,440	-	(356)	2,083	63	(792)	1,354
31	2050	2,083	-	(377)	1,707	63	(649)	1,121
32	2051	1,707	-	(395)	1,312	63	(499)	876
33	2052	1,312	-	(417)	895	64	(341)	618
34	2053	895	-	(437)	458	64	(174)	348
35	2054	458	-	(458)	(0)	64	0	64
			136	(18,252)				

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	543	454	(96)	85	7	270	313	1,576
2	2021	556	408	(29)	87	7	265	283	1,576
3	2022	545	400	(6)	89	7	262	279	1,576
4	2023	534	392	22	91	8	256	274	1,576
5	2024	521	382	52	93	8	251	269	1,576
6	2025	508	372	84	95	8	246	264	1,576
7	2026	493	362	119	97	8	240	258	1,576
8	2027	477	350	159	99	8	232	251	1,576
9	2028	460	337	199	101	8	227	244	1,576
10	2029	441	324	242	103	9	221	237	1,576
11	2030	421	309	290	106	9	213	229	1,576
12	2031	399	293	342	108	9	205	220	1,576
13	2032	376	276	395	110	9	200	210	1,576
14	2033	350	257	455	113	9	192	200	1,576
15	2034	323	237	519	115	10	184	189	1,576
16	2035	294	215	587	118	10	175	177	1,576
17	2036	266	195	655	120	10	165	166	1,576
18	2037	244	179	706	123	10	157	157	1,576
19	2038	226	166	753	126	10	146	149	1,576
20	2039	206	151	800	128	11	138	142	1,576
21	2040	185	136	853	131	11	127	133	1,576
22	2041	163	120	916	134	11	108	125	1,576
23	2042	139	102	964	137	11	108	114	1,576
24	2043	114	83	1,047	140	12	76	105	1,576
25	2044	87	64	1,086	143	12	92	93	1,576
26	2045	70	52	210	146	12	84	45	620
27	2046	65	48	227	150	12	76	43	620
28	2047	59	43	241	153	13	70	41	620
29	2048	52	39	259	156	13	62	38	620
30	2049	46	34	272	160	13	59	36	620
31	2050	39	28	287	163	14	57	33	620
32	2051	31	23	299	167	14	57	29	620
33	2052	24	17	314	170	14	54	26	620
34	2053	15	11	328	174	15	54	23	620
35	2054	7	5	343	178	15	54	19	620
		9,279	6,864	13,893	4,407	368	5,380	5,414	45,605

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	763	596	(143)	85	7	355	410	2,073
2	2021	780	536	(57)	87	7	348	372	2,073
3	2022	766	527	(26)	89	7	344	366	2,073
4	2023	751	516	11	91	8	337	361	2,073
5	2024	734	504	50	93	8	330	354	2,073
6	2025	716	492	93	95	8	323	347	2,073
7	2026	696	478	139	97	8	316	340	2,073
8	2027	674	463	192	99	8	305	332	2,073
9	2028	650	447	246	101	8	298	323	2,073
10	2029	625	429	303	103	9	291	313	2,073
11	2030	597	410	368	106	9	280	303	2,073
12	2031	567	390	439	108	9	270	291	2,073
13	2032	534	367	511	110	9	262	279	2,073
14	2033	499	343	592	113	9	252	266	2,073
15	2034	461	317	679	115	10	241	251	2,073
16	2035	419	288	772	118	10	231	235	2,073
17	2036	379	260	867	120	10	216	220	2,073
18	2037	348	239	939	123	10	206	209	2,073
19	2038	321	221	1,005	126	10	192	199	2,073
20	2039	293	201	1,070	128	11	181	188	2,073
21	2040	263	181	1,143	131	11	167	177	2,073
22	2041	231	159	1,230	134	11	142	166	2,073
23	2042	197	135	1,298	137	11	142	152	2,073
24	2043	160	110	1,412	140	12	99	140	2,073
25	2044	121	83	1,469	143	12	121	124	2,073
26	2045	98	67	269	146	12	110	59	762
27	2046	90	62	292	150	12	99	56	762
28	2047	82	56	312	153	13	92	53	762
29	2048	73	50	337	156	13	82	50	762
30	2049	64	44	356	160	13	78	47	762
31	2050	54	37	377	163	14	74	43	762
32	2051	44	30	395	167	14	74	38	762
33	2052	33	22	417	170	14	71	34	762
34	2053	21	14	437	174	15	71	30	762
35	2054	9	6	458	178	15	71	25	762
		13,114	9,082	18,252	4,407	368	7,069	7,153	59,445

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	86	375	0.63	1,490	4,656	0.88
2	2021	1.118	86	375	0.63	1,490	4,656	0.88
3	2022	1.118	86	375	0.63	1,490	4,656	0.88
4	2023	1.118	86	375	0.63	1,490	4,656	0.88
5	2024	1.118	86	375	0.63	1,490	4,656	0.88
6	2025	1.118	86	375	0.63	1,490	4,656	0.88
7	2026	1.118	86	375	0.63	1,490	4,656	0.88
8	2027	1.118	86	375	0.63	1,490	4,656	0.88
9	2028	1.118	86	375	0.63	1,490	4,656	0.88
10	2029	1.118	86	375	0.63	1,490	4,656	0.88
11	2030	1.118	86	375	0.63	1,490	4,656	0.88
12	2031	1.118	86	375	0.63	1,490	4,656	0.88
13	2032	1.118	86	375	0.63	1,490	4,656	0.88
14	2033	1.118	86	375	0.63	1,490	4,656	0.88
15	2034	1.118	86	375	0.63	1,490	4,656	0.88
16	2035	1.118	86	375	0.63	1,490	4,656	0.88
17	2036	1.118	86	375	0.63	1,490	4,656	0.88
18	2037	1.118	86	375	0.63	1,490	4,656	0.88
19	2038	1.118	86	375	0.63	1,490	4,656	0.88
20	2039	1.118	86	375	0.63	1,490	4,656	0.88
21	2040	1.118	86	375	0.63	1,490	4,656	0.88
22	2041	1.118	86	375	0.63	1,490	4,656	0.88
23	2042	1.118	86	375	0.63	1,490	4,656	0.88
24	2043	1.118	86	375	0.63	1,490	4,656	0.88
25	2044	1.118	86	375	0.63	1,490	4,656	0.88
26	2045	1.118	34	375	0.25	586	4,656	0.34
27	2046	1.118	34	375	0.25	586	4,656	0.34
28	2047	1.118	34	375	0.25	586	4,656	0.34
29	2048	1.118	34	375	0.25	586	4,656	0.34
30	2049	1.118	34	375	0.25	586	4,656	0.34
31	2050	1.118	34	375	0.25	586	4,656	0.34
32	2051	1.118	34	375	0.25	586	4,656	0.34
33	2052	1.118	34	375	0.25	586	4,656	0.34
34	2053	1.118	34	375	0.25	586	4,656	0.34
35	2054	1.118	34	375	0.25	587	4,656	0.35

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	113	375	0.83	1,960	4,656	1.15
2	2021	1.118	113	375	0.83	1,960	4,656	1.15
3	2022	1.118	113	375	0.83	1,960	4,656	1.15
4	2023	1.118	113	375	0.83	1,960	4,656	1.15
5	2024	1.118	113	375	0.83	1,960	4,656	1.15
6	2025	1.118	113	375	0.83	1,960	4,656	1.15
7	2026	1.118	113	375	0.83	1,960	4,656	1.15
8	2027	1.118	113	375	0.83	1,960	4,656	1.15
9	2028	1.118	113	375	0.83	1,960	4,656	1.15
10	2029	1.118	113	375	0.83	1,960	4,656	1.15
11	2030	1.118	113	375	0.83	1,960	4,656	1.15
12	2031	1.118	113	375	0.83	1,960	4,656	1.15
13	2032	1.118	113	375	0.83	1,960	4,656	1.15
14	2033	1.118	113	375	0.83	1,960	4,656	1.15
15	2034	1.118	113	375	0.83	1,960	4,656	1.15
16	2035	1.118	113	375	0.83	1,960	4,656	1.15
17	2036	1.118	113	375	0.83	1,960	4,656	1.15
18	2037	1.118	113	375	0.83	1,960	4,656	1.15
19	2038	1.118	113	375	0.83	1,960	4,656	1.15
20	2039	1.118	113	375	0.83	1,960	4,656	1.15
21	2040	1.118	113	375	0.83	1,960	4,656	1.15
22	2041	1.118	113	375	0.83	1,960	4,656	1.15
23	2042	1.118	113	375	0.83	1,960	4,656	1.15
24	2043	1.118	113	375	0.83	1,960	4,656	1.15
25	2044	1.118	113	375	0.83	1,960	4,656	1.15
26	2045	1.118	42	375	0.30	720	4,656	0.42
27	2046	1.118	42	375	0.30	720	4,656	0.42
28	2047	1.118	42	375	0.30	720	4,656	0.42
29	2048	1.118	42	375	0.30	720	4,656	0.42
30	2049	1.118	42	375	0.30	720	4,656	0.42
31	2050	1.118	42	375	0.30	720	4,656	0.42
32	2051	1.118	42	375	0.30	720	4,656	0.42
33	2052	1.118	42	375	0.30	720	4,656	0.42
34	2053	1.118	42	375	0.30	720	4,656	0.42
35	2054	1.118	42	375	0.30	721	4,656	0.42

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$32B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.6%
10	2029	1.7%	5.4%
11	2030	2.1%	7.5%
12	2031	2.5%	9.9%
13	2032	2.8%	12.8%
14	2033	3.3%	16.0%
15	2034	3.7%	19.8%
16	2035	4.2%	24.0%
17	2036	4.7%	28.7%
18	2037	5.1%	33.8%
19	2038	5.4%	39.2%
20	2039	5.8%	45.0%
21	2040	6.1%	51.1%
22	2041	6.6%	57.7%
23	2042	6.9%	64.6%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.1%
28	2047	1.7%	84.9%
29	2048	1.9%	86.7%
30	2049	2.0%	88.7%
31	2050	2.1%	90.8%
32	2051	2.2%	92.9%
33	2052	2.3%	95.2%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Alaska Pipeline Project - Alaska-Canada Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$41B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.8%	-0.8%
2	2021	-0.3%	-1.1%
3	2022	-0.1%	-1.2%
4	2023	0.1%	-1.2%
5	2024	0.3%	-0.9%
6	2025	0.5%	-0.4%
7	2026	0.8%	0.4%
8	2027	1.1%	1.4%
9	2028	1.3%	2.8%
10	2029	1.7%	4.4%
11	2030	2.0%	6.4%
12	2031	2.4%	8.9%
13	2032	2.8%	11.6%
14	2033	3.2%	14.9%
15	2034	3.7%	18.6%
16	2035	4.2%	22.8%
17	2036	4.7%	27.6%
18	2037	5.1%	32.7%
19	2038	5.5%	38.2%
20	2039	5.9%	44.1%
21	2040	6.3%	50.4%
22	2041	6.7%	57.1%
23	2042	7.1%	64.2%
24	2043	7.7%	72.0%
25	2044	8.0%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.1%
28	2047	1.7%	84.8%
29	2048	1.8%	86.6%
30	2049	2.0%	88.6%
31	2050	2.1%	90.6%
32	2051	2.2%	92.8%
33	2052	2.3%	95.1%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Appendix C

Exhibit K
Valdez Pipeline – Recourse and Negotiated Rate Details

RECOURSE RATE MODEL OUTPUT

(25 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these outputs. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	5	-	1	0	7
2	2011	7	4	-	1	1	12
3	2012	12	5	-	1	1	19
4	2013	19	6	-	1	2	28
5	2014	28	7	0	1	3	39
6	2015	39	26	1	4	4	74
7	2016	74	16	0	3	7	100
8	2017	100	189	4	32	16	341
9	2018	341	193	4	33	35	605
10	2019	605	11	0	2	48	666
11	2020	666	5	-	1	-	671
12	2021	671	0	-	0	-	672
			467	9	80	116	

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these outputs. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	7	-	1	0	9
2	2011	9	5	-	1	1	16
3	2012	16	7	-	1	2	25
4	2013	25	8	-	1	2	37
5	2014	37	9	0	2	3	51
6	2015	51	34	1	6	6	97
7	2016	97	21	0	4	9	131
8	2017	131	246	5	42	22	446
9	2018	446	252	5	43	47	793
10	2019	793	14	0	2	64	873
11	2020	873	6	-	1	-	880
12	2021	880	1	-	0	-	881
			610	12	104	155	

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Cost of Service Details

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Operation and Maintenance Expenses	3	3
2	Negative salvage	0	0
3	Depreciation Expense	27	35
4	Taxes Other Than Income Taxes	12	16
5	Federal Income Taxes	16	21
6	State Income Taxes	4	6
7	Return	48	65
8	Net Cost of Service	111	146
9	Cost of Service – Demand Component	111	146
10	Cost of Service – Commodity Component		
11	Demand Billing Determinants - (1100 MMcf/d*1.000 Btu/cf*12)	13,200	13,200
12	Commodity Billing Determinants		
13	Reservation Rate - ($/MMBtu)	8.43	11.07
14	Commodity Rate ($/MMBtu)		
15	IT/AOS/PAL - 100% Load Factor Rate ($/MMBtu)	0.28	0.36

Alaska Pipeline Project - Valdez Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Depreciation Expense

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Basis - Straight Line		
2	Depreciation Rate	4.00%	4.00%
3	Depreciation Expense	27	35

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Income Taxes

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Return	48	65
2	Less: Interest Expense	21	29
3	Net Equity Return	27	36
4	Depreciation of Equity AFUDC	3	4
5	Total Federal Tax Basis	30	39
6	Federal Income Tax Factor	53.85%	53.85%
7	Federal Income Taxes (Tax Factor = .5385)	16	21
8	Total State Taxable Income (Line 3 + Line 7)	43	57
9	State Income Tax Factor	10.38%	10.38%
10	State Income Taxes	4	6
11	Total Income Taxes	21	27

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)

Rate Base & Rate of Return

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Gas Plant In Service	666	873
	Additions during the year	6	7
2	Reserve for Depreciation	(27)	(35)
3	Net Plant	644	845
4	Working Capital	0	0
5	Accumulated Deferred Income Taxes	(20)	(26)
6	Rate Base	625	820
7	Rate of Return	7.49%	7.64%
8	Return	48	65

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson

US$Millions (Nominal)

Capital Structure & Rate of Return

		2020	
Line No.	Description	$20B Capex	$26B Capex
1	Long-Term Debt	70.00%	70.00%
2	Common Equity	30.00%	30.00%
3	Total	100.00%	100.00%
4	Interest rate	4.70%	4.92%
5	ROE	14.00%	14.00%
6	Rate of Return	7.49%	7.64%

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	104	-	36	5	145
2	2011	145	73	-	25	15	258
3	2012	258	114	-	39	26	437
4	2013	437	157	-	54	42	690
5	2014	690	307	6	100	69	1,172
6	2015	1,172	774	15	252	131	2,344
7	2016	2,344	2,053	41	668	287	5,392
8	2017	5,392	2,005	40	652	520	8,609
9	2018	8,609	1,653	33	538	757	11,591
10	2019	11,591	976	20	317	968	13,871
11	2020	13,871	336	-	116	-	14,322
12	2021	14,322	9	-	3	-	14,334
			8,559	155	2,800	2,819	

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	136	-	47	7	189
2	2011	189	95	-	33	20	337
3	2012	337	149	-	51	34	572
4	2013	572	205	-	71	56	904
5	2014	904	401	8	130	93	1,536
6	2015	1,536	1,011	20	329	175	3,070
7	2016	3,070	2,682	54	873	382	7,061
8	2017	7,061	2,620	52	852	693	11,279
9	2018	11,279	2,161	43	703	1,010	15,196
10	2019	15,196	1,275	25	415	1,290	18,200
11	2020	18,200	438	-	151	-	18,790
12	2021	18,790	12	-	4	-	18,806
			11,185	203	3,659	3,758	

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP

US$Millions (Nominal)

Cost of Service Details

Line No.	Description	2020 $20B Capex	 $26B Capex
1	Operation and Maintenance Expenses	274	274
2	Negative salvage	59	59
3	Depreciation Expense	573	752
4	Taxes Other Than Income Taxes	264	346
5	Federal Income Taxes	344	451
6	State Income Taxes	95	125
7	Return	1,020	1,365
8	Net Cost of Service	2,629	3,372
9	Cost of Service – Demand Component	2,629	3,372
10	Cost of Service – Commodity Component		
11	Demand Billing Determinants - (3000 MMcf/d*1.118 Btu/cf*12)	36,000	36,000
12	Commodity Billing Determinants		
13	Reservation Rate - ($/MMbtu)	73.02	93.66
14	Commodity Rate ($/MMbtu)		
15	IT/AOS/PAL - 100% Load Factor Rate ($/MMBtu)	2.40	3.08

Alaska Pipeline Project - Valdez Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)

Depreciation Expense

		2020	
Line No.	Description	$20B Capex	$26B Capex
1	Basis - Straight Line		
2	Depreciation Rate	4.00%	4.00%
3	Depreciation Expense	573	752

Alaska Pipeline Project - Valdez Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)

Income Taxes

		2020	
Line No.	Description	$20B Capex	$26B Capex
1	Return	1,020	1,365
2	Less: Interest Expense	448	615
3	Net Equity Return	572	750
4	Depreciation of Equity AFUDC	67	88
5	Total Federal Tax Basis	639	838
6	Federal Income Tax Factor	53.85%	53.85%
7	Federal Income Taxes (Tax Factor = .5385)	344	451
8	Total State Taxable Income (Line 3 + Line 7)	916	1,201
9	State Income Tax Factor	10.38%	10.38%
10	State Income Taxes	95	125
11	Total Income Taxes	439	576

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)

Rate Base & Rate of Return

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Gas Plant In Service	13,871	18,200
	Additions during the year	451	590
2	Reserve for Depreciation	(573)	(752)
3	Net Plant	13,749	18,038
4	Working Capital	23	23
5	Accumulated Deferred Income Taxes	(416)	(545)
6	Rate Base	13,356	17,516
7	Rate of Return	7.49%	7.64%
8	Return	1,020	1,365

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP

US$Millions (Nominal)

Capital Structure & Rate of Return

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Long-Term Debt	70.00%	70.00%
2	Common Equity	30.00%	30.00%
3	Total	100.00%	100.00%
4	Interest rate	4.70%	4.92%
5	ROE	14.00%	14.00%
6	Rate of Return	7.49%	7.64%

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	132	-	26	6	164
2	2011	164	90	-	18	16	289
3	2012	289	141	-	28	29	486
4	2013	486	203	-	40	47	776
5	2014	776	230	5	41	71	1,123
6	2015	1,123	270	5	48	101	1,547
7	2016	1,547	353	7	63	139	2,110
8	2017	2,110	1,951	39	348	257	4,704
9	2018	4,704	5,361	107	956	611	11,740
10	2019	11,740	1,886	38	336	999	14,998
11	2020	14,998	108	-	21	-	15,127
12	2021	15,127	11	-	2	-	15,141
			10,736	201	1,928	2,276	

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Line No.	Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
1	2010	-	173	-	34	8	215
2	2011	215	118	-	23	22	378
3	2012	378	184	-	36	38	636
4	2013	636	265	-	53	62	1,017
5	2014	1,017	301	6	54	95	1,472
6	2015	1,472	352	7	63	134	2,029
7	2016	2,029	462	9	82	185	2,768
8	2017	2,768	2,549	51	454	342	6,165
9	2018	6,165	7,006	140	1,249	815	15,375
10	2019	15,375	2,464	49	439	1,332	19,660
11	2020	19,660	141	-	28	-	19,829
12	2021	19,829	14	-	3	-	19,846
			14,030	263	2,519	3,034	

Alaska Pipeline Project - Valdez Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)

Cost of Service Details

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Operation and Maintenance Expenses	62	62
2	Negative salvage	10	10
3	Depreciation Expense	606	794
4	Taxes Other Than Income Taxes	278	364
5	Federal Income Taxes	359	470
6	State Income Taxes	101	132
7	Return	1,091	1,458
8	Net Cost of Service	2,506	3,290
9	Cost of Service – Demand Component (In-State)	253	332
10	Cost of Service – Demand Component (Export)	2,253	2,958
11	Cost of Service – Commodity Component		
12	Demand Billing Determinants - In-State (342 MMcf/d*1.118 Btu/cf*12)	4,594	4,594
13	Demand Billing Determinants - Export (2,658 MMcf/d*1.118 Btu/cf*12)	35,654	35,654
14	Commodity Billing Determinants		
15	Reservation Rate - ($/MMBtu; In-State)	55.11	72.35
16	Reservation Rate - ($/MMBtu; Export)	63.18	82.95
17	Commodity Rate		
18	IT/AOS - 100% Load Factor Rate ($/MMBtu; In-State)	1.81	2.38
19	IT/AOS/PAL - 100% Load Factor Rate ($/MMBtu; Export)	2.08	2.73

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Depreciation Expense

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Basis - Straight Line		
2	Depreciation Rate	4.00%	4.00%
3	Depreciation Expense	606	794

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Income Taxes

Line No.	Description	2020 $20B Capex	2020 $26B Capex
1	Return	1,091	1,458
2	Less: Interest Expense	479	657
3	Net Equity Return	612	801
4	Depreciation of Equity AFUDC	54	71
5	Total Federal Tax Basis	666	872
6	Federal Income Tax Factor	53.85%	53.85%
7	Federal Income Taxes (Tax Factor = .5385)	359	470
8	Total State Taxable Income (Line 3 + Line 7)	970	1,271
9	State Income Tax Factor	10.38%	10.38%
10	State Income Taxes	101	132
11	Total Income Taxes	459	602

Alaska Pipeline Project - Valdez Pipeline
Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)

Rate Base & Rate of Return

		2020	
Line No.	Description	$20B Capex	$26B Capex
1	Gas Plant In Service	14,998	19,660
	Additions during the year	129	169
2	Reserve for Depreciation	(606)	(794)
3	Net Plant	14,522	19,035
4	Working Capital	49	49
5	Accumulated Deferred Income Taxes	(440)	(577)
6	Rate Base	14,131	18,507
7	Rate of Return	7.49%	7.64%
8	Return	1,091	1,458

Alaska Pipeline Project - Valdez Pipeline

Recourse Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section

US$Millions (Nominal)

Capital Structure & Rate of Return

Line No.	Description	2020 $20B Capex	 $26B Capex
1	Long-Term Debt	70.00%	70.00%
2	Common Equity	30.00%	30.00%
3	Total	100.00%	100.00%
4	Interest rate	4.70%	4.92%
5	ROE	14.00%	14.00%
6	Rate of Return	7.49%	7.64%

NEGOTIATED RATE MODEL OUTPUT

(20 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	442
2018	442	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	(2)	658	0	(15)	643
2	2021	658	1	(5)	653	0	(28)	625
3	2022	653	-	(7)	646	0	(41)	605
4	2023	646	-	(9)	637	0	(54)	583
5	2024	637	-	(11)	626	0	(66)	560
6	2025	626	-	(13)	613	0	(78)	535
7	2026	613	-	(15)	598	0	(89)	509
8	2027	598	-	(18)	580	0	(100)	480
9	2028	580	-	(20)	559	0	(110)	449
10	2029	559	-	(23)	536	0	(120)	417
11	2030	536	-	(26)	510	0	(129)	382
12	2031	510	-	(30)	480	0	(137)	344
13	2032	480	-	(33)	448	0	(144)	303
14	2033	448	-	(37)	411	0	(151)	260
15	2034	411	-	(40)	371	0	(143)	228
16	2035	371	-	(43)	328	0	(127)	202
17	2036	328	-	(45)	283	0	(109)	174
18	2037	283	-	(48)	236	0	(90)	145
19	2038	236	-	(51)	185	0	(71)	115
20	2039	185	-	(53)	131	0	(50)	82
			6	(528)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	(1)	867	0	(20)	847
2	2021	867	1	(6)	861	0	(37)	823
3	2022	861	-	(8)	852	0	(55)	798
4	2023	852	-	(11)	841	0	(71)	770
5	2024	841	-	(14)	828	0	(87)	741
6	2025	828	-	(16)	812	0	(103)	709
7	2026	812	-	(19)	792	0	(118)	675
8	2027	792	-	(23)	769	0	(132)	638
9	2028	769	-	(26)	743	0	(146)	598
10	2029	743	-	(30)	713	0	(158)	555
11	2030	713	-	(34)	679	0	(170)	509
12	2031	679	-	(39)	640	0	(181)	459
13	2032	640	-	(43)	596	0	(191)	406
14	2033	596	-	(48)	548	0	(200)	348
15	2034	548	-	(53)	495	0	(191)	304
16	2035	495	-	(57)	438	0	(169)	269
17	2036	438	-	(61)	377	0	(146)	232
18	2037	377	-	(64)	313	0	(120)	193
19	2038	313	-	(68)	245	0	(94)	152
20	2039	245	-	(72)	173	0	(65)	108
			8	(695)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	21	2	3	0	13	15	76
2	2021	22	19	5	3	0	12	14	76
3	2022	22	18	7	3	0	12	13	76
4	2023	21	18	9	3	0	12	13	76
5	2024	20	17	11	3	1	12	13	76
6	2025	19	16	13	3	1	12	12	76
7	2026	18	16	15	3	1	11	12	76
8	2027	17	15	18	3	1	11	11	76
9	2028	16	14	20	3	1	11	11	76
10	2029	15	13	23	3	1	10	10	76
11	2030	14	12	26	3	1	10	10	76
12	2031	13	11	30	3	1	10	9	76
13	2032	11	10	33	4	1	9	8	76
14	2033	10	8	37	4	1	9	8	76
15	2034	9	7	40	4	1	9	7	76
16	2035	8	6	43	4	1	8	7	76
17	2036	7	6	45	4	1	8	6	76
18	2037	6	5	48	4	1	7	6	76
19	2038	5	4	51	4	1	7	5	76
20	2039	3	3	53	4	1	6	5	76
		279	240	528	67	12	199	195	1,520

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	1	3	0	17	20	101
2	2021	32	25	6	3	0	16	18	101
3	2022	31	24	8	3	0	16	17	101
4	2023	30	24	11	3	0	16	17	101
5	2024	29	23	14	3	1	16	17	101
6	2025	28	22	16	3	1	15	16	101
7	2026	27	21	19	3	1	15	15	101
8	2027	25	20	23	3	1	14	15	101
9	2028	24	19	26	3	1	14	14	101
10	2029	22	17	30	3	1	14	14	101
11	2030	20	16	34	3	1	13	13	101
12	2031	19	15	39	3	1	13	12	101
13	2032	17	13	43	4	1	12	11	101
14	2033	14	11	48	4	1	12	10	101
15	2034	13	10	53	4	1	11	10	101
16	2035	11	9	57	4	1	11	9	101
17	2036	10	8	61	4	1	10	8	101
18	2037	8	6	64	4	1	10	8	101
19	2038	7	5	68	4	1	9	7	101
20	2039	5	4	72	4	1	9	6	101
		403	318	695	67	12	262	258	2,015

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	76	1,100	1.000	0.19
2	2021	76	1,100	1.000	0.19
3	2022	76	1,100	1.000	0.19
4	2023	76	1,100	1.000	0.19
5	2024	76	1,100	1.000	0.19
6	2025	76	1,100	1.000	0.19
7	2026	76	1,100	1.000	0.19
8	2027	76	1,100	1.000	0.19
9	2028	76	1,100	1.000	0.19
10	2029	76	1,100	1.000	0.19
11	2030	76	1,100	1.000	0.19
12	2031	76	1,100	1.000	0.19
13	2032	76	1,100	1.000	0.19
14	2033	76	1,100	1.000	0.19
15	2034	76	1,100	1.000	0.19
16	2035	76	1,100	1.000	0.19
17	2036	76	1,100	1.000	0.19
18	2037	76	1,100	1.000	0.19
19	2038	76	1,100	1.000	0.19
20	2039	76	1,100	1.000	0.19

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	101	1,100	1.000	0.25
2	2021	101	1,100	1.000	0.25
3	2022	101	1,100	1.000	0.25
4	2023	101	1,100	1.000	0.25
5	2024	101	1,100	1.000	0.25
6	2025	101	1,100	1.000	0.25
7	2026	101	1,100	1.000	0.25
8	2027	101	1,100	1.000	0.25
9	2028	101	1,100	1.000	0.25
10	2029	101	1,100	1.000	0.25
11	2030	101	1,100	1.000	0.25
12	2031	101	1,100	1.000	0.25
13	2032	101	1,100	1.000	0.25
14	2033	101	1,100	1.000	0.25
15	2034	101	1,100	1.000	0.25
16	2035	101	1,100	1.000	0.25
17	2036	101	1,100	1.000	0.25
18	2037	101	1,100	1.000	0.25
19	2038	101	1,100	1.000	0.25
20	2039	101	1,100	1.000	0.25

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.2%	0.2%
2	2021	0.8%	1.1%
3	2022	1.1%	2.1%
4	2023	1.3%	3.5%
5	2024	1.6%	5.1%
6	2025	2.0%	7.1%
7	2026	2.3%	9.4%
8	2027	2.7%	12.1%
9	2028	3.1%	15.2%
10	2029	3.5%	18.7%
11	2030	4.0%	22.7%
12	2031	4.5%	27.2%
13	2032	5.0%	32.1%
14	2033	5.5%	37.7%
15	2034	6.0%	43.7%
16	2035	6.4%	50.2%
17	2036	6.8%	57.0%
18	2037	7.2%	64.2%
19	2038	7.7%	71.9%
20	2039	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.1%	0.1%
2	2021	0.7%	0.9%
3	2022	1.0%	1.8%
4	2023	1.2%	3.1%
5	2024	1.6%	4.6%
6	2025	1.9%	6.5%
7	2026	2.2%	8.7%
8	2027	2.6%	11.4%
9	2028	3.0%	14.4%
10	2029	3.5%	17.9%
11	2030	3.9%	21.8%
12	2031	4.5%	26.3%
13	2032	5.0%	31.3%
14	2033	5.6%	36.8%
15	2034	6.1%	43.0%
16	2035	6.6%	49.5%
17	2036	7.0%	56.5%
18	2037	7.4%	63.9%
19	2038	7.8%	71.7%
20	2039	8.3%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,520
2015	1,520	1,011	20	329	161	3,041
2016	3,041	2,682	54	873	353	7,004
2017	7,004	2,620	52	852	640	11,168
2018	11,168	2,161	43	703	927	15,002
2019	15,002	1,275	25	415	1,174	17,892
2020	17,892	438	-	151	-	18,482
2021	18,482	12	-	4	-	18,497
		11,185	203	3,659	3,449	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	(52)	13,982	23	(315)	13,689
2	2021	13,982	12	(102)	13,891	24	(601)	13,315
3	2022	13,891	-	(138)	13,753	24	(878)	12,899
4	2023	13,753	-	(186)	13,567	23	(1,148)	12,442
5	2024	13,567	-	(239)	13,328	22	(1,409)	11,941
6	2025	13,328	-	(289)	13,039	22	(1,661)	11,400
7	2026	13,039	-	(339)	12,700	22	(1,902)	10,820
8	2027	12,700	-	(395)	12,305	22	(2,131)	10,196
9	2028	12,305	-	(452)	11,853	22	(2,349)	9,526
10	2029	11,853	-	(512)	11,341	22	(2,553)	8,810
11	2030	11,341	-	(579)	10,762	22	(2,744)	8,040
12	2031	10,762	-	(645)	10,117	22	(2,919)	7,220
13	2032	10,117	-	(712)	9,405	23	(3,079)	6,349
14	2033	9,405	-	(785)	8,620	23	(3,221)	5,422
15	2034	8,620	-	(847)	7,773	24	(2,966)	4,831
16	2035	7,773	-	(894)	6,879	24	(2,621)	4,282
17	2036	6,879	-	(942)	5,937	25	(2,257)	3,705
18	2037	5,937	-	(990)	4,947	25	(1,873)	3,099
19	2038	4,947	-	(1,043)	3,904	26	(1,467)	2,463
20	2039	3,904	-	(1,095)	2,809	26	(1,040)	1,795
			463	(11,236)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,892	590	(50)	18,431	23	(415)	18,039
2	2021	18,431	16	(120)	18,327	24	(791)	17,561
3	2022	18,327	-	(167)	18,160	24	(1,157)	17,027
4	2023	18,160	-	(228)	17,932	23	(1,513)	16,443
5	2024	17,932	-	(295)	17,637	22	(1,858)	15,802
6	2025	17,637	-	(361)	17,276	22	(2,190)	15,108
7	2026	17,276	-	(428)	16,848	22	(2,509)	14,361
8	2027	16,848	-	(503)	16,346	22	(2,813)	13,554
9	2028	16,346	-	(579)	15,767	22	(3,102)	12,687
10	2029	15,767	-	(661)	15,106	22	(3,374)	11,754
11	2030	15,106	-	(752)	14,354	22	(3,628)	10,748
12	2031	14,354	-	(843)	13,512	22	(3,862)	9,672
13	2032	13,512	-	(936)	12,576	23	(4,075)	8,523
14	2033	12,576	-	(1,039)	11,536	23	(4,265)	7,294
15	2034	11,536	-	(1,129)	10,407	24	(3,978)	6,452
16	2035	10,407	-	(1,198)	9,208	24	(3,515)	5,717
17	2036	9,208	-	(1,268)	7,940	25	(3,024)	4,941
18	2037	7,940	-	(1,337)	6,603	25	(2,504)	4,124
19	2038	6,603	-	(1,414)	5,189	26	(1,953)	3,262
20	2039	5,189	-	(1,490)	3,699	26	(1,371)	2,355
			605	(14,798)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	465	450	52	274	59	270	317	1,887
2	2021	476	405	102	289	61	265	289	1,887
3	2022	462	393	138	287	62	262	283	1,887
4	2023	447	380	186	278	63	257	276	1,887
5	2024	430	366	239	267	65	251	269	1,887
6	2025	411	350	289	263	66	246	262	1,887
7	2026	392	333	339	262	67	240	253	1,887
8	2027	370	315	395	262	69	232	243	1,887
9	2028	348	296	452	261	70	227	233	1,887
10	2029	323	275	512	260	72	222	222	1,887
11	2030	297	253	579	260	74	213	211	1,887
12	2031	269	229	645	266	75	205	198	1,887
13	2032	239	204	712	271	77	200	184	1,887
14	2033	207	177	785	277	79	192	170	1,887
15	2034	181	154	847	283	80	184	157	1,887
16	2035	161	137	894	290	82	176	148	1,887
17	2036	141	120	942	296	84	165	139	1,887
18	2037	120	102	990	303	86	157	130	1,887
19	2038	98	83	1,043	309	88	146	120	1,887
20	2039	75	64	1,095	316	90	138	109	1,887
		5,911	5,085	11,236	5,574	1,468	4,247	4,214	37,735

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	667	593	50	274	59	356	417	2,416
2	2021	683	534	120	289	61	349	380	2,416
3	2022	664	519	167	287	62	345	372	2,416
4	2023	642	502	228	278	63	338	364	2,416
5	2024	619	484	295	267	65	331	355	2,416
6	2025	593	464	361	263	66	324	345	2,416
7	2026	566	442	428	262	67	317	334	2,416
8	2027	536	419	503	262	69	306	322	2,416
9	2028	504	394	579	261	70	299	309	2,416
10	2029	469	367	661	260	72	292	295	2,416
11	2030	432	338	752	260	74	281	280	2,416
12	2031	392	306	843	266	75	271	263	2,416
13	2032	349	273	936	271	77	263	245	2,416
14	2033	304	237	1,039	277	79	253	227	2,416
15	2034	264	206	1,129	283	80	242	210	2,416
16	2035	234	183	1,198	290	82	231	198	2,416
17	2036	205	160	1,268	296	84	217	186	2,416
18	2037	174	136	1,337	303	86	207	173	2,416
19	2038	142	111	1,414	309	88	192	160	2,416
20	2039	108	84	1,490	316	90	182	146	2,416
		8,544	6,749	14,798	5,574	1,468	5,597	5,580	48,311

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,887	3,000	1.118	1.54
2	2021	1,887	3,000	1.118	1.54
3	2022	1,887	3,000	1.118	1.54
4	2023	1,887	3,000	1.118	1.54
5	2024	1,887	3,000	1.118	1.54
6	2025	1,887	3,000	1.118	1.54
7	2026	1,887	3,000	1.118	1.54
8	2027	1,887	3,000	1.118	1.54
9	2028	1,887	3,000	1.118	1.54
10	2029	1,887	3,000	1.118	1.54
11	2030	1,887	3,000	1.118	1.54
12	2031	1,887	3,000	1.118	1.54
13	2032	1,887	3,000	1.118	1.54
14	2033	1,887	3,000	1.118	1.54
15	2034	1,887	3,000	1.118	1.54
16	2035	1,887	3,000	1.118	1.54
17	2036	1,887	3,000	1.118	1.54
18	2037	1,887	3,000	1.118	1.54
19	2038	1,887	3,000	1.118	1.54
20	2039	1,887	3,000	1.118	1.54

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,416	3,000	1.118	1.97
2	2021	2,416	3,000	1.118	1.97
3	2022	2,416	3,000	1.118	1.97
4	2023	2,416	3,000	1.118	1.97
5	2024	2,416	3,000	1.118	1.97
6	2025	2,416	3,000	1.118	1.97
7	2026	2,416	3,000	1.118	1.97
8	2027	2,416	3,000	1.118	1.97
9	2028	2,416	3,000	1.118	1.97
10	2029	2,416	3,000	1.118	1.97
11	2030	2,416	3,000	1.118	1.97
12	2031	2,416	3,000	1.118	1.97
13	2032	2,416	3,000	1.118	1.97
14	2033	2,416	3,000	1.118	1.97
15	2034	2,416	3,000	1.118	1.97
16	2035	2,416	3,000	1.118	1.97
17	2036	2,416	3,000	1.118	1.97
18	2037	2,416	3,000	1.118	1.97
19	2038	2,416	3,000	1.118	1.97
20	2039	2,416	3,000	1.118	1.97

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.4%	0.4%
2	2021	0.7%	1.1%
3	2022	1.0%	2.1%
4	2023	1.3%	3.4%
5	2024	1.7%	5.1%
6	2025	2.1%	7.2%
7	2026	2.4%	9.6%
8	2027	2.8%	12.4%
9	2028	3.2%	15.6%
10	2029	3.6%	19.3%
11	2030	4.1%	23.4%
12	2031	4.6%	28.0%
13	2032	5.1%	33.0%
14	2033	5.6%	38.6%
15	2034	6.0%	44.7%
16	2035	6.4%	51.0%
17	2036	6.7%	57.7%
18	2037	7.0%	64.8%
19	2038	7.4%	72.2%
20	2039	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.3%	0.3%
2	2021	0.6%	0.9%
3	2022	0.9%	1.8%
4	2023	1.2%	3.1%
5	2024	1.6%	4.6%
6	2025	2.0%	6.6%
7	2026	2.3%	8.9%
8	2027	2.7%	11.6%
9	2028	3.1%	14.8%
10	2029	3.6%	18.3%
11	2030	4.1%	22.4%
12	2031	4.6%	27.0%
13	2032	5.1%	32.0%
14	2033	5.6%	37.6%
15	2034	6.1%	43.7%
16	2035	6.5%	50.2%
17	2036	6.9%	57.1%
18	2037	7.2%	64.3%
19	2038	7.6%	71.9%
20	2039	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,723
2017	2,723	2,549	51	454	313	6,091
2018	6,091	7,006	140	1,249	752	15,238
2019	15,238	2,464	49	439	1,225	19,416
2020	19,416	141	-	28	-	19,584
2021	19,584	14	-	3	-	19,602
		14,030	263	2,519	2,790	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	(35)	14,864	49	(339)	14,574
2	2021	14,864	13	(119)	14,758	49	(642)	14,165
3	2022	14,758	-	(156)	14,602	49	(937)	13,715
4	2023	14,602	-	(198)	14,404	49	(1,223)	13,231
5	2024	14,404	-	(243)	14,161	49	(1,499)	12,711
6	2025	14,161	-	(292)	13,869	50	(1,764)	12,154
7	2026	13,869	-	(343)	13,526	50	(2,019)	11,557
8	2027	13,526	-	(401)	13,125	50	(2,262)	10,914
9	2028	13,125	-	(459)	12,666	50	(2,491)	10,225
10	2029	12,666	-	(522)	12,144	50	(2,708)	9,487
11	2030	12,144	-	(591)	11,553	50	(2,909)	8,694
12	2031	11,553	-	(666)	10,887	50	(3,094)	7,843
13	2032	10,887	-	(742)	10,146	50	(3,263)	6,934
14	2033	10,146	-	(826)	9,320	51	(3,413)	5,958
15	2034	9,320	-	(904)	8,416	51	(3,275)	5,192
16	2035	8,416	-	(966)	7,450	51	(2,897)	4,605
17	2036	7,450	-	(1,024)	6,426	51	(2,494)	3,983
18	2037	6,426	-	(1,083)	5,343	51	(2,067)	3,327
19	2038	5,343	-	(1,148)	4,195	51	(1,614)	2,633
20	2039	4,195	-	(1,213)	2,982	52	(1,134)	1,900
			142	(11,929)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,416	169	(26)	19,558	49	(445)	19,162
2	2021	19,558	17	(136)	19,440	49	(843)	18,645
3	2022	19,440	-	(184)	19,255	49	(1,231)	18,073
4	2023	19,255	-	(241)	19,015	49	(1,608)	17,456
5	2024	19,015	-	(301)	18,713	49	(1,972)	16,791
6	2025	18,713	-	(366)	18,347	50	(2,323)	16,074
7	2026	18,347	-	(435)	17,912	50	(2,659)	15,303
8	2027	17,912	-	(513)	17,400	50	(2,980)	14,469
9	2028	17,400	-	(592)	16,807	50	(3,285)	13,572
10	2029	16,807	-	(677)	16,130	50	(3,571)	12,609
11	2030	16,130	-	(772)	15,358	50	(3,839)	11,570
12	2031	15,358	-	(873)	14,485	50	(4,085)	10,450
13	2032	14,485	-	(978)	13,508	50	(4,309)	9,249
14	2033	13,508	-	(1,093)	12,415	51	(4,510)	7,956
15	2034	12,415	-	(1,203)	11,212	51	(4,368)	6,895
16	2035	11,212	-	(1,290)	9,922	51	(3,862)	6,111
17	2036	9,922	-	(1,372)	8,551	51	(3,322)	5,280
18	2037	8,551	-	(1,453)	7,097	51	(2,749)	4,400
19	2038	7,097	-	(1,543)	5,554	51	(2,138)	3,467
20	2039	5,554	-	(1,634)	3,920	52	(1,491)	2,481
			186	(15,681)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	500	484	35	62	10	287	340	1,718
2	2021	507	431	119	64	10	281	306	1,718
3	2022	491	418	156	65	10	278	299	1,718
4	2023	475	404	198	67	11	272	291	1,718
5	2024	457	389	243	68	11	267	283	1,718
6	2025	438	373	292	70	11	261	273	1,718
7	2026	418	356	343	71	11	255	264	1,718
8	2027	396	337	401	73	12	247	253	1,718
9	2028	373	317	459	74	12	241	242	1,718
10	2029	347	296	522	76	12	235	230	1,718
11	2030	320	273	591	78	12	227	217	1,718
12	2031	291	248	666	79	13	218	203	1,718
13	2032	260	222	742	81	13	212	188	1,718
14	2033	227	193	826	83	13	204	172	1,718
15	2034	197	167	904	85	13	195	157	1,718
16	2035	173	147	966	86	14	186	146	1,718
17	2036	151	129	1,024	88	14	175	136	1,718
18	2037	129	110	1,083	90	14	166	125	1,718
19	2038	105	89	1,148	92	15	155	114	1,718
20	2039	80	68	1,213	94	15	146	102	1,718
		6,336	5,451	11,929	1,546	246	4,507	4,340	34,355

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	716	637	26	62	10	377	446	2,274
2	2021	726	567	136	64	10	369	402	2,274
3	2022	705	551	184	65	10	366	393	2,274
4	2023	682	533	241	67	11	358	383	2,274
5	2024	657	514	301	68	11	351	372	2,274
6	2025	631	493	366	70	11	343	360	2,274
7	2026	602	471	435	71	11	336	348	2,274
8	2027	571	447	513	73	12	324	335	2,274
9	2028	538	421	592	74	12	317	320	2,274
10	2029	502	393	677	76	12	309	304	2,274
11	2030	464	363	772	78	12	298	288	2,274
12	2031	423	330	873	79	13	287	269	2,274
13	2032	378	295	978	81	13	279	250	2,274
14	2033	330	258	1,093	83	13	268	229	2,274
15	2034	285	223	1,203	85	13	256	209	2,274
16	2035	250	195	1,290	86	14	245	194	2,274
17	2036	219	171	1,372	88	14	230	180	2,274
18	2037	186	145	1,453	90	14	219	166	2,274
19	2038	151	118	1,543	92	15	204	151	2,274
20	2039	114	89	1,634	94	15	192	135	2,274
		9,129	7,213	15,681	1,546	246	5,927	5,733	45,475

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	174	383	1.24	1,544	2,971	1.42
2	2021	1.118	174	383	1.24	1,544	2,971	1.42
3	2022	1.118	174	383	1.24	1,544	2,971	1.42
4	2023	1.118	174	383	1.24	1,544	2,971	1.42
5	2024	1.118	174	383	1.24	1,544	2,971	1.42
6	2025	1.118	174	383	1.24	1,544	2,971	1.42
7	2026	1.118	174	383	1.24	1,544	2,971	1.42
8	2027	1.118	174	383	1.24	1,544	2,971	1.42
9	2028	1.118	174	383	1.24	1,544	2,971	1.42
10	2029	1.118	174	383	1.24	1,544	2,971	1.42
11	2030	1.118	174	383	1.24	1,544	2,971	1.42
12	2031	1.118	174	383	1.24	1,544	2,971	1.42
13	2032	1.118	174	383	1.24	1,544	2,971	1.42
14	2033	1.118	174	383	1.24	1,544	2,971	1.42
15	2034	1.118	174	383	1.24	1,544	2,971	1.42
16	2035	1.118	174	383	1.24	1,544	2,971	1.42
17	2036	1.118	174	383	1.24	1,544	2,971	1.42
18	2037	1.118	174	383	1.24	1,544	2,971	1.42
19	2038	1.118	174	383	1.24	1,544	2,971	1.42
20	2039	1.118	174	383	1.24	1,544	2,971	1.42

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	230	383	1.64	2,044	2,971	1.88
2	2021	1.118	230	383	1.64	2,044	2,971	1.88
3	2022	1.118	230	383	1.64	2,044	2,971	1.88
4	2023	1.118	230	383	1.64	2,044	2,971	1.88
5	2024	1.118	230	383	1.64	2,044	2,971	1.88
6	2025	1.118	230	383	1.64	2,044	2,971	1.88
7	2026	1.118	230	383	1.64	2,044	2,971	1.88
8	2027	1.118	230	383	1.64	2,044	2,971	1.88
9	2028	1.118	230	383	1.64	2,044	2,971	1.88
10	2029	1.118	230	383	1.64	2,044	2,971	1.88
11	2030	1.118	230	383	1.64	2,044	2,971	1.88
12	2031	1.118	230	383	1.64	2,044	2,971	1.88
13	2032	1.118	230	383	1.64	2,044	2,971	1.88
14	2033	1.118	230	383	1.64	2,044	2,971	1.88
15	2034	1.118	230	383	1.64	2,044	2,971	1.88
16	2035	1.118	230	383	1.64	2,044	2,971	1.88
17	2036	1.118	230	383	1.64	2,044	2,971	1.88
18	2037	1.118	230	383	1.64	2,044	2,971	1.88
19	2038	1.118	230	383	1.64	2,044	2,971	1.88
20	2039	1.118	230	383	1.64	2,044	2,971	1.88

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.2%	0.2%
2	2021	0.8%	1.0%
3	2022	1.0%	2.1%
4	2023	1.3%	3.4%
5	2024	1.6%	5.0%
6	2025	2.0%	7.0%
7	2026	2.3%	9.3%
8	2027	2.7%	12.0%
9	2028	3.1%	15.1%
10	2029	3.5%	18.6%
11	2030	4.0%	22.5%
12	2031	4.5%	27.0%
13	2032	5.0%	32.0%
14	2033	5.5%	37.5%
15	2034	6.1%	43.6%
16	2035	6.5%	50.0%
17	2036	6.9%	56.9%
18	2037	7.3%	64.2%
19	2038	7.7%	71.9%
20	2039	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(20 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.1%	0.1%
2	2021	0.7%	0.8%
3	2022	0.9%	1.8%
4	2023	1.2%	3.0%
5	2024	1.5%	4.5%
6	2025	1.9%	6.4%
7	2026	2.2%	8.6%
8	2027	2.6%	11.2%
9	2028	3.0%	14.3%
10	2029	3.5%	17.7%
11	2030	3.9%	21.6%
12	2031	4.5%	26.1%
13	2032	5.0%	31.1%
14	2033	5.6%	36.7%
15	2034	6.1%	42.8%
16	2035	6.6%	49.4%
17	2036	7.0%	56.4%
18	2037	7.4%	63.8%
19	2038	7.9%	71.7%
20	2039	8.3%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(21 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	442
2018	442	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	(0)	659	0	(15)	645
2	2021	659	1	(4)	656	0	(28)	627
3	2022	656	-	(5)	650	0	(41)	609
4	2023	650	-	(7)	643	0	(54)	589
5	2024	643	-	(9)	634	0	(66)	568
6	2025	634	-	(11)	623	0	(78)	545
7	2026	623	-	(13)	610	0	(90)	520
8	2027	610	-	(16)	594	0	(101)	494
9	2028	594	-	(18)	576	0	(111)	465
10	2029	576	-	(21)	556	0	(121)	435
11	2030	556	-	(23)	532	0	(130)	402
12	2031	532	-	(26)	506	0	(139)	367
13	2032	506	-	(30)	476	0	(147)	330
14	2033	476	-	(33)	443	0	(154)	289
15	2034	443	-	(37)	407	0	(157)	249
16	2035	407	-	(39)	367	0	(142)	225
17	2036	367	-	(42)	325	0	(126)	200
18	2037	325	-	(44)	281	0	(108)	173
19	2038	281	-	(47)	234	0	(90)	144
20	2039	234	-	(50)	184	0	(70)	114
21	2040	184	-	(53)	131	0	(50)	82
			6	(528)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	1	869	0	(20)	849
2	2021	869	1	(4)	864	0	(37)	827
3	2022	864	-	(6)	858	0	(55)	804
4	2023	858	-	(9)	849	0	(71)	778
5	2024	849	-	(11)	838	0	(88)	751
6	2025	838	-	(14)	825	0	(103)	722
7	2026	825	-	(17)	808	0	(118)	690
8	2027	808	-	(20)	788	0	(133)	656
9	2028	788	-	(23)	765	0	(147)	619
10	2029	765	-	(27)	739	0	(160)	579
11	2030	739	-	(30)	708	0	(172)	536
12	2031	708	-	(35)	674	0	(184)	490
13	2032	674	-	(39)	635	0	(194)	441
14	2033	635	-	(44)	591	0	(204)	387
15	2034	591	-	(49)	543	0	(210)	333
16	2035	543	-	(53)	490	0	(190)	300
17	2036	490	-	(56)	434	0	(168)	266
18	2037	434	-	(59)	374	0	(145)	230
19	2038	374	-	(63)	311	0	(120)	191
20	2039	311	-	(67)	244	0	(94)	151
21	2040	244	-	(71)	173	0	(66)	108
			8	(695)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	21	0	3	0	13	15	75
2	2021	22	19	4	3	0	12	14	75
3	2022	22	19	5	3	0	12	13	75
4	2023	21	18	7	3	0	12	13	75
5	2024	20	17	9	3	0	12	13	75
6	2025	20	17	11	3	0	12	12	75
7	2026	19	16	13	3	1	11	12	75
8	2027	18	15	16	3	1	11	11	75
9	2028	17	14	18	3	1	11	11	75
10	2029	16	14	21	3	1	10	10	75
11	2030	15	13	23	3	1	10	10	75
12	2031	14	12	26	3	1	10	9	75
13	2032	12	10	30	4	1	9	9	75
14	2033	11	9	33	4	1	9	8	75
15	2034	10	8	37	4	1	9	8	75
16	2035	8	7	39	4	1	8	7	75
17	2036	8	6	42	4	1	8	7	75
18	2037	7	6	44	4	1	7	6	75
19	2038	6	5	47	4	1	7	6	75
20	2039	5	4	50	4	1	6	5	75
21	2040	3	3	53	4	1	6	5	75
		294	253	528	72	12	205	204	1,568

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(1)	3	0	17	20	99
2	2021	32	25	4	3	0	16	18	99
3	2022	31	24	6	3	0	16	17	99
4	2023	30	24	9	3	0	16	17	99
5	2024	29	23	11	3	0	16	17	99
6	2025	28	22	14	3	0	15	16	99
7	2026	27	21	17	3	1	15	16	99
8	2027	26	20	20	3	1	14	15	99
9	2028	25	19	23	3	1	14	15	99
10	2029	23	18	27	3	1	14	14	99
11	2030	21	17	30	3	1	13	13	99
12	2031	20	15	35	3	1	13	13	99
13	2032	18	14	39	4	1	12	12	99
14	2033	16	12	44	4	1	12	11	99
15	2034	14	11	49	4	1	11	10	99
16	2035	12	10	53	4	1	11	9	99
17	2036	11	9	56	4	1	10	9	99
18	2037	10	7	59	4	1	10	8	99
19	2038	8	6	63	4	1	9	8	99
20	2039	7	5	67	4	1	9	7	99
21	2040	5	4	71	4	1	8	6	99
		425	336	695	72	12	271	270	2,080

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	75	1,100	1.000	0.19
2	2021	75	1,100	1.000	0.19
3	2022	75	1,100	1.000	0.19
4	2023	75	1,100	1.000	0.19
5	2024	75	1,100	1.000	0.19
6	2025	75	1,100	1.000	0.19
7	2026	75	1,100	1.000	0.19
8	2027	75	1,100	1.000	0.19
9	2028	75	1,100	1.000	0.19
10	2029	75	1,100	1.000	0.19
11	2030	75	1,100	1.000	0.19
12	2031	75	1,100	1.000	0.19
13	2032	75	1,100	1.000	0.19
14	2033	75	1,100	1.000	0.19
15	2034	75	1,100	1.000	0.19
16	2035	75	1,100	1.000	0.19
17	2036	75	1,100	1.000	0.19
18	2037	75	1,100	1.000	0.19
19	2038	75	1,100	1.000	0.19
20	2039	75	1,100	1.000	0.19
21	2040	75	1,100	1.000	0.19

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	99	1,100	1.000	0.25
2	2021	99	1,100	1.000	0.25
3	2022	99	1,100	1.000	0.25
4	2023	99	1,100	1.000	0.25
5	2024	99	1,100	1.000	0.25
6	2025	99	1,100	1.000	0.25
7	2026	99	1,100	1.000	0.25
8	2027	99	1,100	1.000	0.25
9	2028	99	1,100	1.000	0.25
10	2029	99	1,100	1.000	0.25
11	2030	99	1,100	1.000	0.25
12	2031	99	1,100	1.000	0.25
13	2032	99	1,100	1.000	0.25
14	2033	99	1,100	1.000	0.25
15	2034	99	1,100	1.000	0.25
16	2035	99	1,100	1.000	0.25
17	2036	99	1,100	1.000	0.25
18	2037	99	1,100	1.000	0.25
19	2038	99	1,100	1.000	0.25
20	2039	99	1,100	1.000	0.25
21	2040	99	1,100	1.000	0.25

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.0%	0.0%
2	2021	0.6%	0.6%
3	2022	0.8%	1.5%
4	2023	1.1%	2.6%
5	2024	1.4%	3.9%
6	2025	1.7%	5.6%
7	2026	2.0%	7.6%
8	2027	2.4%	9.9%
9	2028	2.7%	12.7%
10	2029	3.1%	15.8%
11	2030	3.5%	19.3%
12	2031	4.0%	23.3%
13	2032	4.5%	27.8%
14	2033	5.0%	32.8%
15	2034	5.5%	38.3%
16	2035	6.0%	44.3%
17	2036	6.3%	50.7%
18	2037	6.7%	57.4%
19	2038	7.1%	64.5%
20	2039	7.5%	72.0%
21	2040	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.5%	0.4%
3	2022	0.7%	1.2%
4	2023	1.0%	2.1%
5	2024	1.3%	3.4%
6	2025	1.6%	5.0%
7	2026	1.9%	6.9%
8	2027	2.3%	9.2%
9	2028	2.7%	11.8%
10	2029	3.1%	14.9%
11	2030	3.5%	18.4%
12	2031	4.0%	22.4%
13	2032	4.5%	26.8%
14	2033	5.0%	31.9%
15	2034	5.6%	37.5%
16	2035	6.1%	43.5%
17	2036	6.5%	50.0%
18	2037	6.8%	56.8%
19	2038	7.3%	64.1%
20	2039	7.7%	71.8%
21	2040	8.2%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,041
2016	3,041	2,682	54	873	354	7,004
2017	7,004	2,620	52	852	641	11,169
2018	11,169	2,161	43	703	927	15,003
2019	15,003	1,275	25	415	1,175	17,893
2020	17,893	438	-	151	-	18,483
2021	18,483	12	-	4	-	18,499
		11,185	203	3,659	3,451	

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	(24)	14,009	23	(315)	13,717
2	2021	14,009	12	(72)	13,949	24	(600)	13,373
3	2022	13,949	-	(106)	13,843	24	(879)	12,988
4	2023	13,843	-	(151)	13,692	23	(1,150)	12,565
5	2024	13,692	-	(201)	13,491	22	(1,413)	12,100
6	2025	13,491	-	(248)	13,243	22	(1,667)	11,597
7	2026	13,243	-	(295)	12,947	22	(1,912)	11,057
8	2027	12,947	-	(348)	12,600	22	(2,146)	10,476
9	2028	12,600	-	(401)	12,198	22	(2,368)	9,852
10	2029	12,198	-	(458)	11,741	22	(2,579)	9,183
11	2030	11,741	-	(521)	11,219	22	(2,776)	8,465
12	2031	11,219	-	(582)	10,637	22	(2,960)	7,699
13	2032	10,637	-	(645)	9,992	23	(3,128)	6,887
14	2033	9,992	-	(713)	9,279	23	(3,281)	6,021
15	2034	9,279	-	(779)	8,499	24	(3,251)	5,272
16	2035	8,499	-	(831)	7,668	24	(2,932)	4,761
17	2036	7,668	-	(876)	6,792	25	(2,594)	4,223
18	2037	6,792	-	(921)	5,871	25	(2,237)	3,660
19	2038	5,871	-	(970)	4,901	26	(1,860)	3,067
20	2039	4,901	-	(1,019)	3,882	26	(1,463)	2,445
21	2040	3,882	-	(1,073)	2,809	27	(1,044)	1,792
			463	(11,236)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,893	590	(14)	18,469	23	(414)	18,078
2	2021	18,469	16	(80)	18,405	24	(790)	17,639
3	2022	18,405	-	(124)	18,281	24	(1,158)	17,148
4	2023	18,281	-	(181)	18,100	23	(1,515)	16,608
5	2024	18,100	-	(245)	17,856	22	(1,863)	16,015
6	2025	17,856	-	(306)	17,549	22	(2,199)	15,372
7	2026	17,549	-	(369)	17,181	22	(2,523)	14,680
8	2027	17,181	-	(439)	16,742	22	(2,833)	13,931
9	2028	16,742	-	(510)	16,231	22	(3,128)	13,125
10	2029	16,231	-	(587)	15,645	22	(3,408)	12,258
11	2030	15,645	-	(672)	14,972	22	(3,671)	11,323
12	2031	14,972	-	(757)	14,215	22	(3,916)	10,321
13	2032	14,215	-	(844)	13,371	23	(4,142)	9,252
14	2033	13,371	-	(941)	12,430	23	(4,346)	8,108
15	2034	12,430	-	(1,036)	11,394	24	(4,367)	7,051
16	2035	11,394	-	(1,112)	10,282	24	(3,938)	6,368
17	2036	10,282	-	(1,177)	9,104	25	(3,483)	5,646
18	2037	9,104	-	(1,242)	7,862	25	(3,001)	4,886
19	2038	7,862	-	(1,314)	6,548	26	(2,490)	4,084
20	2039	6,548	-	(1,385)	5,163	26	(1,949)	3,240
21	2040	5,163	-	(1,463)	3,700	27	(1,377)	2,350
			605	(14,799)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	465	450	24	274	56	271	316	1,856
2	2021	477	406	72	289	58	265	288	1,856
3	2022	465	395	106	287	59	263	282	1,856
4	2023	450	383	151	278	60	257	276	1,856
5	2024	435	370	201	267	62	252	270	1,856
6	2025	418	355	248	263	63	246	263	1,856
7	2026	399	340	295	262	64	241	255	1,856
8	2027	380	323	348	262	66	233	246	1,856
9	2028	358	305	401	261	67	227	237	1,856
10	2029	335	286	458	260	69	222	226	1,856
11	2030	311	265	521	260	70	214	216	1,856
12	2031	285	242	582	266	72	206	204	1,856
13	2032	257	219	645	271	73	200	191	1,856
14	2033	228	194	713	277	75	192	177	1,856
15	2034	199	169	779	283	77	184	164	1,856
16	2035	177	150	831	290	78	176	154	1,856
17	2036	158	135	876	296	80	165	146	1,856
18	2037	139	118	921	303	82	157	137	1,856
19	2038	119	101	970	309	83	146	128	1,856
20	2039	97	83	1,019	316	85	138	118	1,856
21	2040	75	64	1,073	323	87	127	108	1,856
		6,227	5,354	11,236	5,897	1,485	4,383	4,401	38,984

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	668	593	14	274	56	357	415	2,377
2	2021	686	536	80	289	58	350	379	2,377
3	2022	668	522	124	287	59	346	372	2,377
4	2023	648	506	181	278	60	339	364	2,377
5	2024	627	489	245	267	62	332	356	2,377
6	2025	603	471	306	263	63	325	347	2,377
7	2026	577	451	369	262	64	318	336	2,377
8	2027	550	429	439	262	66	307	325	2,377
9	2028	520	406	510	261	67	300	313	2,377
10	2029	488	381	587	260	69	293	300	2,377
11	2030	453	354	672	260	70	282	286	2,377
12	2031	416	325	757	266	72	271	271	2,377
13	2032	376	294	844	271	73	264	254	2,377
14	2033	333	260	941	277	75	253	237	2,377
15	2034	291	227	1,036	283	77	243	220	2,377
16	2035	258	201	1,112	290	78	232	206	2,377
17	2036	231	180	1,177	296	80	218	195	2,377
18	2037	202	158	1,242	303	82	207	183	2,377
19	2038	172	135	1,314	309	83	193	171	2,377
20	2039	141	110	1,385	316	85	182	158	2,377
21	2040	107	84	1,463	323	87	168	144	2,377
		9,014	7,111	14,799	5,897	1,485	5,777	5,832	49,916

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,856	3,000	1.118	1.52
2	2021	1,856	3,000	1.118	1.52
3	2022	1,856	3,000	1.118	1.52
4	2023	1,856	3,000	1.118	1.52
5	2024	1,856	3,000	1.118	1.52
6	2025	1,856	3,000	1.118	1.52
7	2026	1,856	3,000	1.118	1.52
8	2027	1,856	3,000	1.118	1.52
9	2028	1,856	3,000	1.118	1.52
10	2029	1,856	3,000	1.118	1.52
11	2030	1,856	3,000	1.118	1.52
12	2031	1,856	3,000	1.118	1.52
13	2032	1,856	3,000	1.118	1.52
14	2033	1,856	3,000	1.118	1.52
15	2034	1,856	3,000	1.118	1.52
16	2035	1,856	3,000	1.118	1.52
17	2036	1,856	3,000	1.118	1.52
18	2037	1,856	3,000	1.118	1.52
19	2038	1,856	3,000	1.118	1.52
20	2039	1,856	3,000	1.118	1.52
21	2040	1,856	3,000	1.118	1.52

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,377	3,000	1.118	1.94
2	2021	2,377	3,000	1.118	1.94
3	2022	2,377	3,000	1.118	1.94
4	2023	2,377	3,000	1.118	1.94
5	2024	2,377	3,000	1.118	1.94
6	2025	2,377	3,000	1.118	1.94
7	2026	2,377	3,000	1.118	1.94
8	2027	2,377	3,000	1.118	1.94
9	2028	2,377	3,000	1.118	1.94
10	2029	2,377	3,000	1.118	1.94
11	2030	2,377	3,000	1.118	1.94
12	2031	2,377	3,000	1.118	1.94
13	2032	2,377	3,000	1.118	1.94
14	2033	2,377	3,000	1.118	1.94
15	2034	2,377	3,000	1.118	1.94
16	2035	2,377	3,000	1.118	1.94
17	2036	2,377	3,000	1.118	1.94
18	2037	2,377	3,000	1.118	1.94
19	2038	2,377	3,000	1.118	1.94
20	2039	2,377	3,000	1.118	1.94
21	2040	2,377	3,000	1.118	1.94

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.2%	0.2%
2	2021	0.5%	0.7%
3	2022	0.8%	1.4%
4	2023	1.1%	2.5%
5	2024	1.4%	3.9%
6	2025	1.8%	5.7%
7	2026	2.1%	7.8%
8	2027	2.5%	10.3%
9	2028	2.9%	13.1%
10	2029	3.3%	16.4%
11	2030	3.7%	20.1%
12	2031	4.1%	24.3%
13	2032	4.6%	28.9%
14	2033	5.1%	33.9%
15	2034	5.5%	39.5%
16	2035	5.9%	45.4%
17	2036	6.2%	51.6%
18	2037	6.6%	58.2%
19	2038	6.9%	65.1%
20	2039	7.3%	72.4%
21	2040	7.6%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.1%	0.1%
2	2021	0.4%	0.5%
3	2022	0.7%	1.2%
4	2023	1.0%	2.2%
5	2024	1.3%	3.5%
6	2025	1.7%	5.1%
7	2026	2.0%	7.1%
8	2027	2.4%	9.5%
9	2028	2.8%	12.3%
10	2029	3.2%	15.4%
11	2030	3.6%	19.1%
12	2031	4.1%	23.2%
13	2032	4.6%	27.7%
14	2033	5.1%	32.8%
15	2034	5.6%	38.4%
16	2035	6.0%	44.4%
17	2036	6.4%	50.8%
18	2037	6.7%	57.5%
19	2038	7.1%	64.6%
20	2039	7.5%	72.1%
21	2040	7.9%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,723
2017	2,723	2,549	51	454	313	6,091
2018	6,091	7,006	140	1,249	752	15,238
2019	15,238	2,464	49	439	1,225	19,417
2020	19,417	141	-	28	-	19,586
2021	19,586	14	-	3	-	19,603
		14,030	263	2,519	2,791	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	(5)	14,894	49	(339)	14,604
2	2021	14,894	13	(86)	14,821	49	(642)	14,228
3	2022	14,821	-	(120)	14,701	49	(938)	13,812
4	2023	14,701	-	(160)	14,541	49	(1,225)	13,365
5	2024	14,541	-	(202)	14,339	49	(1,504)	12,884
6	2025	14,339	-	(247)	14,092	50	(1,773)	12,369
7	2026	14,092	-	(295)	13,798	50	(2,032)	11,816
8	2027	13,798	-	(349)	13,449	50	(2,279)	11,220
9	2028	13,449	-	(403)	13,046	50	(2,515)	10,581
10	2029	13,046	-	(462)	12,584	50	(2,738)	9,896
11	2030	12,584	-	(527)	12,058	50	(2,947)	9,161
12	2031	12,058	-	(596)	11,462	50	(3,142)	8,370
13	2032	11,462	-	(667)	10,795	50	(3,320)	7,525
14	2033	10,795	-	(745)	10,049	51	(3,482)	6,618
15	2034	10,049	-	(828)	9,221	51	(3,595)	5,677
16	2035	9,221	-	(895)	8,326	51	(3,245)	5,132
17	2036	8,326	-	(951)	7,375	51	(2,872)	4,554
18	2037	7,375	-	(1,006)	6,369	51	(2,476)	3,944
19	2038	6,369	-	(1,066)	5,303	51	(2,056)	3,299
20	2039	5,303	-	(1,127)	4,176	52	(1,610)	2,617
21	2040	4,176	-	(1,194)	2,982	52	(1,137)	1,897
			142	(11,929)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,417	169	13	19,599	49	(445)	19,203
2	2021	19,599	17	(93)	19,524	49	(844)	18,729
3	2022	19,524	-	(137)	19,386	49	(1,233)	18,203
4	2023	19,386	-	(190)	19,196	49	(1,612)	17,634
5	2024	19,196	-	(246)	18,950	49	(1,979)	17,021
6	2025	18,950	-	(306)	18,644	50	(2,334)	16,359
7	2026	18,644	-	(371)	18,273	50	(2,676)	15,647
8	2027	18,273	-	(443)	17,830	50	(3,004)	14,876
9	2028	17,830	-	(517)	17,313	50	(3,316)	14,047
10	2029	17,313	-	(596)	16,717	50	(3,612)	13,155
11	2030	16,717	-	(684)	16,033	50	(3,890)	12,193
12	2031	16,033	-	(779)	15,254	50	(4,149)	11,156
13	2032	15,254	-	(876)	14,378	50	(4,387)	10,042
14	2033	14,378	-	(984)	13,394	51	(4,602)	8,842
15	2034	13,394	-	(1,099)	12,295	51	(4,794)	7,551
16	2035	12,295	-	(1,195)	11,100	51	(4,331)	6,820
17	2036	11,100	-	(1,271)	9,828	51	(3,831)	6,048
18	2037	9,828	-	(1,348)	8,480	51	(3,300)	5,231
19	2038	8,480	-	(1,432)	7,048	51	(2,735)	4,365
20	2039	7,048	-	(1,517)	5,531	52	(2,134)	3,448
21	2040	5,531	-	(1,610)	3,921	52	(1,496)	2,477
			186	(15,682)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	500	485	5	62	9	287	339	1,688
2	2021	508	432	86	64	10	282	306	1,688
3	2022	494	421	120	65	10	279	299	1,688
4	2023	479	408	160	67	10	273	292	1,688
5	2024	463	394	202	68	10	267	284	1,688
6	2025	445	379	247	70	11	261	275	1,688
7	2026	426	363	295	71	11	256	266	1,688
8	2027	406	346	349	73	11	247	257	1,688
9	2028	384	327	403	74	11	241	246	1,688
10	2029	361	307	462	76	11	236	235	1,688
11	2030	336	286	527	78	12	227	223	1,688
12	2031	309	263	596	79	12	218	210	1,688
13	2032	280	238	667	81	12	213	196	1,688
14	2033	249	212	745	83	13	204	181	1,688
15	2034	217	184	828	85	13	195	166	1,688
16	2035	190	162	895	86	13	187	153	1,688
17	2036	171	145	951	88	13	175	144	1,688
18	2037	150	127	1,006	90	14	167	134	1,688
19	2038	128	109	1,066	92	14	155	124	1,688
20	2039	104	89	1,127	94	14	147	112	1,688
21	2040	80	68	1,194	96	15	135	101	1,688
		6,680	5,744	11,929	1,642	248	4,652	4,544	35,441

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	717	638	(13)	62	9	378	444	2,235
2	2021	729	569	93	64	10	370	401	2,235
3	2022	709	554	137	65	10	367	393	2,235
4	2023	688	538	190	67	10	359	384	2,235
5	2024	666	520	246	68	10	351	374	2,235
6	2025	641	501	306	70	11	344	363	2,235
7	2026	615	480	371	71	11	336	352	2,235
8	2027	586	458	443	73	11	325	339	2,235
9	2028	556	434	517	74	11	317	326	2,235
10	2029	522	408	596	76	11	310	311	2,235
11	2030	487	380	684	78	12	298	296	2,235
12	2031	448	350	779	79	12	287	279	2,235
13	2032	407	318	876	81	12	280	261	2,235
14	2033	363	283	984	83	13	268	242	2,235
15	2034	315	246	1,099	85	13	257	221	2,235
16	2035	276	216	1,195	86	13	246	204	2,235
17	2036	247	193	1,271	88	13	230	191	2,235
18	2037	217	169	1,348	90	14	219	178	2,235
19	2038	184	144	1,432	92	14	204	164	2,235
20	2039	150	117	1,517	94	14	193	149	2,235
21	2040	114	89	1,610	96	15	178	134	2,235
		9,637	7,604	15,682	1,642	248	6,117	6,006	46,937

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	170	383	1.22	1,517	2,971	1.40
2	2021	1.118	170	383	1.22	1,517	2,971	1.40
3	2022	1.118	170	383	1.22	1,517	2,971	1.40
4	2023	1.118	170	383	1.22	1,517	2,971	1.40
5	2024	1.118	170	383	1.22	1,517	2,971	1.40
6	2025	1.118	170	383	1.22	1,517	2,971	1.40
7	2026	1.118	170	383	1.22	1,517	2,971	1.40
8	2027	1.118	170	383	1.22	1,517	2,971	1.40
9	2028	1.118	170	383	1.22	1,517	2,971	1.40
10	2029	1.118	170	383	1.22	1,517	2,971	1.40
11	2030	1.118	170	383	1.22	1,517	2,971	1.40
12	2031	1.118	170	383	1.22	1,517	2,971	1.40
13	2032	1.118	170	383	1.22	1,517	2,971	1.40
14	2033	1.118	170	383	1.22	1,517	2,971	1.40
15	2034	1.118	170	383	1.22	1,517	2,971	1.40
16	2035	1.118	170	383	1.22	1,517	2,971	1.40
17	2036	1.118	170	383	1.22	1,517	2,971	1.40
18	2037	1.118	170	383	1.22	1,517	2,971	1.40
19	2038	1.118	170	383	1.22	1,517	2,971	1.40
20	2039	1.118	170	383	1.22	1,517	2,971	1.40
21	2040	1.118	170	383	1.22	1,517	2,971	1.40

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	226	383	1.62	2,009	2,971	1.85
2	2021	1.118	226	383	1.62	2,009	2,971	1.85
3	2022	1.118	226	383	1.62	2,009	2,971	1.85
4	2023	1.118	226	383	1.62	2,009	2,971	1.85
5	2024	1.118	226	383	1.62	2,009	2,971	1.85
6	2025	1.118	226	383	1.62	2,009	2,971	1.85
7	2026	1.118	226	383	1.62	2,009	2,971	1.85
8	2027	1.118	226	383	1.62	2,009	2,971	1.85
9	2028	1.118	226	383	1.62	2,009	2,971	1.85
10	2029	1.118	226	383	1.62	2,009	2,971	1.85
11	2030	1.118	226	383	1.62	2,009	2,971	1.85
12	2031	1.118	226	383	1.62	2,009	2,971	1.85
13	2032	1.118	226	383	1.62	2,009	2,971	1.85
14	2033	1.118	226	383	1.62	2,009	2,971	1.85
15	2034	1.118	226	383	1.62	2,009	2,971	1.85
16	2035	1.118	226	383	1.62	2,009	2,971	1.85
17	2036	1.118	226	383	1.62	2,009	2,971	1.85
18	2037	1.118	226	383	1.62	2,009	2,971	1.85
19	2038	1.118	226	383	1.62	2,009	2,971	1.85
20	2039	1.118	226	383	1.62	2,009	2,971	1.85
21	2040	1.118	226	383	1.62	2,009	2,971	1.85

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.0%	0.0%
2	2021	0.6%	0.6%
3	2022	0.8%	1.4%
4	2023	1.1%	2.5%
5	2024	1.4%	3.8%
6	2025	1.7%	5.5%
7	2026	2.0%	7.5%
8	2027	2.3%	9.8%
9	2028	2.7%	12.5%
10	2029	3.1%	15.6%
11	2030	3.5%	19.1%
12	2031	4.0%	23.1%
13	2032	4.5%	27.6%
14	2033	5.0%	32.6%
15	2034	5.6%	38.2%
16	2035	6.0%	44.2%
17	2036	6.4%	50.5%
18	2037	6.7%	57.3%
19	2038	7.2%	64.4%
20	2039	7.6%	72.0%
21	2040	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(21 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.5%	0.4%
3	2022	0.7%	1.1%
4	2023	1.0%	2.1%
5	2024	1.3%	3.3%
6	2025	1.6%	4.9%
7	2026	1.9%	6.8%
8	2027	2.3%	9.0%
9	2028	2.6%	11.7%
10	2029	3.0%	14.7%
11	2030	3.5%	18.2%
12	2031	4.0%	22.2%
13	2032	4.5%	26.7%
14	2033	5.0%	31.7%
15	2034	5.6%	37.3%
16	2035	6.1%	43.4%
17	2036	6.5%	49.9%
18	2037	6.9%	56.7%
19	2038	7.3%	64.0%
20	2039	7.7%	71.8%
21	2040	8.2%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(22 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	443
2018	443	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	1	661	0	(15)	646
2	2021	661	1	(3)	658	0	(28)	630
3	2022	658	-	(4)	654	0	(41)	613
4	2023	654	-	(6)	648	0	(54)	594
5	2024	648	-	(7)	641	0	(67)	575
6	2025	641	-	(9)	632	0	(79)	553
7	2026	632	-	(11)	621	0	(90)	530
8	2027	621	-	(13)	607	0	(101)	506
9	2028	607	-	(16)	591	0	(112)	480
10	2029	591	-	(18)	573	0	(122)	451
11	2030	573	-	(21)	552	0	(132)	421
12	2031	552	-	(24)	529	0	(141)	388
13	2032	529	-	(27)	502	0	(149)	353
14	2033	502	-	(30)	472	0	(157)	316
15	2034	472	-	(33)	439	0	(164)	276
16	2035	439	-	(36)	403	0	(156)	247
17	2036	403	-	(39)	364	0	(141)	223
18	2037	364	-	(41)	323	0	(125)	198
19	2038	323	-	(44)	279	0	(108)	171
20	2039	279	-	(46)	233	0	(90)	143
21	2040	233	-	(49)	184	0	(71)	114
22	2041	184	-	(52)	131	0	(50)	82
			6	(528)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	2	870	0	(20)	851
2	2021	870	1	(3)	868	0	(37)	831
3	2022	868	-	(4)	863	0	(55)	809
4	2023	863	-	(7)	857	0	(71)	786
5	2024	857	-	(9)	848	0	(88)	760
6	2025	848	-	(11)	837	0	(104)	733
7	2026	837	-	(14)	823	0	(119)	704
8	2027	823	-	(17)	806	0	(134)	672
9	2028	806	-	(20)	786	0	(148)	638
10	2029	786	-	(23)	762	0	(162)	601
11	2030	762	-	(27)	735	0	(174)	561
12	2031	735	-	(31)	705	0	(186)	519
13	2032	705	-	(35)	670	0	(197)	473
14	2033	670	-	(39)	630	0	(208)	423
15	2034	630	-	(44)	586	0	(217)	370
16	2035	586	-	(48)	538	0	(209)	329
17	2036	538	-	(52)	486	0	(189)	298
18	2037	486	-	(55)	431	0	(167)	264
19	2038	431	-	(59)	372	0	(144)	228
20	2039	372	-	(62)	310	0	(120)	190
21	2040	310	-	(66)	244	0	(94)	150
22	2041	244	-	(71)	173	0	(66)	108
			8	(695)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	21	(1)	3	0	13	15	73
2	2021	22	19	3	3	0	12	14	73
3	2022	22	19	4	3	0	12	13	73
4	2023	21	18	6	3	0	12	13	73
5	2024	21	18	7	3	0	12	13	73
6	2025	20	17	9	3	0	12	12	73
7	2026	19	16	11	3	0	11	12	73
8	2027	18	16	13	3	0	11	12	73
9	2028	17	15	16	3	1	11	11	73
10	2029	16	14	18	3	1	10	11	73
11	2030	15	13	21	3	1	10	10	73
12	2031	14	12	24	3	1	10	10	73
13	2032	13	11	27	4	1	9	9	73
14	2033	12	10	30	4	1	9	9	73
15	2034	10	9	33	4	1	9	8	73
16	2035	9	8	36	4	1	8	7	73
17	2036	8	7	39	4	1	8	7	73
18	2037	7	6	41	4	1	7	7	73
19	2038	7	6	44	4	1	7	6	73
20	2039	6	5	46	4	1	6	6	73
21	2040	5	4	49	4	1	6	5	73
22	2041	3	3	52	4	1	5	5	73
		310	266	528	76	12	211	213	1,616

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(2)	3	0	17	20	97
2	2021	32	25	3	3	0	16	18	97
3	2022	32	25	4	3	0	16	17	97
4	2023	31	24	7	3	0	16	17	97
5	2024	30	23	9	3	0	16	17	97
6	2025	29	22	11	3	0	15	16	97
7	2026	28	22	14	3	0	15	16	97
8	2027	26	21	17	3	0	14	15	97
9	2028	25	20	20	3	1	14	15	97
10	2029	24	19	23	3	1	14	14	97
11	2030	22	17	27	3	1	13	14	97
12	2031	21	16	31	3	1	13	13	97
13	2032	19	15	35	4	1	12	12	97
14	2033	17	13	39	4	1	12	11	97
15	2034	15	12	44	4	1	11	11	97
16	2035	13	11	48	4	1	11	10	97
17	2036	12	9	52	4	1	10	9	97
18	2037	11	8	55	4	1	10	9	97
19	2038	9	7	59	4	1	9	8	97
20	2039	8	6	62	4	1	9	8	97
21	2040	7	5	66	4	1	8	7	97
22	2041	5	4	71	4	1	7	6	97
		448	353	695	76	12	278	282	2,144

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	73	1,100	1.000	0.18
2	2021	73	1,100	1.000	0.18
3	2022	73	1,100	1.000	0.18
4	2023	73	1,100	1.000	0.18
5	2024	73	1,100	1.000	0.18
6	2025	73	1,100	1.000	0.18
7	2026	73	1,100	1.000	0.18
8	2027	73	1,100	1.000	0.18
9	2028	73	1,100	1.000	0.18
10	2029	73	1,100	1.000	0.18
11	2030	73	1,100	1.000	0.18
12	2031	73	1,100	1.000	0.18
13	2032	73	1,100	1.000	0.18
14	2033	73	1,100	1.000	0.18
15	2034	73	1,100	1.000	0.18
16	2035	73	1,100	1.000	0.18
17	2036	73	1,100	1.000	0.18
18	2037	73	1,100	1.000	0.18
19	2038	73	1,100	1.000	0.18
20	2039	73	1,100	1.000	0.18
21	2040	73	1,100	1.000	0.18
22	2041	73	1,100	1.000	0.18

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	97	1,100	1.000	0.24
2	2021	97	1,100	1.000	0.24
3	2022	97	1,100	1.000	0.24
4	2023	97	1,100	1.000	0.24
5	2024	97	1,100	1.000	0.24
6	2025	97	1,100	1.000	0.24
7	2026	97	1,100	1.000	0.24
8	2027	97	1,100	1.000	0.24
9	2028	97	1,100	1.000	0.24
10	2029	97	1,100	1.000	0.24
11	2030	97	1,100	1.000	0.24
12	2031	97	1,100	1.000	0.24
13	2032	97	1,100	1.000	0.24
14	2033	97	1,100	1.000	0.24
15	2034	97	1,100	1.000	0.24
16	2035	97	1,100	1.000	0.24
17	2036	97	1,100	1.000	0.24
18	2037	97	1,100	1.000	0.24
19	2038	97	1,100	1.000	0.24
20	2039	97	1,100	1.000	0.24
21	2040	97	1,100	1.000	0.24
22	2041	97	1,100	1.000	0.24

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.4%	0.3%
3	2022	0.6%	0.9%
4	2023	0.9%	1.7%
5	2024	1.1%	2.8%
6	2025	1.4%	4.2%
7	2026	1.7%	5.9%
8	2027	2.0%	8.0%
9	2028	2.4%	10.4%
10	2029	2.7%	13.1%
11	2030	3.1%	16.2%
12	2031	3.6%	19.8%
13	2032	4.0%	23.8%
14	2033	4.5%	28.4%
15	2034	5.0%	33.4%
16	2035	5.5%	38.9%
17	2036	5.9%	44.8%
18	2037	6.2%	51.1%
19	2038	6.6%	57.7%
20	2039	7.0%	64.7%
21	2040	7.4%	72.1%
22	2041	7.9%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.3%	0.1%
3	2022	0.5%	0.6%
4	2023	0.8%	1.3%
5	2024	1.0%	2.3%
6	2025	1.3%	3.6%
7	2026	1.6%	5.2%
8	2027	2.0%	7.2%
9	2028	2.3%	9.5%
10	2029	2.7%	12.2%
11	2030	3.1%	15.3%
12	2031	3.5%	18.8%
13	2032	4.0%	22.8%
14	2033	4.5%	27.4%
15	2034	5.1%	32.4%
16	2035	5.6%	38.0%
17	2036	6.0%	44.0%
18	2037	6.4%	50.4%
19	2038	6.8%	57.1%
20	2039	7.2%	64.3%
21	2040	7.6%	71.9%
22	2041	8.1%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,042
2016	3,042	2,682	54	873	354	7,004
2017	7,004	2,620	52	852	641	11,169
2018	11,169	2,161	43	703	928	15,004
2019	15,004	1,275	25	415	1,175	17,894
2020	17,894	438	-	151	-	18,484
2021	18,484	12	-	4	-	18,500
		11,185	203	3,659	3,452	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	1	14,035	23	(315)	13,743
2	2021	14,035	12	(45)	14,002	24	(600)	13,426
3	2022	14,002	-	(76)	13,926	24	(879)	13,070
4	2023	13,926	-	(119)	13,807	23	(1,152)	12,678
5	2024	13,807	-	(166)	13,640	22	(1,417)	12,246
6	2025	13,640	-	(211)	13,429	22	(1,674)	11,777
7	2026	13,429	-	(255)	13,174	22	(1,921)	11,275
8	2027	13,174	-	(305)	12,869	22	(2,159)	10,732
9	2028	12,869	-	(355)	12,515	22	(2,386)	10,150
10	2029	12,515	-	(408)	12,107	22	(2,602)	9,526
11	2030	12,107	-	(468)	11,639	22	(2,806)	8,855
12	2031	11,639	-	(525)	11,114	22	(2,997)	8,139
13	2032	11,114	-	(583)	10,531	23	(3,173)	7,380
14	2033	10,531	-	(648)	9,883	23	(3,335)	6,571
15	2034	9,883	-	(716)	9,167	24	(3,481)	5,710
16	2035	9,167	-	(772)	8,395	24	(3,217)	5,202
17	2036	8,395	-	(816)	7,580	25	(2,903)	4,701
18	2037	7,580	-	(857)	6,722	25	(2,572)	4,175
19	2038	6,722	-	(904)	5,818	26	(2,222)	3,622
20	2039	5,818	-	(949)	4,869	26	(1,853)	3,043
21	2040	4,869	-	(1,000)	3,869	27	(1,463)	2,433
22	2041	3,869	-	(1,060)	2,809	28	(1,048)	1,788
			463	(11,236)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,894	590	20	18,504	23	(414)	18,113
2	2021	18,504	16	(43)	18,476	24	(790)	17,710
3	2022	18,476	-	(84)	18,392	24	(1,158)	17,257
4	2023	18,392	-	(138)	18,253	23	(1,518)	16,759
5	2024	18,253	-	(198)	18,055	22	(1,868)	16,210
6	2025	18,055	-	(256)	17,799	22	(2,207)	15,613
7	2026	17,799	-	(315)	17,484	22	(2,535)	14,971
8	2027	17,484	-	(381)	17,103	22	(2,851)	14,275
9	2028	17,103	-	(448)	16,656	22	(3,152)	13,525
10	2029	16,656	-	(519)	16,136	22	(3,440)	12,718
11	2030	16,136	-	(599)	15,537	22	(3,711)	11,847
12	2031	15,537	-	(679)	14,858	22	(3,966)	10,914
13	2032	14,858	-	(760)	14,097	23	(4,203)	9,917
14	2033	14,097	-	(850)	13,247	23	(4,420)	8,850
15	2034	13,247	-	(947)	12,300	24	(4,616)	7,708
16	2035	12,300	-	(1,029)	11,272	24	(4,328)	6,968
17	2036	11,272	-	(1,094)	10,177	25	(3,906)	6,296
18	2037	10,177	-	(1,155)	9,022	25	(3,459)	5,589
19	2038	9,022	-	(1,222)	7,800	26	(2,984)	4,842
20	2039	7,800	-	(1,289)	6,512	26	(2,482)	4,056
21	2040	6,512	-	(1,362)	5,150	27	(1,950)	3,226
22	2041	5,150	-	(1,450)	3,700	28	(1,382)	2,345
			605	(14,800)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	466	451	(1)	274	54	271	314	1,829
2	2021	479	408	45	289	55	266	287	1,829
3	2022	467	397	76	287	56	263	282	1,829
4	2023	454	386	119	278	57	258	277	1,829
5	2024	439	374	166	267	59	252	271	1,829
6	2025	423	360	211	263	60	247	264	1,829
7	2026	406	346	255	262	61	241	256	1,829
8	2027	388	330	305	262	63	233	248	1,829
9	2028	368	313	355	261	64	228	240	1,829
10	2029	347	295	408	260	65	222	230	1,829
11	2030	324	276	468	260	67	214	220	1,829
12	2031	300	255	525	266	68	206	209	1,829
13	2032	274	233	583	271	70	201	197	1,829
14	2033	246	209	648	277	71	193	184	1,829
15	2034	216	184	716	283	73	184	171	1,829
16	2035	192	164	772	290	75	176	160	1,829
17	2036	175	149	816	296	76	165	152	1,829
18	2037	156	133	857	303	78	157	144	1,829
19	2038	137	117	904	309	80	146	135	1,829
20	2039	117	100	949	316	81	138	126	1,829
21	2040	97	82	1,000	323	83	127	116	1,829
22	2041	74	63	1,060	330	85	108	107	1,829
		6,545	5,625	11,236	6,227	1,503	4,500	4,591	40,228

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	669	594	(20)	274	54	358	413	2,342
2	2021	689	537	43	289	55	350	378	2,342
3	2022	672	525	84	287	56	347	371	2,342
4	2023	654	510	138	278	57	340	364	2,342
5	2024	634	495	198	267	59	333	357	2,342
6	2025	612	477	256	263	60	325	348	2,342
7	2026	588	459	315	262	61	318	339	2,342
8	2027	562	439	381	262	63	307	329	2,342
9	2028	534	417	448	261	64	300	317	2,342
10	2029	504	394	519	260	65	293	305	2,342
11	2030	472	368	599	260	67	282	292	2,342
12	2031	437	341	679	266	68	272	278	2,342
13	2032	400	312	760	271	70	265	263	2,342
14	2033	361	282	850	277	71	254	246	2,342
15	2034	318	248	947	283	73	243	229	2,342
16	2035	282	220	1,029	290	75	232	214	2,342
17	2036	255	199	1,094	296	76	218	203	2,342
18	2037	228	178	1,155	303	78	207	192	2,342
19	2038	200	156	1,222	309	80	193	181	2,342
20	2039	171	133	1,289	316	81	182	169	2,342
21	2040	140	109	1,362	323	83	168	156	2,342
22	2041	107	84	1,450	330	85	143	143	2,342
		9,491	7,478	14,800	6,227	1,503	5,932	6,088	51,519

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,829	3,000	1.118	1.49
2	2021	1,829	3,000	1.118	1.49
3	2022	1,829	3,000	1.118	1.49
4	2023	1,829	3,000	1.118	1.49
5	2024	1,829	3,000	1.118	1.49
6	2025	1,829	3,000	1.118	1.49
7	2026	1,829	3,000	1.118	1.49
8	2027	1,829	3,000	1.118	1.49
9	2028	1,829	3,000	1.118	1.49
10	2029	1,829	3,000	1.118	1.49
11	2030	1,829	3,000	1.118	1.49
12	2031	1,829	3,000	1.118	1.49
13	2032	1,829	3,000	1.118	1.49
14	2033	1,829	3,000	1.118	1.49
15	2034	1,829	3,000	1.118	1.49
16	2035	1,829	3,000	1.118	1.49
17	2036	1,829	3,000	1.118	1.49
18	2037	1,829	3,000	1.118	1.49
19	2038	1,829	3,000	1.118	1.49
20	2039	1,829	3,000	1.118	1.49
21	2040	1,829	3,000	1.118	1.49
22	2041	1,829	3,000	1.118	1.49

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,342	3,000	1.118	1.91
2	2021	2,342	3,000	1.118	1.91
3	2022	2,342	3,000	1.118	1.91
4	2023	2,342	3,000	1.118	1.91
5	2024	2,342	3,000	1.118	1.91
6	2025	2,342	3,000	1.118	1.91
7	2026	2,342	3,000	1.118	1.91
8	2027	2,342	3,000	1.118	1.91
9	2028	2,342	3,000	1.118	1.91
10	2029	2,342	3,000	1.118	1.91
11	2030	2,342	3,000	1.118	1.91
12	2031	2,342	3,000	1.118	1.91
13	2032	2,342	3,000	1.118	1.91
14	2033	2,342	3,000	1.118	1.91
15	2034	2,342	3,000	1.118	1.91
16	2035	2,342	3,000	1.118	1.91
17	2036	2,342	3,000	1.118	1.91
18	2037	2,342	3,000	1.118	1.91
19	2038	2,342	3,000	1.118	1.91
20	2039	2,342	3,000	1.118	1.91
21	2040	2,342	3,000	1.118	1.91
22	2041	2,342	3,000	1.118	1.91

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	0.0%	0.0%
2	2021	0.3%	0.3%
3	2022	0.5%	0.9%
4	2023	0.8%	1.7%
5	2024	1.2%	2.9%
6	2025	1.5%	4.4%
7	2026	1.8%	6.2%
8	2027	2.2%	8.4%
9	2028	2.5%	10.9%
10	2029	2.9%	13.8%
11	2030	3.3%	17.1%
12	2031	3.7%	20.9%
13	2032	4.2%	25.0%
14	2033	4.6%	29.6%
15	2034	5.1%	34.7%
16	2035	5.5%	40.2%
17	2036	5.8%	46.0%
18	2037	6.1%	52.1%
19	2038	6.4%	58.6%
20	2039	6.8%	65.3%
21	2040	7.1%	72.5%
22	2041	7.5%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.1%	-0.1%
2	2021	0.2%	0.1%
3	2022	0.5%	0.6%
4	2023	0.7%	1.3%
5	2024	1.1%	2.4%
6	2025	1.4%	3.8%
7	2026	1.7%	5.5%
8	2027	2.1%	7.5%
9	2028	2.4%	10.0%
10	2029	2.8%	12.8%
11	2030	3.2%	16.0%
12	2031	3.7%	19.7%
13	2032	4.1%	23.8%
14	2033	4.6%	28.4%
15	2034	5.1%	33.5%
16	2035	5.6%	39.1%
17	2036	5.9%	45.0%
18	2037	6.2%	51.2%
19	2038	6.6%	57.8%
20	2039	7.0%	64.8%
21	2040	7.4%	72.2%
22	2041	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,723
2017	2,723	2,549	51	454	313	6,091
2018	6,091	7,006	140	1,249	752	15,239
2019	15,239	2,464	49	439	1,226	19,418
2020	19,418	141	-	28	-	19,587
2021	19,587	14	-	3	-	19,604
		14,030	263	2,519	2,792	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	23	14,921	49	(338)	14,632
2	2021	14,921	13	(57)	14,878	49	(642)	14,285
3	2022	14,878	-	(88)	14,790	49	(939)	13,900
4	2023	14,790	-	(125)	14,665	49	(1,228)	13,486
5	2024	14,665	-	(164)	14,501	49	(1,509)	13,041
6	2025	14,501	-	(206)	14,295	50	(1,781)	12,564
7	2026	14,295	-	(251)	14,044	50	(2,043)	12,050
8	2027	14,044	-	(301)	13,743	50	(2,295)	11,497
9	2028	13,743	-	(352)	13,390	50	(2,536)	10,904
10	2029	13,390	-	(407)	12,983	50	(2,765)	10,268
11	2030	12,983	-	(468)	12,516	50	(2,982)	9,584
12	2031	12,516	-	(533)	11,983	50	(3,185)	8,848
13	2032	11,983	-	(599)	11,384	50	(3,373)	8,061
14	2033	11,384	-	(673)	10,711	51	(3,545)	7,216
15	2034	10,711	-	(751)	9,960	51	(3,701)	6,310
16	2035	9,960	-	(823)	9,137	51	(3,568)	5,620
17	2036	9,137	-	(883)	8,254	51	(3,222)	5,083
18	2037	8,254	-	(935)	7,319	51	(2,855)	4,515
19	2038	7,319	-	(992)	6,327	51	(2,464)	3,915
20	2039	6,327	-	(1,049)	5,279	52	(2,050)	3,280
21	2040	5,279	-	(1,111)	4,168	52	(1,611)	2,609
22	2041	4,168	-	(1,185)	2,982	52	(1,140)	1,894
			142	(11,929)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,418	169	49	19,636	49	(445)	19,240
2	2021	19,636	17	(54)	19,600	49	(844)	18,805
3	2022	19,600	-	(95)	19,505	49	(1,234)	18,319
4	2023	19,505	-	(144)	19,361	49	(1,615)	17,795
5	2024	19,361	-	(196)	19,164	49	(1,986)	17,228
6	2025	19,164	-	(252)	18,912	50	(2,345)	16,617
7	2026	18,912	-	(312)	18,600	50	(2,691)	15,958
8	2027	18,600	-	(380)	18,220	50	(3,025)	15,245
9	2028	18,220	-	(449)	17,771	50	(3,344)	14,476
10	2029	17,771	-	(523)	17,248	50	(3,649)	13,650
11	2030	17,248	-	(605)	16,643	50	(3,936)	12,757
12	2031	16,643	-	(694)	15,949	50	(4,206)	11,794
13	2032	15,949	-	(785)	15,165	50	(4,456)	10,759
14	2033	15,165	-	(885)	14,279	51	(4,686)	9,644
15	2034	14,279	-	(993)	13,286	51	(4,894)	8,443
16	2035	13,286	-	(1,095)	12,191	51	(4,766)	7,476
17	2036	12,191	-	(1,179)	11,011	51	(4,303)	6,759
18	2037	11,011	-	(1,251)	9,760	51	(3,811)	6,000
19	2038	9,760	-	(1,331)	8,429	51	(3,286)	5,194
20	2039	8,429	-	(1,410)	7,019	52	(2,729)	4,342
21	2040	7,019	-	(1,498)	5,521	52	(2,136)	3,437
22	2041	5,521	-	(1,601)	3,921	52	(1,500)	2,473
			186	(15,683)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	501	485	(23)	62	9	288	338	1,660
2	2021	510	434	57	64	9	282	305	1,660
3	2022	497	423	88	65	9	279	299	1,660
4	2023	483	411	125	67	10	273	292	1,660
5	2024	468	398	164	68	10	268	285	1,660
6	2025	451	384	206	70	10	262	277	1,660
7	2026	434	369	251	71	10	256	269	1,660
8	2027	415	353	301	73	10	248	260	1,660
9	2028	395	336	352	74	11	242	250	1,660
10	2029	373	318	407	76	11	236	240	1,660
11	2030	350	298	468	78	11	227	229	1,660
12	2031	325	276	533	79	11	219	217	1,660
13	2032	298	254	599	81	12	213	204	1,660
14	2033	269	229	673	83	12	204	190	1,660
15	2034	238	203	751	85	12	196	175	1,660
16	2035	210	179	823	86	12	187	162	1,660
17	2036	189	161	883	88	13	176	152	1,660
18	2037	169	144	935	90	13	167	142	1,660
19	2038	149	126	992	92	13	155	133	1,660
20	2039	127	108	1,049	94	14	147	122	1,660
21	2040	104	88	1,111	96	14	135	111	1,660
22	2041	79	68	1,185	98	14	115	100	1,660
		7,033	6,044	11,929	1,741	251	4,776	4,754	36,528

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	718	638	(49)	62	9	379	443	2,200
2	2021	731	571	54	64	9	371	401	2,200
3	2022	714	557	95	65	9	367	393	2,200
4	2023	694	542	144	67	10	360	385	2,200
5	2024	673	525	196	68	10	352	375	2,200
6	2025	651	508	252	70	10	345	366	2,200
7	2026	626	489	312	71	10	337	355	2,200
8	2027	600	468	380	73	10	326	344	2,200
9	2028	571	446	449	74	11	318	331	2,200
10	2029	541	422	523	76	11	310	318	2,200
11	2030	508	396	605	78	11	299	303	2,200
12	2031	472	368	694	79	11	288	288	2,200
13	2032	433	338	785	81	12	280	271	2,200
14	2033	392	306	885	83	12	269	253	2,200
15	2034	348	271	993	85	12	257	234	2,200
16	2035	306	239	1,095	86	12	246	215	2,200
17	2036	274	214	1,179	88	13	231	202	2,200
18	2037	245	191	1,251	90	13	220	189	2,200
19	2038	215	168	1,331	92	13	204	176	2,200
20	2039	183	143	1,410	94	14	193	163	2,200
21	2040	150	117	1,498	96	14	178	148	2,200
22	2041	114	89	1,601	98	14	151	133	2,200
		10,158	8,005	15,683	1,741	251	6,281	6,286	48,404

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	168	383	1.20	1,493	2,971	1.38
2	2021	1.118	168	383	1.20	1,493	2,971	1.38
3	2022	1.118	168	383	1.20	1,493	2,971	1.38
4	2023	1.118	168	383	1.20	1,493	2,971	1.38
5	2024	1.118	168	383	1.20	1,493	2,971	1.38
6	2025	1.118	168	383	1.20	1,493	2,971	1.38
7	2026	1.118	168	383	1.20	1,493	2,971	1.38
8	2027	1.118	168	383	1.20	1,493	2,971	1.38
9	2028	1.118	168	383	1.20	1,493	2,971	1.38
10	2029	1.118	168	383	1.20	1,493	2,971	1.38
11	2030	1.118	168	383	1.20	1,493	2,971	1.38
12	2031	1.118	168	383	1.20	1,493	2,971	1.38
13	2032	1.118	168	383	1.20	1,493	2,971	1.38
14	2033	1.118	168	383	1.20	1,493	2,971	1.38
15	2034	1.118	168	383	1.20	1,493	2,971	1.38
16	2035	1.118	168	383	1.20	1,493	2,971	1.38
17	2036	1.118	168	383	1.20	1,493	2,971	1.38
18	2037	1.118	168	383	1.20	1,493	2,971	1.38
19	2038	1.118	168	383	1.20	1,493	2,971	1.38
20	2039	1.118	168	383	1.20	1,493	2,971	1.38
21	2040	1.118	168	383	1.20	1,493	2,971	1.38
22	2041	1.118	168	383	1.20	1,493	2,971	1.38

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	222	383	1.59	1,978	2,971	1.82
2	2021	1.118	222	383	1.59	1,978	2,971	1.82
3	2022	1.118	222	383	1.59	1,978	2,971	1.82
4	2023	1.118	222	383	1.59	1,978	2,971	1.82
5	2024	1.118	222	383	1.59	1,978	2,971	1.82
6	2025	1.118	222	383	1.59	1,978	2,971	1.82
7	2026	1.118	222	383	1.59	1,978	2,971	1.82
8	2027	1.118	222	383	1.59	1,978	2,971	1.82
9	2028	1.118	222	383	1.59	1,978	2,971	1.82
10	2029	1.118	222	383	1.59	1,978	2,971	1.82
11	2030	1.118	222	383	1.59	1,978	2,971	1.82
12	2031	1.118	222	383	1.59	1,978	2,971	1.82
13	2032	1.118	222	383	1.59	1,978	2,971	1.82
14	2033	1.118	222	383	1.59	1,978	2,971	1.82
15	2034	1.118	222	383	1.59	1,978	2,971	1.82
16	2035	1.118	222	383	1.59	1,978	2,971	1.82
17	2036	1.118	222	383	1.59	1,978	2,971	1.82
18	2037	1.118	222	383	1.59	1,978	2,971	1.82
19	2038	1.118	222	383	1.59	1,978	2,971	1.82
20	2039	1.118	222	383	1.59	1,978	2,971	1.82
21	2040	1.118	222	383	1.59	1,978	2,971	1.82
22	2041	1.118	222	383	1.59	1,978	2,971	1.82

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.4%	0.2%
3	2022	0.6%	0.8%
4	2023	0.8%	1.7%
5	2024	1.1%	2.8%
6	2025	1.4%	4.1%
7	2026	1.7%	5.8%
8	2027	2.0%	7.8%
9	2028	2.4%	10.2%
10	2029	2.7%	12.9%
11	2030	3.1%	16.1%
12	2031	3.6%	19.6%
13	2032	4.0%	23.7%
14	2033	4.5%	28.2%
15	2034	5.0%	33.2%
16	2035	5.5%	38.7%
17	2036	5.9%	44.6%
18	2037	6.3%	50.9%
19	2038	6.6%	57.6%
20	2039	7.0%	64.6%
21	2040	7.5%	72.1%
22	2041	7.9%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(22 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.3%	0.0%
3	2022	0.5%	0.5%
4	2023	0.7%	1.2%
5	2024	1.0%	2.2%
6	2025	1.3%	3.5%
7	2026	1.6%	5.1%
8	2027	1.9%	7.1%
9	2028	2.3%	9.4%
10	2029	2.7%	12.0%
11	2030	3.1%	15.1%
12	2031	3.5%	18.6%
13	2032	4.0%	22.6%
14	2033	4.5%	27.2%
15	2034	5.1%	32.2%
16	2035	5.6%	37.8%
17	2036	6.0%	43.8%
18	2037	6.4%	50.2%
19	2038	6.8%	57.0%
20	2039	7.2%	64.2%
21	2040	7.6%	71.8%
22	2041	8.2%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(23 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	443
2018	443	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	2	662	0	(15)	647
2	2021	662	1	(1)	660	0	(28)	632
3	2022	660	-	(3)	658	0	(42)	616
4	2023	658	-	(4)	653	0	(54)	599
5	2024	653	-	(6)	647	0	(67)	581
6	2025	647	-	(8)	640	0	(79)	561
7	2026	640	-	(9)	630	0	(91)	540
8	2027	630	-	(12)	619	0	(102)	517
9	2028	619	-	(14)	605	0	(113)	493
10	2029	605	-	(16)	589	0	(123)	466
11	2030	589	-	(18)	571	0	(133)	438
12	2031	571	-	(21)	550	0	(142)	408
13	2032	550	-	(24)	526	0	(151)	375
14	2033	526	-	(27)	499	0	(159)	340
15	2034	499	-	(30)	469	0	(167)	302
16	2035	469	-	(33)	435	0	(169)	267
17	2036	435	-	(36)	399	0	(155)	244
18	2037	399	-	(38)	361	0	(140)	221
19	2038	361	-	(41)	320	0	(124)	196
20	2039	320	-	(43)	277	0	(107)	170
21	2040	277	-	(46)	231	0	(89)	142
22	2041	231	-	(49)	183	0	(70)	113
23	2042	183	-	(51)	131	0	(50)	82
			6	(528)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	4	872	0	(20)	852
2	2021	872	1	(1)	871	0	(37)	834
3	2022	871	-	(3)	868	0	(55)	814
4	2023	868	-	(5)	863	0	(72)	792
5	2024	863	-	(7)	857	0	(88)	769
6	2025	857	-	(9)	847	0	(104)	744
7	2026	847	-	(12)	836	0	(120)	716
8	2027	836	-	(14)	821	0	(135)	687
9	2028	821	-	(17)	804	0	(149)	655
10	2029	804	-	(20)	784	0	(163)	621
11	2030	784	-	(24)	760	0	(176)	584
12	2031	760	-	(27)	733	0	(188)	544
13	2032	733	-	(31)	701	0	(200)	502
14	2033	701	-	(35)	666	0	(211)	455
15	2034	666	-	(40)	626	0	(221)	406
16	2035	626	-	(44)	582	0	(226)	356
17	2036	582	-	(48)	533	0	(208)	326
18	2037	533	-	(51)	482	0	(188)	295
19	2038	482	-	(55)	428	0	(166)	262
20	2039	428	-	(58)	370	0	(143)	227
21	2040	370	-	(62)	308	0	(119)	189
22	2041	308	-	(66)	242	0	(93)	149
23	2042	242	-	(69)	173	0	(66)	107
			8	(695)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	21	(2)	3	0	13	15	72
2	2021	23	19	1	3	0	12	13	72
3	2022	22	19	3	3	0	12	13	72
4	2023	21	18	4	3	0	12	13	72
5	2024	21	18	6	3	0	12	13	72
6	2025	20	17	8	3	0	12	12	72
7	2026	19	17	9	3	0	11	12	72
8	2027	19	16	12	3	0	11	12	72
9	2028	18	15	14	3	0	11	11	72
10	2029	17	14	16	3	0	10	11	72
11	2030	16	14	18	3	1	10	10	72
12	2031	15	13	21	3	1	10	10	72
13	2032	14	12	24	4	1	9	9	72
14	2033	13	11	27	4	1	9	9	72
15	2034	11	10	30	4	1	9	8	72
16	2035	10	9	33	4	1	8	8	72
17	2036	9	8	36	4	1	8	7	72
18	2037	8	7	38	4	1	7	7	72
19	2038	7	6	41	4	1	7	6	72
20	2039	6	6	43	4	1	6	6	72
21	2040	6	5	46	4	1	6	6	72
22	2041	5	4	49	4	1	5	5	72
23	2042	3	3	51	4	1	5	5	72
		325	279	528	80	12	216	222	1,664

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(4)	3	0	17	20	96
2	2021	32	25	1	3	0	16	18	96
3	2022	32	25	3	3	0	16	17	96
4	2023	31	24	5	3	0	16	17	96
5	2024	30	23	7	3	0	16	17	96
6	2025	29	23	9	3	0	15	16	96
7	2026	28	22	12	3	0	15	16	96
8	2027	27	21	14	3	0	14	15	96
9	2028	26	20	17	3	0	14	15	96
10	2029	25	19	20	3	0	14	14	96
11	2030	23	18	24	3	1	13	14	96
12	2031	22	17	27	3	1	13	13	96
13	2032	20	16	31	4	1	12	13	96
14	2033	18	14	35	4	1	12	12	96
15	2034	17	13	40	4	1	11	11	96
16	2035	15	11	44	4	1	11	10	96
17	2036	13	10	48	4	1	10	10	96
18	2037	12	9	51	4	1	10	9	96
19	2038	11	8	55	4	1	9	9	96
20	2039	9	7	58	4	1	9	8	96
21	2040	8	6	62	4	1	8	8	96
22	2041	7	5	66	4	1	7	7	96
23	2042	5	4	69	4	1	7	6	96
		471	371	695	80	12	285	295	2,209

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	72	1,100	1.000	0.18
2	2021	72	1,100	1.000	0.18
3	2022	72	1,100	1.000	0.18
4	2023	72	1,100	1.000	0.18
5	2024	72	1,100	1.000	0.18
6	2025	72	1,100	1.000	0.18
7	2026	72	1,100	1.000	0.18
8	2027	72	1,100	1.000	0.18
9	2028	72	1,100	1.000	0.18
10	2029	72	1,100	1.000	0.18
11	2030	72	1,100	1.000	0.18
12	2031	72	1,100	1.000	0.18
13	2032	72	1,100	1.000	0.18
14	2033	72	1,100	1.000	0.18
15	2034	72	1,100	1.000	0.18
16	2035	72	1,100	1.000	0.18
17	2036	72	1,100	1.000	0.18
18	2037	72	1,100	1.000	0.18
19	2038	72	1,100	1.000	0.18
20	2039	72	1,100	1.000	0.18
21	2040	72	1,100	1.000	0.18
22	2041	72	1,100	1.000	0.18
23	2042	72	1,100	1.000	0.18

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	96	1,100	1.000	0.24
2	2021	96	1,100	1.000	0.24
3	2022	96	1,100	1.000	0.24
4	2023	96	1,100	1.000	0.24
5	2024	96	1,100	1.000	0.24
6	2025	96	1,100	1.000	0.24
7	2026	96	1,100	1.000	0.24
8	2027	96	1,100	1.000	0.24
9	2028	96	1,100	1.000	0.24
10	2029	96	1,100	1.000	0.24
11	2030	96	1,100	1.000	0.24
12	2031	96	1,100	1.000	0.24
13	2032	96	1,100	1.000	0.24
14	2033	96	1,100	1.000	0.24
15	2034	96	1,100	1.000	0.24
16	2035	96	1,100	1.000	0.24
17	2036	96	1,100	1.000	0.24
18	2037	96	1,100	1.000	0.24
19	2038	96	1,100	1.000	0.24
20	2039	96	1,100	1.000	0.24
21	2040	96	1,100	1.000	0.24
22	2041	96	1,100	1.000	0.24
23	2042	96	1,100	1.000	0.24

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.2%	-0.1%
3	2022	0.4%	0.3%
4	2023	0.6%	1.0%
5	2024	0.9%	1.9%
6	2025	1.2%	3.0%
7	2026	1.4%	4.4%
8	2027	1.7%	6.2%
9	2028	2.1%	8.3%
10	2029	2.4%	10.7%
11	2030	2.8%	13.5%
12	2031	3.2%	16.7%
13	2032	3.6%	20.3%
14	2033	4.1%	24.3%
15	2034	4.6%	28.9%
16	2035	5.1%	34.0%
17	2036	5.5%	39.5%
18	2037	5.8%	45.3%
19	2038	6.2%	51.4%
20	2039	6.5%	58.0%
21	2040	6.9%	64.9%
22	2041	7.4%	72.3%
23	2042	7.7%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.4%	-0.4%
2	2021	0.1%	-0.3%
3	2022	0.3%	0.0%
4	2023	0.5%	0.5%
5	2024	0.8%	1.3%
6	2025	1.1%	2.4%
7	2026	1.3%	3.7%
8	2027	1.7%	5.4%
9	2028	2.0%	7.4%
10	2029	2.3%	9.7%
11	2030	2.7%	12.5%
12	2031	3.2%	15.6%
13	2032	3.6%	19.2%
14	2033	4.1%	23.3%
15	2034	4.6%	27.8%
16	2035	5.1%	33.0%
17	2036	5.6%	38.5%
18	2037	5.9%	44.4%
19	2038	6.3%	50.7%
20	2039	6.7%	57.4%
21	2040	7.1%	64.5%
22	2041	7.6%	72.0%
23	2042	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,042
2016	3,042	2,682	54	873	354	7,004
2017	7,004	2,620	52	852	641	11,170
2018	11,170	2,161	43	703	928	15,005
2019	15,005	1,275	25	415	1,176	17,895
2020	17,895	438	-	151	-	18,485
2021	18,485	12	-	4	-	18,501
		11,185	203	3,659	3,453	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	24	14,057	23	(314)	13,766
2	2021	14,057	12	(20)	14,049	24	(600)	13,473
3	2022	14,049	-	(49)	13,999	24	(880)	13,144
4	2023	13,999	-	(90)	13,909	23	(1,153)	12,779
5	2024	13,909	-	(136)	13,774	22	(1,420)	12,376
6	2025	13,774	-	(178)	13,596	22	(1,679)	11,939
7	2026	13,596	-	(219)	13,377	22	(1,930)	11,469
8	2027	13,377	-	(266)	13,111	22	(2,171)	10,961
9	2028	13,111	-	(313)	12,797	22	(2,402)	10,417
10	2029	12,797	-	(364)	12,434	22	(2,623)	9,832
11	2030	12,434	-	(420)	12,014	22	(2,833)	9,203
12	2031	12,014	-	(474)	11,540	22	(3,030)	8,532
13	2032	11,540	-	(528)	11,012	23	(3,214)	7,820
14	2033	11,012	-	(589)	10,423	23	(3,384)	7,062
15	2034	10,423	-	(653)	9,770	24	(3,539)	6,254
16	2035	9,770	-	(713)	9,057	24	(3,477)	5,604
17	2036	9,057	-	(761)	8,296	25	(3,185)	5,136
18	2037	8,296	-	(800)	7,496	25	(2,876)	4,645
19	2038	7,496	-	(844)	6,652	26	(2,550)	4,128
20	2039	6,652	-	(886)	5,766	26	(2,206)	3,586
21	2040	5,766	-	(934)	4,832	27	(1,843)	3,016
22	2041	4,832	-	(991)	3,842	28	(1,456)	2,413
23	2042	3,842	-	(1,032)	2,809	28	(1,052)	1,785
			463	(11,236)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,895	590	50	18,535	23	(414)	18,144
2	2021	18,535	16	(11)	18,540	24	(790)	17,774
3	2022	18,540	-	(49)	18,491	24	(1,159)	17,356
4	2023	18,491	-	(100)	18,391	23	(1,520)	16,894
5	2024	18,391	-	(157)	18,234	22	(1,872)	16,384
6	2025	18,234	-	(212)	18,023	22	(2,215)	15,830
7	2026	18,023	-	(266)	17,756	22	(2,546)	15,232
8	2027	17,756	-	(328)	17,428	22	(2,867)	14,583
9	2028	17,428	-	(391)	17,036	22	(3,174)	13,884
10	2029	17,036	-	(459)	16,578	22	(3,468)	13,131
11	2030	16,578	-	(534)	16,043	22	(3,747)	12,318
12	2031	16,043	-	(609)	15,435	22	(4,011)	11,446
13	2032	15,435	-	(685)	14,750	23	(4,257)	10,515
14	2033	14,750	-	(769)	13,980	23	(4,486)	9,518
15	2034	13,980	-	(860)	13,121	24	(4,695)	8,450
16	2035	13,121	-	(947)	12,174	24	(4,683)	7,515
17	2036	12,174	-	(1,019)	11,155	25	(4,291)	6,889
18	2037	11,155	-	(1,076)	10,079	25	(3,875)	6,229
19	2038	10,079	-	(1,139)	8,940	26	(3,434)	5,532
20	2039	8,940	-	(1,201)	7,739	26	(2,967)	4,798
21	2040	7,739	-	(1,270)	6,469	27	(2,472)	4,024
22	2041	6,469	-	(1,353)	5,116	28	(1,942)	3,201
23	2042	5,116	-	(1,416)	3,700	28	(1,387)	2,341
			605	(14,801)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	466	451	(24)	274	52	272	313	1,804
2	2021	480	409	20	289	53	266	286	1,804
3	2022	469	399	49	287	54	264	282	1,804
4	2023	457	389	90	278	55	258	277	1,804
5	2024	443	377	136	267	56	253	271	1,804
6	2025	429	365	178	263	57	247	265	1,804
7	2026	413	351	219	262	59	242	258	1,804
8	2027	395	336	266	262	60	234	251	1,804
9	2028	377	321	313	261	61	228	242	1,804
10	2029	357	304	364	260	63	223	234	1,804
11	2030	335	286	420	260	64	215	224	1,804
12	2031	313	266	474	266	65	206	214	1,804
13	2032	288	245	528	271	67	201	202	1,804
14	2033	262	223	589	277	68	193	191	1,804
15	2034	235	200	653	283	70	185	178	1,804
16	2035	209	178	713	290	71	177	166	1,804
17	2036	189	161	761	296	73	166	157	1,804
18	2037	172	147	800	303	75	158	150	1,804
19	2038	155	132	844	309	76	147	142	1,804
20	2039	136	116	886	316	78	139	133	1,804
21	2040	116	99	934	323	80	128	124	1,804
22	2041	96	81	991	330	81	109	115	1,804
23	2042	74	63	1,032	337	83	109	105	1,804
		6,866	5,898	11,236	6,565	1,521	4,616	4,781	41,483

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	670	594	(50)	274	52	358	412	2,310
2	2021	691	539	11	289	53	351	377	2,310
3	2022	676	527	49	287	54	347	371	2,310
4	2023	659	514	100	278	55	340	365	2,310
5	2024	640	499	157	267	56	333	358	2,310
6	2025	620	483	212	263	57	326	350	2,310
7	2026	597	466	266	262	59	319	341	2,310
8	2027	573	447	328	262	60	308	331	2,310
9	2028	548	427	391	261	61	301	321	2,310
10	2029	520	405	459	260	63	294	310	2,310
11	2030	489	382	534	260	64	283	298	2,310
12	2031	457	356	609	266	65	272	285	2,310
13	2032	422	329	685	271	67	265	270	2,310
14	2033	385	300	769	277	68	254	255	2,310
15	2034	346	270	860	283	70	244	239	2,310
16	2035	307	239	947	290	71	233	223	2,310
17	2036	277	216	1,019	296	73	218	211	2,310
18	2037	252	197	1,076	303	75	208	200	2,310
19	2038	226	176	1,139	309	76	193	190	2,310
20	2039	199	155	1,201	316	78	183	179	2,310
21	2040	170	132	1,270	323	80	168	167	2,310
22	2041	139	108	1,353	330	81	143	155	2,310
23	2042	107	83	1,416	337	83	143	141	2,310
		9,969	7,847	14,801	6,565	1,521	6,085	6,345	53,133

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,804	3,000	1.118	1.47
2	2021	1,804	3,000	1.118	1.47
3	2022	1,804	3,000	1.118	1.47
4	2023	1,804	3,000	1.118	1.47
5	2024	1,804	3,000	1.118	1.47
6	2025	1,804	3,000	1.118	1.47
7	2026	1,804	3,000	1.118	1.47
8	2027	1,804	3,000	1.118	1.47
9	2028	1,804	3,000	1.118	1.47
10	2029	1,804	3,000	1.118	1.47
11	2030	1,804	3,000	1.118	1.47
12	2031	1,804	3,000	1.118	1.47
13	2032	1,804	3,000	1.118	1.47
14	2033	1,804	3,000	1.118	1.47
15	2034	1,804	3,000	1.118	1.47
16	2035	1,804	3,000	1.118	1.47
17	2036	1,804	3,000	1.118	1.47
18	2037	1,804	3,000	1.118	1.47
19	2038	1,804	3,000	1.118	1.47
20	2039	1,804	3,000	1.118	1.47
21	2040	1,804	3,000	1.118	1.47
22	2041	1,804	3,000	1.118	1.47
23	2042	1,804	3,000	1.118	1.47

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,310	3,000	1.118	1.89
2	2021	2,310	3,000	1.118	1.89
3	2022	2,310	3,000	1.118	1.89
4	2023	2,310	3,000	1.118	1.89
5	2024	2,310	3,000	1.118	1.89
6	2025	2,310	3,000	1.118	1.89
7	2026	2,310	3,000	1.118	1.89
8	2027	2,310	3,000	1.118	1.89
9	2028	2,310	3,000	1.118	1.89
10	2029	2,310	3,000	1.118	1.89
11	2030	2,310	3,000	1.118	1.89
12	2031	2,310	3,000	1.118	1.89
13	2032	2,310	3,000	1.118	1.89
14	2033	2,310	3,000	1.118	1.89
15	2034	2,310	3,000	1.118	1.89
16	2035	2,310	3,000	1.118	1.89
17	2036	2,310	3,000	1.118	1.89
18	2037	2,310	3,000	1.118	1.89
19	2038	2,310	3,000	1.118	1.89
20	2039	2,310	3,000	1.118	1.89
21	2040	2,310	3,000	1.118	1.89
22	2041	2,310	3,000	1.118	1.89
23	2042	2,310	3,000	1.118	1.89

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.2%	-0.2%
2	2021	0.1%	0.0%
3	2022	0.4%	0.3%
4	2023	0.6%	1.0%
5	2024	1.0%	1.9%
6	2025	1.3%	3.2%
7	2026	1.6%	4.8%
8	2027	1.9%	6.7%
9	2028	2.2%	8.9%
10	2029	2.6%	11.5%
11	2030	3.0%	14.5%
12	2031	3.4%	17.8%
13	2032	3.8%	21.6%
14	2033	4.2%	25.8%
15	2034	4.6%	30.4%
16	2035	5.1%	35.5%
17	2036	5.4%	40.9%
18	2037	5.7%	46.6%
19	2038	6.0%	52.6%
20	2039	6.3%	58.9%
21	2040	6.6%	65.6%
22	2041	7.1%	72.6%
23	2042	7.4%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.1%	-0.2%
3	2022	0.3%	0.1%
4	2023	0.5%	0.6%
5	2024	0.8%	1.4%
6	2025	1.1%	2.6%
7	2026	1.4%	4.0%
8	2027	1.8%	5.8%
9	2028	2.1%	7.9%
10	2029	2.5%	10.4%
11	2030	2.9%	13.3%
12	2031	3.3%	16.6%
13	2032	3.7%	20.3%
14	2033	4.2%	24.4%
15	2034	4.6%	29.1%
16	2035	5.1%	34.2%
17	2036	5.5%	39.7%
18	2037	5.8%	45.5%
19	2038	6.2%	51.7%
20	2039	6.5%	58.2%
21	2040	6.9%	65.0%
22	2041	7.3%	72.3%
23	2042	7.7%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,723
2017	2,723	2,549	51	454	314	6,091
2018	6,091	7,006	140	1,249	753	15,239
2019	15,239	2,464	49	439	1,226	19,419
2020	19,419	141	-	28	-	19,587
2021	19,587	14	-	3	-	19,605
		14,030	263	2,519	2,793	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	48	14,946	49	(338)	14,657
2	2021	14,946	13	(30)	14,930	49	(642)	14,337
3	2022	14,930	-	(59)	14,871	49	(940)	13,980
4	2023	14,871	-	(93)	14,778	49	(1,230)	13,597
5	2024	14,778	-	(130)	14,648	49	(1,513)	13,184
6	2025	14,648	-	(169)	14,479	50	(1,788)	12,741
7	2026	14,479	-	(211)	14,268	50	(2,054)	12,264
8	2027	14,268	-	(258)	14,010	50	(2,310)	11,750
9	2028	14,010	-	(306)	13,703	50	(2,556)	11,198
10	2029	13,703	-	(357)	13,346	50	(2,791)	10,606
11	2030	13,346	-	(414)	12,932	50	(3,014)	9,969
12	2031	12,932	-	(475)	12,457	50	(3,224)	9,283
13	2032	12,457	-	(537)	11,920	50	(3,421)	8,549
14	2033	11,920	-	(606)	11,313	51	(3,603)	7,761
15	2034	11,313	-	(680)	10,633	51	(3,769)	6,915
16	2035	10,633	-	(756)	9,876	51	(3,862)	6,065
17	2036	9,876	-	(821)	9,055	51	(3,541)	5,565
18	2037	9,055	-	(870)	8,186	51	(3,200)	5,037
19	2038	8,186	-	(923)	7,262	51	(2,837)	4,477
20	2039	7,262	-	(977)	6,285	52	(2,452)	3,885
21	2040	6,285	-	(1,036)	5,249	52	(2,042)	3,259
22	2041	5,249	-	(1,106)	4,143	52	(1,604)	2,591
23	2042	4,143	-	(1,160)	2,982	52	(1,144)	1,891
			142	(11,929)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,419	169	82	19,669	49	(444)	19,274
2	2021	19,669	17	(18)	19,669	49	(844)	18,874
3	2022	19,669	-	(56)	19,612	49	(1,236)	18,426
4	2023	19,612	-	(102)	19,510	49	(1,618)	17,941
5	2024	19,510	-	(151)	19,360	49	(1,991)	17,418
6	2025	19,360	-	(203)	19,157	50	(2,354)	16,852
7	2026	19,157	-	(259)	18,898	50	(2,705)	16,242
8	2027	18,898	-	(323)	18,575	50	(3,044)	15,581
9	2028	18,575	-	(387)	18,188	50	(3,370)	14,868
10	2029	18,188	-	(456)	17,732	50	(3,682)	14,101
11	2030	17,732	-	(533)	17,199	50	(3,978)	13,271
12	2031	17,199	-	(616)	16,583	50	(4,258)	12,376
13	2032	16,583	-	(701)	15,882	50	(4,520)	11,413
14	2033	15,882	-	(795)	15,087	51	(4,763)	10,375
15	2034	15,087	-	(897)	14,190	51	(4,985)	9,256
16	2035	14,190	-	(1,004)	13,186	51	(5,162)	8,075
17	2036	13,186	-	(1,095)	12,091	51	(4,733)	7,409
18	2037	12,091	-	(1,163)	10,928	51	(4,277)	6,702
19	2038	10,928	-	(1,238)	9,690	51	(3,790)	5,952
20	2039	9,690	-	(1,313)	8,378	52	(3,272)	5,158
21	2040	8,378	-	(1,395)	6,983	52	(2,720)	4,315
22	2041	6,983	-	(1,493)	5,490	52	(2,128)	3,414
23	2042	5,490	-	(1,569)	3,921	52	(1,504)	2,469
			186	(15,684)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	501	486	(48)	62	9	288	337	1,636
2	2021	511	435	30	64	9	283	305	1,636
3	2022	499	425	59	65	9	280	299	1,636
4	2023	486	414	93	67	9	274	293	1,636
5	2024	472	402	130	68	9	268	286	1,636
6	2025	457	389	169	70	10	262	279	1,636
7	2026	441	375	211	71	10	257	271	1,636
8	2027	423	360	258	73	10	248	263	1,636
9	2028	404	344	306	74	10	242	254	1,636
10	2029	384	327	357	76	10	236	244	1,636
11	2030	363	309	414	78	11	228	234	1,636
12	2031	339	289	475	79	11	219	223	1,636
13	2032	314	267	537	81	11	213	211	1,636
14	2033	287	245	606	83	11	205	198	1,636
15	2034	259	220	680	85	12	196	184	1,636
16	2035	229	195	756	86	12	187	170	1,636
17	2036	205	174	821	88	12	176	159	1,636
18	2037	187	159	870	90	12	167	150	1,636
19	2038	168	143	923	92	13	156	141	1,636
20	2039	147	125	977	94	13	147	131	1,636
21	2040	126	107	1,036	96	13	136	121	1,636
22	2041	103	88	1,106	98	14	115	111	1,636
23	2042	79	67	1,160	101	14	115	99	1,636
		7,385	6,344	11,929	1,841	254	4,900	4,963	37,617

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	719	639	(82)	62	9	379	442	2,168
2	2021	734	572	18	64	9	372	400	2,168
3	2022	717	559	56	65	9	368	393	2,168
4	2023	699	546	102	67	9	360	385	2,168
5	2024	680	530	151	68	9	353	377	2,168
6	2025	659	514	203	70	10	345	368	2,168
7	2026	637	496	259	71	10	338	358	2,168
8	2027	612	477	323	73	10	326	348	2,168
9	2028	586	457	387	74	10	319	336	2,168
10	2029	557	435	456	76	10	311	324	2,168
11	2030	526	411	533	78	11	300	310	2,168
12	2031	493	385	616	79	11	288	296	2,168
13	2032	458	357	701	81	11	281	280	2,168
14	2033	419	327	795	83	11	269	264	2,168
15	2034	378	294	897	85	12	258	245	2,168
16	2035	333	260	1,004	86	12	247	226	2,168
17	2036	298	232	1,095	88	12	231	211	2,168
18	2037	271	212	1,163	90	12	220	200	2,168
19	2038	243	190	1,238	92	13	205	188	2,168
20	2039	214	167	1,313	94	13	193	175	2,168
21	2040	182	142	1,395	96	13	178	161	2,168
22	2041	149	116	1,493	98	14	152	147	2,168
23	2042	113	88	1,569	101	14	152	131	2,168
		10,678	8,405	15,684	1,841	254	6,444	6,566	49,872

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	165	383	1.18	1,470	2,971	1.36
2	2021	1.118	165	383	1.18	1,470	2,971	1.36
3	2022	1.118	165	383	1.18	1,470	2,971	1.36
4	2023	1.118	165	383	1.18	1,470	2,971	1.36
5	2024	1.118	165	383	1.18	1,470	2,971	1.36
6	2025	1.118	165	383	1.18	1,470	2,971	1.36
7	2026	1.118	165	383	1.18	1,470	2,971	1.36
8	2027	1.118	165	383	1.18	1,470	2,971	1.36
9	2028	1.118	165	383	1.18	1,470	2,971	1.36
10	2029	1.118	165	383	1.18	1,470	2,971	1.36
11	2030	1.118	165	383	1.18	1,470	2,971	1.36
12	2031	1.118	165	383	1.18	1,470	2,971	1.36
13	2032	1.118	165	383	1.18	1,470	2,971	1.36
14	2033	1.118	165	383	1.18	1,470	2,971	1.36
15	2034	1.118	165	383	1.18	1,470	2,971	1.36
16	2035	1.118	165	383	1.18	1,470	2,971	1.36
17	2036	1.118	165	383	1.18	1,470	2,971	1.36
18	2037	1.118	165	383	1.18	1,470	2,971	1.36
19	2038	1.118	165	383	1.18	1,470	2,971	1.36
20	2039	1.118	165	383	1.18	1,470	2,971	1.36
21	2040	1.118	165	383	1.18	1,470	2,971	1.36
22	2041	1.118	165	383	1.18	1,470	2,971	1.36
23	2042	1.118	165	383	1.18	1,470	2,971	1.36

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	219	383	1.57	1,949	2,971	1.80
2	2021	1.118	219	383	1.57	1,949	2,971	1.80
3	2022	1.118	219	383	1.57	1,949	2,971	1.80
4	2023	1.118	219	383	1.57	1,949	2,971	1.80
5	2024	1.118	219	383	1.57	1,949	2,971	1.80
6	2025	1.118	219	383	1.57	1,949	2,971	1.80
7	2026	1.118	219	383	1.57	1,949	2,971	1.80
8	2027	1.118	219	383	1.57	1,949	2,971	1.80
9	2028	1.118	219	383	1.57	1,949	2,971	1.80
10	2029	1.118	219	383	1.57	1,949	2,971	1.80
11	2030	1.118	219	383	1.57	1,949	2,971	1.80
12	2031	1.118	219	383	1.57	1,949	2,971	1.80
13	2032	1.118	219	383	1.57	1,949	2,971	1.80
14	2033	1.118	219	383	1.57	1,949	2,971	1.80
15	2034	1.118	219	383	1.57	1,949	2,971	1.80
16	2035	1.118	219	383	1.57	1,949	2,971	1.80
17	2036	1.118	219	383	1.57	1,949	2,971	1.80
18	2037	1.118	219	383	1.57	1,949	2,971	1.80
19	2038	1.118	219	383	1.57	1,949	2,971	1.80
20	2039	1.118	219	383	1.57	1,949	2,971	1.80
21	2040	1.118	219	383	1.57	1,949	2,971	1.80
22	2041	1.118	219	383	1.57	1,949	2,971	1.80
23	2042	1.118	219	383	1.57	1,949	2,971	1.80

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.2%	-0.1%
3	2022	0.4%	0.3%
4	2023	0.6%	0.9%
5	2024	0.9%	1.8%
6	2025	1.1%	2.9%
7	2026	1.4%	4.3%
8	2027	1.7%	6.0%
9	2028	2.1%	8.1%
10	2029	2.4%	10.5%
11	2030	2.8%	13.3%
12	2031	3.2%	16.5%
13	2032	3.6%	20.1%
14	2033	4.1%	24.1%
15	2034	4.6%	28.7%
16	2035	5.1%	33.8%
17	2036	5.5%	39.3%
18	2037	5.8%	45.1%
19	2038	6.2%	51.3%
20	2039	6.6%	57.8%
21	2040	6.9%	64.8%
22	2041	7.4%	72.2%
23	2042	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(23 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.4%	-0.4%
2	2021	0.1%	-0.3%
3	2022	0.3%	0.0%
4	2023	0.5%	0.5%
5	2024	0.8%	1.3%
6	2025	1.0%	2.3%
7	2026	1.3%	3.6%
8	2027	1.6%	5.3%
9	2028	2.0%	7.2%
10	2029	2.3%	9.6%
11	2030	2.7%	12.3%
12	2031	3.1%	15.4%
13	2032	3.6%	19.0%
14	2033	4.1%	23.0%
15	2034	4.6%	27.6%
16	2035	5.1%	32.7%
17	2036	5.6%	38.3%
18	2037	5.9%	44.3%
19	2038	6.3%	50.6%
20	2039	6.7%	57.3%
21	2040	7.1%	64.4%
22	2041	7.6%	72.0%
23	2042	8.0%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(24 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	443
2018	443	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	3	663	0	(15)	648
2	2021	663	1	(0)	662	0	(28)	634
3	2022	662	-	(2)	661	0	(42)	620
4	2023	661	-	(3)	658	0	(54)	604
5	2024	658	-	(4)	654	0	(67)	587
6	2025	654	-	(6)	647	0	(79)	568
7	2026	647	-	(8)	640	0	(91)	549
8	2027	640	-	(10)	630	0	(103)	527
9	2028	630	-	(12)	618	0	(114)	505
10	2029	618	-	(14)	604	0	(124)	480
11	2030	604	-	(16)	588	0	(134)	454
12	2031	588	-	(19)	569	0	(144)	425
13	2032	569	-	(21)	548	0	(153)	395
14	2033	548	-	(24)	524	0	(162)	362
15	2034	524	-	(27)	496	0	(169)	327
16	2035	496	-	(30)	466	0	(177)	290
17	2036	466	-	(33)	432	0	(168)	265
18	2037	432	-	(36)	397	0	(154)	243
19	2038	397	-	(38)	359	0	(140)	220
20	2039	359	-	(40)	319	0	(124)	195
21	2040	319	-	(43)	276	0	(107)	169
22	2041	276	-	(46)	231	0	(89)	142
23	2042	231	-	(48)	183	0	(71)	113
24	2043	183	-	(52)	131	0	(50)	82
			6	(528)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	5	873	0	(20)	854
2	2021	873	1	0	874	0	(37)	836
3	2022	874	-	(1)	873	0	(55)	818
4	2023	873	-	(3)	870	0	(72)	798
5	2024	870	-	(5)	865	0	(88)	776
6	2025	865	-	(7)	857	0	(105)	753
7	2026	857	-	(9)	848	0	(120)	728
8	2027	848	-	(12)	836	0	(135)	701
9	2028	836	-	(15)	821	0	(150)	671
10	2029	821	-	(18)	804	0	(164)	640
11	2030	804	-	(21)	783	0	(178)	605
12	2031	783	-	(24)	758	0	(191)	568
13	2032	758	-	(28)	731	0	(203)	528
14	2033	731	-	(32)	699	0	(214)	485
15	2034	699	-	(36)	663	0	(224)	439
16	2035	663	-	(40)	623	0	(234)	389
17	2036	623	-	(45)	578	0	(225)	353
18	2037	578	-	(48)	531	0	(207)	324
19	2038	531	-	(51)	480	0	(187)	293
20	2039	480	-	(54)	426	0	(166)	260
21	2040	426	-	(57)	369	0	(143)	226
22	2041	369	-	(61)	307	0	(119)	188
23	2042	307	-	(65)	243	0	(94)	149
24	2043	243	-	(70)	173	0	(66)	107
			8	(695)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	21	(3)	3	0	13	15	71
2	2021	23	19	0	3	0	13	13	71
3	2022	22	19	2	3	0	12	13	71
4	2023	22	18	3	3	0	12	13	71
5	2024	21	18	4	3	0	12	13	71
6	2025	20	17	6	3	0	12	12	71
7	2026	20	17	8	3	0	11	12	71
8	2027	19	16	10	3	0	11	12	71
9	2028	18	15	12	3	0	11	11	71
10	2029	17	15	14	3	0	10	11	71
11	2030	16	14	16	3	0	10	11	71
12	2031	16	13	19	3	0	10	10	71
13	2032	14	12	21	4	1	9	10	71
14	2033	13	11	24	4	1	9	9	71
15	2034	12	10	27	4	1	9	9	71
16	2035	11	9	30	4	1	8	8	71
17	2036	10	8	33	4	1	8	8	71
18	2037	9	8	36	4	1	7	7	71
19	2038	8	7	38	4	1	7	7	71
20	2039	7	6	40	4	1	7	6	71
21	2040	6	5	43	4	1	6	6	71
22	2041	6	5	46	4	1	5	6	71
23	2042	5	4	48	4	1	5	5	71
24	2043	3	3	52	4	1	4	5	71
		341	293	528	85	12	220	232	1,712

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(5)	3	0	17	20	95
2	2021	33	25	(0)	3	0	16	18	95
3	2022	32	25	1	3	0	16	17	95
4	2023	31	24	3	3	0	16	17	95
5	2024	30	24	5	3	0	16	17	95
6	2025	29	23	7	3	0	15	16	95
7	2026	29	22	9	3	0	15	16	95
8	2027	28	21	12	3	0	14	16	95
9	2028	26	21	15	3	0	14	15	95
10	2029	25	20	18	3	0	14	15	95
11	2030	24	19	21	3	0	13	14	95
12	2031	23	18	24	3	0	13	14	95
13	2032	21	16	28	4	1	12	13	95
14	2033	20	15	32	4	1	12	12	95
15	2034	18	14	36	4	1	11	12	95
16	2035	16	12	40	4	1	11	11	95
17	2036	14	11	45	4	1	10	10	95
18	2037	13	10	48	4	1	10	10	95
19	2038	12	9	51	4	1	9	9	95
20	2039	11	8	54	4	1	9	9	95
21	2040	9	7	57	4	1	8	8	95
22	2041	8	6	61	4	1	7	7	95
23	2042	7	5	65	4	1	7	7	95
24	2043	5	4	70	4	1	5	6	95
		495	389	695	85	12	290	307	2,274

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	71	1,100	1.000	0.18
2	2021	71	1,100	1.000	0.18
3	2022	71	1,100	1.000	0.18
4	2023	71	1,100	1.000	0.18
5	2024	71	1,100	1.000	0.18
6	2025	71	1,100	1.000	0.18
7	2026	71	1,100	1.000	0.18
8	2027	71	1,100	1.000	0.18
9	2028	71	1,100	1.000	0.18
10	2029	71	1,100	1.000	0.18
11	2030	71	1,100	1.000	0.18
12	2031	71	1,100	1.000	0.18
13	2032	71	1,100	1.000	0.18
14	2033	71	1,100	1.000	0.18
15	2034	71	1,100	1.000	0.18
16	2035	71	1,100	1.000	0.18
17	2036	71	1,100	1.000	0.18
18	2037	71	1,100	1.000	0.18
19	2038	71	1,100	1.000	0.18
20	2039	71	1,100	1.000	0.18
21	2040	71	1,100	1.000	0.18
22	2041	71	1,100	1.000	0.18
23	2042	71	1,100	1.000	0.18
24	2043	71	1,100	1.000	0.18

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	95	1,100	1.000	0.24
2	2021	95	1,100	1.000	0.24
3	2022	95	1,100	1.000	0.24
4	2023	95	1,100	1.000	0.24
5	2024	95	1,100	1.000	0.24
6	2025	95	1,100	1.000	0.24
7	2026	95	1,100	1.000	0.24
8	2027	95	1,100	1.000	0.24
9	2028	95	1,100	1.000	0.24
10	2029	95	1,100	1.000	0.24
11	2030	95	1,100	1.000	0.24
12	2031	95	1,100	1.000	0.24
13	2032	95	1,100	1.000	0.24
14	2033	95	1,100	1.000	0.24
15	2034	95	1,100	1.000	0.24
16	2035	95	1,100	1.000	0.24
17	2036	95	1,100	1.000	0.24
18	2037	95	1,100	1.000	0.24
19	2038	95	1,100	1.000	0.24
20	2039	95	1,100	1.000	0.24
21	2040	95	1,100	1.000	0.24
22	2041	95	1,100	1.000	0.24
23	2042	95	1,100	1.000	0.24
24	2043	95	1,100	1.000	0.24

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	0.0%	-0.4%
3	2022	0.2%	-0.2%
4	2023	0.4%	0.3%
5	2024	0.7%	0.9%
6	2025	0.9%	1.9%
7	2026	1.2%	3.0%
8	2027	1.5%	4.5%
9	2028	1.8%	6.3%
10	2029	2.1%	8.4%
11	2030	2.5%	10.9%
12	2031	2.8%	13.7%
13	2032	3.2%	16.9%
14	2033	3.7%	20.6%
15	2034	4.1%	24.7%
16	2035	4.6%	29.3%
17	2036	5.1%	34.4%
18	2037	5.4%	39.8%
19	2038	5.7%	45.6%
20	2039	6.1%	51.6%
21	2040	6.4%	58.1%
22	2041	6.9%	65.0%
23	2042	7.2%	72.2%
24	2043	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.6%
3	2022	0.1%	-0.5%
4	2023	0.3%	-0.2%
5	2024	0.6%	0.4%
6	2025	0.8%	1.2%
7	2026	1.1%	2.3%
8	2027	1.4%	3.7%
9	2028	1.7%	5.4%
10	2029	2.0%	7.4%
11	2030	2.4%	9.8%
12	2031	2.8%	12.6%
13	2032	3.2%	15.8%
14	2033	3.6%	19.5%
15	2034	4.1%	23.6%
16	2035	4.6%	28.2%
17	2036	5.1%	33.4%
18	2037	5.5%	38.8%
19	2038	5.8%	44.7%
20	2039	6.2%	50.9%
21	2040	6.6%	57.5%
22	2041	7.1%	64.5%
23	2042	7.4%	72.0%
24	2043	8.0%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,042
2016	3,042	2,682	54	873	354	7,004
2017	7,004	2,620	52	852	641	11,170
2018	11,170	2,161	43	703	928	15,005
2019	15,005	1,275	25	415	1,176	17,897
2020	17,897	438	-	151	-	18,486
2021	18,486	12	-	4	-	18,502
		11,185	203	3,659	3,454	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	45	14,079	23	(314)	13,787
2	2021	14,079	12	3	14,093	24	(600)	13,517
3	2022	14,093	-	(25)	14,069	24	(880)	13,212
4	2023	14,069	-	(63)	14,005	23	(1,155)	12,873
5	2024	14,005	-	(107)	13,899	22	(1,423)	12,498
6	2025	13,899	-	(147)	13,752	22	(1,684)	12,090
7	2026	13,752	-	(186)	13,566	22	(1,937)	11,651
8	2027	13,566	-	(230)	13,336	22	(2,182)	11,176
9	2028	13,336	-	(274)	13,062	22	(2,417)	10,666
10	2029	13,062	-	(322)	12,740	22	(2,643)	10,119
11	2030	12,740	-	(375)	12,365	22	(2,858)	9,529
12	2031	12,365	-	(426)	11,939	22	(3,061)	8,900
13	2032	11,939	-	(477)	11,462	23	(3,252)	8,233
14	2033	11,462	-	(534)	10,928	23	(3,430)	7,522
15	2034	10,928	-	(594)	10,334	24	(3,594)	6,764
16	2035	10,334	-	(657)	9,677	24	(3,721)	5,980
17	2036	9,677	-	(710)	8,967	25	(3,449)	5,543
18	2037	8,967	-	(746)	8,221	25	(3,162)	5,084
19	2038	8,221	-	(787)	7,434	26	(2,858)	4,602
20	2039	7,434	-	(827)	6,607	26	(2,538)	4,095
21	2040	6,607	-	(872)	5,735	27	(2,199)	3,563
22	2041	5,735	-	(926)	4,809	28	(1,838)	2,998
23	2042	4,809	-	(964)	3,845	28	(1,462)	2,411
24	2043	3,845	-	(1,036)	2,809	29	(1,056)	1,782
			463	(11,236)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,897	590	78	18,564	23	(413)	18,174
2	2021	18,564	16	20	18,600	24	(790)	17,834
3	2022	18,600	-	(16)	18,584	24	(1,160)	17,448
4	2023	18,584	-	(64)	18,520	23	(1,522)	17,021
5	2024	18,520	-	(118)	18,402	22	(1,877)	16,547
6	2025	18,402	-	(170)	18,232	22	(2,222)	16,032
7	2026	18,232	-	(221)	18,011	22	(2,557)	15,476
8	2027	18,011	-	(280)	17,731	22	(2,882)	14,871
9	2028	17,731	-	(339)	17,392	22	(3,194)	14,220
10	2029	17,392	-	(402)	16,990	22	(3,494)	13,517
11	2030	16,990	-	(473)	16,517	22	(3,781)	12,757
12	2031	16,517	-	(543)	15,973	22	(4,053)	11,943
13	2032	15,973	-	(614)	15,359	23	(4,309)	11,073
14	2033	15,359	-	(694)	14,665	23	(4,547)	10,141
15	2034	14,665	-	(778)	13,887	24	(4,768)	9,142
16	2035	13,887	-	(869)	13,018	24	(4,969)	8,073
17	2036	13,018	-	(946)	12,072	25	(4,652)	7,444
18	2037	12,072	-	(1,001)	11,071	25	(4,266)	6,829
19	2038	11,071	-	(1,061)	10,010	26	(3,856)	6,179
20	2039	10,010	-	(1,119)	8,891	26	(3,422)	5,495
21	2040	8,891	-	(1,184)	7,706	27	(2,961)	4,772
22	2041	7,706	-	(1,263)	6,444	28	(2,468)	4,003
23	2042	6,444	-	(1,320)	5,123	28	(1,951)	3,200
24	2043	5,123	-	(1,423)	3,700	29	(1,392)	2,337
			605	(14,802)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	466	451	(45)	274	49	272	312	1,780
2	2021	481	410	(3)	289	50	267	286	1,780
3	2022	471	401	25	287	52	264	281	1,780
4	2023	460	391	63	278	53	259	277	1,780
5	2024	447	381	107	267	54	253	272	1,780
6	2025	433	369	147	263	55	248	266	1,780
7	2026	418	356	186	262	56	242	260	1,780
8	2027	402	342	230	262	57	234	253	1,780
9	2028	385	328	274	261	59	229	245	1,780
10	2029	366	312	322	260	60	223	237	1,780
11	2030	346	295	375	260	61	215	228	1,780
12	2031	325	276	426	266	63	207	218	1,780
13	2032	302	257	477	271	64	201	208	1,780
14	2033	278	236	534	277	66	193	197	1,780
15	2034	252	214	594	283	67	185	185	1,780
16	2035	225	191	657	290	68	177	172	1,780
17	2036	203	173	710	296	70	166	163	1,780
18	2037	187	159	746	303	71	158	155	1,780
19	2038	171	145	787	309	73	147	148	1,780
20	2039	153	130	827	316	75	139	140	1,780
21	2040	135	115	872	323	76	128	132	1,780
22	2041	116	98	926	330	78	109	123	1,780
23	2042	95	81	964	337	80	109	114	1,780
24	2043	74	63	1,036	345	81	76	105	1,780
		7,193	6,176	11,236	6,909	1,539	4,700	4,975	42,728

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	671	595	(78)	274	49	359	411	2,281
2	2021	693	540	(20)	289	50	352	376	2,281
3	2022	679	529	16	287	52	348	370	2,281
4	2023	663	517	64	278	53	341	365	2,281
5	2024	646	504	118	267	54	334	358	2,281
6	2025	627	489	170	263	55	326	351	2,281
7	2026	606	473	221	262	56	319	343	2,281
8	2027	584	455	280	262	57	309	334	2,281
9	2028	560	436	339	261	59	301	324	2,281
10	2029	534	416	402	260	60	294	314	2,281
11	2030	506	394	473	260	61	283	303	2,281
12	2031	475	371	543	266	63	273	291	2,281
13	2032	443	345	614	271	64	265	277	2,281
14	2033	408	318	694	277	66	255	263	2,281
15	2034	371	289	778	283	67	244	248	2,281
16	2035	331	258	869	290	68	233	231	2,281
17	2036	299	233	946	296	70	219	218	2,281
18	2037	275	214	1,001	303	71	208	208	2,281
19	2038	250	195	1,061	309	73	194	198	2,281
20	2039	225	175	1,119	316	75	183	188	2,281
21	2040	198	154	1,184	323	76	169	177	2,281
22	2041	169	132	1,263	330	78	144	166	2,281
23	2042	139	108	1,320	337	80	144	153	2,281
24	2043	107	83	1,423	345	81	100	141	2,281
		10,458	8,223	14,802	6,909	1,539	6,196	6,608	54,735

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,780	3,000	1.118	1.45
2	2021	1,780	3,000	1.118	1.45
3	2022	1,780	3,000	1.118	1.45
4	2023	1,780	3,000	1.118	1.45
5	2024	1,780	3,000	1.118	1.45
6	2025	1,780	3,000	1.118	1.45
7	2026	1,780	3,000	1.118	1.45
8	2027	1,780	3,000	1.118	1.45
9	2028	1,780	3,000	1.118	1.45
10	2029	1,780	3,000	1.118	1.45
11	2030	1,780	3,000	1.118	1.45
12	2031	1,780	3,000	1.118	1.45
13	2032	1,780	3,000	1.118	1.45
14	2033	1,780	3,000	1.118	1.45
15	2034	1,780	3,000	1.118	1.45
16	2035	1,780	3,000	1.118	1.45
17	2036	1,780	3,000	1.118	1.45
18	2037	1,780	3,000	1.118	1.45
19	2038	1,780	3,000	1.118	1.45
20	2039	1,780	3,000	1.118	1.45
21	2040	1,780	3,000	1.118	1.45
22	2041	1,780	3,000	1.118	1.45
23	2042	1,780	3,000	1.118	1.45
24	2043	1,780	3,000	1.118	1.45

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,281	3,000	1.118	1.86
2	2021	2,281	3,000	1.118	1.86
3	2022	2,281	3,000	1.118	1.86
4	2023	2,281	3,000	1.118	1.86
5	2024	2,281	3,000	1.118	1.86
6	2025	2,281	3,000	1.118	1.86
7	2026	2,281	3,000	1.118	1.86
8	2027	2,281	3,000	1.118	1.86
9	2028	2,281	3,000	1.118	1.86
10	2029	2,281	3,000	1.118	1.86
11	2030	2,281	3,000	1.118	1.86
12	2031	2,281	3,000	1.118	1.86
13	2032	2,281	3,000	1.118	1.86
14	2033	2,281	3,000	1.118	1.86
15	2034	2,281	3,000	1.118	1.86
16	2035	2,281	3,000	1.118	1.86
17	2036	2,281	3,000	1.118	1.86
18	2037	2,281	3,000	1.118	1.86
19	2038	2,281	3,000	1.118	1.86
20	2039	2,281	3,000	1.118	1.86
21	2040	2,281	3,000	1.118	1.86
22	2041	2,281	3,000	1.118	1.86
23	2042	2,281	3,000	1.118	1.86
24	2043	2,281	3,000	1.118	1.86

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.3%	-0.3%
2	2021	0.0%	-0.3%
3	2022	0.2%	-0.2%
4	2023	0.5%	0.3%
5	2024	0.8%	1.0%
6	2025	1.0%	2.1%
7	2026	1.3%	3.4%
8	2027	1.6%	5.0%
9	2028	2.0%	7.0%
10	2029	2.3%	9.3%
11	2030	2.7%	12.0%
12	2031	3.0%	15.0%
13	2032	3.4%	18.4%
14	2033	3.8%	22.2%
15	2034	4.2%	26.4%
16	2035	4.7%	31.1%
17	2036	5.1%	36.2%
18	2037	5.3%	41.5%
19	2038	5.6%	47.1%
20	2039	5.9%	53.0%
21	2040	6.2%	59.2%
22	2041	6.6%	65.8%
23	2042	6.9%	72.6%
24	2043	7.4%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.4%	-0.4%
2	2021	-0.1%	-0.5%
3	2022	0.1%	-0.4%
4	2023	0.3%	-0.1%
5	2024	0.6%	0.5%
6	2025	0.9%	1.5%
7	2026	1.2%	2.7%
8	2027	1.5%	4.2%
9	2028	1.8%	6.0%
10	2029	2.2%	8.2%
11	2030	2.6%	10.7%
12	2031	2.9%	13.7%
13	2032	3.3%	17.0%
14	2033	3.7%	20.7%
15	2034	4.2%	24.9%
16	2035	4.7%	29.6%
17	2036	5.1%	34.8%
18	2037	5.4%	40.2%
19	2038	5.7%	45.9%
20	2039	6.0%	51.9%
21	2040	6.4%	58.3%
22	2041	6.8%	65.2%
23	2042	7.1%	72.3%
24	2043	7.7%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,724
2017	2,724	2,549	51	454	314	6,092
2018	6,092	7,006	140	1,249	753	15,240
2019	15,240	2,464	49	439	1,227	19,419
2020	19,419	141	-	28	-	19,588
2021	19,588	14	-	3	-	19,606
		14,030	263	2,519	2,794	

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	71	14,969	49	(338)	14,680
2	2021	14,969	13	(4)	14,978	49	(642)	14,385
3	2022	14,978	-	(32)	14,946	49	(941)	14,055
4	2023	14,946	-	(64)	14,883	49	(1,233)	13,699
5	2024	14,883	-	(98)	14,785	49	(1,517)	13,317
6	2025	14,785	-	(135)	14,650	50	(1,794)	12,905
7	2026	14,650	-	(174)	14,476	50	(2,063)	12,462
8	2027	14,476	-	(219)	14,257	50	(2,323)	11,984
9	2028	14,257	-	(263)	13,994	50	(2,574)	11,470
10	2029	13,994	-	(311)	13,683	50	(2,814)	10,919
11	2030	13,683	-	(365)	13,318	50	(3,043)	10,326
12	2031	13,318	-	(422)	12,896	50	(3,260)	9,687
13	2032	12,896	-	(480)	12,416	50	(3,465)	9,002
14	2033	12,416	-	(545)	11,871	51	(3,656)	8,266
15	2034	11,871	-	(614)	11,257	51	(3,832)	7,476
16	2035	11,257	-	(688)	10,569	51	(3,992)	6,627
17	2036	10,569	-	(757)	9,811	51	(3,842)	6,020
18	2037	9,811	-	(809)	9,002	51	(3,526)	5,528
19	2038	9,002	-	(860)	8,143	51	(3,188)	5,006
20	2039	8,143	-	(910)	7,233	52	(2,830)	4,454
21	2040	7,233	-	(966)	6,267	52	(2,449)	3,870
22	2041	6,267	-	(1,033)	5,235	52	(2,041)	3,246
23	2042	5,235	-	(1,083)	4,152	52	(1,611)	2,593
24	2043	4,152	-	(1,170)	2,982	52	(1,146)	1,888
			142	(11,929)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,419	169	112	19,700	49	(444)	19,305
2	2021	19,700	17	15	19,733	49	(844)	18,937
3	2022	19,733	-	(21)	19,712	49	(1,237)	18,524
4	2023	19,712	-	(63)	19,649	49	(1,621)	18,077
5	2024	19,649	-	(109)	19,540	49	(1,997)	17,592
6	2025	19,540	-	(158)	19,382	50	(2,363)	17,069
7	2026	19,382	-	(210)	19,172	50	(2,718)	16,504
8	2027	19,172	-	(270)	18,903	50	(3,062)	15,890
9	2028	18,903	-	(330)	18,573	50	(3,394)	15,229
10	2029	18,573	-	(394)	18,179	50	(3,713)	14,516
11	2030	18,179	-	(467)	17,712	50	(4,017)	13,745
12	2031	17,712	-	(544)	17,168	50	(4,306)	12,912
13	2032	17,168	-	(624)	16,544	50	(4,579)	12,016
14	2033	16,544	-	(712)	15,832	51	(4,833)	11,049
15	2034	15,832	-	(807)	15,025	51	(5,069)	10,007
16	2035	15,025	-	(909)	14,115	51	(5,283)	8,883
17	2036	14,115	-	(1,007)	13,109	51	(5,139)	8,021
18	2037	13,109	-	(1,080)	12,029	51	(4,716)	7,364
19	2038	12,029	-	(1,151)	10,878	51	(4,264)	6,666
20	2039	10,878	-	(1,221)	9,657	52	(3,782)	5,926
21	2040	9,657	-	(1,299)	8,358	52	(3,269)	5,140
22	2041	8,358	-	(1,391)	6,967	52	(2,718)	4,300
23	2042	6,967	-	(1,463)	5,504	52	(2,138)	3,418
24	2043	5,504	-	(1,583)	3,921	52	(1,508)	2,466
			186	(15,684)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	502	486	(71)	62	8	289	336	1,613
2	2021	512	436	4	64	8	283	305	1,613
3	2022	501	427	32	65	9	280	299	1,613
4	2023	489	416	64	67	9	274	293	1,613
5	2024	476	405	98	68	9	269	287	1,613
6	2025	462	393	135	70	9	263	281	1,613
7	2026	447	381	174	71	9	257	273	1,613
8	2027	431	367	219	73	10	248	266	1,613
9	2028	413	352	263	74	10	243	257	1,613
10	2029	395	336	311	76	10	237	248	1,613
11	2030	374	319	365	78	10	228	239	1,613
12	2031	353	300	422	79	10	220	228	1,613
13	2032	329	280	480	81	11	214	217	1,613
14	2033	304	259	545	83	11	205	205	1,613
15	2034	277	236	614	85	11	196	192	1,613
16	2035	249	212	688	86	11	188	179	1,613
17	2036	223	190	757	88	12	176	166	1,613
18	2037	204	173	809	90	12	168	157	1,613
19	2038	186	158	860	92	12	156	149	1,613
20	2039	167	142	910	94	12	147	140	1,613
21	2040	147	125	966	96	13	136	130	1,613
22	2041	125	107	1,033	98	13	116	121	1,613
23	2042	103	88	1,083	101	13	116	110	1,613
24	2043	79	67	1,170	103	14	81	99	1,613
		7,748	6,653	11,929	1,944	257	4,988	5,179	38,700

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	720	639	(112)	62	8	380	441	2,139
2	2021	736	574	(15)	64	8	372	400	2,139
3	2022	721	562	21	65	9	368	393	2,139
4	2023	704	549	63	67	9	361	386	2,139
5	2024	686	535	109	68	9	353	378	2,139
6	2025	667	520	158	70	9	346	370	2,139
7	2026	646	504	210	71	9	338	361	2,139
8	2027	623	486	270	73	10	327	351	2,139
9	2028	599	467	330	74	10	319	341	2,139
10	2029	572	446	394	76	10	312	329	2,139
11	2030	544	424	467	78	10	300	317	2,139
12	2031	513	400	544	79	10	289	303	2,139
13	2032	480	374	624	81	11	281	289	2,139
14	2033	444	346	712	83	11	270	273	2,139
15	2034	405	316	807	85	11	258	256	2,139
16	2035	364	283	909	86	11	247	238	2,139
17	2036	325	254	1,007	88	12	232	222	2,139
18	2037	296	231	1,080	90	12	220	209	2,139
19	2038	270	210	1,151	92	12	205	198	2,139
20	2039	242	189	1,221	94	12	194	186	2,139
21	2040	213	166	1,299	96	13	179	174	2,139
22	2041	182	142	1,391	98	13	152	161	2,139
23	2042	149	116	1,463	101	13	152	146	2,139
24	2043	113	88	1,583	103	14	106	132	2,139
		11,215	8,819	15,684	1,944	257	6,561	6,855	51,336

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	163	383	1.17	1,450	2,971	1.34
2	2021	1.118	163	383	1.17	1,450	2,971	1.34
3	2022	1.118	163	383	1.17	1,450	2,971	1.34
4	2023	1.118	163	383	1.17	1,450	2,971	1.34
5	2024	1.118	163	383	1.17	1,450	2,971	1.34
6	2025	1.118	163	383	1.17	1,450	2,971	1.34
7	2026	1.118	163	383	1.17	1,450	2,971	1.34
8	2027	1.118	163	383	1.17	1,450	2,971	1.34
9	2028	1.118	163	383	1.17	1,450	2,971	1.34
10	2029	1.118	163	383	1.17	1,450	2,971	1.34
11	2030	1.118	163	383	1.17	1,450	2,971	1.34
12	2031	1.118	163	383	1.17	1,450	2,971	1.34
13	2032	1.118	163	383	1.17	1,450	2,971	1.34
14	2033	1.118	163	383	1.17	1,450	2,971	1.34
15	2034	1.118	163	383	1.17	1,450	2,971	1.34
16	2035	1.118	163	383	1.17	1,450	2,971	1.34
17	2036	1.118	163	383	1.17	1,450	2,971	1.34
18	2037	1.118	163	383	1.17	1,450	2,971	1.34
19	2038	1.118	163	383	1.17	1,450	2,971	1.34
20	2039	1.118	163	383	1.17	1,450	2,971	1.34
21	2040	1.118	163	383	1.17	1,450	2,971	1.34
22	2041	1.118	163	383	1.17	1,450	2,971	1.34
23	2042	1.118	163	383	1.17	1,450	2,971	1.34
24	2043	1.118	163	383	1.17	1,450	2,971	1.34

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	216	383	1.55	1,923	2,971	1.77
2	2021	1.118	216	383	1.55	1,923	2,971	1.77
3	2022	1.118	216	383	1.55	1,923	2,971	1.77
4	2023	1.118	216	383	1.55	1,923	2,971	1.77
5	2024	1.118	216	383	1.55	1,923	2,971	1.77
6	2025	1.118	216	383	1.55	1,923	2,971	1.77
7	2026	1.118	216	383	1.55	1,923	2,971	1.77
8	2027	1.118	216	383	1.55	1,923	2,971	1.77
9	2028	1.118	216	383	1.55	1,923	2,971	1.77
10	2029	1.118	216	383	1.55	1,923	2,971	1.77
11	2030	1.118	216	383	1.55	1,923	2,971	1.77
12	2031	1.118	216	383	1.55	1,923	2,971	1.77
13	2032	1.118	216	383	1.55	1,923	2,971	1.77
14	2033	1.118	216	383	1.55	1,923	2,971	1.77
15	2034	1.118	216	383	1.55	1,923	2,971	1.77
16	2035	1.118	216	383	1.55	1,923	2,971	1.77
17	2036	1.118	216	383	1.55	1,923	2,971	1.77
18	2037	1.118	216	383	1.55	1,923	2,971	1.77
19	2038	1.118	216	383	1.55	1,923	2,971	1.77
20	2039	1.118	216	383	1.55	1,923	2,971	1.77
21	2040	1.118	216	383	1.55	1,923	2,971	1.77
22	2041	1.118	216	383	1.55	1,923	2,971	1.77
23	2042	1.118	216	383	1.55	1,923	2,971	1.77
24	2043	1.118	216	383	1.55	1,923	2,971	1.77

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	0.0%	-0.4%
3	2022	0.2%	-0.2%
4	2023	0.4%	0.2%
5	2024	0.7%	0.9%
6	2025	0.9%	1.8%
7	2026	1.2%	2.9%
8	2027	1.5%	4.4%
9	2028	1.8%	6.2%
10	2029	2.1%	8.2%
11	2030	2.4%	10.7%
12	2031	2.8%	13.5%
13	2032	3.2%	16.7%
14	2033	3.7%	20.4%
15	2034	4.1%	24.5%
16	2035	4.6%	29.1%
17	2036	5.1%	34.2%
18	2037	5.4%	39.6%
19	2038	5.8%	45.4%
20	2039	6.1%	51.5%
21	2040	6.5%	58.0%
22	2041	6.9%	64.9%
23	2042	7.3%	72.2%
24	2043	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(24 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.6%
3	2022	0.1%	-0.5%
4	2023	0.3%	-0.2%
5	2024	0.6%	0.3%
6	2025	0.8%	1.1%
7	2026	1.1%	2.2%
8	2027	1.4%	3.6%
9	2028	1.7%	5.3%
10	2029	2.0%	7.3%
11	2030	2.4%	9.7%
12	2031	2.8%	12.4%
13	2032	3.2%	15.6%
14	2033	3.6%	19.2%
15	2034	4.1%	23.4%
16	2035	4.6%	28.0%
17	2036	5.1%	33.1%
18	2037	5.5%	38.6%
19	2038	5.9%	44.5%
20	2039	6.2%	50.7%
21	2040	6.6%	57.4%
22	2041	7.1%	64.5%
23	2042	7.5%	71.9%
24	2043	8.1%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(25 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	443
2018	443	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	4	664	0	(15)	649
2	2021	664	1	1	664	0	(28)	636
3	2022	664	-	(0)	664	0	(42)	623
4	2023	664	-	(2)	662	0	(55)	608
5	2024	662	-	(3)	659	0	(67)	592
6	2025	659	-	(5)	654	0	(79)	575
7	2026	654	-	(6)	648	0	(91)	557
8	2027	648	-	(8)	640	0	(103)	537
9	2028	640	-	(10)	630	0	(114)	516
10	2029	630	-	(12)	618	0	(125)	493
11	2030	618	-	(14)	603	0	(136)	468
12	2031	603	-	(17)	587	0	(145)	442
13	2032	587	-	(19)	568	0	(155)	413
14	2033	568	-	(22)	546	0	(164)	383
15	2034	546	-	(25)	521	0	(172)	350
16	2035	521	-	(28)	494	0	(179)	314
17	2036	494	-	(31)	463	0	(180)	283
18	2037	463	-	(33)	429	0	(167)	262
19	2038	429	-	(35)	394	0	(154)	241
20	2039	394	-	(37)	357	0	(139)	218
21	2040	357	-	(40)	317	0	(123)	194
22	2041	317	-	(43)	274	0	(107)	168
23	2042	274	-	(45)	230	0	(89)	141
24	2043	230	-	(48)	181	0	(70)	112
25	2044	181	-	(50)	131	0	(50)	82
			6	(528)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	6	874	0	(20)	855
2	2021	874	1	2	876	0	(37)	839
3	2022	876	-	0	877	0	(55)	822
4	2023	877	-	(1)	875	0	(72)	804
5	2024	875	-	(3)	872	0	(89)	783
6	2025	872	-	(5)	866	0	(105)	762
7	2026	866	-	(7)	859	0	(121)	738
8	2027	859	-	(10)	849	0	(136)	713
9	2028	849	-	(12)	836	0	(151)	686
10	2029	836	-	(15)	821	0	(165)	656
11	2030	821	-	(18)	803	0	(179)	624
12	2031	803	-	(21)	782	0	(192)	590
13	2032	782	-	(25)	757	0	(205)	553
14	2033	757	-	(28)	729	0	(217)	512
15	2034	729	-	(32)	697	0	(228)	469
16	2035	697	-	(37)	660	0	(238)	423
17	2036	660	-	(41)	619	0	(241)	378
18	2037	619	-	(44)	575	0	(224)	351
19	2038	575	-	(47)	527	0	(206)	322
20	2039	527	-	(50)	477	0	(186)	291
21	2040	477	-	(53)	424	0	(165)	259
22	2041	424	-	(57)	366	0	(143)	224
23	2042	366	-	(60)	306	0	(119)	187
24	2043	306	-	(65)	241	0	(93)	148
25	2044	241	-	(68)	173	0	(66)	107
			8	(695)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	22	(4)	3	0	13	15	70
2	2021	23	19	(1)	3	0	13	13	70
3	2022	22	19	0	3	0	12	13	70
4	2023	22	18	2	3	0	12	13	70
5	2024	21	18	3	3	0	12	13	70
6	2025	21	18	5	3	0	12	12	70
7	2026	20	17	6	3	0	11	12	70
8	2027	19	16	8	3	0	11	12	70
9	2028	19	16	10	3	0	11	12	70
10	2029	18	15	12	3	0	10	11	70
11	2030	17	14	14	3	0	10	11	70
12	2031	16	14	17	3	0	10	10	70
13	2032	15	13	19	4	0	9	10	70
14	2033	14	12	22	4	0	9	9	70
15	2034	13	11	25	4	1	9	9	70
16	2035	12	10	28	4	1	8	8	70
17	2036	11	9	31	4	1	8	8	70
18	2037	10	8	33	4	1	7	7	70
19	2038	9	8	35	4	1	7	7	70
20	2039	8	7	37	4	1	7	7	70
21	2040	7	6	40	4	1	6	6	70
22	2041	6	5	43	4	1	5	6	70
23	2042	5	5	45	4	1	5	6	70
24	2043	4	4	48	4	1	4	5	70
25	2044	3	3	50	5	1	4	5	70
		357	307	528	89	12	225	241	1,760

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(6)	3	0	17	19	94
2	2021	33	25	(2)	3	0	16	18	94
3	2022	32	25	(0)	3	0	16	17	94
4	2023	31	24	1	3	0	16	17	94
5	2024	31	24	3	3	0	16	17	94
6	2025	30	23	5	3	0	15	16	94
7	2026	29	23	7	3	0	15	16	94
8	2027	28	22	10	3	0	14	16	94
9	2028	27	21	12	3	0	14	15	94
10	2029	26	20	15	3	0	14	15	94
11	2030	25	19	18	3	0	13	14	94
12	2031	23	18	21	3	0	13	14	94
13	2032	22	17	25	4	0	12	13	94
14	2033	21	16	28	4	0	12	13	94
15	2034	19	15	32	4	1	11	12	94
16	2035	17	13	37	4	1	11	11	94
17	2036	15	12	41	4	1	10	10	94
18	2037	14	11	44	4	1	10	10	94
19	2038	13	10	47	4	1	9	9	94
20	2039	12	9	50	4	1	9	9	94
21	2040	11	8	53	4	1	8	9	94
22	2041	9	7	57	4	1	7	8	94
23	2042	8	6	60	4	1	7	7	94
24	2043	6	5	65	4	1	5	7	94
25	2044	5	4	68	5	1	6	6	94
		518	407	695	89	12	296	320	2,339

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	70	1,100	1.000	0.18
2	2021	70	1,100	1.000	0.18
3	2022	70	1,100	1.000	0.18
4	2023	70	1,100	1.000	0.18
5	2024	70	1,100	1.000	0.18
6	2025	70	1,100	1.000	0.18
7	2026	70	1,100	1.000	0.18
8	2027	70	1,100	1.000	0.18
9	2028	70	1,100	1.000	0.18
10	2029	70	1,100	1.000	0.18
11	2030	70	1,100	1.000	0.18
12	2031	70	1,100	1.000	0.18
13	2032	70	1,100	1.000	0.18
14	2033	70	1,100	1.000	0.18
15	2034	70	1,100	1.000	0.18
16	2035	70	1,100	1.000	0.18
17	2036	70	1,100	1.000	0.18
18	2037	70	1,100	1.000	0.18
19	2038	70	1,100	1.000	0.18
20	2039	70	1,100	1.000	0.18
21	2040	70	1,100	1.000	0.18
22	2041	70	1,100	1.000	0.18
23	2042	70	1,100	1.000	0.18
24	2043	70	1,100	1.000	0.18
25	2044	70	1,100	1.000	0.18

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	94	1,100	1.000	0.23
2	2021	94	1,100	1.000	0.23
3	2022	94	1,100	1.000	0.23
4	2023	94	1,100	1.000	0.23
5	2024	94	1,100	1.000	0.23
6	2025	94	1,100	1.000	0.23
7	2026	94	1,100	1.000	0.23
8	2027	94	1,100	1.000	0.23
9	2028	94	1,100	1.000	0.23
10	2029	94	1,100	1.000	0.23
11	2030	94	1,100	1.000	0.23
12	2031	94	1,100	1.000	0.23
13	2032	94	1,100	1.000	0.23
14	2033	94	1,100	1.000	0.23
15	2034	94	1,100	1.000	0.23
16	2035	94	1,100	1.000	0.23
17	2036	94	1,100	1.000	0.23
18	2037	94	1,100	1.000	0.23
19	2038	94	1,100	1.000	0.23
20	2039	94	1,100	1.000	0.23
21	2040	94	1,100	1.000	0.23
22	2041	94	1,100	1.000	0.23
23	2042	94	1,100	1.000	0.23
24	2043	94	1,100	1.000	0.23
25	2044	94	1,100	1.000	0.23

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.7%
3	2022	0.1%	-0.6%
4	2023	0.3%	-0.4%
5	2024	0.5%	0.1%
6	2025	0.7%	0.8%
7	2026	1.0%	1.8%
8	2027	1.2%	3.0%
9	2028	1.5%	4.6%
10	2029	1.8%	6.4%
11	2030	2.2%	8.5%
12	2031	2.5%	11.1%
13	2032	2.9%	14.0%
14	2033	3.3%	17.2%
15	2034	3.7%	21.0%
16	2035	4.2%	25.2%
17	2036	4.7%	29.8%
18	2037	5.0%	34.9%
19	2038	5.4%	40.2%
20	2039	5.7%	45.9%
21	2040	6.0%	51.9%
22	2041	6.4%	58.4%
23	2042	6.8%	65.1%
24	2043	7.3%	72.4%
25	2044	7.6%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.7%
10	2029	1.7%	5.4%
11	2030	2.1%	7.5%
12	2031	2.5%	9.9%
13	2032	2.8%	12.8%
14	2033	3.3%	16.0%
15	2034	3.7%	19.8%
16	2035	4.2%	24.0%
17	2036	4.7%	28.7%
18	2037	5.1%	33.8%
19	2038	5.4%	39.2%
20	2039	5.8%	45.0%
21	2040	6.2%	51.2%
22	2041	6.6%	57.8%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,042
2016	3,042	2,682	54	873	354	7,005
2017	7,005	2,620	52	852	641	11,171
2018	11,171	2,161	43	703	929	15,006
2019	15,006	1,275	25	415	1,176	17,897
2020	17,897	438	-	151	-	18,487
2021	18,487	12	-	4	-	18,503
		11,185	203	3,659	3,455	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	64	14,097	23	(314)	13,806
2	2021	14,097	12	23	14,132	24	(600)	13,557
3	2022	14,132	-	(3)	14,130	24	(881)	13,273
4	2023	14,130	-	(40)	14,090	23	(1,156)	12,957
5	2024	14,090	-	(81)	14,009	22	(1,426)	12,606
6	2025	14,009	-	(119)	13,890	22	(1,689)	12,223
7	2026	13,890	-	(156)	13,734	22	(1,944)	11,812
8	2027	13,734	-	(198)	13,536	22	(2,192)	11,366
9	2028	13,536	-	(240)	13,296	22	(2,431)	10,887
10	2029	13,296	-	(285)	13,011	22	(2,660)	10,373
11	2030	13,011	-	(336)	12,675	22	(2,880)	9,817
12	2031	12,675	-	(383)	12,292	22	(3,088)	9,226
13	2032	12,292	-	(431)	11,861	23	(3,286)	8,598
14	2033	11,861	-	(485)	11,376	23	(3,470)	7,928
15	2034	11,376	-	(542)	10,834	24	(3,642)	7,215
16	2035	10,834	-	(602)	10,231	24	(3,800)	6,456
17	2036	10,231	-	(658)	9,573	25	(3,687)	5,911
18	2037	9,573	-	(698)	8,875	25	(3,419)	5,481
19	2038	8,875	-	(737)	8,138	26	(3,135)	5,029
20	2039	8,138	-	(774)	7,364	26	(2,836)	4,555
21	2040	7,364	-	(816)	6,548	27	(2,520)	4,055
22	2041	6,548	-	(868)	5,680	28	(2,182)	3,526
23	2042	5,680	-	(903)	4,777	28	(1,830)	2,975
24	2043	4,777	-	(972)	3,805	29	(1,450)	2,385
25	2044	3,805	-	(996)	2,809	29	(1,059)	1,779
			463	(11,236)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,897	590	103	18,590	23	(413)	18,200
2	2021	18,590	16	47	18,652	24	(790)	17,887
3	2022	18,652	-	14	18,666	24	(1,160)	17,530
4	2023	18,666	-	(32)	18,634	23	(1,524)	17,133
5	2024	18,634	-	(84)	18,550	22	(1,880)	16,692
6	2025	18,550	-	(133)	18,417	22	(2,228)	16,211
7	2026	18,417	-	(181)	18,236	22	(2,566)	15,692
8	2027	18,236	-	(236)	18,000	22	(2,895)	15,127
9	2028	18,000	-	(292)	17,708	22	(3,212)	14,517
10	2029	17,708	-	(352)	17,356	22	(3,518)	13,860
11	2030	17,356	-	(419)	16,936	22	(3,811)	13,147
12	2031	16,936	-	(485)	16,451	22	(4,090)	12,384
13	2032	16,451	-	(552)	15,899	23	(4,354)	11,568
14	2033	15,899	-	(627)	15,273	23	(4,602)	10,694
15	2034	15,273	-	(706)	14,566	24	(4,833)	9,757
16	2035	14,566	-	(791)	13,775	24	(5,046)	8,753
17	2036	13,775	-	(874)	12,901	25	(4,979)	7,947
18	2037	12,901	-	(935)	11,967	25	(4,619)	7,372
19	2038	11,967	-	(991)	10,976	26	(4,237)	6,765
20	2039	10,976	-	(1,046)	9,930	26	(3,832)	6,124
21	2040	9,930	-	(1,107)	8,824	27	(3,402)	5,448
22	2041	8,824	-	(1,181)	7,642	28	(2,942)	4,728
23	2042	7,642	-	(1,235)	6,407	28	(2,459)	3,976
24	2043	6,407	-	(1,333)	5,074	29	(1,936)	3,167
25	2044	5,074	-	(1,373)	3,701	29	(1,396)	2,334
			605	(14,802)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	467	452	(64)	274	47	273	311	1,760
2	2021	482	410	(23)	289	48	267	285	1,760
3	2022	473	402	3	287	49	264	281	1,760
4	2023	462	393	40	278	51	259	277	1,760
5	2024	451	383	81	267	52	253	272	1,760
6	2025	438	372	119	263	53	248	267	1,760
7	2026	424	361	156	262	54	243	261	1,760
8	2027	409	348	198	262	55	234	254	1,760
9	2028	392	334	240	261	56	229	247	1,760
10	2029	375	319	285	260	58	223	239	1,760
11	2030	356	303	336	260	59	215	231	1,760
12	2031	336	286	383	266	60	207	222	1,760
13	2032	314	267	431	271	62	202	212	1,760
14	2033	291	248	485	277	63	193	202	1,760
15	2034	267	227	542	283	64	185	191	1,760
16	2035	241	205	602	290	66	177	179	1,760
17	2036	218	185	658	296	67	166	168	1,760
18	2037	201	171	698	303	69	158	161	1,760
19	2038	185	158	737	309	70	147	154	1,760
20	2039	169	144	774	316	72	139	146	1,760
21	2040	152	129	816	323	73	128	138	1,760
22	2041	134	114	868	330	75	109	131	1,760
23	2042	115	98	903	337	76	109	121	1,760
24	2043	94	80	972	345	78	76	114	1,760
25	2044	73	62	996	352	80	93	102	1,760
		7,517	6,452	11,236	7,262	1,557	4,799	5,168	43,991

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	672	595	(103)	274	47	359	409	2,254
2	2021	695	541	(47)	289	48	352	375	2,254
3	2022	682	531	(14)	287	49	349	370	2,254
4	2023	667	520	32	278	51	341	365	2,254
5	2024	651	507	84	267	52	334	359	2,254
6	2025	634	494	133	263	53	327	352	2,254
7	2026	614	479	181	262	54	320	345	2,254
8	2027	593	462	236	262	55	309	337	2,254
9	2028	571	445	292	261	56	302	328	2,254
10	2029	546	426	352	260	58	295	318	2,254
11	2030	520	405	419	260	59	284	307	2,254
12	2031	492	383	485	266	60	273	296	2,254
13	2032	461	359	552	271	62	266	283	2,254
14	2033	429	334	627	277	63	255	270	2,254
15	2034	394	307	706	283	64	244	256	2,254
16	2035	356	278	791	290	66	234	240	2,254
17	2036	322	251	874	296	67	219	226	2,254
18	2037	295	230	935	303	69	208	215	2,254
19	2038	272	212	991	309	70	194	206	2,254
20	2039	248	193	1,046	316	72	183	196	2,254
21	2040	223	174	1,107	323	73	169	186	2,254
22	2041	196	153	1,181	330	75	144	176	2,254
23	2042	168	131	1,235	337	76	144	164	2,254
24	2043	138	107	1,333	345	78	101	153	2,254
25	2044	106	83	1,373	352	80	122	138	2,254
		10,944	8,598	14,802	7,262	1,557	6,327	6,870	56,360

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,760	3,000	1.118	1.44
2	2021	1,760	3,000	1.118	1.44
3	2022	1,760	3,000	1.118	1.44
4	2023	1,760	3,000	1.118	1.44
5	2024	1,760	3,000	1.118	1.44
6	2025	1,760	3,000	1.118	1.44
7	2026	1,760	3,000	1.118	1.44
8	2027	1,760	3,000	1.118	1.44
9	2028	1,760	3,000	1.118	1.44
10	2029	1,760	3,000	1.118	1.44
11	2030	1,760	3,000	1.118	1.44
12	2031	1,760	3,000	1.118	1.44
13	2032	1,760	3,000	1.118	1.44
14	2033	1,760	3,000	1.118	1.44
15	2034	1,760	3,000	1.118	1.44
16	2035	1,760	3,000	1.118	1.44
17	2036	1,760	3,000	1.118	1.44
18	2037	1,760	3,000	1.118	1.44
19	2038	1,760	3,000	1.118	1.44
20	2039	1,760	3,000	1.118	1.44
21	2040	1,760	3,000	1.118	1.44
22	2041	1,760	3,000	1.118	1.44
23	2042	1,760	3,000	1.118	1.44
24	2043	1,760	3,000	1.118	1.44
25	2044	1,760	3,000	1.118	1.44

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,254	3,000	1.118	1.84
2	2021	2,254	3,000	1.118	1.84
3	2022	2,254	3,000	1.118	1.84
4	2023	2,254	3,000	1.118	1.84
5	2024	2,254	3,000	1.118	1.84
6	2025	2,254	3,000	1.118	1.84
7	2026	2,254	3,000	1.118	1.84
8	2027	2,254	3,000	1.118	1.84
9	2028	2,254	3,000	1.118	1.84
10	2029	2,254	3,000	1.118	1.84
11	2030	2,254	3,000	1.118	1.84
12	2031	2,254	3,000	1.118	1.84
13	2032	2,254	3,000	1.118	1.84
14	2033	2,254	3,000	1.118	1.84
15	2034	2,254	3,000	1.118	1.84
16	2035	2,254	3,000	1.118	1.84
17	2036	2,254	3,000	1.118	1.84
18	2037	2,254	3,000	1.118	1.84
19	2038	2,254	3,000	1.118	1.84
20	2039	2,254	3,000	1.118	1.84
21	2040	2,254	3,000	1.118	1.84
22	2041	2,254	3,000	1.118	1.84
23	2042	2,254	3,000	1.118	1.84
24	2043	2,254	3,000	1.118	1.84
25	2044	2,254	3,000	1.118	1.84

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.2%	-0.6%
3	2022	0.0%	-0.6%
4	2023	0.3%	-0.3%
5	2024	0.6%	0.3%
6	2025	0.8%	1.1%
7	2026	1.1%	2.2%
8	2027	1.4%	3.6%
9	2028	1.7%	5.3%
10	2029	2.0%	7.4%
11	2030	2.4%	9.8%
12	2031	2.7%	12.5%
13	2032	3.1%	15.6%
14	2033	3.5%	19.0%
15	2034	3.9%	22.9%
16	2035	4.3%	27.2%
17	2036	4.7%	31.8%
18	2037	5.0%	36.8%
19	2038	5.2%	42.1%
20	2039	5.5%	47.6%
21	2040	5.8%	53.4%
22	2041	6.2%	59.6%
23	2042	6.4%	66.0%
24	2043	6.9%	72.9%
25	2044	7.1%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.3%	-0.8%
3	2022	-0.1%	-0.9%
4	2023	0.2%	-0.7%
5	2024	0.5%	-0.3%
6	2025	0.7%	0.5%
7	2026	1.0%	1.4%
8	2027	1.3%	2.7%
9	2028	1.6%	4.3%
10	2029	1.9%	6.2%
11	2030	2.3%	8.5%
12	2031	2.6%	11.1%
13	2032	3.0%	14.1%
14	2033	3.4%	17.5%
15	2034	3.8%	21.3%
16	2035	4.3%	25.6%
17	2036	4.7%	30.3%
18	2037	5.1%	35.3%
19	2038	5.4%	40.7%
20	2039	5.7%	46.3%
21	2040	6.0%	52.3%
22	2041	6.4%	58.7%
23	2042	6.7%	65.4%
24	2043	7.2%	72.6%
25	2044	7.4%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,724
2017	2,724	2,549	51	454	314	6,092
2018	6,092	7,006	140	1,249	753	15,240
2019	15,240	2,464	49	439	1,227	19,420
2020	19,420	141	-	28	-	19,589
2021	19,589	14	-	3	-	19,606
		14,030	263	2,519	2,794	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	92	14,990	49	(338)	14,701
2	2021	14,990	13	18	15,021	49	(643)	14,428
3	2022	15,021	-	(7)	15,014	49	(942)	14,122
4	2023	15,014	-	(37)	14,977	49	(1,235)	13,792
5	2024	14,977	-	(70)	14,907	49	(1,521)	13,436
6	2025	14,907	-	(104)	14,803	50	(1,800)	13,053
7	2026	14,803	-	(141)	14,663	50	(2,072)	12,640
8	2027	14,663	-	(183)	14,480	50	(2,335)	12,194
9	2028	14,480	-	(225)	14,255	50	(2,590)	11,715
10	2029	14,255	-	(269)	13,986	50	(2,835)	11,201
11	2030	13,986	-	(320)	13,666	50	(3,069)	10,647
12	2031	13,666	-	(374)	13,292	50	(3,293)	10,049
13	2032	13,292	-	(429)	12,863	50	(3,505)	9,409
14	2033	12,863	-	(490)	12,373	51	(3,703)	8,721
15	2034	12,373	-	(555)	11,818	51	(3,889)	7,980
16	2035	11,818	-	(625)	11,194	51	(4,059)	7,186
17	2036	11,194	-	(698)	10,496	51	(4,115)	6,432
18	2037	10,496	-	(754)	9,742	51	(3,820)	5,973
19	2038	9,742	-	(802)	8,940	51	(3,506)	5,486
20	2039	8,940	-	(849)	8,091	52	(3,172)	4,970
21	2040	8,091	-	(902)	7,189	52	(2,817)	4,424
22	2041	7,189	-	(966)	6,223	52	(2,435)	3,840
23	2042	6,223	-	(1,013)	5,211	52	(2,034)	3,228
24	2043	5,211	-	(1,096)	4,115	52	(1,599)	2,568
25	2044	4,115	-	(1,132)	2,982	52	(1,149)	1,886
			142	(11,929)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,420	169	139	19,728	49	(444)	19,333
2	2021	19,728	17	44	19,790	49	(844)	18,995
3	2022	19,790	-	12	19,802	49	(1,238)	18,613
4	2023	19,802	-	(28)	19,773	49	(1,624)	18,199
5	2024	19,773	-	(71)	19,702	49	(2,002)	17,750
6	2025	19,702	-	(117)	19,586	50	(2,371)	17,265
7	2026	19,586	-	(165)	19,420	50	(2,730)	16,740
8	2027	19,420	-	(222)	19,199	50	(3,078)	16,170
9	2028	19,199	-	(278)	18,921	50	(3,416)	15,555
10	2029	18,921	-	(338)	18,583	50	(3,741)	14,892
11	2030	18,583	-	(406)	18,176	50	(4,052)	14,174
12	2031	18,176	-	(480)	17,697	50	(4,350)	13,397
13	2032	17,697	-	(554)	17,143	50	(4,632)	12,561
14	2033	17,143	-	(637)	16,505	51	(4,897)	11,659
15	2034	16,505	-	(727)	15,778	51	(5,144)	10,685
16	2035	15,778	-	(822)	14,956	51	(5,372)	9,635
17	2036	14,956	-	(925)	14,031	51	(5,506)	8,576
18	2037	14,031	-	(1,006)	13,025	51	(5,113)	7,963
19	2038	13,025	-	(1,072)	11,953	51	(4,693)	7,312
20	2039	11,953	-	(1,138)	10,815	52	(4,245)	6,622
21	2040	10,815	-	(1,212)	9,603	52	(3,767)	5,888
22	2041	9,603	-	(1,300)	8,304	52	(3,253)	5,103
23	2042	8,304	-	(1,366)	6,937	52	(2,711)	4,278
24	2043	6,937	-	(1,481)	5,456	52	(2,122)	3,386
25	2044	5,456	-	(1,535)	3,921	52	(1,511)	2,462
			186	(15,685)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	502	486	(92)	62	8	289	335	1,592
2	2021	513	437	(18)	64	8	283	304	1,592
3	2022	503	428	7	65	8	281	299	1,592
4	2023	492	419	37	67	8	275	294	1,592
5	2024	480	408	70	68	9	269	288	1,592
6	2025	467	397	104	70	9	263	282	1,592
7	2026	453	385	141	71	9	257	275	1,592
8	2027	438	373	183	73	9	249	268	1,592
9	2028	421	359	225	74	9	243	260	1,592
10	2029	404	344	269	76	10	237	252	1,592
11	2030	385	328	320	78	10	229	243	1,592
12	2031	365	310	374	79	10	220	233	1,592
13	2032	343	292	429	81	10	214	223	1,592
14	2033	320	272	490	83	11	205	212	1,592
15	2034	294	251	555	85	11	197	200	1,592
16	2035	267	227	625	86	11	188	187	1,592
17	2036	240	204	698	88	11	176	174	1,592
18	2037	219	186	754	90	11	168	164	1,592
19	2038	202	172	802	92	12	156	156	1,592
20	2039	184	157	849	94	12	148	148	1,592
21	2040	166	141	902	96	12	136	139	1,592
22	2041	146	124	966	98	13	116	130	1,592
23	2042	125	106	1,013	101	13	116	119	1,592
24	2043	102	87	1,096	103	13	81	110	1,592
25	2044	78	67	1,132	105	13	98	97	1,592
		8,109	6,960	11,929	2,049	260	5,094	5,393	39,794

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	721	640	(139)	62	8	380	440	2,112
2	2021	738	575	(44)	64	8	373	399	2,112
3	2022	724	564	(12)	65	8	369	393	2,112
4	2023	709	552	28	67	8	361	387	2,112
5	2024	692	539	71	68	9	354	380	2,112
6	2025	674	525	117	70	9	346	372	2,112
7	2026	655	510	165	71	9	339	363	2,112
8	2027	634	494	222	73	9	327	354	2,112
9	2028	611	476	278	74	9	320	345	2,112
10	2029	586	457	338	76	10	312	334	2,112
11	2030	560	436	406	78	10	301	322	2,112
12	2031	531	414	480	79	10	289	310	2,112
13	2032	500	389	554	81	10	282	296	2,112
14	2033	466	363	637	83	11	270	282	2,112
15	2034	430	335	727	85	11	259	266	2,112
16	2035	391	305	822	86	11	247	249	2,112
17	2036	351	273	925	88	11	232	232	2,112
18	2037	318	248	1,006	90	11	221	218	2,112
19	2038	294	229	1,072	92	12	205	208	2,112
20	2039	268	209	1,138	94	12	194	197	2,112
21	2040	241	188	1,212	96	12	179	185	2,112
22	2041	212	165	1,300	98	13	152	173	2,112
23	2042	181	141	1,366	101	13	152	159	2,112
24	2043	148	115	1,481	103	13	107	146	2,112
25	2044	113	88	1,535	105	13	129	130	2,112
		11,747	9,229	15,685	2,049	260	6,700	7,141	52,812

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	161	383	1.15	1,431	2,971	1.32
2	2021	1.118	161	383	1.15	1,431	2,971	1.32
3	2022	1.118	161	383	1.15	1,431	2,971	1.32
4	2023	1.118	161	383	1.15	1,431	2,971	1.32
5	2024	1.118	161	383	1.15	1,431	2,971	1.32
6	2025	1.118	161	383	1.15	1,431	2,971	1.32
7	2026	1.118	161	383	1.15	1,431	2,971	1.32
8	2027	1.118	161	383	1.15	1,431	2,971	1.32
9	2028	1.118	161	383	1.15	1,431	2,971	1.32
10	2029	1.118	161	383	1.15	1,431	2,971	1.32
11	2030	1.118	161	383	1.15	1,431	2,971	1.32
12	2031	1.118	161	383	1.15	1,431	2,971	1.32
13	2032	1.118	161	383	1.15	1,431	2,971	1.32
14	2033	1.118	161	383	1.15	1,431	2,971	1.32
15	2034	1.118	161	383	1.15	1,431	2,971	1.32
16	2035	1.118	161	383	1.15	1,431	2,971	1.32
17	2036	1.118	161	383	1.15	1,431	2,971	1.32
18	2037	1.118	161	383	1.15	1,431	2,971	1.32
19	2038	1.118	161	383	1.15	1,431	2,971	1.32
20	2039	1.118	161	383	1.15	1,431	2,971	1.32
21	2040	1.118	161	383	1.15	1,431	2,971	1.32
22	2041	1.118	161	383	1.15	1,431	2,971	1.32
23	2042	1.118	161	383	1.15	1,431	2,971	1.32
24	2043	1.118	161	383	1.15	1,431	2,971	1.32
25	2044	1.118	161	383	1.15	1,431	2,971	1.32

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	213	383	1.53	1,899	2,971	1.75
2	2021	1.118	213	383	1.53	1,899	2,971	1.75
3	2022	1.118	213	383	1.53	1,899	2,971	1.75
4	2023	1.118	213	383	1.53	1,899	2,971	1.75
5	2024	1.118	213	383	1.53	1,899	2,971	1.75
6	2025	1.118	213	383	1.53	1,899	2,971	1.75
7	2026	1.118	213	383	1.53	1,899	2,971	1.75
8	2027	1.118	213	383	1.53	1,899	2,971	1.75
9	2028	1.118	213	383	1.53	1,899	2,971	1.75
10	2029	1.118	213	383	1.53	1,899	2,971	1.75
11	2030	1.118	213	383	1.53	1,899	2,971	1.75
12	2031	1.118	213	383	1.53	1,899	2,971	1.75
13	2032	1.118	213	383	1.53	1,899	2,971	1.75
14	2033	1.118	213	383	1.53	1,899	2,971	1.75
15	2034	1.118	213	383	1.53	1,899	2,971	1.75
16	2035	1.118	213	383	1.53	1,899	2,971	1.75
17	2036	1.118	213	383	1.53	1,899	2,971	1.75
18	2037	1.118	213	383	1.53	1,899	2,971	1.75
19	2038	1.118	213	383	1.53	1,899	2,971	1.75
20	2039	1.118	213	383	1.53	1,899	2,971	1.75
21	2040	1.118	213	383	1.53	1,899	2,971	1.75
22	2041	1.118	213	383	1.53	1,899	2,971	1.75
23	2042	1.118	213	383	1.53	1,899	2,971	1.75
24	2043	1.118	213	383	1.53	1,899	2,971	1.75
25	2044	1.118	213	383	1.53	1,899	2,971	1.75

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.7%
3	2022	0.0%	-0.7%
4	2023	0.3%	-0.4%
5	2024	0.5%	0.0%
6	2025	0.7%	0.7%
7	2026	0.9%	1.7%
8	2027	1.2%	2.9%
9	2028	1.5%	4.4%
10	2029	1.8%	6.2%
11	2030	2.1%	8.4%
12	2031	2.5%	10.9%
13	2032	2.9%	13.7%
14	2033	3.3%	17.0%
15	2034	3.7%	20.7%
16	2035	4.2%	24.9%
17	2036	4.7%	29.6%
18	2037	5.1%	34.7%
19	2038	5.4%	40.0%
20	2039	5.7%	45.7%
21	2040	6.0%	51.8%
22	2041	6.5%	58.3%
23	2042	6.8%	65.1%
24	2043	7.3%	72.4%
25	2044	7.6%	80.0%
		80.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(25 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	-0.1%	-1.0%
4	2023	0.1%	-0.9%
5	2024	0.4%	-0.5%
6	2025	0.6%	0.1%
7	2026	0.8%	0.9%
8	2027	1.1%	2.1%
9	2028	1.4%	3.5%
10	2029	1.7%	5.2%
11	2030	2.1%	7.3%
12	2031	2.4%	9.7%
13	2032	2.8%	12.6%
14	2033	3.3%	15.8%
15	2034	3.7%	19.5%
16	2035	4.2%	23.7%
17	2036	4.7%	28.4%
18	2037	5.1%	33.6%
19	2038	5.5%	39.0%
20	2039	5.8%	44.8%
21	2040	6.2%	51.0%
22	2041	6.6%	57.6%
23	2042	7.0%	64.6%
24	2043	7.6%	72.2%
25	2044	7.8%	80.0%
		80.0%	

NEGOTIATED RATE MODEL OUTPUT

(30 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	443
2018	443	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	4	664	0	(15)	649
2	2021	664	1	1	664	0	(28)	636
3	2022	664	-	(0)	664	0	(42)	623
4	2023	664	-	(2)	662	0	(55)	608
5	2024	662	-	(3)	659	0	(67)	592
6	2025	659	-	(5)	654	0	(80)	575
7	2026	654	-	(6)	648	0	(91)	557
8	2027	648	-	(8)	640	0	(103)	537
9	2028	640	-	(10)	630	0	(114)	516
10	2029	630	-	(12)	618	0	(125)	493
11	2030	618	-	(14)	603	0	(136)	468
12	2031	603	-	(17)	587	0	(145)	442
13	2032	587	-	(19)	568	0	(155)	413
14	2033	568	-	(22)	546	0	(164)	383
15	2034	546	-	(25)	521	0	(172)	350
16	2035	521	-	(28)	494	0	(179)	315
17	2036	494	-	(31)	463	0	(180)	283
18	2037	463	-	(33)	430	0	(167)	262
19	2038	430	-	(35)	394	0	(154)	241
20	2039	394	-	(37)	357	0	(139)	218
21	2040	357	-	(40)	317	0	(123)	194
22	2041	317	-	(43)	274	0	(107)	168
23	2042	274	-	(45)	230	0	(89)	141
24	2043	230	-	(48)	181	0	(70)	112
25	2044	181	-	(50)	131	0	(50)	82
26	2045	131	-	(23)	108	0	(42)	67
27	2046	108	-	(25)	83	0	(32)	51
28	2047	83	-	(26)	57	0	(22)	35
29	2048	57	-	(28)	29	0	(11)	18
30	2049	29	-	(29)	(1)	0	(0)	(0)
			6	(660)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	6	874	0	(20)	855
2	2021	874	1	2	876	0	(37)	839
3	2022	876	-	0	877	0	(55)	822
4	2023	877	-	(1)	875	0	(72)	804
5	2024	875	-	(3)	872	0	(89)	784
6	2025	872	-	(5)	867	0	(105)	762
7	2026	867	-	(7)	859	0	(121)	739
8	2027	859	-	(10)	849	0	(136)	713
9	2028	849	-	(12)	837	0	(151)	686
10	2029	837	-	(15)	821	0	(165)	656
11	2030	821	-	(18)	803	0	(179)	624
12	2031	803	-	(21)	782	0	(192)	590
13	2032	782	-	(25)	757	0	(205)	553
14	2033	757	-	(28)	729	0	(217)	513
15	2034	729	-	(32)	697	0	(228)	469
16	2035	697	-	(37)	660	0	(238)	423
17	2036	660	-	(41)	619	0	(242)	378
18	2037	619	-	(44)	575	0	(224)	351
19	2038	575	-	(47)	527	0	(206)	322
20	2039	527	-	(50)	477	0	(186)	291
21	2040	477	-	(53)	424	0	(165)	259
22	2041	424	-	(57)	366	0	(143)	224
23	2042	366	-	(60)	306	0	(119)	188
24	2043	306	-	(65)	241	0	(93)	148
25	2044	241	-	(68)	173	0	(66)	107
26	2045	173	-	(31)	142	0	(55)	88
27	2046	142	-	(33)	110	0	(42)	68
28	2047	110	-	(35)	75	0	(29)	46
29	2048	75	-	(37)	38	0	(15)	24
30	2049	38	-	(39)	(1)	0	(0)	(0)
			8	(869)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	22	(4)	3	0	13	15	70
2	2021	23	19	(1)	3	0	13	13	70
3	2022	22	19	0	3	0	12	13	70
4	2023	22	18	2	3	0	12	13	70
5	2024	21	18	3	3	0	12	13	70
6	2025	21	18	5	3	0	12	12	70
7	2026	20	17	6	3	0	11	12	70
8	2027	19	16	8	3	0	11	12	70
9	2028	19	16	10	3	0	11	12	70
10	2029	18	15	12	3	0	10	11	70
11	2030	17	14	14	3	0	10	11	70
12	2031	16	14	17	3	0	10	10	70
13	2032	15	13	19	4	0	9	10	70
14	2033	14	12	22	4	0	9	9	70
15	2034	13	11	25	4	0	9	9	70
16	2035	12	10	28	4	0	8	8	70
17	2036	11	9	31	4	0	8	8	70
18	2037	10	8	33	4	0	7	7	70
19	2038	9	8	35	4	0	7	7	70
20	2039	8	7	37	4	0	7	7	70
21	2040	7	6	40	4	0	6	6	70
22	2041	6	5	43	4	0	5	6	70
23	2042	5	5	45	4	1	5	6	70
24	2043	4	4	48	4	1	4	5	70
25	2044	3	3	50	5	1	4	5	70
26	2045	3	2	23	5	1	4	3	40
27	2046	2	2	25	5	1	4	3	40
28	2047	2	1	26	5	1	3	2	40
29	2048	1	1	28	5	1	3	2	40
30	2049	0	0	29	5	1	3	2	40
		365	313	660	114	13	242	253	1,959

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(6)	3	0	17	19	93
2	2021	33	25	(2)	3	0	16	18	93
3	2022	32	25	(0)	3	0	16	17	93
4	2023	31	24	1	3	0	16	17	93
5	2024	31	24	3	3	0	16	17	93
6	2025	30	23	5	3	0	15	16	93
7	2026	29	23	7	3	0	15	16	93
8	2027	28	22	10	3	0	14	16	93
9	2028	27	21	12	3	0	14	15	93
10	2029	26	20	15	3	0	14	15	93
11	2030	25	19	18	3	0	13	14	93
12	2031	23	18	21	3	0	13	14	93
13	2032	22	17	25	4	0	12	13	93
14	2033	21	16	28	4	0	12	13	93
15	2034	19	15	32	4	0	11	12	93
16	2035	17	13	37	4	0	11	11	93
17	2036	15	12	41	4	0	10	10	93
18	2037	14	11	44	4	0	10	10	93
19	2038	13	10	47	4	0	9	9	93
20	2039	12	9	50	4	0	9	9	93
21	2040	11	8	53	4	0	8	9	93
22	2041	9	7	57	4	0	7	8	93
23	2042	8	6	60	4	1	7	7	93
24	2043	6	5	65	4	1	5	7	93
25	2044	5	4	68	5	1	6	6	93
26	2045	4	3	31	5	1	5	4	51
27	2046	3	2	33	5	1	5	3	51
28	2047	2	2	35	5	1	4	3	51
29	2048	1	1	37	5	1	4	3	51
30	2049	0	0	39	5	1	4	2	51
		529	416	869	114	13	318	335	2,594

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	70	1,100	1.000	0.18
2	2021	70	1,100	1.000	0.18
3	2022	70	1,100	1.000	0.18
4	2023	70	1,100	1.000	0.18
5	2024	70	1,100	1.000	0.18
6	2025	70	1,100	1.000	0.18
7	2026	70	1,100	1.000	0.18
8	2027	70	1,100	1.000	0.18
9	2028	70	1,100	1.000	0.18
10	2029	70	1,100	1.000	0.18
11	2030	70	1,100	1.000	0.18
12	2031	70	1,100	1.000	0.18
13	2032	70	1,100	1.000	0.18
14	2033	70	1,100	1.000	0.18
15	2034	70	1,100	1.000	0.18
16	2035	70	1,100	1.000	0.18
17	2036	70	1,100	1.000	0.18
18	2037	70	1,100	1.000	0.18
19	2038	70	1,100	1.000	0.18
20	2039	70	1,100	1.000	0.18
21	2040	70	1,100	1.000	0.18
22	2041	70	1,100	1.000	0.18
23	2042	70	1,100	1.000	0.18
24	2043	70	1,100	1.000	0.18
25	2044	70	1,100	1.000	0.18
26	2045	40	1,100	1.000	0.10
27	2046	40	1,100	1.000	0.10
28	2047	40	1,100	1.000	0.10
29	2048	40	1,100	1.000	0.10
30	2049	40	1,100	1.000	0.10

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	93	1,100	1.000	0.23
2	2021	93	1,100	1.000	0.23
3	2022	93	1,100	1.000	0.23
4	2023	93	1,100	1.000	0.23
5	2024	93	1,100	1.000	0.23
6	2025	93	1,100	1.000	0.23
7	2026	93	1,100	1.000	0.23
8	2027	93	1,100	1.000	0.23
9	2028	93	1,100	1.000	0.23
10	2029	93	1,100	1.000	0.23
11	2030	93	1,100	1.000	0.23
12	2031	93	1,100	1.000	0.23
13	2032	93	1,100	1.000	0.23
14	2033	93	1,100	1.000	0.23
15	2034	93	1,100	1.000	0.23
16	2035	93	1,100	1.000	0.23
17	2036	93	1,100	1.000	0.23
18	2037	93	1,100	1.000	0.23
19	2038	93	1,100	1.000	0.23
20	2039	93	1,100	1.000	0.23
21	2040	93	1,100	1.000	0.23
22	2041	93	1,100	1.000	0.23
23	2042	93	1,100	1.000	0.23
24	2043	93	1,100	1.000	0.23
25	2044	93	1,100	1.000	0.23
26	2045	51	1,100	1.000	0.13
27	2046	51	1,100	1.000	0.13
28	2047	51	1,100	1.000	0.13
29	2048	51	1,100	1.000	0.13
30	2049	51	1,100	1.000	0.13

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.7%
3	2022	0.1%	-0.6%
4	2023	0.3%	-0.4%
5	2024	0.5%	0.1%
6	2025	0.7%	0.8%
7	2026	1.0%	1.8%
8	2027	1.2%	3.0%
9	2028	1.5%	4.5%
10	2029	1.8%	6.4%
11	2030	2.2%	8.5%
12	2031	2.5%	11.0%
13	2032	2.9%	13.9%
14	2033	3.3%	17.2%
15	2034	3.7%	21.0%
16	2035	4.2%	25.2%
17	2036	4.7%	29.8%
18	2037	5.0%	34.9%
19	2038	5.4%	40.2%
20	2039	5.7%	45.9%
21	2040	6.0%	51.9%
22	2041	6.4%	58.4%
23	2042	6.8%	65.1%
24	2043	7.3%	72.4%
25	2044	7.6%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.2%	95.5%
30	2049	4.5%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-1.0%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.1%	2.2%
9	2028	1.4%	3.6%
10	2029	1.7%	5.4%
11	2030	2.1%	7.5%
12	2031	2.5%	9.9%
13	2032	2.8%	12.8%
14	2033	3.3%	16.0%
15	2034	3.7%	19.7%
16	2035	4.2%	23.9%
17	2036	4.7%	28.7%
18	2037	5.1%	33.8%
19	2038	5.4%	39.2%
20	2039	5.8%	45.0%
21	2040	6.2%	51.2%
22	2041	6.6%	57.8%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.2%	95.5%
30	2049	4.5%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,042
2016	3,042	2,682	54	873	354	7,005
2017	7,005	2,620	52	852	641	11,171
2018	11,171	2,161	43	703	929	15,006
2019	15,006	1,275	25	415	1,176	17,897
2020	17,897	438	-	151	-	18,487
2021	18,487	12	-	4	-	18,503
		11,185	203	3,659	3,455	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	66	14,099	23	(314)	13,808
2	2021	14,099	12	25	14,136	24	(600)	13,560
3	2022	14,136	-	(1)	14,135	24	(881)	13,278
4	2023	14,135	-	(38)	14,097	23	(1,156)	12,964
5	2024	14,097	-	(79)	14,017	22	(1,426)	12,614
6	2025	14,017	-	(118)	13,900	22	(1,689)	12,233
7	2026	13,900	-	(155)	13,745	22	(1,945)	11,822
8	2027	13,745	-	(197)	13,549	22	(2,193)	11,378
9	2028	13,549	-	(239)	13,310	22	(2,432)	10,900
10	2029	13,310	-	(284)	13,026	22	(2,661)	10,386
11	2030	13,026	-	(335)	12,691	22	(2,881)	9,831
12	2031	12,691	-	(383)	12,308	22	(3,090)	9,240
13	2032	12,308	-	(431)	11,877	23	(3,288)	8,612
14	2033	11,877	-	(485)	11,393	23	(3,473)	7,943
15	2034	11,393	-	(542)	10,851	24	(3,645)	7,230
16	2035	10,851	-	(602)	10,249	24	(3,803)	6,470
17	2036	10,249	-	(659)	9,590	25	(3,694)	5,921
18	2037	9,590	-	(699)	8,891	25	(3,425)	5,491
19	2038	8,891	-	(738)	8,153	26	(3,141)	5,038
20	2039	8,153	-	(776)	7,377	26	(2,841)	4,562
21	2040	7,377	-	(818)	6,559	27	(2,524)	4,062
22	2041	6,559	-	(870)	5,690	28	(2,186)	3,531
23	2042	5,690	-	(906)	4,784	28	(1,833)	2,979
24	2043	4,784	-	(975)	3,809	29	(1,451)	2,387
25	2044	3,809	-	(1,000)	2,809	29	(1,059)	1,779
26	2045	2,809	-	(525)	2,284	30	(863)	1,452
27	2046	2,284	-	(551)	1,733	31	(655)	1,109
28	2047	1,733	-	(575)	1,158	31	(438)	752
29	2048	1,158	-	(604)	554	32	(209)	378
30	2049	554	-	(554)	(0)	39	0	39
			463	(14,045)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,897	590	104	18,592	23	(413)	18,202
2	2021	18,592	16	48	18,656	24	(790)	17,890
3	2022	18,656	-	15	18,671	24	(1,160)	17,535
4	2023	18,671	-	(31)	18,640	23	(1,524)	17,139
5	2024	18,640	-	(82)	18,558	22	(1,880)	16,700
6	2025	18,558	-	(131)	18,427	22	(2,228)	16,221
7	2026	18,427	-	(180)	18,247	22	(2,567)	15,702
8	2027	18,247	-	(235)	18,012	22	(2,896)	15,138
9	2028	18,012	-	(291)	17,721	22	(3,213)	14,530
10	2029	17,721	-	(351)	17,370	22	(3,519)	13,873
11	2030	17,370	-	(418)	16,952	22	(3,812)	13,161
12	2031	16,952	-	(484)	16,467	22	(4,092)	12,398
13	2032	16,467	-	(551)	15,916	23	(4,356)	11,583
14	2033	15,916	-	(626)	15,290	23	(4,604)	10,709
15	2034	15,290	-	(706)	14,584	24	(4,836)	9,772
16	2035	14,584	-	(791)	13,793	24	(5,049)	8,768
17	2036	13,793	-	(874)	12,918	25	(4,986)	7,957
18	2037	12,918	-	(936)	11,983	25	(4,626)	7,382
19	2038	11,983	-	(992)	10,991	26	(4,243)	6,773
20	2039	10,991	-	(1,047)	9,944	26	(3,838)	6,132
21	2040	9,944	-	(1,109)	8,835	27	(3,407)	5,455
22	2041	8,835	-	(1,184)	7,651	28	(2,945)	4,733
23	2042	7,651	-	(1,238)	6,414	28	(2,462)	3,980
24	2043	6,414	-	(1,336)	5,077	29	(1,937)	3,169
25	2044	5,077	-	(1,377)	3,701	29	(1,396)	2,334
26	2045	3,701	-	(679)	3,022	30	(1,142)	1,910
27	2046	3,022	-	(717)	2,305	31	(873)	1,463
28	2047	2,305	-	(753)	1,552	31	(588)	995
29	2048	1,552	-	(795)	758	32	(286)	503
30	2049	758	-	(758)	(0)	39	(0)	39
			605	(18,503)				

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	467	452	(66)	274	39	273	311	1,750
2	2021	482	411	(25)	289	40	267	285	1,750
3	2022	473	403	1	287	41	264	281	1,750
4	2023	463	394	38	278	42	259	277	1,750
5	2024	451	384	79	267	43	253	273	1,750
6	2025	438	373	118	263	44	248	267	1,750
7	2026	424	361	155	262	45	243	261	1,750
8	2027	409	348	197	262	46	234	255	1,750
9	2028	393	334	239	261	47	229	247	1,750
10	2029	375	319	284	260	48	223	240	1,750
11	2030	356	303	335	260	49	215	231	1,750
12	2031	336	286	383	266	50	207	222	1,750
13	2032	315	268	431	271	51	202	212	1,750
14	2033	292	248	485	277	52	194	202	1,750
15	2034	267	228	542	283	54	185	191	1,750
16	2035	241	205	602	290	55	177	179	1,750
17	2036	218	186	659	296	56	166	169	1,750
18	2037	201	171	699	303	57	158	161	1,750
19	2038	186	158	738	309	58	147	154	1,750
20	2039	169	144	776	316	60	139	146	1,750
21	2040	152	129	818	323	61	128	139	1,750
22	2041	134	114	870	330	62	109	131	1,750
23	2042	115	98	906	337	64	109	122	1,750
24	2043	95	80	975	345	65	76	114	1,750
25	2044	73	62	1,000	352	67	93	103	1,750
26	2045	57	48	525	360	68	84	65	1,208
27	2046	45	38	551	368	70	76	59	1,208
28	2047	33	28	575	376	71	71	53	1,208
29	2048	20	17	604	384	73	63	48	1,208
30	2049	7	6	554	468	74	60	37	1,208
		7,687	6,596	14,045	9,219	1,653	5,154	5,435	49,790

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	672	595	(104)	274	39	359	409	2,245
2	2021	695	541	(48)	289	40	352	375	2,245
3	2022	682	531	(15)	287	41	349	370	2,245
4	2023	668	520	31	278	42	341	365	2,245
5	2024	652	508	82	267	43	334	359	2,245
6	2025	634	494	131	263	44	327	352	2,245
7	2026	615	479	180	262	45	320	345	2,245
8	2027	594	463	235	262	46	309	337	2,245
9	2028	571	445	291	261	47	302	328	2,245
10	2029	547	426	351	260	48	295	318	2,245
11	2030	521	406	418	260	49	284	308	2,245
12	2031	492	383	484	266	50	273	296	2,245
13	2032	462	360	551	271	51	266	283	2,245
14	2033	429	334	626	277	52	255	270	2,245
15	2034	394	307	706	283	54	244	256	2,245
16	2035	357	278	791	290	55	234	241	2,245
17	2036	322	251	874	296	56	219	226	2,245
18	2037	295	230	936	303	57	208	215	2,245
19	2038	273	212	992	309	58	194	206	2,245
20	2039	248	194	1,047	316	60	183	197	2,245
21	2040	223	174	1,109	323	61	169	186	2,245
22	2041	196	153	1,184	330	62	144	176	2,245
23	2042	168	131	1,238	337	64	144	164	2,245
24	2043	138	107	1,336	345	65	101	153	2,245
25	2044	106	83	1,377	352	67	122	138	2,245
26	2045	82	64	679	360	68	111	84	1,448
27	2046	65	51	717	368	70	101	77	1,448
28	2047	47	37	753	376	71	93	70	1,448
29	2048	29	22	795	384	73	83	62	1,448
30	2049	10	8	758	468	74	79	50	1,448
		11,186	8,786	18,503	9,219	1,653	6,795	7,218	63,360

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,750	3,000	1.118	1.43
2	2021	1,750	3,000	1.118	1.43
3	2022	1,750	3,000	1.118	1.43
4	2023	1,750	3,000	1.118	1.43
5	2024	1,750	3,000	1.118	1.43
6	2025	1,750	3,000	1.118	1.43
7	2026	1,750	3,000	1.118	1.43
8	2027	1,750	3,000	1.118	1.43
9	2028	1,750	3,000	1.118	1.43
10	2029	1,750	3,000	1.118	1.43
11	2030	1,750	3,000	1.118	1.43
12	2031	1,750	3,000	1.118	1.43
13	2032	1,750	3,000	1.118	1.43
14	2033	1,750	3,000	1.118	1.43
15	2034	1,750	3,000	1.118	1.43
16	2035	1,750	3,000	1.118	1.43
17	2036	1,750	3,000	1.118	1.43
18	2037	1,750	3,000	1.118	1.43
19	2038	1,750	3,000	1.118	1.43
20	2039	1,750	3,000	1.118	1.43
21	2040	1,750	3,000	1.118	1.43
22	2041	1,750	3,000	1.118	1.43
23	2042	1,750	3,000	1.118	1.43
24	2043	1,750	3,000	1.118	1.43
25	2044	1,750	3,000	1.118	1.43
26	2045	1,208	3,000	1.118	0.99
27	2046	1,208	3,000	1.118	0.99
28	2047	1,208	3,000	1.118	0.99
29	2048	1,208	3,000	1.118	0.99
30	2049	1,208	3,000	1.118	0.99

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,245	3,000	1.118	1.83
2	2021	2,245	3,000	1.118	1.83
3	2022	2,245	3,000	1.118	1.83
4	2023	2,245	3,000	1.118	1.83
5	2024	2,245	3,000	1.118	1.83
6	2025	2,245	3,000	1.118	1.83
7	2026	2,245	3,000	1.118	1.83
8	2027	2,245	3,000	1.118	1.83
9	2028	2,245	3,000	1.118	1.83
10	2029	2,245	3,000	1.118	1.83
11	2030	2,245	3,000	1.118	1.83
12	2031	2,245	3,000	1.118	1.83
13	2032	2,245	3,000	1.118	1.83
14	2033	2,245	3,000	1.118	1.83
15	2034	2,245	3,000	1.118	1.83
16	2035	2,245	3,000	1.118	1.83
17	2036	2,245	3,000	1.118	1.83
18	2037	2,245	3,000	1.118	1.83
19	2038	2,245	3,000	1.118	1.83
20	2039	2,245	3,000	1.118	1.83
21	2040	2,245	3,000	1.118	1.83
22	2041	2,245	3,000	1.118	1.83
23	2042	2,245	3,000	1.118	1.83
24	2043	2,245	3,000	1.118	1.83
25	2044	2,245	3,000	1.118	1.83
26	2045	1,448	3,000	1.118	1.18
27	2046	1,448	3,000	1.118	1.18
28	2047	1,448	3,000	1.118	1.18
29	2048	1,448	3,000	1.118	1.18
30	2049	1,448	3,000	1.118	1.18

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.2%	-0.6%
3	2022	0.0%	-0.6%
4	2023	0.3%	-0.4%
5	2024	0.6%	0.2%
6	2025	0.8%	1.0%
7	2026	1.1%	2.1%
8	2027	1.4%	3.5%
9	2028	1.7%	5.2%
10	2029	2.0%	7.3%
11	2030	2.4%	9.6%
12	2031	2.7%	12.4%
13	2032	3.1%	15.4%
14	2033	3.5%	18.9%
15	2034	3.9%	22.7%
16	2035	4.3%	27.0%
17	2036	4.7%	31.7%
18	2037	5.0%	36.7%
19	2038	5.3%	42.0%
20	2039	5.5%	47.5%
21	2040	5.8%	53.3%
22	2041	6.2%	59.5%
23	2042	6.4%	65.9%
24	2043	6.9%	72.9%
25	2044	7.1%	80.0%
26	2045	3.7%	83.7%
27	2046	3.9%	87.7%
28	2047	4.1%	91.8%
29	2048	4.3%	96.1%
30	2049	3.9%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.3%	-0.8%
3	2022	-0.1%	-0.9%
4	2023	0.2%	-0.7%
5	2024	0.4%	-0.3%
6	2025	0.7%	0.4%
7	2026	1.0%	1.4%
8	2027	1.3%	2.7%
9	2028	1.6%	4.2%
10	2029	1.9%	6.1%
11	2030	2.3%	8.4%
12	2031	2.6%	11.0%
13	2032	3.0%	14.0%
14	2033	3.4%	17.4%
15	2034	3.8%	21.2%
16	2035	4.3%	25.5%
17	2036	4.7%	30.2%
18	2037	5.1%	35.2%
19	2038	5.4%	40.6%
20	2039	5.7%	46.3%
21	2040	6.0%	52.3%
22	2041	6.4%	58.6%
23	2042	6.7%	65.3%
24	2043	7.2%	72.6%
25	2044	7.4%	80.0%
26	2045	3.7%	83.7%
27	2046	3.9%	87.5%
28	2047	4.1%	91.6%
29	2048	4.3%	95.9%
30	2049	4.1%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,724
2017	2,724	2,549	51	454	314	6,092
2018	6,092	7,006	140	1,249	753	15,240
2019	15,240	2,464	49	439	1,227	19,420
2020	19,420	141	-	28	-	19,589
2021	19,589	14	-	3	-	19,606
		14,030	263	2,519	2,794	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	92	14,990	49	(338)	14,701
2	2021	14,990	13	18	15,022	49	(643)	14,428
3	2022	15,022	-	(7)	15,015	49	(942)	14,123
4	2023	15,015	-	(37)	14,978	49	(1,235)	13,793
5	2024	14,978	-	(69)	14,909	49	(1,521)	13,437
6	2025	14,909	-	(104)	14,805	50	(1,800)	13,054
7	2026	14,805	-	(140)	14,665	50	(2,072)	12,642
8	2027	14,665	-	(182)	14,482	50	(2,335)	12,196
9	2028	14,482	-	(224)	14,258	50	(2,590)	11,718
10	2029	14,258	-	(269)	13,988	50	(2,835)	11,204
11	2030	13,988	-	(320)	13,669	50	(3,070)	10,649
12	2031	13,669	-	(374)	13,295	50	(3,293)	10,052
13	2032	13,295	-	(429)	12,866	50	(3,505)	9,412
14	2033	12,866	-	(490)	12,376	51	(3,704)	8,723
15	2034	12,376	-	(555)	11,821	51	(3,889)	7,983
16	2035	11,821	-	(625)	11,196	51	(4,059)	7,188
17	2036	11,196	-	(698)	10,499	51	(4,116)	6,434
18	2037	10,499	-	(754)	9,745	51	(3,821)	5,975
19	2038	9,745	-	(802)	8,943	51	(3,507)	5,487
20	2039	8,943	-	(850)	8,093	52	(3,173)	4,972
21	2040	8,093	-	(902)	7,191	52	(2,818)	4,425
22	2041	7,191	-	(966)	6,225	52	(2,436)	3,841
23	2042	6,225	-	(1,013)	5,212	52	(2,035)	3,229
24	2043	5,212	-	(1,096)	4,115	52	(1,599)	2,568
25	2044	4,115	-	(1,133)	2,982	52	(1,149)	1,886
26	2045	2,982	-	(529)	2,453	53	(947)	1,559
27	2046	2,453	-	(563)	1,891	53	(731)	1,213
28	2047	1,891	-	(595)	1,296	53	(502)	847
29	2048	1,296	-	(632)	664	53	(258)	460
30	2049	664	-	(664)	-	53	0	53
			142	(14,912)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,420	169	140	19,729	49	(444)	19,334
2	2021	19,729	17	45	19,791	49	(844)	18,995
3	2022	19,791	-	12	19,803	49	(1,238)	18,614
4	2023	19,803	-	(28)	19,775	49	(1,624)	18,200
5	2024	19,775	-	(71)	19,704	49	(2,002)	17,751
6	2025	19,704	-	(116)	19,587	50	(2,371)	17,266
7	2026	19,587	-	(165)	19,422	50	(2,730)	16,742
8	2027	19,422	-	(221)	19,201	50	(3,078)	16,172
9	2028	19,201	-	(278)	18,923	50	(3,416)	15,557
10	2029	18,923	-	(338)	18,585	50	(3,741)	14,894
11	2030	18,585	-	(406)	18,179	50	(4,053)	14,176
12	2031	18,179	-	(479)	17,699	50	(4,350)	13,400
13	2032	17,699	-	(554)	17,146	50	(4,632)	12,564
14	2033	17,146	-	(637)	16,508	51	(4,898)	11,661
15	2034	16,508	-	(727)	15,781	51	(5,145)	10,687
16	2035	15,781	-	(822)	14,959	51	(5,373)	9,637
17	2036	14,959	-	(925)	14,034	51	(5,508)	8,577
18	2037	14,034	-	(1,006)	13,028	51	(5,114)	7,965
19	2038	13,028	-	(1,072)	11,956	51	(4,694)	7,314
20	2039	11,956	-	(1,139)	10,817	52	(4,246)	6,623
21	2040	10,817	-	(1,212)	9,605	52	(3,768)	5,890
22	2041	9,605	-	(1,300)	8,305	52	(3,253)	5,104
23	2042	8,305	-	(1,367)	6,938	52	(2,711)	4,279
24	2043	6,938	-	(1,482)	5,457	52	(2,122)	3,386
25	2044	5,457	-	(1,535)	3,921	52	(1,511)	2,462
26	2045	3,921	-	(691)	3,230	53	(1,247)	2,035
27	2046	3,230	-	(737)	2,493	53	(965)	1,581
28	2047	2,493	-	(782)	1,711	53	(663)	1,101
29	2048	1,711	-	(833)	878	53	(341)	591
30	2049	878	-	(878)	(0)	53	(0)	53
			186	(19,606)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	502	486	(92)	62	7	289	335	1,590
2	2021	513	437	(18)	64	7	283	304	1,590
3	2022	503	428	7	65	7	281	299	1,590
4	2023	492	419	37	67	7	275	294	1,590
5	2024	480	408	69	68	7	269	288	1,590
6	2025	467	397	104	70	7	263	282	1,590
7	2026	453	385	140	71	8	257	275	1,590
8	2027	438	373	182	73	8	249	268	1,590
9	2028	421	359	224	74	8	243	260	1,590
10	2029	404	344	269	76	8	237	252	1,590
11	2030	385	328	320	78	8	229	243	1,590
12	2031	365	311	374	79	8	220	234	1,590
13	2032	343	292	429	81	9	214	223	1,590
14	2033	320	272	490	83	9	205	212	1,590
15	2034	294	251	555	85	9	197	200	1,590
16	2035	267	228	625	86	9	188	187	1,590
17	2036	240	204	698	88	9	176	174	1,590
18	2037	219	186	754	90	10	168	164	1,590
19	2038	202	172	802	92	10	156	156	1,590
20	2039	184	157	850	94	10	148	148	1,590
21	2040	166	141	902	96	10	136	139	1,590
22	2041	146	124	966	98	10	116	130	1,590
23	2042	125	106	1,013	101	11	116	119	1,590
24	2043	102	87	1,096	103	11	81	110	1,590
25	2044	79	67	1,133	105	11	98	97	1,590
26	2045	61	52	529	107	11	90	60	910
27	2046	49	42	563	110	12	81	54	910
28	2047	36	31	595	112	12	75	48	910
29	2048	23	20	632	115	12	67	42	910
30	2049	9	8	664	117	12	64	35	910
		8,288	7,113	14,912	2,611	276	5,470	5,633	44,302

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	721	640	(140)	62	7	380	440	2,111
2	2021	738	575	(45)	64	7	373	399	2,111
3	2022	724	564	(12)	65	7	369	393	2,111
4	2023	709	552	28	67	7	361	387	2,111
5	2024	692	539	71	68	7	354	380	2,111
6	2025	674	525	116	70	7	346	372	2,111
7	2026	655	510	165	71	8	339	363	2,111
8	2027	634	494	221	73	8	327	355	2,111
9	2028	611	476	278	74	8	320	345	2,111
10	2029	586	457	338	76	8	312	334	2,111
11	2030	560	436	406	78	8	301	322	2,111
12	2031	531	414	479	79	8	289	310	2,111
13	2032	500	389	554	81	9	282	297	2,111
14	2033	466	363	637	83	9	270	282	2,111
15	2034	430	335	727	85	9	259	266	2,111
16	2035	391	305	822	86	9	247	249	2,111
17	2036	351	273	925	88	9	232	232	2,111
18	2037	319	248	1,006	90	10	221	218	2,111
19	2038	294	229	1,072	92	10	205	208	2,111
20	2039	268	209	1,139	94	10	194	197	2,111
21	2040	241	188	1,212	96	10	179	185	2,111
22	2041	212	165	1,300	98	10	152	173	2,111
23	2042	181	141	1,367	101	11	152	159	2,111
24	2043	148	115	1,482	103	11	107	146	2,111
25	2044	113	88	1,535	105	11	129	130	2,111
26	2045	87	67	691	107	11	118	78	1,160
27	2046	70	54	737	110	12	107	71	1,160
28	2047	52	40	782	112	12	99	63	1,160
29	2048	33	25	833	115	12	88	55	1,160
30	2049	12	10	878	117	12	84	46	1,160
		12,002	9,427	19,606	2,611	276	7,194	7,454	58,571

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	161	383	1.15	1,430	2,971	1.32
2	2021	1.118	161	383	1.15	1,430	2,971	1.32
3	2022	1.118	161	383	1.15	1,430	2,971	1.32
4	2023	1.118	161	383	1.15	1,430	2,971	1.32
5	2024	1.118	161	383	1.15	1,430	2,971	1.32
6	2025	1.118	161	383	1.15	1,430	2,971	1.32
7	2026	1.118	161	383	1.15	1,430	2,971	1.32
8	2027	1.118	161	383	1.15	1,430	2,971	1.32
9	2028	1.118	161	383	1.15	1,430	2,971	1.32
10	2029	1.118	161	383	1.15	1,430	2,971	1.32
11	2030	1.118	161	383	1.15	1,430	2,971	1.32
12	2031	1.118	161	383	1.15	1,430	2,971	1.32
13	2032	1.118	161	383	1.15	1,430	2,971	1.32
14	2033	1.118	161	383	1.15	1,430	2,971	1.32
15	2034	1.118	161	383	1.15	1,430	2,971	1.32
16	2035	1.118	161	383	1.15	1,430	2,971	1.32
17	2036	1.118	161	383	1.15	1,430	2,971	1.32
18	2037	1.118	161	383	1.15	1,430	2,971	1.32
19	2038	1.118	161	383	1.15	1,430	2,971	1.32
20	2039	1.118	161	383	1.15	1,430	2,971	1.32
21	2040	1.118	161	383	1.15	1,430	2,971	1.32
22	2041	1.118	161	383	1.15	1,430	2,971	1.32
23	2042	1.118	161	383	1.15	1,430	2,971	1.32
24	2043	1.118	161	383	1.15	1,430	2,971	1.32
25	2044	1.118	161	383	1.15	1,430	2,971	1.32
26	2045	1.118	92	383	0.66	818	2,971	0.75
27	2046	1.118	92	383	0.66	818	2,971	0.75
28	2047	1.118	92	383	0.66	818	2,971	0.75
29	2048	1.118	92	383	0.66	818	2,971	0.75
30	2049	1.118	92	383	0.66	818	2,971	0.75

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	213	383	1.53	1,898	2,971	1.75
2	2021	1.118	213	383	1.53	1,898	2,971	1.75
3	2022	1.118	213	383	1.53	1,898	2,971	1.75
4	2023	1.118	213	383	1.53	1,898	2,971	1.75
5	2024	1.118	213	383	1.53	1,898	2,971	1.75
6	2025	1.118	213	383	1.53	1,898	2,971	1.75
7	2026	1.118	213	383	1.53	1,898	2,971	1.75
8	2027	1.118	213	383	1.53	1,898	2,971	1.75
9	2028	1.118	213	383	1.53	1,898	2,971	1.75
10	2029	1.118	213	383	1.53	1,898	2,971	1.75
11	2030	1.118	213	383	1.53	1,898	2,971	1.75
12	2031	1.118	213	383	1.53	1,898	2,971	1.75
13	2032	1.118	213	383	1.53	1,898	2,971	1.75
14	2033	1.118	213	383	1.53	1,898	2,971	1.75
15	2034	1.118	213	383	1.53	1,898	2,971	1.75
16	2035	1.118	213	383	1.53	1,898	2,971	1.75
17	2036	1.118	213	383	1.53	1,898	2,971	1.75
18	2037	1.118	213	383	1.53	1,898	2,971	1.75
19	2038	1.118	213	383	1.53	1,898	2,971	1.75
20	2039	1.118	213	383	1.53	1,898	2,971	1.75
21	2040	1.118	213	383	1.53	1,898	2,971	1.75
22	2041	1.118	213	383	1.53	1,898	2,971	1.75
23	2042	1.118	213	383	1.53	1,898	2,971	1.75
24	2043	1.118	213	383	1.53	1,898	2,971	1.75
25	2044	1.118	213	383	1.53	1,898	2,971	1.75
26	2045	1.118	117	383	0.84	1,043	2,971	0.96
27	2046	1.118	117	383	0.84	1,043	2,971	0.96
28	2047	1.118	117	383	0.84	1,043	2,971	0.96
29	2048	1.118	117	383	0.84	1,043	2,971	0.96
30	2049	1.118	117	383	0.84	1,043	2,971	0.96

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.7%
3	2022	0.0%	-0.7%
4	2023	0.2%	-0.4%
5	2024	0.5%	0.0%
6	2025	0.7%	0.7%
7	2026	0.9%	1.7%
8	2027	1.2%	2.9%
9	2028	1.5%	4.4%
10	2029	1.8%	6.2%
11	2030	2.1%	8.3%
12	2031	2.5%	10.8%
13	2032	2.9%	13.7%
14	2033	3.3%	17.0%
15	2034	3.7%	20.7%
16	2035	4.2%	24.9%
17	2036	4.7%	29.6%
18	2037	5.1%	34.7%
19	2038	5.4%	40.0%
20	2039	5.7%	45.7%
21	2040	6.1%	51.8%
22	2041	6.5%	58.3%
23	2042	6.8%	65.0%
24	2043	7.4%	72.4%
25	2044	7.6%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.2%	95.5%
30	2049	4.5%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(30 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	-0.1%	-1.0%
4	2023	0.1%	-0.9%
5	2024	0.4%	-0.5%
6	2025	0.6%	0.1%
7	2026	0.8%	0.9%
8	2027	1.1%	2.1%
9	2028	1.4%	3.5%
10	2029	1.7%	5.2%
11	2030	2.1%	7.3%
12	2031	2.4%	9.7%
13	2032	2.8%	12.6%
14	2033	3.3%	15.8%
15	2034	3.7%	19.5%
16	2035	4.2%	23.7%
17	2036	4.7%	28.4%
18	2037	5.1%	33.6%
19	2038	5.5%	39.0%
20	2039	5.8%	44.8%
21	2040	6.2%	51.0%
22	2041	6.6%	57.6%
23	2042	7.0%	64.6%
24	2043	7.6%	72.2%
25	2044	7.8%	80.0%
26	2045	3.5%	83.5%
27	2046	3.8%	87.3%
28	2047	4.0%	91.3%
29	2048	4.2%	95.5%
30	2049	4.5%	100.0%
		100.0%	

NEGOTIATED RATE MODEL OUTPUT

(35 Year Contract Term)
Valdez Pipeline

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	5	-	1	0	7
2011	7	4	-	1	1	12
2012	12	5	-	1	1	19
2013	19	6	-	1	2	28
2014	28	7	0	1	2	38
2015	38	26	1	4	4	73
2016	73	16	0	3	6	98
2017	98	189	4	32	15	337
2018	337	193	4	33	32	598
2019	598	11	0	2	43	654
2020	654	5	-	1	-	660
2021	660	0	-	0	-	660
		467	9	80	105	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	7	-	1	0	9
2011	9	5	-	1	1	16
2012	16	7	-	1	1	25
2013	25	8	-	1	2	36
2014	36	9	0	2	3	51
2015	51	34	1	6	5	96
2016	96	21	0	4	8	129
2017	129	246	5	42	20	443
2018	443	252	5	43	43	786
2019	786	14	0	2	58	861
2020	861	6	-	1	-	868
2021	868	1	-	0	-	869
		610	12	104	143	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	654	6	4	664	0	(15)	649
2	2021	664	1	1	664	0	(28)	636
3	2022	664	-	(0)	664	0	(42)	623
4	2023	664	-	(2)	662	0	(55)	608
5	2024	662	-	(3)	659	0	(67)	592
6	2025	659	-	(5)	654	0	(79)	575
7	2026	654	-	(6)	648	0	(91)	557
8	2027	648	-	(8)	639	0	(103)	537
9	2028	639	-	(10)	629	0	(114)	515
10	2029	629	-	(12)	617	0	(125)	492
11	2030	617	-	(14)	603	0	(136)	468
12	2031	603	-	(17)	586	0	(145)	441
13	2032	586	-	(19)	567	0	(155)	413
14	2033	567	-	(22)	545	0	(164)	382
15	2034	545	-	(25)	521	0	(172)	349
16	2035	521	-	(28)	493	0	(179)	314
17	2036	493	-	(31)	462	0	(178)	284
18	2037	462	-	(33)	429	0	(165)	264
19	2038	429	-	(35)	393	0	(151)	243
20	2039	393	-	(37)	356	0	(137)	220
21	2040	356	-	(40)	316	0	(121)	196
22	2041	316	-	(42)	274	0	(104)	170
23	2042	274	-	(45)	229	0	(86)	143
24	2043	229	-	(48)	181	0	(67)	114
25	2044	181	-	(50)	131	0	(48)	84
26	2045	131	-	(10)	122	0	(44)	78
27	2046	122	-	(11)	111	0	(40)	71
28	2047	111	-	(11)	100	0	(36)	64
29	2048	100	-	(12)	87	0	(32)	56
30	2049	87	-	(13)	74	0	(27)	47
31	2050	74	-	(14)	61	0	(23)	39
32	2051	61	-	(14)	46	0	(17)	30
33	2052	46	-	(15)	31	0	(12)	20
34	2053	31	-	(16)	16	0	(6)	10
35	2054	16	-	(16)	(1)	0	(0)	(0)
			6	(660)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	861	7	6	874	0	(20)	855
2	2021	874	1	2	876	0	(37)	839
3	2022	876	-	0	876	0	(55)	822
4	2023	876	-	(1)	875	0	(72)	803
5	2024	875	-	(3)	872	0	(89)	783
6	2025	872	-	(5)	866	0	(105)	762
7	2026	866	-	(8)	859	0	(121)	738
8	2027	859	-	(10)	849	0	(136)	713
9	2028	849	-	(13)	836	0	(151)	685
10	2029	836	-	(15)	821	0	(165)	656
11	2030	821	-	(18)	803	0	(179)	624
12	2031	803	-	(21)	781	0	(192)	589
13	2032	781	-	(25)	756	0	(205)	552
14	2033	756	-	(28)	728	0	(217)	512
15	2034	728	-	(32)	696	0	(228)	468
16	2035	696	-	(37)	659	0	(238)	421
17	2036	659	-	(41)	618	0	(238)	380
18	2037	618	-	(44)	574	0	(221)	353
19	2038	574	-	(47)	526	0	(203)	324
20	2039	526	-	(50)	476	0	(183)	294
21	2040	476	-	(53)	423	0	(162)	261
22	2041	423	-	(57)	366	0	(139)	227
23	2042	366	-	(60)	306	0	(115)	191
24	2043	306	-	(65)	241	0	(90)	151
25	2044	241	-	(67)	173	0	(63)	111
26	2045	173	-	(13)	160	0	(58)	102
27	2046	160	-	(14)	147	0	(54)	93
28	2047	147	-	(15)	132	0	(48)	84
29	2048	132	-	(16)	116	0	(43)	74
30	2049	116	-	(17)	99	0	(37)	63
31	2050	99	-	(18)	81	0	(30)	51
32	2051	81	-	(19)	62	0	(23)	39
33	2052	62	-	(20)	42	0	(16)	27
34	2053	42	-	(21)	21	0	(8)	14
35	2054	21	-	(22)	(1)	0	(0)	(0)
			8	(869)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	22	22	(4)	3	0	13	15	70
2	2021	23	19	(1)	3	0	13	13	70
3	2022	22	19	0	3	0	12	13	70
4	2023	22	18	2	3	0	12	13	70
5	2024	21	18	3	3	0	12	13	70
6	2025	21	18	5	3	0	12	12	70
7	2026	20	17	6	3	0	11	12	70
8	2027	19	16	8	3	0	11	12	70
9	2028	19	16	10	3	0	11	12	70
10	2029	18	15	12	3	0	10	11	70
11	2030	17	14	14	3	0	10	11	70
12	2031	16	14	17	3	0	10	10	70
13	2032	15	13	19	4	0	9	10	70
14	2033	14	12	22	4	0	9	9	70
15	2034	13	11	25	4	0	9	9	70
16	2035	12	10	28	4	0	8	8	70
17	2036	11	9	31	4	0	8	8	70
18	2037	10	8	33	4	0	7	7	70
19	2038	9	8	35	4	0	7	7	70
20	2039	8	7	37	4	0	7	7	70
21	2040	7	6	40	4	0	6	6	70
22	2041	6	6	42	4	0	5	6	70
23	2042	6	5	45	4	0	5	6	70
24	2043	5	4	48	4	0	4	5	70
25	2044	4	3	50	5	0	4	5	70
26	2045	3	2	10	5	0	4	2	27
27	2046	3	2	11	5	0	4	2	27
28	2047	2	2	11	5	0	3	2	27
29	2048	2	2	12	5	0	3	2	27
30	2049	2	2	13	5	1	3	2	27
31	2050	2	1	14	5	1	3	2	27
32	2051	1	1	14	5	1	3	1	27
33	2052	1	1	15	5	1	3	1	27
34	2053	1	0	16	6	1	3	1	27
35	2054	0	0	16	6	1	3	1	27
		374	321	660	141	14	255	258	2,023

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	32	28	(6)	3	0	17	19	93
2	2021	33	25	(2)	3	0	16	18	93
3	2022	32	25	(0)	3	0	16	17	93
4	2023	31	24	1	3	0	16	17	93
5	2024	31	24	3	3	0	16	17	93
6	2025	30	23	5	3	0	15	16	93
7	2026	29	23	8	3	0	15	16	93
8	2027	28	22	10	3	0	14	16	93
9	2028	27	21	13	3	0	14	15	93
10	2029	26	20	15	3	0	14	15	93
11	2030	25	19	18	3	0	13	14	93
12	2031	23	18	21	3	0	13	14	93
13	2032	22	17	25	4	0	12	13	93
14	2033	21	16	28	4	0	12	13	93
15	2034	19	15	32	4	0	11	12	93
16	2035	17	13	37	4	0	11	11	93
17	2036	15	12	41	4	0	10	11	93
18	2037	14	11	44	4	0	10	10	93
19	2038	13	10	47	4	0	9	10	93
20	2039	12	9	50	4	0	9	9	93
21	2040	11	8	53	4	0	8	9	93
22	2041	9	7	57	4	0	7	8	93
23	2042	8	6	60	4	0	7	7	93
24	2043	7	5	65	4	0	5	7	93
25	2044	5	4	67	5	0	6	6	93
26	2045	4	3	13	5	0	5	3	33
27	2046	4	3	14	5	0	5	3	33
28	2047	3	3	15	5	0	4	3	33
29	2048	3	2	16	5	0	4	2	33
30	2049	3	2	17	5	1	4	2	33
31	2050	2	2	18	5	1	4	2	33
32	2051	2	1	19	5	1	4	2	33
33	2052	1	1	20	5	1	3	2	33
34	2053	1	1	21	6	1	3	2	33
35	2054	0	0	22	6	1	3	1	33
		542	426	869	141	14	335	342	2,670

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	70	1,100	1.000	0.18
2	2021	70	1,100	1.000	0.18
3	2022	70	1,100	1.000	0.18
4	2023	70	1,100	1.000	0.18
5	2024	70	1,100	1.000	0.18
6	2025	70	1,100	1.000	0.18
7	2026	70	1,100	1.000	0.18
8	2027	70	1,100	1.000	0.18
9	2028	70	1,100	1.000	0.18
10	2029	70	1,100	1.000	0.18
11	2030	70	1,100	1.000	0.18
12	2031	70	1,100	1.000	0.18
13	2032	70	1,100	1.000	0.18
14	2033	70	1,100	1.000	0.18
15	2034	70	1,100	1.000	0.18
16	2035	70	1,100	1.000	0.18
17	2036	70	1,100	1.000	0.18
18	2037	70	1,100	1.000	0.18
19	2038	70	1,100	1.000	0.18
20	2039	70	1,100	1.000	0.18
21	2040	70	1,100	1.000	0.18
22	2041	70	1,100	1.000	0.18
23	2042	70	1,100	1.000	0.18
24	2043	70	1,100	1.000	0.18
25	2044	70	1,100	1.000	0.18
26	2045	27	1,100	1.000	0.07
27	2046	27	1,100	1.000	0.07
28	2047	27	1,100	1.000	0.07
29	2048	27	1,100	1.000	0.07
30	2049	27	1,100	1.000	0.07
31	2050	27	1,100	1.000	0.07
32	2051	27	1,100	1.000	0.07
33	2052	27	1,100	1.000	0.07
34	2053	27	1,100	1.000	0.07
35	2054	27	1,100	1.000	0.07

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	93	1,100	1.000	0.23
2	2021	93	1,100	1.000	0.23
3	2022	93	1,100	1.000	0.23
4	2023	93	1,100	1.000	0.23
5	2024	93	1,100	1.000	0.23
6	2025	93	1,100	1.000	0.23
7	2026	93	1,100	1.000	0.23
8	2027	93	1,100	1.000	0.23
9	2028	93	1,100	1.000	0.23
10	2029	93	1,100	1.000	0.23
11	2030	93	1,100	1.000	0.23
12	2031	93	1,100	1.000	0.23
13	2032	93	1,100	1.000	0.23
14	2033	93	1,100	1.000	0.23
15	2034	93	1,100	1.000	0.23
16	2035	93	1,100	1.000	0.23
17	2036	93	1,100	1.000	0.23
18	2037	93	1,100	1.000	0.23
19	2038	93	1,100	1.000	0.23
20	2039	93	1,100	1.000	0.23
21	2040	93	1,100	1.000	0.23
22	2041	93	1,100	1.000	0.23
23	2042	93	1,100	1.000	0.23
24	2043	93	1,100	1.000	0.23
25	2044	93	1,100	1.000	0.23
26	2045	33	1,100	1.000	0.08
27	2046	33	1,100	1.000	0.08
28	2047	33	1,100	1.000	0.08
29	2048	33	1,100	1.000	0.08
30	2049	33	1,100	1.000	0.08
31	2050	33	1,100	1.000	0.08
32	2051	33	1,100	1.000	0.08
33	2052	33	1,100	1.000	0.08
34	2053	33	1,100	1.000	0.08
35	2054	33	1,100	1.000	0.08

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.7%
3	2022	0.1%	-0.6%
4	2023	0.3%	-0.4%
5	2024	0.5%	0.1%
6	2025	0.7%	0.9%
7	2026	1.0%	1.8%
8	2027	1.2%	3.1%
9	2028	1.5%	4.6%
10	2029	1.8%	6.4%
11	2030	2.2%	8.6%
12	2031	2.5%	11.1%
13	2032	2.9%	14.0%
14	2033	3.3%	17.3%
15	2034	3.7%	21.1%
16	2035	4.2%	25.3%
17	2036	4.7%	30.0%
18	2037	5.0%	35.0%
19	2038	5.3%	40.3%
20	2039	5.7%	46.0%
21	2040	6.0%	52.0%
22	2041	6.4%	58.4%
23	2042	6.7%	65.2%
24	2043	7.3%	72.5%
25	2044	7.5%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.1%
28	2047	1.7%	84.8%
29	2048	1.9%	86.7%
30	2049	2.0%	88.7%
31	2050	2.1%	90.7%
32	2051	2.2%	92.9%
33	2052	2.3%	95.1%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 1 - Point Thomson Pipeline
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	0.0%	-0.9%
4	2023	0.2%	-0.8%
5	2024	0.4%	-0.4%
6	2025	0.6%	0.2%
7	2026	0.9%	1.1%
8	2027	1.2%	2.3%
9	2028	1.4%	3.7%
10	2029	1.8%	5.5%
11	2030	2.1%	7.6%
12	2031	2.5%	10.0%
13	2032	2.9%	12.9%
14	2033	3.3%	16.2%
15	2034	3.7%	19.9%
16	2035	4.2%	24.1%
17	2036	4.7%	28.8%
18	2037	5.1%	33.9%
19	2038	5.4%	39.3%
20	2039	5.8%	45.1%
21	2040	6.1%	51.2%
22	2041	6.6%	57.8%
23	2042	6.9%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.0%
28	2047	1.7%	84.8%
29	2048	1.8%	86.6%
30	2049	2.0%	88.5%
31	2050	2.1%	90.6%
32	2051	2.2%	92.8%
33	2052	2.3%	95.1%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	104	-	36	5	144
2011	144	73	-	25	13	256
2012	256	114	-	39	23	433
2013	433	157	-	54	38	682
2014	682	307	6	100	63	1,157
2015	1,157	774	15	252	118	2,316
2016	2,316	2,053	41	668	259	5,337
2017	5,337	2,005	40	652	470	8,504
2018	8,504	1,653	33	538	680	11,408
2019	11,408	976	20	317	861	13,582
2020	13,582	336	-	116	-	14,033
2021	14,033	9	-	3	-	14,045
		8,559	155	2,800	2,531	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	136	-	47	7	189
2011	189	95	-	33	18	335
2012	335	149	-	51	32	568
2013	568	205	-	71	52	896
2014	896	401	8	130	85	1,521
2015	1,521	1,011	20	329	161	3,042
2016	3,042	2,682	54	873	354	7,005
2017	7,005	2,620	52	852	641	11,171
2018	11,171	2,161	43	703	929	15,006
2019	15,006	1,275	25	415	1,176	17,897
2020	17,897	438	-	151	-	18,487
2021	18,487	12	-	4	-	18,503
		11,185	203	3,659	3,455	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	13,582	451	66	14,099	23	(314)	13,809
2	2021	14,099	12	25	14,136	24	(600)	13,561
3	2022	14,136	-	(1)	14,136	24	(881)	13,279
4	2023	14,136	-	(38)	14,098	23	(1,156)	12,964
5	2024	14,098	-	(79)	14,018	22	(1,426)	12,614
6	2025	14,018	-	(118)	13,901	22	(1,689)	12,233
7	2026	13,901	-	(155)	13,746	22	(1,945)	11,823
8	2027	13,746	-	(197)	13,548	22	(2,193)	11,378
9	2028	13,548	-	(240)	13,309	22	(2,432)	10,899
10	2029	13,309	-	(285)	13,024	22	(2,661)	10,384
11	2030	13,024	-	(336)	12,688	22	(2,881)	9,828
12	2031	12,688	-	(384)	12,304	22	(3,090)	9,236
13	2032	12,304	-	(432)	11,872	23	(3,288)	8,607
14	2033	11,872	-	(487)	11,385	23	(3,473)	7,936
15	2034	11,385	-	(544)	10,841	24	(3,645)	7,220
16	2035	10,841	-	(605)	10,236	24	(3,802)	6,458
17	2036	10,236	-	(660)	9,576	25	(3,642)	5,960
18	2037	9,576	-	(698)	8,879	25	(3,371)	5,533
19	2038	8,879	-	(736)	8,142	26	(3,085)	5,083
20	2039	8,142	-	(774)	7,368	26	(2,783)	4,611
21	2040	7,368	-	(816)	6,552	27	(2,464)	4,115
22	2041	6,552	-	(868)	5,684	28	(2,123)	3,588
23	2042	5,684	-	(904)	4,780	28	(1,768)	3,040
24	2043	4,780	-	(973)	3,807	29	(1,384)	2,451
25	2044	3,807	-	(998)	2,809	29	(991)	1,848
26	2045	2,809	-	(280)	2,529	30	(892)	1,667
27	2046	2,529	-	(294)	2,235	31	(788)	1,477
28	2047	2,235	-	(306)	1,928	31	(679)	1,281
29	2048	1,928	-	(321)	1,607	32	(563)	1,076
30	2049	1,607	-	(258)	1,349	39	(474)	914
31	2050	1,349	-	(263)	1,086	40	(383)	743
32	2051	1,086	-	(266)	821	41	(291)	571
33	2052	821	-	(271)	550	42	(196)	396
34	2053	550	-	(273)	277	43	(100)	219
35	2054	277	-	(283)	(6)	44	0	37
			463	(14,052)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

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Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	17,897	590	105	18,592	23	(413)	18,202
2	2021	18,592	16	48	18,656	24	(790)	17,890
3	2022	18,656	-	15	18,671	24	(1,160)	17,535
4	2023	18,671	-	(31)	18,640	23	(1,524)	17,139
5	2024	18,640	-	(83)	18,557	22	(1,880)	16,699
6	2025	18,557	-	(132)	18,426	22	(2,228)	16,219
7	2026	18,426	-	(180)	18,245	22	(2,567)	15,700
8	2027	18,245	-	(236)	18,009	22	(2,895)	15,135
9	2028	18,009	-	(292)	17,717	22	(3,213)	14,525
10	2029	17,717	-	(352)	17,364	22	(3,519)	13,867
11	2030	17,364	-	(420)	16,944	22	(3,812)	13,154
12	2031	16,944	-	(486)	16,458	22	(4,091)	12,389
13	2032	16,458	-	(554)	15,904	23	(4,355)	11,571
14	2033	15,904	-	(629)	15,275	23	(4,604)	10,694
15	2034	15,275	-	(709)	14,566	24	(4,835)	9,755
16	2035	14,566	-	(795)	13,771	24	(5,048)	8,747
17	2036	13,771	-	(875)	12,896	25	(4,916)	8,005
18	2037	12,896	-	(934)	11,962	25	(4,553)	7,434
19	2038	11,962	-	(990)	10,972	26	(4,168)	6,830
20	2039	10,972	-	(1,045)	9,928	26	(3,760)	6,194
21	2040	9,928	-	(1,106)	8,822	27	(3,326)	5,522
22	2041	8,822	-	(1,181)	7,641	28	(2,862)	4,806
23	2042	7,641	-	(1,235)	6,406	28	(2,376)	4,058
24	2043	6,406	-	(1,333)	5,074	29	(1,850)	3,252
25	2044	5,074	-	(1,373)	3,701	29	(1,307)	2,423
26	2045	3,701	-	(341)	3,360	30	(1,188)	2,202
27	2046	3,360	-	(361)	2,999	31	(1,061)	1,968
28	2047	2,999	-	(379)	2,619	31	(927)	1,724
29	2048	2,619	-	(402)	2,218	32	(784)	1,466
30	2049	2,218	-	(345)	1,873	39	(664)	1,249
31	2050	1,873	-	(356)	1,518	40	(539)	1,018
32	2051	1,518	-	(364)	1,153	41	(411)	783
33	2052	1,153	-	(376)	777	42	(278)	541
34	2053	777	-	(385)	393	43	(142)	293
35	2054	393	-	(397)	(4)	44	0	39
			605	(18,507)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	467	452	(66)	274	34	273	311	1,744
2	2021	482	411	(25)	289	35	267	285	1,744
3	2022	473	403	1	287	35	264	281	1,744
4	2023	463	394	38	278	36	259	277	1,744
5	2024	451	384	79	267	37	253	273	1,744
6	2025	438	373	118	263	38	248	267	1,744
7	2026	424	361	155	262	39	243	261	1,744
8	2027	409	348	197	262	39	234	255	1,744
9	2028	393	334	240	261	40	229	247	1,744
10	2029	375	319	285	260	41	224	240	1,744
11	2030	356	303	336	260	42	215	231	1,744
12	2031	336	286	384	266	43	207	222	1,744
13	2032	314	268	432	271	44	202	212	1,744
14	2033	292	248	487	277	45	194	202	1,744
15	2034	267	227	544	283	46	185	191	1,744
16	2035	241	205	605	290	47	177	179	1,744
17	2036	219	186	660	296	48	166	169	1,744
18	2037	203	172	698	303	49	158	162	1,744
19	2038	187	159	736	309	50	147	155	1,744
20	2039	171	145	774	316	51	139	147	1,744
21	2040	154	131	816	323	52	128	140	1,744
22	2041	136	116	868	330	53	109	132	1,744
23	2042	117	99	904	337	55	109	123	1,744
24	2043	97	82	973	345	56	76	115	1,744
25	2044	76	64	998	352	57	93	104	1,744
26	2045	62	53	280	360	58	84	53	951
27	2046	55	47	294	368	60	76	50	951
28	2047	49	41	306	376	61	71	47	951
29	2048	42	35	321	384	62	63	44	951
30	2049	35	30	258	468	64	60	36	951
31	2050	29	25	263	479	65	57	33	951
32	2051	23	20	266	489	66	57	30	951
33	2052	17	15	271	500	68	55	26	951
34	2053	11	9	273	511	69	55	23	951
35	2054	5	4	283	522	71	55	19	959
		7,867	6,750	14,052	11,720	1,757	5,432	5,542	53,120

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	672	595	(105)	274	34	359	409	2,239
2	2021	695	541	(48)	289	35	352	375	2,239
3	2022	682	531	(15)	287	35	349	370	2,239
4	2023	668	520	31	278	36	341	365	2,239
5	2024	652	508	83	267	37	334	359	2,239
6	2025	634	494	132	263	38	327	352	2,239
7	2026	615	479	180	262	39	320	345	2,239
8	2027	594	463	236	262	39	309	337	2,239
9	2028	571	445	292	261	40	302	328	2,239
10	2029	547	426	352	260	41	295	318	2,239
11	2030	520	405	420	260	42	284	308	2,239
12	2031	492	383	486	266	43	273	296	2,239
13	2032	461	359	554	271	44	266	283	2,239
14	2033	429	334	629	277	45	255	270	2,239
15	2034	394	307	709	283	46	244	256	2,239
16	2035	356	278	795	290	47	234	240	2,239
17	2036	323	251	875	296	48	219	227	2,239
18	2037	297	232	934	303	49	208	216	2,239
19	2038	275	214	990	309	50	194	207	2,239
20	2039	251	195	1,045	316	51	183	198	2,239
21	2040	226	176	1,106	323	52	169	188	2,239
22	2041	199	155	1,181	330	53	144	177	2,239
23	2042	171	133	1,235	337	55	144	165	2,239
24	2043	141	110	1,333	345	56	101	155	2,239
25	2044	109	85	1,373	352	57	122	140	2,239
26	2045	89	69	341	360	58	111	68	1,097
27	2046	80	63	361	368	60	101	65	1,097
28	2047	71	55	379	376	61	93	61	1,097
29	2048	61	48	402	384	62	83	57	1,097
30	2049	52	41	345	468	64	79	49	1,097
31	2050	44	34	356	479	65	75	45	1,097
32	2051	35	27	364	489	66	75	40	1,097
33	2052	26	20	376	500	68	72	36	1,097
34	2053	16	13	385	511	69	72	31	1,097
35	2054	7	5	397	522	71	72	27	1,100
		11,452	8,993	18,507	11,720	1,757	7,161	7,363	66,952

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	1,744	3,000	1.118	1.42
2	2021	1,744	3,000	1.118	1.42
3	2022	1,744	3,000	1.118	1.42
4	2023	1,744	3,000	1.118	1.42
5	2024	1,744	3,000	1.118	1.42
6	2025	1,744	3,000	1.118	1.42
7	2026	1,744	3,000	1.118	1.42
8	2027	1,744	3,000	1.118	1.42
9	2028	1,744	3,000	1.118	1.42
10	2029	1,744	3,000	1.118	1.42
11	2030	1,744	3,000	1.118	1.42
12	2031	1,744	3,000	1.118	1.42
13	2032	1,744	3,000	1.118	1.42
14	2033	1,744	3,000	1.118	1.42
15	2034	1,744	3,000	1.118	1.42
16	2035	1,744	3,000	1.118	1.42
17	2036	1,744	3,000	1.118	1.42
18	2037	1,744	3,000	1.118	1.42
19	2038	1,744	3,000	1.118	1.42
20	2039	1,744	3,000	1.118	1.42
21	2040	1,744	3,000	1.118	1.42
22	2041	1,744	3,000	1.118	1.42
23	2042	1,744	3,000	1.118	1.42
24	2043	1,744	3,000	1.118	1.42
25	2044	1,744	3,000	1.118	1.42
26	2045	951	3,000	1.118	0.78
27	2046	951	3,000	1.118	0.78
28	2047	951	3,000	1.118	0.78
29	2048	951	3,000	1.118	0.78
30	2049	951	3,000	1.118	0.78
31	2050	951	3,000	1.118	0.78
32	2051	951	3,000	1.118	0.78
33	2052	951	3,000	1.118	0.78
34	2053	951	3,000	1.118	0.78
35	2054	959	3,000	1.118	0.78

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate

Project yr#	Fiscal Year	Revenue requirement	MDQ (MMcf/d)	MMBtu/ Mcf	Rate - $/MMBtu
1	2020	2,239	3,000	1.118	1.83
2	2021	2,239	3,000	1.118	1.83
3	2022	2,239	3,000	1.118	1.83
4	2023	2,239	3,000	1.118	1.83
5	2024	2,239	3,000	1.118	1.83
6	2025	2,239	3,000	1.118	1.83
7	2026	2,239	3,000	1.118	1.83
8	2027	2,239	3,000	1.118	1.83
9	2028	2,239	3,000	1.118	1.83
10	2029	2,239	3,000	1.118	1.83
11	2030	2,239	3,000	1.118	1.83
12	2031	2,239	3,000	1.118	1.83
13	2032	2,239	3,000	1.118	1.83
14	2033	2,239	3,000	1.118	1.83
15	2034	2,239	3,000	1.118	1.83
16	2035	2,239	3,000	1.118	1.83
17	2036	2,239	3,000	1.118	1.83
18	2037	2,239	3,000	1.118	1.83
19	2038	2,239	3,000	1.118	1.83
20	2039	2,239	3,000	1.118	1.83
21	2040	2,239	3,000	1.118	1.83
22	2041	2,239	3,000	1.118	1.83
23	2042	2,239	3,000	1.118	1.83
24	2043	2,239	3,000	1.118	1.83
25	2044	2,239	3,000	1.118	1.83
26	2045	1,097	3,000	1.118	0.90
27	2046	1,097	3,000	1.118	0.90
28	2047	1,097	3,000	1.118	0.90
29	2048	1,097	3,000	1.118	0.90
30	2049	1,097	3,000	1.118	0.90
31	2050	1,097	3,000	1.118	0.90
32	2051	1,097	3,000	1.118	0.90
33	2052	1,097	3,000	1.118	0.90
34	2053	1,097	3,000	1.118	0.90
35	2054	1,100	3,000	1.118	0.90

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.5%	-0.5%
2	2021	-0.2%	-0.6%
3	2022	0.0%	-0.6%
4	2023	0.3%	-0.4%
5	2024	0.6%	0.2%
6	2025	0.8%	1.0%
7	2026	1.1%	2.1%
8	2027	1.4%	3.5%
9	2028	1.7%	5.2%
10	2029	2.0%	7.3%
11	2030	2.4%	9.7%
12	2031	2.7%	12.4%
13	2032	3.1%	15.5%
14	2033	3.5%	18.9%
15	2034	3.9%	22.8%
16	2035	4.3%	27.1%
17	2036	4.7%	31.8%
18	2037	5.0%	36.8%
19	2038	5.2%	42.0%
20	2039	5.5%	47.5%
21	2040	5.8%	53.4%
22	2041	6.2%	59.5%
23	2042	6.4%	66.0%
24	2043	6.9%	72.9%
25	2044	7.1%	80.0%
26	2045	2.0%	82.0%
27	2046	2.1%	84.1%
28	2047	2.2%	86.3%
29	2048	2.3%	88.6%
30	2049	1.8%	90.4%
31	2050	1.9%	92.3%
32	2051	1.9%	94.2%
33	2052	1.9%	96.1%
34	2053	1.9%	98.0%
35	2054	2.0%	100.1%
		100.1%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 2 - GTP
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.3%	-0.8%
3	2022	-0.1%	-0.9%
4	2023	0.2%	-0.7%
5	2024	0.4%	-0.3%
6	2025	0.7%	0.4%
7	2026	1.0%	1.4%
8	2027	1.3%	2.7%
9	2028	1.6%	4.2%
10	2029	1.9%	6.2%
11	2030	2.3%	8.4%
12	2031	2.6%	11.1%
13	2032	3.0%	14.0%
14	2033	3.4%	17.4%
15	2034	3.8%	21.3%
16	2035	4.3%	25.6%
17	2036	4.7%	30.3%
18	2037	5.0%	35.4%
19	2038	5.3%	40.7%
20	2039	5.6%	46.3%
21	2040	6.0%	52.3%
22	2041	6.4%	58.7%
23	2042	6.7%	65.4%
24	2043	7.2%	72.6%
25	2044	7.4%	80.0%
26	2045	1.8%	81.8%
27	2046	2.0%	83.8%
28	2047	2.1%	85.8%
29	2048	2.2%	88.0%
30	2049	1.9%	89.9%
31	2050	1.9%	91.8%
32	2051	2.0%	93.8%
33	2052	2.0%	95.8%
34	2053	2.1%	97.9%
35	2054	2.1%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	132	-	26	5	164
2011	164	90	-	18	15	287
2012	287	141	-	28	26	482
2013	482	203	-	40	42	767
2014	767	230	5	41	64	1,107
2015	1,107	270	5	48	90	1,521
2016	1,521	353	7	63	124	2,068
2017	2,068	1,951	39	348	230	4,635
2018	4,635	5,361	107	956	552	11,611
2019	11,611	1,886	38	336	899	14,769
2020	14,769	108	-	21	-	14,898
2021	14,898	11	-	2	-	14,912
		10,736	201	1,928	2,047	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate base build-up during Development & Execution Phases

Fiscal Year	Opening balance	Additions (Real$)	Property Taxes during contruction (Real$)	Escalation	AFUDC	Closing balance
2010	-	173	-	34	7	214
2011	214	118	-	23	21	376
2012	376	184	-	36	35	632
2013	632	265	-	53	58	1,008
2014	1,008	301	6	54	87	1,456
2015	1,456	352	7	63	123	2,001
2016	2,001	462	9	82	169	2,724
2017	2,724	2,549	51	454	314	6,092
2018	6,092	7,006	140	1,249	753	15,240
2019	15,240	2,464	49	439	1,227	19,420
2020	19,420	141	-	28	-	19,589
2021	19,589	14	-	3	-	19,606
		14,030	263	2,519	2,794	

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	14,769	129	91	14,990	49	(338)	14,701
2	2021	14,990	13	18	15,021	49	(643)	14,427
3	2022	15,021	-	(7)	15,013	49	(942)	14,121
4	2023	15,013	-	(38)	14,976	49	(1,235)	13,790
5	2024	14,976	-	(70)	14,906	49	(1,521)	13,434
6	2025	14,906	-	(105)	14,801	50	(1,800)	13,051
7	2026	14,801	-	(141)	14,660	50	(2,072)	12,638
8	2027	14,660	-	(183)	14,476	50	(2,335)	12,191
9	2028	14,476	-	(226)	14,251	50	(2,590)	11,711
10	2029	14,251	-	(270)	13,980	50	(2,834)	11,196
11	2030	13,980	-	(321)	13,659	50	(3,069)	10,640
12	2031	13,659	-	(375)	13,284	50	(3,292)	10,042
13	2032	13,284	-	(430)	12,854	50	(3,504)	9,400
14	2033	12,854	-	(492)	12,362	51	(3,703)	8,710
15	2034	12,362	-	(557)	11,805	51	(3,888)	7,968
16	2035	11,805	-	(627)	11,178	51	(4,058)	7,171
17	2036	11,178	-	(698)	10,480	51	(4,071)	6,460
18	2037	10,480	-	(753)	9,727	51	(3,775)	6,004
19	2038	9,727	-	(800)	8,927	51	(3,459)	5,520
20	2039	8,927	-	(848)	8,079	52	(3,123)	5,008
21	2040	8,079	-	(900)	7,179	52	(2,767)	4,464
22	2041	7,179	-	(964)	6,216	52	(2,384)	3,884
23	2042	6,216	-	(1,010)	5,205	52	(1,982)	3,276
24	2043	5,205	-	(1,093)	4,112	52	(1,545)	2,619
25	2044	4,112	-	(1,130)	2,982	52	(1,094)	1,941
26	2045	2,982	-	(223)	2,759	53	(1,015)	1,796
27	2046	2,759	-	(241)	2,518	53	(929)	1,641
28	2047	2,518	-	(258)	2,260	53	(837)	1,477
29	2048	2,260	-	(277)	1,983	53	(736)	1,300
30	2049	1,983	-	(292)	1,691	53	(629)	1,115
31	2050	1,691	-	(308)	1,383	54	(515)	921
32	2051	1,383	-	(322)	1,061	54	(396)	718
33	2052	1,061	-	(339)	722	54	(270)	506
34	2053	722	-	(354)	368	54	(138)	284
35	2054	368	-	(368)	0	55	0	55
			142	(14,912)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate Base Changes During Operating Phase

Project yr#	Fiscal Year	Gas Plant in Service	Additions	Depreciation	Net Plant	Working capital	Accumulated Deferred Income Tax	Rate Base
1	2020	19,420	169	139	19,728	49	(444)	19,333
2	2021	19,728	17	44	19,789	49	(844)	18,994
3	2022	19,789	-	11	19,800	49	(1,238)	18,611
4	2023	19,800	-	(29)	19,771	49	(1,624)	18,197
5	2024	19,771	-	(72)	19,700	49	(2,002)	17,747
6	2025	19,700	-	(118)	19,582	50	(2,370)	17,261
7	2026	19,582	-	(167)	19,415	50	(2,729)	16,736
8	2027	19,415	-	(223)	19,193	50	(3,078)	16,164
9	2028	19,193	-	(279)	18,913	50	(3,415)	15,548
10	2029	18,913	-	(340)	18,574	50	(3,740)	14,884
11	2030	18,574	-	(408)	18,166	50	(4,052)	14,164
12	2031	18,166	-	(481)	17,684	50	(4,349)	13,385
13	2032	17,684	-	(556)	17,128	50	(4,631)	12,548
14	2033	17,128	-	(640)	16,488	51	(4,896)	11,643
15	2034	16,488	-	(729)	15,759	51	(5,143)	10,667
16	2035	15,759	-	(825)	14,934	51	(5,370)	9,614
17	2036	14,934	-	(926)	14,008	51	(5,448)	8,611
18	2037	14,008	-	(1,004)	13,004	51	(5,053)	8,003
19	2038	13,004	-	(1,070)	11,934	51	(4,630)	7,355
20	2039	11,934	-	(1,136)	10,798	52	(4,180)	6,669
21	2040	10,798	-	(1,209)	9,589	52	(3,701)	5,940
22	2041	9,589	-	(1,297)	8,293	52	(3,185)	5,160
23	2042	8,293	-	(1,363)	6,929	52	(2,642)	4,340
24	2043	6,929	-	(1,478)	5,452	52	(2,052)	3,453
25	2044	5,452	-	(1,531)	3,921	52	(1,440)	2,534
26	2045	3,921	-	(287)	3,635	53	(1,339)	2,348
27	2046	3,635	-	(312)	3,323	53	(1,228)	2,148
28	2047	3,323	-	(334)	2,988	53	(1,108)	1,934
29	2048	2,988	-	(362)	2,627	53	(976)	1,704
30	2049	2,627	-	(383)	2,244	53	(836)	1,461
31	2050	2,244	-	(405)	1,839	54	(687)	1,206
32	2051	1,839	-	(425)	1,414	54	(530)	938
33	2052	1,414	-	(449)	965	54	(362)	657
34	2053	965	-	(471)	494	54	(186)	362
35	2054	494	-	(494)	(0)	55	(0)	54
			186	(19,606)				

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	502	486	(91)	62	6	289	335	1,590
2	2021	513	437	(18)	64	6	283	304	1,590
3	2022	503	428	7	65	6	281	299	1,590
4	2023	492	419	38	67	6	275	294	1,590
5	2024	480	408	70	68	6	269	288	1,590
6	2025	467	397	105	70	6	263	282	1,590
7	2026	453	385	141	71	6	257	275	1,590
8	2027	438	372	183	73	7	249	268	1,590
9	2028	421	359	226	74	7	243	260	1,590
10	2029	404	344	270	76	7	237	252	1,590
11	2030	385	328	321	78	7	229	243	1,590
12	2031	365	310	375	79	7	220	233	1,590
13	2032	343	292	430	81	7	214	223	1,590
14	2033	319	272	492	83	8	205	212	1,590
15	2034	294	250	557	85	8	197	200	1,590
16	2035	267	227	627	86	8	188	187	1,590
17	2036	240	204	698	88	8	176	174	1,590
18	2037	220	187	753	90	8	168	164	1,590
19	2038	203	173	800	92	8	156	157	1,590
20	2039	186	158	848	94	9	148	148	1,590
21	2040	167	142	900	96	9	136	140	1,590
22	2041	147	125	964	98	9	116	131	1,590
23	2042	126	107	1,010	101	9	116	120	1,590
24	2043	104	88	1,093	103	9	81	111	1,590
25	2044	80	68	1,130	105	10	98	98	1,590
26	2045	66	56	223	107	10	90	49	601
27	2046	61	52	241	110	10	81	47	601
28	2047	55	47	258	112	10	75	44	601
29	2048	49	42	277	115	10	67	41	601
30	2049	43	36	292	117	11	64	38	601
31	2050	36	31	308	120	11	61	35	601
32	2051	29	25	322	122	11	61	32	601
33	2052	22	18	339	125	11	58	28	601
34	2053	14	12	354	128	12	58	24	601
35	2054	6	5	368	131	12	58	20	600
		8,497	7,290	14,912	3,236	294	5,765	5,757	45,751

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Annual Revenue Requirement

Project yr#	Fiscal Year	Interest Expense	Equity return	Depreciation	O&M	Negative salvage	Property tax	Tax allowance	Revenue requirement
1	2020	721	640	(139)	62	6	380	440	2,111
2	2021	738	575	(44)	64	6	373	399	2,111
3	2022	724	564	(11)	65	6	369	393	2,111
4	2023	709	552	29	67	6	361	387	2,111
5	2024	692	539	72	68	6	354	380	2,111
6	2025	674	525	118	70	6	346	372	2,111
7	2026	655	510	167	71	6	339	363	2,111
8	2027	633	494	223	73	7	327	354	2,111
9	2028	611	476	279	74	7	320	345	2,111
10	2029	586	456	340	76	7	312	334	2,111
11	2030	559	436	408	78	7	301	322	2,111
12	2031	530	413	481	79	7	289	310	2,111
13	2032	499	389	556	81	7	282	296	2,111
14	2033	466	363	640	83	8	270	282	2,111
15	2034	430	335	729	85	8	259	266	2,111
16	2035	391	304	825	86	8	247	249	2,111
17	2036	351	273	926	88	8	232	232	2,111
18	2037	320	249	1,004	90	8	221	219	2,111
19	2038	296	230	1,070	92	8	205	208	2,111
20	2039	270	210	1,136	94	9	194	197	2,111
21	2040	243	189	1,209	96	9	179	186	2,111
22	2041	214	167	1,297	98	9	152	174	2,111
23	2042	183	142	1,363	101	9	152	160	2,111
24	2043	150	117	1,478	103	9	107	147	2,111
25	2044	115	90	1,531	105	10	129	131	2,111
26	2045	94	73	287	107	10	118	64	753
27	2046	87	67	312	110	10	107	61	753
28	2047	79	61	334	112	10	99	58	753
29	2048	70	55	362	115	10	88	54	753
30	2049	61	47	383	117	11	84	50	753
31	2050	51	40	405	120	11	80	46	753
32	2051	41	32	425	122	11	80	41	753
33	2052	31	24	449	125	11	76	37	753
34	2053	20	15	471	128	12	76	32	753
35	2054	8	6	494	131	12	76	26	753
		12,301	9,660	19,606	3,236	294	7,582	7,616	60,296

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	161	383	1.15	1,429	2,971	1.32
2	2021	1.118	161	383	1.15	1,429	2,971	1.32
3	2022	1.118	161	383	1.15	1,429	2,971	1.32
4	2023	1.118	161	383	1.15	1,429	2,971	1.32
5	2024	1.118	161	383	1.15	1,429	2,971	1.32
6	2025	1.118	161	383	1.15	1,429	2,971	1.32
7	2026	1.118	161	383	1.15	1,429	2,971	1.32
8	2027	1.118	161	383	1.15	1,429	2,971	1.32
9	2028	1.118	161	383	1.15	1,429	2,971	1.32
10	2029	1.118	161	383	1.15	1,429	2,971	1.32
11	2030	1.118	161	383	1.15	1,429	2,971	1.32
12	2031	1.118	161	383	1.15	1,429	2,971	1.32
13	2032	1.118	161	383	1.15	1,429	2,971	1.32
14	2033	1.118	161	383	1.15	1,429	2,971	1.32
15	2034	1.118	161	383	1.15	1,429	2,971	1.32
16	2035	1.118	161	383	1.15	1,429	2,971	1.32
17	2036	1.118	161	383	1.15	1,429	2,971	1.32
18	2037	1.118	161	383	1.15	1,429	2,971	1.32
19	2038	1.118	161	383	1.15	1,429	2,971	1.32
20	2039	1.118	161	383	1.15	1,429	2,971	1.32
21	2040	1.118	161	383	1.15	1,429	2,971	1.32
22	2041	1.118	161	383	1.15	1,429	2,971	1.32
23	2042	1.118	161	383	1.15	1,429	2,971	1.32
24	2043	1.118	161	383	1.15	1,429	2,971	1.32
25	2044	1.118	161	383	1.15	1,429	2,971	1.32
26	2045	1.118	61	383	0.43	540	2,971	0.50
27	2046	1.118	61	383	0.43	540	2,971	0.50
28	2047	1.118	61	383	0.43	540	2,971	0.50
29	2048	1.118	61	383	0.43	540	2,971	0.50
30	2049	1.118	61	383	0.43	540	2,971	0.50
31	2050	1.118	61	383	0.43	540	2,971	0.50
32	2051	1.118	61	383	0.43	540	2,971	0.50
33	2052	1.118	61	383	0.43	540	2,971	0.50
34	2053	1.118	61	383	0.43	540	2,971	0.50
35	2054	1.118	61	383	0.43	539	2,971	0.50

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Rate

			In-state			Export		
Project yr#	Fiscal Year	MMBtu/ Mcf	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu	Revenue requirement	MDQ (MMBtu/d)	Rate - $/MMBtu
1	2020	1.118	213	383	1.53	1,897	2,971	1.75
2	2021	1.118	213	383	1.53	1,897	2,971	1.75
3	2022	1.118	213	383	1.53	1,897	2,971	1.75
4	2023	1.118	213	383	1.53	1,897	2,971	1.75
5	2024	1.118	213	383	1.53	1,897	2,971	1.75
6	2025	1.118	213	383	1.53	1,897	2,971	1.75
7	2026	1.118	213	383	1.53	1,897	2,971	1.75
8	2027	1.118	213	383	1.53	1,897	2,971	1.75
9	2028	1.118	213	383	1.53	1,897	2,971	1.75
10	2029	1.118	213	383	1.53	1,897	2,971	1.75
11	2030	1.118	213	383	1.53	1,897	2,971	1.75
12	2031	1.118	213	383	1.53	1,897	2,971	1.75
13	2032	1.118	213	383	1.53	1,897	2,971	1.75
14	2033	1.118	213	383	1.53	1,897	2,971	1.75
15	2034	1.118	213	383	1.53	1,897	2,971	1.75
16	2035	1.118	213	383	1.53	1,897	2,971	1.75
17	2036	1.118	213	383	1.53	1,897	2,971	1.75
18	2037	1.118	213	383	1.53	1,897	2,971	1.75
19	2038	1.118	213	383	1.53	1,897	2,971	1.75
20	2039	1.118	213	383	1.53	1,897	2,971	1.75
21	2040	1.118	213	383	1.53	1,897	2,971	1.75
22	2041	1.118	213	383	1.53	1,897	2,971	1.75
23	2042	1.118	213	383	1.53	1,897	2,971	1.75
24	2043	1.118	213	383	1.53	1,897	2,971	1.75
25	2044	1.118	213	383	1.53	1,897	2,971	1.75
26	2045	1.118	76	383	0.54	677	2,971	0.62
27	2046	1.118	76	383	0.54	677	2,971	0.62
28	2047	1.118	76	383	0.54	677	2,971	0.62
29	2048	1.118	76	383	0.54	677	2,971	0.62
30	2049	1.118	76	383	0.54	677	2,971	0.62
31	2050	1.118	76	383	0.54	677	2,971	0.62
32	2051	1.118	76	383	0.54	677	2,971	0.62
33	2052	1.118	76	383	0.54	677	2,971	0.62
34	2053	1.118	76	383	0.54	677	2,971	0.62
35	2054	1.118	76	383	0.54	677	2,971	0.62

Alaska Pipeline Project - Valdez Pipeline

Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$20B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.6%	-0.6%
2	2021	-0.1%	-0.7%
3	2022	0.0%	-0.7%
4	2023	0.3%	-0.4%
5	2024	0.5%	0.0%
6	2025	0.7%	0.7%
7	2026	0.9%	1.7%
8	2027	1.2%	2.9%
9	2028	1.5%	4.4%
10	2029	1.8%	6.2%
11	2030	2.2%	8.4%
12	2031	2.5%	10.9%
13	2032	2.9%	13.8%
14	2033	3.3%	17.1%
15	2034	3.7%	20.8%
16	2035	4.2%	25.0%
17	2036	4.7%	29.7%
18	2037	5.0%	34.8%
19	2038	5.4%	40.1%
20	2039	5.7%	45.8%
21	2040	6.0%	51.9%
22	2041	6.5%	58.3%
23	2042	6.8%	65.1%
24	2043	7.3%	72.4%
25	2044	7.6%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.1%
28	2047	1.7%	84.8%
29	2048	1.9%	86.7%
30	2049	2.0%	88.7%
31	2050	2.1%	90.7%
32	2051	2.2%	92.9%
33	2052	2.3%	95.2%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Alaska Pipeline Project - Valdez Pipeline
Negotiated Rate Model Output

The model output shown below are the results of calculations that are based on a number of input assumptions. A change in one or more of these assumptions will result in a change in these output information. For rate modeling purposes, full year volumes are assumed in year 1.

Numbers may not add due to rounding.

Zone 3 - Alaska Section
US$Millions (Nominal)
(35 Year Contract Term)
$26B Capex Case

Annual depreciation rate

Project yr#	Fiscal Year	Depreciation rate	Cumulative Depreciation
1	2020	-0.7%	-0.7%
2	2021	-0.2%	-0.9%
3	2022	-0.1%	-1.0%
4	2023	0.1%	-0.8%
5	2024	0.4%	-0.5%
6	2025	0.6%	0.1%
7	2026	0.8%	1.0%
8	2027	1.1%	2.1%
9	2028	1.4%	3.5%
10	2029	1.7%	5.3%
11	2030	2.1%	7.3%
12	2031	2.5%	9.8%
13	2032	2.8%	12.6%
14	2033	3.3%	15.9%
15	2034	3.7%	19.6%
16	2035	4.2%	23.8%
17	2036	4.7%	28.6%
18	2037	5.1%	33.7%
19	2038	5.5%	39.1%
20	2039	5.8%	44.9%
21	2040	6.2%	51.1%
22	2041	6.6%	57.7%
23	2042	7.0%	64.7%
24	2043	7.5%	72.2%
25	2044	7.8%	80.0%
26	2045	1.5%	81.5%
27	2046	1.6%	83.1%
28	2047	1.7%	84.8%
29	2048	1.8%	86.6%
30	2049	2.0%	88.6%
31	2050	2.1%	90.6%
32	2051	2.2%	92.8%
33	2052	2.3%	95.1%
34	2053	2.4%	97.5%
35	2054	2.5%	100.0%
		100.0%	

Appendix C

Exhibit L
Definitions

Terms	Definitions
2009$	U.S. Dollars, In Real 2009 Dollars
AACEI	Association For The Advancement Of Cost Engineering International
ACA	Annual Charge Adjustment
ADFG	Alaska Department Of Fish And Game
ADNR	Alaska Department Of Natural Resources
AEA	Alaska Energy Authority
AECO	Alberta Energy Company, Alberta Gas Hub
AGIA	Alaska Gasline Inducement Act
AGPPT	Alaska Gas Pipeline Producer Team
AGRU	Acid Gas Removal Unit
AHFC	Alaska Housing Finance Corporation
ANGDA	Alaska Natural Gas Development Authority
ANGPA	Alaska Natural Gas Pipeline Act
ANRTL	Alaska Natural Resources To Liquids, LLC
AOS	Authorized Overrun Service
APP	Alaska Pipeline Project
APT	Alaska Power And Telephone
ASRC	Arctic Slope Regional Corporation
AVEC	Alaska Village Electric Cooperative
BACT	Best Available Control Technology
BCF	Billion Cubic Feet
BCF/D	Billion Standard Cubic Feet Per Day
BHP	Brake Horsepower
BPS	Basis Points
BTU	British Thermal Units
CCF	Hundred Cubic Feet
CDP	Concept Definition Phase
CEA	Chugach Electric Association
CF	Cubic Feet
CI	Combustion Inspection
CIRI	Cook Inlet Regional Inc.
COE	Corps Of Engineers

Terms	Definitions
CP	Conditions Precedent
CDT	Central Daylight Time
CVEA	Copper Valley Electric Association
D/E	Debt To Equity
DSM	Demand-Side Management
EIA	Energy Information Administration
EM	ExxonMobil
EMAMGI	ExxonMobil Alaska Midstream Gas Investments Inc.
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FUEL	Fuel And Lost And Unaccounted For Gas
FLG	Federal Loan Guarantee
FNG	Fairbanks Natural Gas, LLC
FTSA	Firm Transportation Service Agreement
GG	Gas Generator
GHG	Greenhouse Gas
GPM	Gallons Per Minute
GTG	Gas Turbine Generator
GTL	Gas To Liquids
GTP	Gas Treatment Plant
GVEA	Golden Valley Electric Association
HAP	Hazardous Air Pollutants
HEA	Homer Electric Association
HGPI	Hot Gas Path Inspection
HHV	Higher Heating Value
IPA	Interim Project Agreement
ISER	Institute Of Social And Economic Research
KWH	Kilowatt-Hour
LDC	Local Distribution Company
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
m^3	Cubic Meter
MCF	Thousand Cubic Feet
MDEA	Methyldiethanolamine

Terms	Definitions
MDQ	Maximum Daily Quantity
MEA	Matanuska Electric Association
MEQ	Maximum Extraction Quantity
MI	Major Inspection
ML&P	Anchorage Municipal Light And Power
MMBTU	Million British Thermal Units
MMBTU/D	Million British Thermal Units Per Day
MMCF	Million Cubic Feet
MMCF/D	Million Cubic Feet Per Day
MMCF/Y	Million Cubic Feet Per Year
MMTPA	Million Metric Tons Per Annum
MTQ	Maximum Treatment Quantity
MW	Megawatt
NAESB	North American Energy Standards Board
NEB	National Energy Board
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratories
NGA	Natural Gas Act
NGTL	Nova Gas Transmission Limited
NPA	Northern Pipeline Act
NPV	Net Present Value
NS	North Slope
NSB	North Slope Borough
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
OS	Open Season
PA	Precedent Agreement
PBU	Prudhoe Bay Unit
PFA	Project Funding Agreement
PFD	Process Flow Diagram
PL	Pipeline
PPMV	Parts Per Million On A Volume Basis
PSB	Project Scope Basis

Terms	**Definitions**
PSD	Prevention Of Significant Deterioration
PSIA	Pounds Per Square Inch, Absolute
PSIG	Pounds Per Square Inch, Gauge
PT	Project Team
PTU	Point Thomson Unit
RFA	AGIA Request For Application
RIRP	Regional Integrated Resource Plan
ROE	Return On Equity
S&P	Standard And Poor's
SAIC	Science Applications International Corporation
SCF	Standard Cubic Foot @ 14.696 Psia And 60°F
SES	Seward Electric System
SITE	Principal Design/Procurement And Construction Locations Conducting Project/Sub-Project Work
SLP	City Of Seward Light And Power
SOA	State Of Alaska
TAPS	Trans-Alaska Pipeline System
TC	TransCanada
TCF	Trillion Cubic Feet
TONNE	Metric Tonne, 1000 Kilograms
WDC	West Dock Causeway
WGQ	Wholesale Gas Quadrant
YTF	Yet To Flow