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April 7, 2010

VIA ELECTRONIC FILING

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

Re: Denali - The Alaska Gas Pipeline LLC, Docket No. PF08-26-001

Dear Ms. Bose:

Denali – The Alaska Gas Pipeline LLC ("Denali") hereby submits, for electronic filing in the above captioned matter, its Request for Commission Approval of Plan for Conducting an Open Season ("Plan") under the Alaska Natural Gas Pipeline Act,[1] and the regulations of the Federal Energy Regulatory Commission ("Commission").[2] Denali has also attached and incorporated as a part of its submission comprehensive documents, including the information required by the Commission ("Open Season Plan Documents"). Denali respectfully requests that the Commission approve Denali's Plan for its Alaska natural gas transportation project ("Alaska Project").

As more fully described in the attached materials, the Alaska Project will consist of jurisdictional transmission lines, a jurisdictional gas treatment plant, and a jurisdictional mainline that will extend from the Alaska North Slope to the border between Alaska and Canada. Volume I of the Open Season Plan Documents contains the proposed Open Season Notice as well as a proposed precedent agreement. Volume II contains the In-State Needs Study required by 18 C.F.R. Section 157.34(b), and related exhibits. Volume III contains the information required by 18 C.F.R. Section 157.34(c), and related exhibits A-N.

The required Commission notice of Denali's request for approval of its Open Season Plan must establish a date on which comments from interested persons are due and a date by which the Commission will act on the proposed Plan, which "shall be within 60 days of receipt" of Denali's filing. To ensure that the Commission has a complete and accurate record upon which to act on the proposed Plan, Denali requests that the Commission permit the filing by Denali of reply comments under its authority under Rule 213(a)(2) of the Commission's Rules of Practice

[1] Public Law 108-324 October 13 2004, 118 Stat. 1220 (Codified 15 U.S.C. § 720(a) et seq).
[2] 18 C.F.R. § 157.38.

and Procedure, 18 C.F.R. § 385.213(a)(2). Denali anticipates replying only as necessary to comments that are submitted regarding its proposed Plan.

Unless the Commission directs otherwise, its action on the proposed plan is to occur within 60 days from today (*i.e.* by June 4, 2010). *See* 18 C.F.R. § 157.38. Denali proposes that this 60 days be allocated by giving interested parties 30 days to file any comments (*i.e.* by May 7, 2010), and 15 days to Denali in which to file reply comments (*i.e.* by May 21, 2010).

Denali is submitting a proposed notice establishing due dates for comments and reply comments, as described above.

Please do not hesitate to contact the undersigned at (202) 220-6915 should you have any questions or require further information.

Respectfully submitted,

James F. Moriarty
Counsel for
DENALI-THE ALASKA GAS PIPELINE LLC

Encls.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Denali – The Alaska Gas Pipeline LLC	)))	Docket No. PF08-26-001

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

Take notice that on April 7, 2010, pursuant to the Alaska Natural Gas Pipeline Act and 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, Denali – The Alaska Gas Pipeline LLC ("Denali") filed its Request for Commission Approval of Plan for Conducting an Open Season ("Plan").

Denali is holding the proposed open season to solicit binding commitments for firm transmission, gas treatment plant services (treating and compression), and transportation provided by Denali's Alaska project ("Alaska Project"). When completed, the Alaska Project will consist of two FERC-jurisdictional transmission lines, a FERC-jurisdictional gas treatment plant that will treat North Slope gas for pipeline transportation, and a FERC-jurisdictional gas mainline that will extend from the Alaska North Slope to the border between Alaska and Canada. In accordance with Section 157.38 of the Commission's Regulations, the Commission must act on Denali's proposed Plan within 60 days of its filing. If Denali's Plan is approved by the Commission, the Open Season will commence on July 6, 2010, and conclude on October 4, 2010.

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 Commission's 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.

Please note that the review of Denali's Plan is being done as part of the pre-filing phase. Docket No. PF08-26-001 has been reserved for the Plan and commenters should use the -001 sub-docket for filings regarding the Plan. The Commission's webpage for eSubscription allows for subscription only to this specific sub-docket, Docket No. PF08-26-001 or, for those interested in the entire pre-filing process to, "Subscribe to root docket and all existing and new sub-dockets."

Pursuant to Section 157.38 of the Commission's Regulations, the Commission plans to act on Denali's Plan by June 4, 2010. Denali states that if its Plan is approved by the Commission, its open season will begin on July 6, 2010 and end on October 4, 2010.

Any questions regarding Denali's Request for Approval may be directed to:

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Any interested person desiring to comment on this filing or file a motion to intervene in this phase of the Alaska Project must file in accordance with Rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.212. All comments will be considered by the Commission in determining the appropriate action to be taken. In addition to the filing of comments, the Commission will permit the filing of reply comments pursuant to its authority under Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213. The due dates for motions to intervene, comments and reply comments are listed below.

The Commission strongly urges electronic filings of comments 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 seven copies of their comments or reply comments to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 (Label cover letter or first page with case name, Denali – The Alaska Gas Pipeline LLC – Docket No. PF08-26-001).

COMMENT DATE: May 7, 2010

REPLY COMMENT DATE: May 21, 2010

COMMISSION ACTION DATE: June 4, 2010

Kimberly D. Bose
Secretary

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

DENALI – THE ALASKA GAS PIPELINE LLC	)))	DOCKET NO. PF08-26-001

REQUEST FOR COMMISSION APPROVAL OF PLAN FOR CONDUCTING AN OPEN SEASON

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BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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REQUEST FOR COMMISSION APPROVAL OF PLAN FOR CONDUCTING AN OPEN SEASON

In the Alaska Natural Gas Pipeline Act (ANGPA), the United States Congress instructed the Federal Energy Regulatory Commission (Commission) to adopt special regulations governing the conduct of an open season for any Alaska natural gas transportation project (Alaska Regulations). In so doing, the Commission required that a prospective applicant file for Commission approval of a detailed plan (Plan) to conduct an open season "in conformance with [these regulations]."[1]

Denali – The Alaska Gas Pipeline LLC (Denali) hereby files its request for Commission approval of its Plan (Request).[2] Denali's Plan is in conformance with the Alaska Regulations.[3] Once approved by the Commission, Denali will conduct its open season in an effort to secure binding commitments from prospective qualified Alaska natural gas shippers (Shippers) for firm transmission (transportation service on the transmission lines), Gas Treatment Plant (GTP)

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[1] 18 C.F.R. § 157.38.

[2] Denali's Request is submitted under ANGPA, the Alaska Regulations (18 C.F.R. §§ 157.30-.39), and Rule 204 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.204).

[3] On March 18, 2010, the Commission issued Order No. 2005-B which amended portions of the Alaska Regulations (18 C.F.R. §§ 157.34(c)(19) – (21) and 157.35(c) – (d)). Though the amended regulations are not effective until April 28, 2010 (30 days after publication in the Federal Register on March 29, 2010), Denali has structured its compliance in conformance with Order No. 2005-B. *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, 130 FERC ¶ 61,196 (2010) (Order No. 2005-B). This Plan incorporates Denali's application of the recently issued Order No. 2005-B (as subsequently clarified) without waiving any of Denali's rights to seek rehearing of that Order.

services (treating and compression), and transportation (Open Season). As part of Denali's Request, Denali is submitting a proposed open season notice (Notice), with the following three volumes of Appendices: (A) a proposed Precedent Agreement; (B) the In-State Needs Study; and (C) 21 items of information required by 18 C.F.R. §§ 157.34(c)(1) – (21) about Denali's project and Denali itself, including an indicative FERC Gas Tariff (collectively, Plan Documents).

I. EXECUTIVE SUMMARY

A. OFFERING AND PROJECT SUMMARY

Denali and its affiliate, Denali Canada – The Alaska Gas Pipeline (West), Inc. (Denali Canada), are offering to construct and operate an Alaska natural gas transportation project to bring natural gas resources from the Alaska North Slope (ANS) to North American gas markets (Project). Denali would construct the Alaska portion of the Project (Alaska Project) and Denali Canada would construct the Canada portion of the Project (Canada Project).

Denali seeks prompt Commission approval of its Plan to conduct an Open Season for the Alaska Project. During the Open Season, Denali will request bids from Shippers for binding commitments for transportation and other services. Binding, long-term commitments are necessary to support Denali to advance the Project through its remaining phases, including submitting an application for a Certificate of Public Convenience and Necessity (CPCN) for the Alaska Project, obtaining a CPCN from the Commission, securing Project financing, completing detailed engineering, and constructing and commissioning the Project.

The Project is one of significance for the United States, particularly for the State of Alaska (State), and for Canada. Indeed, the U.S. Congress has already found that a compelling public need exists to construct and operate the Project.[4] However, any Alaska natural gas

[4] 15 U.S.C. § 720a(b)(2)(A) (2009).

transportation project of this scale will face "daunting challenges."[5] A predicate to the unprecedented investment and commitment of resources to construct the Alaska Project is Denali's ability to substantiate the Project's viability through the Congressionally-mandated and Commission-regulated open season process. The key indicator of viability will be whether there is sufficient Shipper interest to enter into binding firm service contracts for necessary capacity on the Project.[6]

The Alaska Project will consist of the following FERC jurisdictional facilities:

- **Transmission Lines.** Denali is planning two Transmission Lines: one beginning in the Point Thomson area and one beginning at the Central Gas Facility in the Prudhoe Bay Unit. The Transmission Lines will transport gas to the GTP.
- **GTP.** The GTP will be located in the Prudhoe Bay Unit on the ANS and is designed to receive gas from the producing fields and to treat and condition the gas for delivery into the Alaska Mainline. The GTP's services (gas treating and compression/chilling) will be unbundled.
- **Alaska Mainline.** The 730-mile Alaska Mainline will be a large diameter, high-pressure natural gas pipeline and related facilities for the transportation of natural gas from the outlet of the GTP to Alaska in-state delivery points (five in-state delivery points downstream of the GTP and one at the GTP) and the international border between Alaska and Canada.

[5] *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, FERC Stats. & Regs. ¶ 31,174 (2005) (Order No. 2005); *order on reh'g*, FERC Stats. & Regs. ¶ 31,187 (2005) (Order No. 2005-A); *as amended*, 130 FERC ¶ 61,196 (2010) (Order No. 2005-B).

[6] The Commission has recognized the importance of firm commitments to advance any pipeline project. Indeed, the Commission refuses to allow construction to begin without them unless the pipeline can assume full financial responsibility for the project. *See Statement of Policy*, 88 FERC ¶ 61,227 (1999); *Williston Basin Interstate Pipeline Co.*, 103 FERC ¶ 61,269 at P 21 (2003).

The Canada Project consists of the Canada Mainline, which includes a large diameter, high-pressure pipeline and related facilities for the transportation of natural gas from the Alaska-Canada border about 1,020 miles to Alberta, Canada. In Canada, Denali Canada will offer connections to multiple pipelines to provide Shippers options for transporting their gas to North American markets.

In preparation for Open Season, Denali has invested over 600,000 man-hours and over $140 million of private money. Denali has utilized the expertise of seconded personnel from its owner companies[7] as well as the expertise of world-class engineering firms (Bechtel for the Mainline and Arctic Solutions, a joint venture between Fluor and WorleyParsons, for the GTP) to complete an initial cost estimate and schedule for the Project. Denali's projected cost estimate is a high quality AACEI[8] Class 4 estimate and is summarized below in Table 1. The estimated in-service date for the Project is 2020.

Table 1 – Capital Cost Summary in 2009 U.S. Dollars (Billions)

	Transmission Lines		**GTP**	**Mainline**		**Total, GTP + Mainline**
	Prudhoe Bay Transmission Line	Point Thomson Transmission Line		Alaska	Canada	
Estimated Capital Cost	0.1	0.8	**12.2**	**10.4**	**12.5**	**35.1**

Denali's Open Season offer is based upon its cost estimate and schedule. In recognition of the risks of the Project, to provide open access, to be responsive to Shippers, and to meet Commission requirements to provide unbundled services, Denali's offer includes a number of

[7] Denali's owners, BP America Inc. affiliates (BP) and ConocoPhillips Company affiliates (ConocoPhillips) possess substantial experience with major arctic, ANS, and pipeline projects.

[8] Association for the Advancement of Cost Engineering International.

distinctive features. Among the features included in Denali's offer are the following:

1. Unbundled transmission (transportation service on the Transmission Lines), GTP, and transportation services that allow Shippers to select only those services that are necessary to treat and transport each Shipper's gas to market;
2. Terms that recognize the Project's significant economic uncertainty and risks, including decision points at Project milestones for a Shipper to decide whether to continue its participation as new Project information is developed;
3. A minimum credit rating requirement of BBB (Standard & Poor's) or Baa2 (Moody's Investors Service, Inc.) and no minimum volume commitment to encourage smaller leaseholders, explorers, and end users to participate in Denali's Open Season;
4. A substantially levelized rate over 20 years for negotiated rate Shippers and a three-year levelization period at the start-up of operations for recourse rate Shippers;
5. Distance-sensitive rates based on mileage;
6. No requirement that existing Shippers subsidize expansion Shippers;
7. Credit of 100 percent of the net revenues from interruptible and authorized overrun service to firm Shippers on a pro-rata basis; and
8. If Denali does not receive commitments for at least 85 percent of the design capacity at Open Season, a framework for Shippers and Denali to work together to consider a scaled down project, a different project such as a pipeline to an LNG facility, or to generate additional commitments to allow the original Project to proceed.

Denali's estimated levelized, negotiated rates for its various services as well as its estimated rates for delivery to in-state gas delivery points[9] are shown in Tables 2 and 3.

[9] As identified in the In-State Gas Demand Study attached as Appendix B.

Table 2 - Rate Summary, Estimated $/MMBtu (excluding fuel)

	Service	Negotiated Rate, 2009 U.S. $/MMBtu	Negotiated Rate, Money of the Day, U.S. $/MMBtu
Transmission Lines	Prudhoe Bay Transmission Line	0.004	0.005
	Point Thomson Transmission Line	0.26	0.31
GTP	Acid Gas Removal and Treated Gas Return	0.67	0.79
	Compression and Chilling	0.23	0.27
	Total	**0.90**	**1.06**
Alaska Mainline	Inlet of Alaska Mainline to Alaska-Canada Border	0.80	0.98
Canada Mainline*	Alaska-Canada Border to Alberta	0.97	1.21
Inlet of GTP to Alberta		**2.67**	**3.25**

* The rates for the Canada Mainline will be established in accordance with the rules and regulations of the NEB.

Table 3 - In-State Gas Delivery Rates, Estimated $/MMBtu ** **(excluding fuel)**

Inlet Alaska Mainline to Delivery Point	Negotiated Rate, 2009 U.S. $/MMBtu	Negotiated Rate, Money of the Day $/MMBtu
Livengood	0.44	0.55
Parks Highway Spur	0.49	0.61
Fairbanks	0.50	0.61
Delta Junction	0.59	0.73
Tok	0.70	0.87

** Distance-sensitive rates based on mileage.

Denali intends to take advantage of the modern, streamlined regulatory processes available in the U.S. and in Canada to progress the Project. In the U.S., Denali will proceed under ANGPA and the Commission's regulations with federal coordination assistance provided by the Office of the Federal Coordinator. Denali will also adhere to the right-of-way and permitting requirements of the State. State law cannot, and does not, give any project an exclusive right-of-way across

State lands or any special treatment in the State permitting process.[10] Similarly, in Canada, no proponent has an exclusive right to build a project. Denali Canada will apply to the National Energy Board of Canada (NEB) for a CPCN. The NEB, like the Commission, is mandated to evaluate projects – including in relation to competing projects – on the basis of the public interest. Additionally, the Canada Project will be advanced through a single, coordinated, and modern assessment process under the auspices of the Major Projects Management Office (MPMO).[11]

Denali believes that the quality of work it has performed to estimate the cost of the Project will provide Shippers confidence in the basis for Denali's offer. Denali's commercial terms and conditions address Project risks and provide Shippers unbundled rates (see Exhibit A for a summary of Denali's estimated negotiated and recourse rates) and commercial flexibility. Denali's Open Season offer will provide Shippers the best opportunity to assess the competitiveness of ANS gas in the North American market.

B. CONFORMANCE WITH THE ALASKA REGULATIONS

In developing its Plan and its service offerings, Denali has proceeded in a manner that is consistent with the Commission's purposes in adopting the Alaska Regulations to allow "sufficient economic certainty to support the construction of the [Project]"[12] and "to prevent unduly discriminatory behavior and limit the ability of a project applicant . . . to unduly favor its affiliates in the open season process."[13] Indeed, in the face of criticism that the Commission's

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[10] *See* Office of the Federal Coordinator, Alaska Natural Gas Pipeline Project Fact Sheet, http://www.arcticgas.gov/sites/default/files/August%20Fact%20Sheet%20(2).pdf.

[11] The MPMO was established in 2007 by the Government of Canada to support an approach to the federal regulatory review of major resource projects that ensures a more effective, accountable, transparent, and timely review. This coordinated process will consider current consultation and assessment requirements and afford the Project critical confidence as to the applicable requirements.

[12] Order No. 2005-A at P 2.

[13] Order No. 2005-B at P 8.

regulations over-emphasize certainty for a prospective applicant, the Commission concluded that failure to balance shipper access with the needs of pipeline developers for certainty "would overlook the [ANGPA's] overall objective of facilitating the timely development of an [Alaska Project]."[14]

To further its goal of non-discriminatory access, the Commission ordered that all Shippers, whether affiliated with the project applicant or not, be "equally informed on matters essential to their decision whether to bid for capacity" on the Project as a means to "level . . . the playing field" for all Shippers.[15] To do so, the Alaska Regulations require an applicant to provide 21 categories of information designed to assure that "relevant information about the design, cost, operation and feasibility of an Alaska pipeline" is available to all Shippers.[16] Denali has provided, as part of this Plan, all the information required by the Commission to support the engineering, costs, project design, and schedule, and other information regarding the services it proposes to offer. The Plan Documents include Denali's proposed Precedent Agreement, the Alaska-approved In-State Gas Demand Study, an indicative FERC Gas Tariff, and projected rates.

To facilitate the availability of required information, Denali will establish, for the use of Shippers and representatives of regulatory agencies with jurisdiction over this Open Season process, readily accessible "Shipper Reading Rooms" (SRR) with relevant documents available. For Shippers' convenience, information will be available through a Virtual SRR and in Physical SRRs located in Anchorage, Alaska; Calgary, Alberta; and Houston, Texas. These measures will

[14] Order No. 2005 at P 16.

[15] Order No. 2005 at P 72; Order No. 2005-A at P 69.

[16] Order No. 2005-A at P 106.

provide access to interested parties to the wide range of information identified in the Alaska Regulations, so that all Shippers will have equal access to information.

In support of the goal of non-discriminatory access to information, the Commission adopted regulations to ensure that an applicant, if affiliated with a potential shipper, functions independent of its affiliate personnel performing marketing functions.[17] Denali is structured to comply with the Alaska Regulations and has posted Implementation Procedures for Standards of Conduct on Denali's website. Denali's owners have also taken appropriate measures to ensure separation and compliance with the Commission's Alaska Regulations. Finally, the Alaska Regulations were designed to ensure that the open season would be conducted without undue discrimination or preference. Denali's offering fully complies with that goal.

In summary, because Denali's Plan fully conforms with the Commission's Alaska Regulations, Denali respectfully requests that the Commission approve its Request within 60 days, by June 4, 2010, so that Denali may promptly conduct its Open Season.

II. COMMUNICATIONS

Communications with regard to Denali's Request should be directed to:

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[17] Order No. 2005-B at PP 9, 12, 15.

III. DESCRIPTION OF DENALI PARTICIPANTS AND THE PROJECT

A. DESCRIPTION OF DENALI'S MEMBERS/OWNERS

On June 11, 2008, BP and ConocoPhillips formed Denali as a separate entity.[18] Denali's owners have extensive ANS construction and operating experience, significant gas treatment plant construction and operating experience, pipeline construction and operating experience, and financial strength. Both have a long history of arctic project successes, technological innovations, and basin opening project experience. Both have repeatedly demonstrated their ability to deliver world-class projects.

Denali's owners account for about 50 percent of the known ANS gas resources. As significant ANS natural gas leaseholders, these companies also have a very strong interest in ensuring that any Alaska project meets cost and schedule expectations and is operated efficiently and safely. This interest benefits all Shippers including the State and other leaseholders that want a viable, safe, and efficient service, which will increase revenue to the State and leaseholders.

A critical component of the development of any oil and gas infrastructure on the ANS is the proven experience to successfully manage projects under the unique challenges of the Alaskan arctic. To date, the overwhelming number of major projects on the ANS have been managed and operated by Denali's owners. To ensure the Project benefits from the expertise of Denali's owners, Denali is comprised of many seconded BP and ConocoPhillips employees who bring proven expertise in arctic operations, pipeline engineering and construction, and mega-project management. Denali's team is exceptionally qualified to successfully deliver the Project.

[18] Denali is a Delaware limited liability company (LLC) and, under Delaware law, the company's owners are called "members." *See* 18 Del. Code. Ann. 301 (2009).

B. DENALI AND DENALI CANADA

Denali and Denali Canada were formed as corporate entities, separate from their owners, to evaluate and advance the Project. Denali's and Denali Canada's headquarters are located in Anchorage, Alaska, and Calgary, Alberta, respectively.

C. DENALI'S AND ITS OWNERS' EFFORTS TO BRING ALASKA GAS TO MARKETS

Denali's owners and their predecessors have been involved in efforts to bring ANS gas to market since its discovery in the late 1960s and, over time, have spent hundreds of millions of dollars on those efforts.[19]

Denali's owners have dedicated significant resources to evaluate the commercialization of ANS gas. Specifically, from 2001 through 2002, they joined with ExxonMobil Corporation forming the Alaska Gas Producers Pipeline Team (AGPPT). The team conducted a joint feasibility study to evaluate the viability of a natural gas pipeline to commercialize the ANS gas resources. This study assessed the cost, technology, regulatory, and environmental issues associated with the Alaska gas pipeline project. Approximately $125 million was spent on the study, which involved 110 owner company representatives and approximately 535 contractor representatives. After the study's conclusion, Denali's owners continued their efforts and independently conducted further planning for an Alaska gas pipeline prior to forming Denali.[20]

Denali has leveraged off of these previous efforts and, shortly after its formation, Denali

[19] BP Exploration External Affairs Department, *Juneau Report: Alaska's Gas … What's the Next Move?* 12 (Spring 1998); BP Exploration External Affairs Department, *Juneau Report: Alaska Natural Gas – Clean Energy for North America* 10, 12 (Winter 2000).

[20] *See* Federal Energy Regulatory Commission, *Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline* 4 (Feb. 2006), http://www.ferc.gov/legal/staff-reports/alaska-report.pdf; Federal Energy Regulatory Commission, *Second Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline* 8 (Jul. 2006), http://www.ferc.gov/legal/staff-reports/angta-second.pdf; Federal Energy Regulatory Commission, *Fifth Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline* 3 (Feb. 2008), http://www.ferc.gov/legal/staff-reports/angta-fifth.pdf.

approached the Commission to discuss advancing the Alaska Project. On June 25, 2008, Denali became the first Alaska project applicant accepted by the Commission to participate in its pre-filing process. Since that time, Denali has actively engaged many stakeholders by holding over 450 meetings with communities, professional organizations, trade organizations, regulatory agencies, labor unions, Alaska Native organizations, Canadian Aboriginal groups, landowners, and the general public. On October 17, 2009, Denali filed its right-of-way application with the Bureau of Land Management to begin the process of obtaining the right to cross federal land in Alaska. Working with the Commission staff, Denali contracted with Argonne National Laboratory (Argonne) on March 22, 2010 to act as the Commission's third-party contractor to prepare the Environmental Impact Statement for the Alaska Project and satisfy the National Environmental Policy Act's compliance requirements.

Denali and Denali Canada have engaged over 75 contractor and supplier companies in their efforts to prepare the Project for Open Season. Many local contractors were employed in the field work that Denali and Denali Canada performed in Alaska and Canada as well as in support of the engineering efforts. Denali has also contracted with world-class engineering firms to support its cost estimating and engineering efforts. Bechtel, a leader in pipeline engineering, planning, and execution, has supported the Mainline work. Fluor WorleyParsons Arctic Solutions, a joint venture between Fluor and WorleyParsons, has supported the GTP work. CH2M HILL's Anchorage office has provided support for both the GTP and the Mainline. CH2M HILL has decades of ANS experience while WorleyParsons designed many of the major ANS facilities. Fluor also has Alaska experience and is a major process engineering firm.

In summary, Denali has performed significant work in preparing for Open Season. As a result of these efforts, Denali is ready to conduct an Open Season for services on the Alaska

Project as described in the next sections.

D. DESCRIPTION OF THE PROJECT

When built, the Project will be the largest private energy construction project in North American history and will consist of the Transmission Lines, the GTP, and the Alaska Mainline and Canada Mainline (collectively, Mainline). Each of these facilities will be described in the following sections.

1. Transmission Lines

Denali's proposal includes two Transmission Lines from the two largest known gas resources on the ANS – one from the Point Thomson area (Point Thomson Transmission Line) and one from the Prudhoe Bay Unit (Prudhoe Bay Transmission Line) – to the GTP. The Point Thomson Transmission Line will be a 36-inch outside diameter pipeline approximately 62 miles in length and will be designed to deliver 1.1 Bscf/d to the GTP inlet. The Point Thomson Transmission Line will generally run from the Point Thomson area west to the Badami Field and then will parallel the Badami and Endicott oil pipelines into the Prudhoe Bay Unit and on to the GTP. The Prudhoe Bay Transmission Line will be a 60-inch outside diameter pipeline approximately 1.2 miles in length and will be designed to deliver 4.6 Bscf/d from the Prudhoe Bay Unit Central Gas Facility to the GTP inlet.

2. GTP

When built, the GTP will be the largest operating facility on the ANS and one of the largest facilities of its kind in the world. The GTP will receive gas from the Point Thomson Transmission Line, Prudhoe Bay Transmission Line, and other potential sources. The GTP will consist of four processing trains of activated amine and will:

- remove acid gases such as carbon dioxide and hydrogen sulfide from the gas and dehydrate the gas delivered by Shippers;

- compress and chill the treated gas (to prevent thawing of permafrost) before the gas enters the Alaska Mainline;
- return to Shippers the carbon dioxide and hydrogen sulfide removed in the treating process for use in enhanced oil recovery, disposal, or sequestration; and
- make available low-carbon dioxide gas to ANS consumers for potential use as fuel which has the potential to reduce emissions on the ANS.

The GTP will be capable of treating approximately 5.8 Bscf/d of gas and delivering 4.5 Bscf/d of sales gas[21] on an annual average basis to the Alaska Mainline. Figure 1 depicts the proposed GTP configuration.

Figure 1: GTP Configuration

[21] The term "sales gas" refers to pipeline-quality gas owned by Shippers and transported on the Alaska Project (exclusive of fuel and lost and unaccounted for gas related to the Project).

3. Mainline

The Alaska Mainline is designed as a 48-inch diameter, high-pressure (2500 psig) pipeline and related facilities to transport 4.5 Bscf/d annual average of sales gas. The Alaska Mainline will begin at the outlet of the GTP and will generally follow the Dalton Highway and other Alaska state highways to Delta Junction, Alaska. From there, the route will generally parallel the Alaska Highway to the Alaska-Canada Border where it will connect with the Canada Mainline. The Alaska Mainline route will cover a total of approximately 730 miles and will require six compressor stations.

Denali has designed for six delivery points inside Alaska. Specifically, Denali will provide for a delivery point at the outlet of the GTP treating section prior to final compression (to provide treated, low-carbon dioxide gas for ANS users), as well as five additional delivery points along the Alaska Mainline as identified in the In-State Gas Demand Study (Demand Study). During the Open Season process, Shippers may express interest in other receipt points or delivery points and Denali will consider including such requests in its plans.

Similar to the Alaska Mainline, the NEB-regulated Canada Mainline will be a 48-inch, high-pressure (2500 psig) pipeline and related facilities and is designed to transport 4.5 Bscf/d of sales gas on an annual average basis. The Canada Mainline will begin at the Alaska-Canada border where it will connect with the Alaska Mainline and generally follow the Alaska Highway through the Yukon Territory and northeast British Columbia (BC) to a point near Liard Hot Springs. From Liard Hot Springs, the route deviates from the highway and runs south and east through British Columbia to Boundary Lake, Alberta. In BC and Alberta, Denali Canada will offer delivery points for connections to multiple pipeline systems, allowing Shippers options for transporting gas to North American markets. At Boundary Lake, the pipeline diameter is reduced from 48 inches to 36 inches, and the pipeline will continue in a southerly direction to its final terminus near Blueberry Hill, Alberta. The Canada Mainline route will cover a total of approximately 1,020 miles and will require nine compressor stations. Denali Canada has designed for intermediate receipt and delivery points. Final receipt and delivery point locations will be dependent upon Shipper feedback through the Open Season process.

Figure 2: Mainline Route

4. Project Expansion

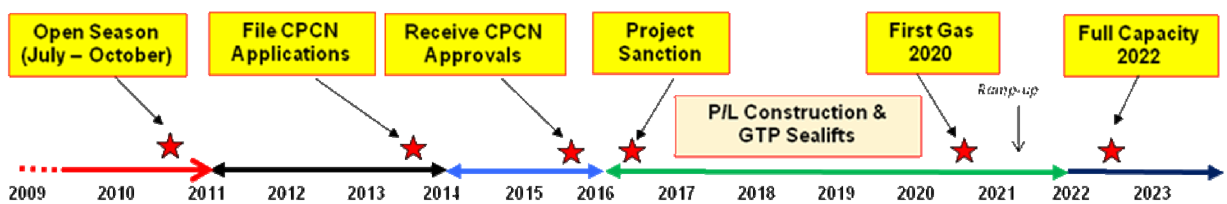
Denali anticipates the Alaska Project capacity that will be proposed in the Open Season will be sufficient to meet the current needs of ANS Shippers. Should additional capacity be required, Denali will consider the options for adding capacity. More capacity can be added through the addition of compression as well as additional treating facilities at the GTP. The

Alaska Project design proposed for the Open Season provides for expansion up to a capacity of 5.6 Bscf/d of sales gas on an annual average basis. Additional details regarding expansion capabilities can be found in Item 2 of Appendix C.

E. PROJECT SCHEDULE

The success case Project schedule is shown in Figure 3.

Figure 3: Denali Project Schedule



F. BENEFITS OF THE PROJECT

The Project, if successful, will create significant benefits for the Lower 48, Alaska, and Canada. Among other benefits, the Project will:

- Bring domestically produced, clean-burning natural gas to U.S. consumers;
- Provide Alaskan and Canadian consumers the opportunity to access or deliver gas at key locations along the pipeline route;
- During its construction phase, Denali and Denali Canada will create thousands of direct construction jobs, as well as tens of thousands of indirect and induced jobs, significantly enhancing the economies of the communities through which the Project will traverse;
- Provide access to markets that will help drive a new era of gas exploration, development, and production on the ANS, U.S. federal waters, and in other areas

across Alaska and Canada;

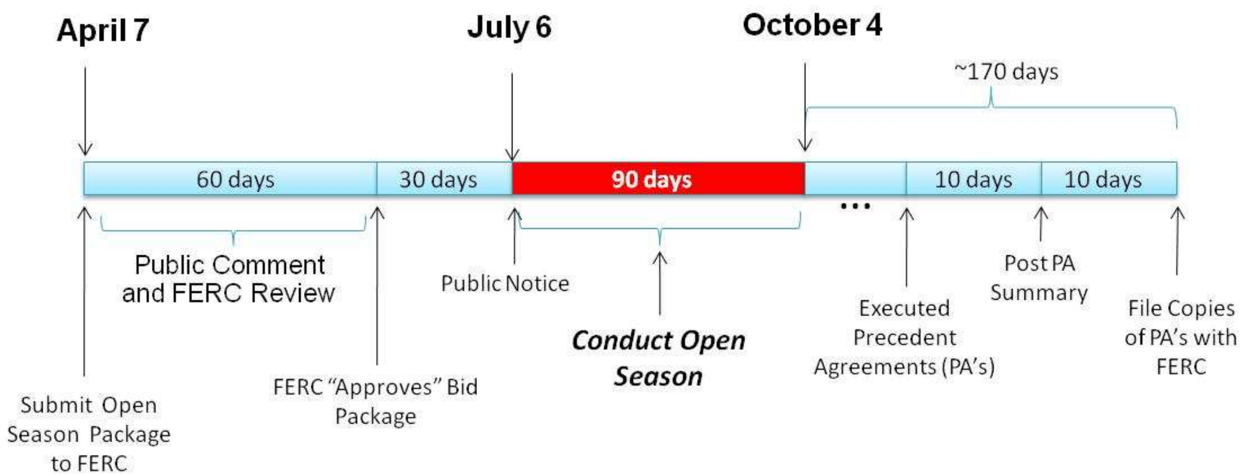
- Extend ANS oil production by providing an opportunity for additional revenue which will extend the economic life of fields like Prudhoe Bay;
- Provide clean gas for fuel that may reduce ANS carbon dioxide emissions;
- Create new business opportunities for suppliers and contractors both during and after construction; and
- Generate new royalties, production taxes, property taxes, and income taxes that will provide new governmental revenue.

As noted in the Executive Summary, the U.S. Congress has already found that a significant need for the Project exists.

IV. DENALI'S OPEN SEASON PLAN

Denali is conducting an Open Season to seek the submission and execution of binding Precedent Agreements for one or more of the following firm services: (1) gas transmission service (transportation service on the Transmission Lines); (2) gas treating service; (3) gas compression service; and (4) gas transportation service on the Alaska Project. The U.S. Open Season will be overseen by the Commission and is a "binding" Open Season, meaning that a Shipper submitting a bid in the Open Season will be expected to execute a binding Precedent Agreement during the 90-day Open Season. Concurrent with the Alaska Open Season, Denali Canada will also conduct an open season for transportation capacity on the Canada Mainline, which will be subject to review by the NEB.

Figure 4: Open Season Timeline



The timeline shown in Figure 4 reflects the requirements of the open season process and is consistent with the process set forth in the Alaska Regulations. Denali plans to issue its Notice and begin conducting the Open Season on July 6, 2010. Consistent with the Alaska Regulations, the Open Season will end 90 days later.

The Canadian open season process will follow the same general timeline as the Alaska Open Season. In preparation for the Canadian open season, Denali Canada has sought an "Expression of Interest," from Shippers interested in transporting gas on the Canada Mainline. In seeking out those Shippers, Denali Canada mailed several hundred Expression of Interest letters to Canadian Shippers. Denali Canada is developing a Canadian precedent agreement and tariff with terms similar to the U.S. terms, amended as necessary to conform to Canadian regulations and practices. Denali and Denali Canada will place, in its SRRs, similar information about both the Alaska Project and the Canada Project.

A. PRINCIPLES

In developing its Plan, Denali adopted certain principles. Among other things, the Project will provide:

- **Open Access/No Undue Discrimination**. Any creditworthy Shipper can submit a binding Precedent Agreement to reserve capacity.
- **Equal Access to Essential Information**. Denali will maintain SRRs to make essential bidding information available to all Shippers who conform to the SRR Procedures.
- **Reasonable Rates based on Sound Estimates**. Rates for service will be just and reasonable and for the Mainline will reasonably reflect material variations in cost due to distance over which the transportation is based. The details supporting Denali's capital cost and operational estimates will be available in the SRRs.
- **Recognition of Project Risk**. Denali's commercial offer recognizes the risk that the Project carries. As such, Denali's terms and conditions provide decision points to Shippers to decide whether to continue its participation as new information is developed.
- **Multiple Receipt and Delivery Points**. Denali is providing opportunities to accept or deliver gas at key locations throughout the Project.
- **Expansion**. As discussed in Section III(D)(4), the Project will provide for efficient, future expandability. After the initial successful Open Season and CPCN approval, Denali will solicit interest in capacity expansion every two years.
- **Multiple Interconnecting Pipeline Options in Canada**. Depending on Shipper interest, Denali Canada will provide delivery points for connections to multiple pipeline systems to allow Shippers flexibility in moving their gas to market through existing pipeline systems.
- **Rolled-in rates**. Denali will provide for rolled in rates for later expansions consistent

with applicable Commission regulations. Denali will not propose a toll structure for expansions that requires existing Shippers to subsidize expansion shippers.

B. PLAN OFFERING

1. Shipper Classes

Denali is offering Shippers the opportunity for service on the Project under two different classes of Shippers: Foundation Shippers and Standard Shippers. Denali will move the Project forward in cooperation with Shippers by providing updates as new information is developed. Each class of Shippers will have distinct rights for the capacity commensurate with the term of their commitment to the Project. The following generally describes the criteria that must be met by a Shipper to qualify as a Foundation Shipper, as well as the rate options that are available to each Shipper class:

- **Foundation Shippers:** Foundation Shippers will be those Shippers submitting conforming bids electing to take firm service for a minimum term of 20 years (term threshold). Foundation Shippers may select one of two rate options for service on the Transmission Lines, GTP, and Alaska Mainline: (1) recourse rates; or (2) negotiated rates based on a lower return on equity than that used to estimate the recourse rates (Negotiated Rates). Each of the rate options is mutually exclusive. Any Shipper qualifying for and electing the Negotiated Rate option will be committing to that rate structure for the term of its service agreements. Foundation Shippers will have the right to reconsider their participation in the Project at designated points related to cost estimate updates and regulatory milestones. Foundation Shippers, who elect to discontinue their participation in the Project at one of these decision points, will pay their proportional share of the costs incurred. These costs do not include pre-Open Season costs. Foundation Shippers are also recognized for their early commitment to the Project through the provision of levelized Negotiated Rates, extension rights, and most favored nations rights.

- **Standard Shippers:** Standard Shippers will be those Shippers taking firm service that do not meet the criteria to be a Foundation Shipper. Standard Shippers will be offered the recourse rate option only.

2. Pre-Subscription Agreements

Denali has not entered into any pre-subscription agreements (PSA) for capacity related to the Project. As required by the Alaska Regulations, should Denali enter into a PSA with a Shipper, Denali will make the PSA public within 10 days of its execution and include it in the SRR. Denali will also offer capacity to all prospective bidders at the same rates and on the same terms and conditions as contained in the PSAs.

3. Required Bid Information

A Shipper must submit a Bid Sheet in the form of Exhibit A attached to the Precedent Agreement containing the following information:

- **Contact Information:** Relevant contact information;
- **Creditworthiness:** Information establishing the Shipper's creditworthiness requirements;
- **Contract Term:** The term which must equal or exceed 20 years;
- **Services Desired:** Specification of all services for which the Shipper is bidding;
- **Receipt and Delivery Points for Each Service Desired:** Identification of the receipt and delivery points for each desired service;
- **Quantities for Each Receipt and Delivery Point Desired:** Identification of the quantity the Shipper desires to be made available for each of its receipt and

delivery points;

- **Rate Option Election:** If a Shipper qualifies as a Foundation Shipper, identification of its election to receive service under recourse rates or negotiated rates; and
- **Warranty of Title:** The Shipper warrants that it has, or will have at the time of delivery, the title or right to deliver gas to Denali, for the quantities bid.

Any bid meeting the above requirements and returned to Denali, along with a signed Precedent Agreement, before the close of Open Season will be considered a conforming bid. A bidder may add conditions precedent to the Precedent Agreement without necessarily rendering a bid non-conforming. Any bid not meeting the above requirements or containing conditions precedent that materially change the terms of the Precedent Agreement will be considered a non-conforming bid, including Late Bids described in Section IV(B)(4).

4. Consideration of Late Bids

Any bid submitted after the Open Season's conclusion (a Late Bid) will be a non-conforming bid and will be evaluated and considered by Denali as long as the Late Bid:

- would have otherwise been deemed a conforming bid if it had been submitted before the Open Season deadline; and
- does not result in any economic, engineering, design, capacity, or operational constraints such that the Late Bid cannot be accommodated.

A Shipper submitting a Late Bid must explain the circumstances that prevented the Shipper from submitting a timely bid and the change in those circumstances. If the Late Bid is rejected, Denali will explain why such bid cannot be considered. Denali may, at any time after the end of the Open Season, request approval from the Commission to summarily reject any further Late Bids that can no longer be accommodated.

5. Method for Evaluating Bids

All conforming bids accepted by Denali in the Open Season will be valued on an equal basis for the purposes of awarding capacity. Denali will not differentiate among conforming bids for purposes of valuation on the basis of chosen delivery points within or outside the State. Denali may choose to accept non-conforming bids in a not unduly discriminatory manner if capacity is available. Denali will provide an explanation to any Shipper who submits a non-conforming bid rejected by Denali.

6. Awarding Capacity/Precedent Agreements

Denali will notify all bidders contemporaneously whether their bids were accepted and, if so, the amount of capacity that has been awarded. If Denali receives bids for more capacity than is available in the Open Season, Denali may re-design the Alaska Project to accommodate all bids accepted by Denali for firm service within the feasible design capacity determined by Denali, taking into account economic, engineering, design, capacity, and operational constraints and potential impacts on the timely development of the Alaska Project. In the event bids accepted by Denali for firm service received from shippers during the Open Season exceed the feasible design capacity or Denali chooses not to re-design the Project, Denali shall award capacity in the following order:

- First, to conforming bids;
- Next, to capacity secured in pre-subscription agreements pursuant to 18 C.F.R. § 157.34(c)(15); and
- Last, to non-conforming bids that are acceptable to Denali.[22]

[22] For purposes of the requirement that all capacity subject to the terms and conditions of pre-subscription

Capacity awarded for each category listed above, to the extent capacity exists, will be handled on a pro-rata basis among all Shippers within the same category. Section 4.2(c) of the proposed Precedent Agreement (Appendix A) describes the allocation process in further detail.

If required, post Open Season discussions with Shippers will continue for up to 90 days after the close of Open Season, at which time final Precedent Agreements will be issued to shippers, including capacity reservations. Any Shipper awarded capacity as a result of the Open Season process must sign a binding Precedent Agreement before the close of Open Season and obtain all requisite internal approvals to perform its obligations under the Precedent Agreement by February 1, 2011. After all Shippers that have submitted signed Precedent Agreements provide evidence of all requisite internal approvals related to the Precedent Agreements, Denali intends to execute the Precedent Agreements within 30 days. Denali reserves the right to change the timing described above on a not unduly discriminatory basis.

Within 10 days after a Precedent Agreement has been executed by a Shipper and Denali, Denali will publicly release the name, term, and capacity awarded to each Shipper. Furthermore, within 20 days after Precedent Agreements have been signed, Denali will submit to the Commission copies of all executed Precedent Agreements, as well as copies of any relevant correspondence with bidders who were not awarded capacity.

7. Consideration of Whether or Not to Proceed

Upon Denali's execution of the Precedent Agreement, Denali and the Shipper are bound to the terms of the Precedent Agreement. If executed Precedent Agreements result in capacity reservations at the inlet of the Alaska Mainline greater than or equal to 85% of the design capacity of the Alaska Mainline, Denali may configure the current design to best meet the

agreements be allocated prior to allocating capacity bid for in the open season, Denali will consider capacity awarded to non-conforming bids as capacity awarded outside the Open Season process.

aggregate capacity reserved and shall inform Shippers of revised rate estimates.

If executed Precedent Agreements result in capacity reservations at the inlet of the Alaska Mainline less than 85% of the design capacity of the Alaska Mainline, the obligations of both Denali and Shippers will be suspended. Denali will consult with Shippers to determine if Shippers are willing to make additional firm service commitments to progress the Project's development, or if Shippers are interested in Denali developing a modified project design to deliver gas to North America or to a natural gas liquefaction facility at a location to be specified by interested Shippers.

If either (1) sufficient commitments for the current Project design are not received by Denali or (2) either Denali or Shipper does not elect to proceed under an amended Precedent Agreement for a modified project by December 31, 2011, then either Denali or the Shipper may terminate the Precedent Agreement with at least 30 days prior written notice.

V. THE COMMISSION SHOULD APPROVE DENALI'S REQUEST BECAUSE ITS PLAN FULLY CONFORMS WITH THE ESTABLISHED STANDARD FOR THE COMMISSION'S REVIEW

It is highly unusual for the Commission to review and approve the procedures by which a new interstate natural gas pipeline plans to conduct an open season. Because of this undertaking's unique nature, the Commission instituted a rulemaking proceeding that culminated in the Alaska Regulations. There, all interested parties – with often disparate views – were invited to describe how they believed an open season should be conducted. Balancing these distinct viewpoints and fulfilling its ultimate policy-making responsibility, the Commission adopted the Alaska Regulations. They contain a pre-approval process providing the Commission with an opportunity to assess and resolve any issues associated with a proposed plan to conduct an open season "and its conformance with the open season rules."[23]

In its recent Order approving a different plan to conduct an Alaska open season, the Commission stated that it was not its intent "in establishing the open season procedures to create a forum in which to pre-litigate issues that may arise during certificate and rate proceedings. Rather, the intent of the pre-open season review is to determine whether potential bidders will be treated in a non-discriminatory manner. Consequently, we agree with those parties who urge a relatively limited review of [a] filing [for approval of a plan to conduct an Alaska open season]."[24] The Commission concluded that its "pre-approval of a . . . plan . . . does not contemplate a close examination of the prospective applicant's cost and tariff. Rather, our task is to ensure that the plan conforms to the Open Season regulations' provisions regarding transparency and non-discrimination."[25]

Accordingly, the Commission must determine whether Denali's proposed Plan conforms with the Alaska Regulations. Certain regulations are key to this assessment. As will be discussed in the next sections, Denali's Plan satisfies the requirements of each of these key regulations and should be approved.[26]

A. THE PLAN'S NOTICE PROVISIONS COMPLY WITH THE ALASKA REGULATIONS

Denali is providing timely notice of its Open Season through the filing of this Plan, which includes its proposed Notice.[27] Denali will provide reasonable public notice and actual notice to

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[23] *See* Order No. 2005-A at PP 64, 71.

[24] *TransCanada Alaska Co. LLC*, 130 FERC ¶ 61,263 at P 34 (2010).

[25] *Id.* at P 44.

[26] *See* 18 C.F.R. § 157.38.

[27] *Id.*

the State and the Office of the Federal Coordinator.[28] Denali will provide Shippers 90 days within which to submit requests for transportation services.[29] All of the notice requirements are satisfied.

B. DENALI'S PLAN SATISFIES ALL OF THE IN-STATE NEEDS REQUIREMENTS

Denali's Plan complies with the Commission's requirement that an applicant conducts or adopts a study of gas consumption needs and prospective points of delivery within the State. A consultant team conducted a Demand Study to project the "potential demand from Alaska residents and industries for natural gas . . . that would be available with construction of a natural gas pipeline to commercialize North Slope gas."[30] The State has approved this Demand Study and authorized its use for purposes of complying with this requirement of the Alaska Regulations.[31] The Demand Study is attached as Appendix B.[32]

The Demand Study analyzed potential off-take locations along the proposed route. The Demand Study also projects that the total net in-state demand for ANS gas in years 1-5 of pipeline operations is approximately 340 MMscf/d for an Alaska Mainline.[33] Using a Current Industry demand scenario, the Demand Study determined that the most likely off-take points

[28] 18 C.F.R. § 157.34(a).

[29] 18 C.F.R. § 157.34(d)(1).

[30] Demand Study at ES-1.

[31] Letter from Alaska Commissioner of Natural Resources Thomas E. Irwin (October 30, 2009 Letter), and Letter from Alaska Commissioner of Natural Resources Thomas E. Irwin (January 22, 2010 Letter), both attached as Exhibits A and B to Appendix B.

[32] The referenced study was requested by TransCanada Alaska, and as the Commission's Alaska Regulations make clear, an applicant may "adopt" a relevant study. 18 C.F.R. § 157.34(b). Moreover, a letter recently issued by the Commissioner of the State's Department of Natural Resources and Department of Revenue specifically approved use of the Demand Study by TransCanada Alaska "and other gas pipeline sponsors" as a reasonable assessment of in-state natural gas consumption needs.

[33] Demand Study at 79.

along the route will be: (i) Livengood, (ii) Fairbanks, (iii) Parks Highway spur, (iv) Delta Junction area/Richardson Highway spur, and (v) Tok. Denali has included in Exhibit A to the Precedent Agreement all of these locations as potential delivery points. The final determination of which locations Denali will serve will depend on the results of the Open Season. Denali intends to provide at least five in-state gas delivery points.

C. DENALI'S PLAN PROVIDES THE INFORMATION REQUIRED BY § 157.34(C)(1)-(17)

Denali's Plan contains, based on the best available information, all of the project and commercial information the Commission has determined is required so that Shippers may evaluate Denali's Open Season offering and determine whether to bid for capacity. Each of the seventeen types of information specified in the Alaska Regulations, and Denali's compliance with them, is summarized below and addressed in detail in Appendix C.

Denali is making its best, current information available to Shippers. Nevertheless, as the Commission recognized, it might be appropriate or necessary for an applicant to begin an open season before some of the required information is fully or finally available.[34] Denali continues to fully evaluate the project, progress rigorous cost estimates and schedules, and update its technology and engineering. For example, Denali is evaluating engineering design, technology, and project execution alternatives for the GTP which, if shown to yield significant improvements in cost, efficiency, flexibility, or operability, may be incorporated into this Open Season offer. If new, different, or better information becomes available during the Open Season, Denali will provide that information contemporaneously to all Shippers through the SRRs.

1. The Plan provides the required technical information - §§ 157.34(c)(1)-(5) & (c)(10)

[34] *See* Order No. 2005 at P 71.

The first five information requirements in Section 157.34(c)(1)-(5) relate to technical descriptions of the Project. This information includes the route of the pipeline, its size and design capacity, including a description of possible expanded designs, the maximum allowable and expected operating pressures, the delivery pressures, and the projected in-service date. Denali has provided this information in Items 1-5, and in Exhibits A through C, of Appendix C.

Section 157.34(c)(10) requires that the applicant provide the quality specifications and any other requirements applicable to gas that is delivered to the Project. The specifications and requirements are set forth in Item 10 of Appendix C and in Article 4 of the General Terms and Conditions of Denali's indicative FERC Gas Tariff, which is attached as Exhibit G to Appendix C.

2. The Plan provides the required commercial information - §§ 157.34(c)(6)-(9) & (c)(11)-(17)

Section 157.34(c)(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 and surcharges. Section 157.34(c)(7) requires information about the estimated cost of service (*i.e.*, estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expense), estimated cost allocations, and rate design volumes upon which the rates are developed. Denali has provided this information in Items 6 and 7, Exhibits H through J of Appendix C, and in Exhibit B to the proposed Precedent Agreement.

Section 157.34(c)(8) requires an estimated transportation rate for deliveries in the State. Information for the Denali Project is provided in Item 6 (for recourse rates), Item 8, and Item 9 (for negotiated rates) of Appendix C.

Section 157.34(c)(9) requires 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 the Open Season. The negotiated rate options Denali is providing are addressed in Item 9, and Exhibits K through N, of Appendix C, and are described in Exhibit C to the proposed Precedent Agreement.

Section 157.34(c)(11) requires that the applicant provide the terms and conditions for each service offered. To meet this requirement, Denali has prepared an indicative FERC Gas Tariff, which is attached as Exhibit G to Appendix C. Before the tariff is filed as part of Denali's CPCN application, it will be updated to reflect changes resulting from negotiations associated with the conduct of its Open Season, changes deemed necessary by Denali, and any changes required to satisfy then-current North American Energy Standards Board requirements.

Section 157.34(c)(12) requires that Denali identify creditworthiness standards, and any other collateral requirements, that will apply to Shippers. Denali has provided this information in Section 9.4 of the proposed Precedent Agreement. Denali's Plan establishes that some Shippers may be "Foundation Shippers." Foundation Shippers are Shippers who submit conforming bids (including a 20 year minimum term) in the Open Season. Because of the challenges in financing a project of this scope, Foundation Shippers will be subject to a more stringent creditworthiness requirement relative to that applicable to Standard Shippers. In accordance with Commission policy, these creditworthiness standards are specified in the Precedent Agreement and are not reflected in the indicative FERC Gas Tariff.

Section 157.34(c)(13) requires that Denali provide the date for the execution of Precedent Agreements. It is provided in Item 13 of Appendix C.

Section 157.34(c)(14) mandates a detailed methodology for determining the value of bids for deliveries within the State and outside the State. In related fashion, Section 157.34(c)(15) requires a description of the methodology by which capacity will be awarded in the case of over-subscription on the Project. That information is provided in Items 14 and 15 of Appendix C. Because there is no currently pre-subscribed capacity, the Section 157.34(c)(15) requirements are not applicable. If Denali enters into a PSA with a Shipper before the Open Season, it will comply with the Alaska Regulations' requirements regarding posting and making the terms and conditions of the PSA available to other Shippers.

Section 157.34(c)(16) requires Denali to specify the required bid information, including whether bids are binding or not, receipt and delivery point requirements, the form of a Precedent Agreement and its time of execution, and the definition and treatment of non-conforming bids. That information is provided in Item 16 of Appendix C. All bids will be binding. Denali's proposed Precedent Agreement is attached as Appendix A to the Request. Exhibit A to that form of Precedent Agreement identifies the receipt and delivery point requirements.

Section 157.34(c)(17) requires the applicant to provide its projected date for filing an application at the Commission. The expected date for Denali's CPCN application filing is the fourth quarter of 2013.

D. DENALI'S PLAN CONFORMS WITH THE INFORMATION REQUIREMENTS IN § 157.34(C)(18)

Section 157.34(c)(18) is the "catch all" provision that requires disclosure of all information in the applicant's possession pertaining to the service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, that the prospective applicant has made available to, or obtained from, any potential shipper, including affiliates of the prospective applicant (Shared Information).

The scope of the information specified for inclusion in this provision is extensive and some of it is competitively sensitive information.[35] Accordingly, this Plan need not contain copies of all the responsive documents, but rather the Notice may identify a reading room where such information is available for review and where the information may be accessed.

Denali will make a large amount of information available to qualified parties. On its website (www.denalipipeline.com), Denali will post its Plan (except the § 157.34(c)(18) information) and its Implementation Procedures for Standards of Conduct.

Denali has also established SRRs that will contain the information responsive to (c)(18). The volume of information, including historical data, is large, comprising thousands of pages of information. The SRRs will include engineering, technical, execution, and cost information to allow Shippers to assess the basis for Denali's Open Season offer.

Furthermore, the SRRs will contain the Shared Information. Denali has transferred all of this information received from any potential Shipper, including its affiliated shippers, to the SRRs except appropriate Shipper confidential information. This information includes AGPPT study information received from BP and ConocoPhillips.

Before the start of the Open Season,[36] SRRs will be set up at the following locations:

- Physical SRRs – located in Anchorage, Calgary, and Houston; and
- Virtual SRR – accessible from anywhere in the world with a password. The Virtual Reading Room will contain, among other items, notices of new information placed in the SRRs and any information that might be provided to

[35] Order No. 2005-A at P 106. Some of the included information may be proprietary or confidential and, in such instances, access to this information will be addressed as it is in any commercially-sensitive situation.

[36] Since the Commission's recent Order regarding the conduct of an Alaska open season, Denali has implemented steps to open its SRRs without "undue delay" and is now populating its SRRs with the required materials. *See* TransCanada Alaska Co. LLC, 130 FERC ¶ 61,263 at P 64. Denali will use its best efforts to open its SRRs as promptly as possible. Denali will have the SRR in Anchorage open on April 12, 2010 and will have the SRRs in Calgary and Houston open shortly thereafter. The SRRs will be open well in advance of the 120 days deemed adequate by the Commission. *See id.* at n.44 (120-day review period deemed "adequate").

other Shippers during the Open Season.

Because some information in the SRRs is commercially and competitively sensitive, Denali will treat information contained in the SRRs that is not in the public domain as confidential information and will limit access to any interested Shipper and representatives of regulatory agencies with jurisdiction over this Open Season process. Any interested Shipper seeking to access the SRRs who has not executed a Confidentiality Agreement with Denali that would apply to information in the SRRs must execute and comply with Denali's SRR Confidentiality Agreement in the form attached as Exhibit E to Appendix C.[37] Each Shipper or regulatory agency representative seeking access to the SRRs must also comply with all Denali SRR Procedures described in Exhibit F to Appendix C.

Finally, certain information in the Physical SRRs is subject to third-party confidentiality restrictions. This information will only be made available to those who have qualified for access to the SRRs (as described above) and have obtained a release from, or signed a confidentiality agreement with, such third parties.

E. DENALI FUNCTIONS INDEPENDENT OF ITS AFFILIATES AND HAS SUBMITTED THE INFORMATION REGARDING THE ORGANIZATION OF DENALI'S AFFILIATES REQUIRED BY §§ 157.34(C)(19)-(21)[38]

1. Denali's Employees Function Independently

As clarified in Order No. 2005-B, the Alaska Regulations require a prospective applicant

[37] The Denali Shipper Reading Room Confidentiality Agreement contains terms consistent with the Commission's Model Protective Order.

[38] The implementation procedures described in this section were undertaken prior to the effectiveness of Order No. 2005-B and "may be in some ways more restrictive . . . than would be required if wholly fashioned to correspond to the employee functional approach that now applies to conducting open seasons." *See TransCanada Alaska Co. LLC*, 130 FERC ¶ 61,263 at P 94. In any case, Denali intends to fully comply with "the applicable Standards of Conduct now imposed in Order No. 2005-B and [Denali will] comply with all of the principles of Order No. 717 and its progeny and Order No. 2005-B." *See id*.

"conducting an open season" to "function independent of the other divisions of the prospective applicant as well as the prospective applicant's 'affiliates' performing a 'marketing function' . . . as those terms are defined in . . . the Commission's regulations, except that the [producer] exemption . . . shall not apply."[39] This would include Alaska production employees engaged in marketing functions as specified in the Commission's recent order regarding the conduct of an Alaska open season.[40] Denali was created with this purpose in mind and has no divisions or units and performs no marketing functions.

To further ensure independent functioning, Denali has established a firewall regarding the transfer or distribution of transmission function information, which for purposes of the Open Season means information relating to the Open Season (Open Season Information) that is non-public. On one side of the firewall are Denali employees[41] and those employees of Denali's affiliates who manage the owners' interests in Denali and their support staff who are actively and personally engaged on a day-to-day basis in conducting the Denali Open Season (Management Committee Employees). On the other side of the firewall are Denali affiliates with employees engaged in marketing functions as defined in the Commission's regulations (Marketing Affiliate) and divisions of affiliates involved in the production of natural gas in the State (Alaska Production Affiliate).[42] Outside of the firewalls, but subject to the "No Conduit Rule" (which prohibits the use of anyone as a conduit for the disclosure of non-public Open Season

[39] *See* Order No. 2005-B.

[40] *See TransCanada Alaska Co. LLC*, 130 FERC ¶ 61,263 at P 80.

[41] Denali employees include secondees, employees, contractors, and other representatives.

[42] By definition, the "Alaska Production Affiliate" would include employees of an affiliate involved in the production of natural gas in the State of Alaska who actively and personally engage on a day-to-day basis in any of the following activities relating to an Alaska open season: (a) the submission of a bid for capacity; (b) the negotiation of a precedent agreement with a transmission provider; and (c) the negotiation of a sale of gas. *See TransCanada Alaska Co. LLC*, 130 FERC ¶ 61,263 at P 80.

Information to any affiliate or non-affiliate), are:

- senior officers within each owner organization who have corporate oversight over both the respective owner's interest in Denali and other areas but are neither transmission function employees nor marketing function employees (Senior Officers), and
- support employees providing business, legal, or technical support who are not actively and personally engaged on a day-to-day basis in conducting the Denali Open Season (Affiliate Support Employees).

The firewall is designed to ensure Denali will not share any non-public Open Season Information as described above unless it is contemporaneously disclosed to all potential shippers. Furthermore, Denali will not act, or use anyone, as a conduit to share such information with any Marketing Affiliate or any Alaska Production Affiliate.

Denali has taken other measures to further ensure independent functioning. Denali has trained[43] all employees regarding this rule and the implementation of Denali's Open Season independent functioning obligations. Denali employees, except for Denali Open Season employees (those employees involved in the planning, directing, organizing, or carrying out of activities related to the Open Season), have been instructed and trained that they cannot interact or communicate with any marketing, shipper affiliate, or non-affiliate employee about non-public Open Season Information. Denali's Open Season employees may only interact or communicate with any marketing, shipper affiliate, or non-affiliate employee for the limited purpose of discussing participation in the Open Season, must log that interaction or communication, and must contemporaneously post in the SRR any non-public Open Season

[43] As part of Denali's comprehensive compliance program, all employees will also receive annual training in addition to the training received when hired.

Information shared with those affiliate employees. All Denali employees will follow the No Conduit Rule, as discussed above. Finally, Denali employees are physically located in office space that is physically secure from those of any affiliate.

Denali has also taken specific measures to secure its non-public Open Season Information and to keep customer information confidential. These measures are designed to allow all affiliated Shippers and all non-affiliated Shippers to have access to the same Open Season Information. No unauthorized access is available to any non-public Open Season Information or to information about Shippers. Further, Denali will follow the “Transparency Rule,” which requires Denali to make available to all affiliated Shippers and all non-affiliated Shippers in the SRRs, the Open Season Information that is required to be disclosed under the Alaska Regulations. Additionally, any information that is provided to one Shipper during the Open Season will be posted contemporaneously in the SRRs.

As described in Section V(F), Denali and its personnel will follow the “Non-Discrimination Rule,” which means they will conduct the Open Season without undue discrimination and without granting any undue preference in the rates, terms, or conditions of service. Additionally, all capacity allocated as a result of the Open Season will be awarded without undue discrimination or preference of any kind.

Finally, to implement its compliance, Denali has posted its Implementation Procedures for Standards of Conduct on its Internet website and distributed that document to its employees. As noted above, Denali will timely train its employees on the Alaska Regulations and applicable Commission Standards of Conduct. Further, Denali has designated the Vice President, Regulatory Affairs, as Denali’s Chief Compliance Officer (CCO). The CCO reports directly to Denali’s President and has the authority to address any potential compliance issue raised. Denali has also established a "Helpline" telephone number where compliance concerns may be reported anonymously to an independent third party. Denali has also informed its employees about FERC's Enforcement Hotline.

2. Denali's Owners' Compliance Measures Conform with the Alaska Regulations

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."[44] To this end, Denali's owners have undertaken extensive measures, in addition to those taken by Denali itself, to satisfy the Commission's regulations regarding the Open Season process.

a. The owners' § 157.34(c)(21) statements

As required by the Alaska Regulations, BP and ConocoPhillips, as Denali's affiliates, have made statements that generally provide:

> officers and directors of [BP's or ConocoPhillips'] affiliated sales and marketing units and [BP's or ConocoPhillips'] affiliates involved in the production of natural gas in the State of Alaska 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.[45]

These statements are provided in Item 21 of Appendix C.

b. The owners' §§ 157.34(c)(19)&(20) organizational descriptions

As required by the Alaska Regulations, Denali is attaching the following materials provided by its owners:

- the names and addresses of Denali's parent entities' affiliated sales and marketing units

[44] Order No. 2005 at P 74.

[45] *See* 18 C.F.R. § 157.34(c)(21).

and affiliates involved in the production of natural gas in the State;

- comprehensive charts showing the organizational structure of Denali's parent entities with the relative position of their respective marketing and sales units and affiliates involved in the production of natural gas in the State; and
- the job titles and descriptions and chain of command for all officers and directors of BP's and ConocoPhillips' marketing and sales units and any affiliates involved in the production of natural gas in the State.

This information, provided as Items 19 and 20 of Appendix C, shows that the entities that own interests in Denali are separate from their marketing and sales units and affiliates involved in the production of natural gas in the State.

c. The owners' actions taken to support compliance

BP and ConocoPhillips have undertaken measures to separate their Management Committee Employees from employees of their Marketing Affiliates and Alaska Production Affiliates. They have also implemented measures which prohibit (a) employees of Marketing Affiliates or Alaska Production Affiliates from conducting transmission functions or having access to Management Committee facilities and (b) their transmission function employees from conducting marketing functions. Further, they have taken measures to prevent the transmittal of any non-public Open Season Information outside the strict parameters of the Alaska Regulations.

Among other steps, BP and ConocoPhillips have taken these steps to support compliance with the independent functioning rule:

- the physical separation of Management Committee Employees[46] from the employees of Marketing Affiliates and Alaska Production Affiliates;

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[46] BP and ConocoPhillips have implemented measures to ensure that the Management Committee Employees do not improperly communicate non-public Open Season Information to other BP or ConocoPhillips employees.

- Management Committee Employees are not engaged in any natural gas exploration and production operation or any natural gas marketing or shipping operation for BP or ConocoPhillips or any of their affiliates in Alaska or in the Lower 48; and
- none of the Denali personnel, including the Denali President, is an officer of BP or ConocoPhillips nor performs any role in any natural gas exploration and production operation or any natural gas marketing or shipping operation for BP or ConocoPhillips or any of their affiliates in Alaska or in the Lower 48.

BP and ConocoPhillips have also implemented procedures to comply with the No Conduit Rule and to provide appropriate training. These measures include:

- the implementation of Alaska Regulations and applicable Commission Standards of Conduct training programs for the following:
    - Management Committee Employees,
    - Senior Officers, and
    - Affiliate Support Employees; and
- the strict adherence to the Alaska Regulations and applicable Commission Standards of Conduct, including specifically that the above employees will not, or will not use a conduit to, provide non-public Open Season Information to employees of Marketing Affiliates or Alaska Production Affiliates.

These measures taken by Denali and its owners demonstrate the independence of Denali as required by Order No. 2005-B.

F. DENALI'S PLAN DOES NOT UNDULY DISCRIMINATE AGAINST OR UNDULY PREFER ANY CLASS OF POTENTIAL SHIPPERS

In issuing Order No. 2005, the Commission recognized the importance of information sharing, structural enhancements (such as the creation of a separate unit or entity to conduct the open season), and equal treatment for all shippers in an open season.[47] By strict adherence to the independent functioning, separation of functions, information access, and disclosure requirements, all Shippers may obtain transportation service under terms that are not unduly preferential or unduly discriminatory.

Additionally, through its Plan, Denali seeks to provide unbundled services to Shippers. Denali is offering a separate rate for transportation service unbundled from the rate for optional gas treatment service. Gas treatment service is further unbundled into gas treating and gas compression. A Shipper does not have to bid for all services and Denali will not evaluate bids based on whether a Shipper requested all services.

Denali's Plan (including the indicative FERC Gas Tariff and Precedent Agreement, SRR Procedures, and in-depth Project information) is comprehensive, transparent, and contemporaneously available for all to study and evaluate under the identical terms and conditions. Information is available to all Shippers without regard to affiliate relationships.

Finally, none of Denali's commercial terms and conditions unduly discriminate against any shipper. Denali will process all similar Open Season requests for capacity and services in a similar manner.[48] Denali's methodology for awarding capacity to Shippers is publicly disclosed and provides no undue preference to any Shipper, whether affiliated or not affiliated with Denali. Denali does distinguish between a Foundation Shipper and a Standard Shipper. The Commission, however, has recognized that such a distinction is not unduly discriminatory or does not grant an undue preference because long term commitments are necessary to advance

[47] Order No. 2005 at PP 73-74.

[48] *See* 18 C.F.R. § 358.4(c) ("A transmission provider may not, through its tariffs or otherwise, give undue preference to any person in matters relating to the sale or purchase of transmission service (including, but not limited to, issues of price, curtailments, scheduling, priority, ancillary services, or balancing).").

major pipeline projects and to obtain financing for the projects.[49] In sum, Denali's Plan does not unduly discriminate against or unduly prefer any class of potential Shippers.

VI. CONCLUSION

Denali was formed as a separate entity as the best means to advance this important and challenging undertaking. At considerable expense and the training of personnel and resources, every proper step has been taken by Denali to formulate an Open Season Plan that is fair and transparent to all Shippers, whether affiliated with Denali or not, and that fully complies with the policies and requirements of ANGPA and the Alaska Regulations. No undue discrimination or undue preference can occur and none will. It is the market that will decide if, and under what circumstances, the Alaska Project will proceed, as the United States Congress and this Commission intended.

[49] *See Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272 (2006).

WHEREFORE, Denali respectfully requests that the Commission approve its Open Season Plan within 60 days of this filing.

Respectfully submitted,

/s/ James F. Moriarty

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Counsel for DENALI – THE ALASKA GAS PIPELINE LLC

DATED: APRIL 7, 2010

Exhibit A
Summary of Estimated Negotiated and Recourse Rates

Note: Denali is proposing two recourse rate periods. Period One recourse rates are substantially levelized over the first three years of operation while the Project ramps up to full capacity. Period Two recourse rates (full capacity) apply thereafter and are not levelized. The recourse rates shown below for Period Two are for the first year of Period Two. Negotiated rates are levelized over 20 years. All rates exclude fuel.

Service Rates,[2] $/MMBtu

Service		Negotiated Rate, MOD[1]	Recourse Rate, MOD[1] Period One/Two	Negotiated Rate, 2009 $	Recourse Rate, 2009 $ Period One/Two	Fuel, %
Transmission Lines	Prudhoe Transmission Line	0.005	0.009/0.006	0.004	0.007/0.005	0
	Point Thomson Transmission Line	0.31	0.55/0.37	0.26	0.48/0.31	0
GTP	Acid Gas Removal & GTP Treated Gas Return	0.79	1.25/0.98	0.67	1.10/0.84	2.6
	Compression and Chilling	0.27	0.42/0.34	0.23	0.37/0.29	1.6
	Total GTP	**1.06**	**1.67/1.32**	**0.90**	**1.47/1.13**	**4.2**
Alaska Mainline	Inlet Alaska Mainline to Alaska/Canada border	0.98	1.67/1.18	0.80	1.39/0.97	1.5
Canada Mainline[3]	Alaska/Canada Border to Alberta	1.21	1.69/1.29	0.97	1.38/1.05	1.7
Inlet GTP to Alberta		**3.25**	**5.03/3.79**	**2.67**	**4.24/3.15**	**7.4**

In-State Gas Delivery Rates,[2,4] $/MMBTU

Delivery Point	Negotiated Rate, MOD[1]	Recourse Rate, MOD[1] Period One/Two	Negotiated Rate, 2009 $	Recourse Rate, 2009 $ Period One/Two
Livengood	0.55	0.92/0.65	0.44	0.77/0.54
Parks Highway Spur	0.61	1.03/0.73	0.49	0.86/0.60
Fairbanks	0.61	1.03/0.73	0.50	0.86/0.61
Delta Junction	0.73	1.23/0.87	0.59	1.03/0.72
Tok	0.87	1.47/1.04	0.70	1.23/0.86

[1] Money of the day.
[2] Calculated using 12% return on equity for negotiated rates, 14% for recourse rates.
[3] The rates for the Canada Mainline (including those characterized as "Recourse") are provided for information purposes only. Actual rates for the Canada Mainline will be established in accordance with the requirements of the National Energy Board Act (Canada).
[4] Distance sensitive rates based upon mileage.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

DENALI – THE ALASKA GAS PIPELINE LLC	)))	DOCKET NO. PF08-26-001

OPEN SEASON PLAN DOCUMENTS
SUBMITTED IN CONJUNCTION WITH DENALI'S
REQUEST FOR COMMISSION APPROVAL OF PLAN
FOR CONDUCTING AN OPEN SEASON

Volume I of III

(Proposed Open Season Notice and Precedent Agreement)

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DENALI
the alaska gas pipeline

OPEN SEASON NOTICE

FOR

ALASKA NATURAL GAS TRANSPORTATION PROJECT

July 6, 2010 – October 4, 2010

DENALI – THE ALASKA GAS PIPELINE LLC

OPEN SEASON NOTICE FOR ALASKA NATURAL GAS TRANSPORTATION PROJECT

I. NOTICE OF OPEN SEASON

Denali – The Alaska Gas Pipeline LLC (Denali) hereby gives notice (Notice) that it will conduct an Open Season to seek the submission and execution of binding Precedent Agreements for one or more of the following firm services: (1) gas transmission service (transportation service on the transmission lines); (2) gas treating service; (3) gas compression service; and (4) gas transportation service on its Alaska natural gas transportation project (Alaska Project), beginning at 8:00 a.m. CDT on Tuesday, July 6, 2010 and ending at 5:00 p.m. CDT on Monday, October 4, 2010 (Open Season).

Under the terms of this Open Season, in a non-discriminatory manner, Denali intends to award capacity to bidders for these services if:

- Denali receives sufficient bids that conform to its requirements or Denali waives the applicable requirements; and
- Denali decides to proceed with the Alaska Project under the terms of this Open Season.

Denali Canada – The Alaska Gas Pipeline (West), Inc. (Denali Canada), a Denali affiliate, intends to conduct an open season for firm transportation commitments on the Canada portion of the project (Canada Project).

The Alaska Project and Canada Project collectively are referred to as the Project.

II. PURPOSE OF NOTICE

Denali is issuing this Notice to comply with the Federal Energy Regulatory Commission (Commission) regulations governing all binding open seasons for Alaska natural gas transportation projects, 18 C.F.R. §§ 157.30 - 157.39 (Alaska Regulations), and to provide reasonable notice of, and information about, Denali's Open Season to the public and prospective shippers as well as to provide actual notice to the State of Alaska and the Office of the Federal Coordinator.

III. INFORMATION AVAILABLE

Denali is including as attachments to this Notice a proposed precedent agreement (Appendix A) and, in accordance with 18 C.F.R. §§ 157.34(b) and 157.34(c) an endorsed In-State Needs

Study[1] (Appendix B) and the 21 informational elements specified by the Commission in the Alaska Regulations (Appendix C) (Commission Required Information).

Denali is making the following information regarding the Open Season available to the public at Denali's website (www.denalipipeline.com):

- General information about Denali including Commission Required Information about Denali's Open Season; and

- Denali's Implementation Procedures for Standards of Conduct.

General Commission information about Alaska natural gas transportation projects and Denali's pre-filing for its Alaska Project (Docket No. PF08-26) is also available at www.ferc.gov.

Denali has also established virtual and physical Shipper Reading Rooms to enable prospective shippers and regulatory agencies with jurisdiction over this Open Season process to access additional information about Denali, its Alaska Project, and its Open Season, including engineering, technical, execution, and cost information. Physical Shipper Reading Rooms are located in Anchorage, Alaska; Calgary, Alberta; and Houston, Texas. Detailed information about Denali's Shipper Reading Rooms is available in Appendix C (Item 18 and Exhibit F).

A. INFORMATION REGARDING THE CANADA OPEN SEASON

General information regarding the Canada Project is available at www.denalipipeline.com and information for prospective shippers is available in the Shipper Reading Rooms. Information about the open season for the Canada Project will be placed in advertisements in key publications in Canada.

Denali Canada intends to conduct its open season for the Canada Project in the same timeframe as the U.S. Open Season for the Alaska Project. Denali Canada will be accepting bids for capacity on the Canada Project not only from shippers on the Alaska Project, but from within Canada as well. Subject to National Energy Board of Canada (NEB) regulations, capacity will be allocated on the Canada Project on a basis comparable to that used for the Commission-regulated Alaska Project.

Precedent agreements and tariff documents for both the Canada and Alaska Projects will be available for prospective shippers to review. Provisions in the documents will be similar except where policy or regulatory requirements between the NEB and the Commission dictate otherwise. For general information regarding Denali Canada, please contact Bob Bleaney at bob.bleaney@denalipipeline.com or (403) 767-7602.

[1] "In-State Gas Demand Study" by Northern Economics, January 2010. As required by the Alaska Regulations, Denali has adopted and relied upon this study in developing the contents of this Notice. 18 C.F.R. § 157.34(b).

B. ADDITIONAL INFORMATION

The public and any prospective shipper may obtain additional information about Denali and Denali Canada's open seasons by contacting:

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IV. DISCLAIMER

Denali is making this information regarding its Open Season available for informational purposes so that prospective shippers can express an interest in bidding for and obtaining firm service on the Project. The information contained in this Notice and provided in response to questions and requests for information does not create a contractual or other relationship between Denali and any other person or entity. Any contractual or other relationship resulting from this Open Season may only be reflected in a written agreement entered into by Denali and a prospective shipper.

DENALI – THE ALASKA GAS PIPELINE LLC
PROPOSED PRO FORMA PRECEDENT AGREEMENT

This binding Precedent Agreement (the "Precedent Agreement") is made and entered into this ___ day of _______, 2010, by and between Denali – The Alaska Gas Pipeline LLC ("Transporter") and ________________________ ("Shipper"). Transporter and Shipper are sometimes referred to herein individually as a "Party," or collectively as the "Parties."

RECITALS

A. Transporter is developing, subject to FERC approval, an Alaska natural gas transportation system to carry Alaska natural gas to the border between Alaska and Canada, which system will include all related facilities such as the Gas Treatment Plant, compressor stations, and any transmission lines (collectively, the "Project").

B. Shipper desires to obtain Firm Service on the Project, or portions of the Project, subject to the terms and conditions of this Precedent Agreement.

C. On __________, 2010, Transporter initiated an open season with respect to the Capacity on the Project.

D. The facilities and capacities described in this Precedent Agreement may change based on the final project design, shipper commitments, and regulatory authorizations.

E. The commitment provided by Shipper in this Precedent Agreement, together with other similar agreements, will be used as support for the financing, construction, and operation of the Project.

F. Transporter is willing to continue its efforts to develop the Project and to proceed with obtaining governmental authorizations to construct and acquire the required facilities; provided that Transporter receives sufficient commitments from prospective shippers.

G. Transporter shall seek negotiated rate authority from FERC and, where necessary, shall use such authority to effectuate the terms of this Precedent Agreement.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, and intending to be legally bound, Transporter and Shipper agree to the following:

1. Definitions and Interpretive Conventions.

1.1 Definitions. Capitalized terms used in this Precedent Agreement shall have the following meanings:

"Acid Gas" means the stream of gas removed at the Gas Treatment Plant consisting primarily of carbon dioxide.

"Affiliate" when used to indicate a relationship with a specific Person, means another Person that directly, or indirectly through one or more intermediaries or otherwise, controls, is controlled by, or is under common control with, such specific Person. A corporation shall be deemed to be an Affiliate of another corporation if one directly or indirectly controls the other or if each of them is directly or indirectly controlled by the same Person.

"Alaska Mainline" means Transporter's large diameter, high-pressure natural gas pipeline and all pipeline related facilities that will carry natural gas from the outlet of the GTP about 730 miles to the international border between Alaska and Canada.

"Alaska Natural Gas Pipeline Act" means Sections 720 through 720n of Title 15 of the United States Code, as amended or recodified from time to time.

"AOS" means authorized overrun service, and is defined as Shipper's right to a pro-rata share of available capacity, above its MDQ, as specified in Transporter's Tariff.

"Btu" means British thermal unit, and is defined as the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit from 59 degrees Fahrenheit to 60 degrees Fahrenheit at a standard pressure of 14.73 psia.

"Canada Mainline" means the natural gas transportation system and all pipeline related facilities to be owned by Canadian Transporter that will carry Gas within Canada.

"Canadian Transporter" means Denali Canada – The Alaska Gas Pipeline (West), Inc.

"Capacity" means Shipper's capacity (in Dth) held under an agreement for Firm Service, together, if applicable, with the AOS rights associated with Shipper's capacity.

"Capital Cost Share" has the meaning ascribed to such term in Section 9.4(a)(i).

"Central Clock Time" means central daylight time when central savings time is in effect and central standard time when central savings time is not in effect.

"Certificate of Public Convenience and Necessity" means a certificate issued by FERC authorizing Transporter to provide services identified in Transporter's Tariff.

"Compression Agreement" means an agreement, in the form attached hereto as Exhibit G, which, subject to the terms and conditions of this Precedent Agreement, will be entered into by Transporter and Shipper and under which Transporter shall provide Compression Service to Shipper.

"Compression Service" means compressing Shipper's Gas under Rate Schedule FC of Transporter's Tariff pursuant to a Compression Agreement at the First Stage Compression Facility so that the Gas has a pressure and temperature sufficient to enter Transporter's pipeline facilities at the outlet of the First Stage Compression Facility.

"Cubic Foot" means that volume of Gas occupying one cubic foot when such Gas is at a temperature of 60 degrees Fahrenheit and at a pressure of 14.73 psia.

"Daily" or "Day" means a period beginning at 9:00 a.m. Central Clock Time on a calendar day and ending at 9:00 a.m. Central Clock Time on the following calendar day, unless otherwise mutually agreed in writing by Shipper and Transporter.

"Decatherm," "Dekatherm," or "Dth" means the Quantity of energy that is equivalent to ten therms or 1,000,000 Btus.

"Delivery Point" means, for each Firm Service, a point identified on Exhibit A of this Precedent Agreement and in Attachment 1 of the applicable Service Agreement, where Transporter will deliver Gas to Shipper or for Shipper's Account.

"Development Costs" has the meaning ascribed to such term in Section 11.3.

"FERC" means the Federal Energy Regulatory Commission.

"Firm Service" means any combination of Transmission Service, Gas Treating Service, Compression Service, or Transportation Service, as applicable.

"First Stage Compression Facility" means Transporter's compression facility to be located at, or adjacent to, the Gas Treatment Plant where Gas will be compressed prior to entering Transporter's high-pressure pipeline system.

"Foundation Shipper" means a Shipper who satisfies the criteria specified in Section 6.1 of this Precedent Agreement.

"Fuel" means Gas consumed in Transporter's operation of the Project.

"Fuel Requirement" means the sum of: (a) a Quantity of Gas equal to the applicable Monthly Fuel percentage established by Transporter for the applicable service, (b) a Quantity of Gas equal to Transporter's reasonable estimate of Lost or Unaccounted for Gas attributable to such service; and (c) a Quantity of Gas equal to the Monthly fuel percentage established by Canadian Transporter for transportation service on the Canada Mainline, if applicable.

"Gas" means methane, and such other hydrocarbon and non-hydrocarbon constituents, or a mixture of two or more of them that, in any case, meets the applicable Gas Quality Standards.

"Gas Quality Standards" means the applicable quality standards specified in Transporter's Tariff.

"Gas Treating Agreement" means an agreement, in the form attached hereto as Exhibit F, which, subject to the terms and conditions of this Precedent Agreement, will be entered into by Transporter and Shipper and under which Transporter shall provide Gas Treating Service to Shipper.

"Gas Treating Service" means the separation of Acid Gas from Shipper's Gas delivered into the Gas Treatment Plant and the dehydration of Shipper's Gas under Rate Schedule FGT of Transporter's Tariff pursuant to a Gas Treating Agreement so that it meets the Gas Quality

Standards applicable downstream of the Gas Treatment Plant for Transportation Service and Compression Service.

"Gas Treatment Plant" or "GTP" means the gas treatment facility, which will be subject to the jurisdiction of FERC under the Alaska Natural Gas Pipeline Act.

"In-Service Date" means the date on which service commences through the applicable Project facilities under a Service Agreement entered into pursuant to the terms of this Precedent Agreement.

"Interim Time Frame" has the meaning ascribed to such term in Section 4.3(a).

"Lenders" means any Person with whom Transporter, from time to time, has entered into a debt financing arrangement or other loan or credit facility with respect to the financing of Transporter's facilities, or with whom Canadian Transporter, from time to time, has entered into a debt financing arrangement or other loan or credit facility with respect to the financing of Canadian Transporter's facilities.

"Lost or Unaccounted for Gas" means the Quantity of Gas reasonably determined by Transporter to be lost, or gained, during the provision of any service, expressed as Dth, other than Gas consumed and measured in Transporter's operations.

"Maximum Rate" means the applicable maximum rate Transporter can charge for the applicable Service under Transporter's Tariff, as amended and approved from time to time by FERC.

"Mcf" means 1,000 Cubic Feet.

"MDQ" means the maximum Capacity, not including Fuel and Lost or Unaccounted for Gas, expressed in Dth per Day, Transporter shall make available to a Shipper on a firm basis under an agreement for Firm Service, as specified in Attachment 1 to the applicable Service Agreement.

"Month" or "Monthly" means a period extending from 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 succeeding calendar month, or at such other hour as Shipper and Transporter agree upon.

"Negotiated Rate" means the rates calculated in accordance with Exhibit C, which Transporter and Shipper have agreed will be charged for Firm Service under a Service Agreement entered into pursuant to this Precedent Agreement.

"Open Season" means an open season seeking shippers to commit to Firm Service prior to the installation of the applicable facilities, which has been conducted pursuant to FERC regulations.

"Party" and "Parties" have the meaning ascribed to such terms in the preamble.

"Person" means an individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company, or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator, or other legal personal representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted.

"Post-Open Season Development Period" has the meaning ascribed to such term in Section 11.3.

"PPBoR" has the meaning ascribed to such term in Section 7.1(b).

"Precedent Agreement" has the meaning ascribed to such term in the preamble.

"Project" has the meaning ascribed to such term in Recital A.

"Psia" or "psia" means pounds per square inch absolute.

"Quantity" means the applicable amount of Gas calculated in Btu or Dth.

"Receipt Point" means, for each Firm Service, a point on Exhibit A of this Precedent Agreement and in Attachment 1 of the applicable Service Agreement, where Shipper will tender, or cause to be tendered, Gas for Firm Service.

"Recourse Rate" has the meaning ascribed to such term in Section 3.2.

"Service Agreement" means a Transportation Agreement, a Gas Treating Agreement, a Compression Agreement, or a Transmission Agreement between Transporter and Shipper entered into pursuant to the terms of this Precedent Agreement.

"Shipper" has the meaning ascribed to such term in the preamble.

"Shipper Condition Precedent" has the meaning ascribed to such term in Section 10.

"Shipper's Account" means Shipper's Gas account under the applicable Service Agreement with Transporter.

"Tangible Net Worth" has the meaning ascribed to such term in Section 9.4(a)(iii).

"Transmission" means the receipt of Gas for Shipper's Account at the Receipt Point pursuant to Shipper's Transmission Agreement, and the delivery of equivalent Quantities of Gas, adjusted for the Fuel Requirement, for Shipper's Account at the applicable Delivery Point.

"Transmission Agreement" means an agreement, in the form attached hereto as Exhibit E, which, subject to the terms and conditions of this Precedent Agreement, will be entered into by Transporter and Shipper and under which Transporter shall provide Transmission Service to Shipper.

"Transmission Service" means the Transmission of Shipper's Gas under Rate Schedule FTR of Transporter's Tariff pursuant to a Transmission Agreement.

"Transportation" means the receipt of Gas for Shipper's Account at the Receipt Point that is available to Shipper pursuant to Shipper's Transportation Agreement, and the delivery of Gas, adjusted for the Fuel Requirement, for Shipper's Account at the Delivery Point(s).

"Transportation Agreement" means an agreement, in the form attached hereto as Exhibit H, which, subject to the terms and conditions of this Precedent Agreement, will be entered into by Transporter and Shipper and under which Transporter shall provide Transportation Service to Shipper.

"Transportation Service" means the Transportation of Shipper's Gas under Rate Schedule FT of Transporter's Tariff pursuant to a Transportation Agreement.

"Transporter" has the meaning ascribed to such term in the preamble.

"Transporter Condition Precedent" has the meaning ascribed to such term in Section 8.

"Transporter's Tariff" means Transporter's FERC Gas Tariff, as amended by Transporter and approved by FERC from time to time.

"Year" means a period of 365 consecutive days, provided, however, that any such year containing a date of February 29 shall consist of 366 consecutive days.

1.2 Interpretive Conventions. Unless otherwise specifically provided, the following interpretative conventions apply to the interpretation of this Precedent Agreement:

(a) *Gender*. A reference to one gender includes the others.

(b) *References*. A reference to a "Section" or "Exhibit" is to a Section or Exhibit, as the case may be, of this Precedent Agreement.

(c) *Conjunctions*.

(i) And. The word "and" can have two different connotations:

(1) the several "and": A and B, jointly or severally; or

(2) the joint "and": A and B, jointly but not severally.

In this Agreement, "and" should be interpreted in the joint sense, uniting things as a whole group, not in the several sense.

(ii) Or. The word "or" can have two different connotations:

(1) the inclusive "or": A or B, or both; or

(2) the exclusive "or": A or B, but not both.

In this Agreement, "or" should be interpreted in the inclusive sense, not in the exclusive sense. If "or" is used in the exclusive sense, it is written as "either A or B" or other phrase indicating the exclusive connotation.

(d) *Singular/Plural.* A word denoting the singular only includes the plural, or vice versa, where the context requires.

(e) *Amended Statutes & Regulations.* A reference to a statue or regulation is a reference to the law as later changed or a change caused by a change to another law.

(f) *Amended Agreement.* A reference to an agreement is a reference to the agreement as later changed.

(g) *Include.* The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(h) *Headings.* The headings in this Precedent Agreement are included for convenience and do not affect the construction of this Precedent Agreement.

(i) *Drafting Construction.* Each Party has had the opportunity to consult attorneys and other advisors in connection with entering into this Precedent Agreement, and as a consequence the rule calling for an agreement to be construed against the drafter does not apply.

(j) *May.* The word "may" means "is authorized or permitted to in its sole discretion," while "may not" means "is not authorized or permitted to."

(k) *Successor/Assigns.* A references to a Person includes that Person's permitted successors and assigns and, in the case of any governmental Person, the Person succeeding to the relevant functions of that governmental Person.

(l) *References to Agencies or Officials*. A reference to a governmental department, division, agency, or official continues to apply regardless of any changes in name or title, and applies to the successor department, division, agency, or official to which the referenced responsibilities or functions may be transferred. A reference to a government official includes the official's designee.

(m) *Successor Publications*. Where this Precedent Agreement references information or uses an information source that is no longer available, the Parties shall reference information or use an information source that is substantially similar.

2. Effective Date and Term

2.1 This Precedent Agreement shall be effective as of the date first set forth above, and shall remain in effect until the earlier of: (i) termination pursuant to Section 11 of this Precedent Agreement; or (ii) execution of all agreements for Firm Service pursuant to this Precedent Agreement.

2.2 The primary term of each agreement for Firm Service executed pursuant to this Precedent Agreement shall commence with the In-Service Date of the applicable portion of the Project and shall continue for the applicable number of Years specified on Exhibit A beyond the last In-Service date under all Service Agreements entered into pursuant to this Precedent Agreement. The minimum primary term of Firm Service for any Service Agreement entered into pursuant to this Precedent Agreement is 20 Years.

2.3 The Project will become operational in phases. A line-fill phase will begin upon the completion of construction of the Alaska Mainline and will end (and a start-up phase will begin) when the line fill has been delivered into the Alaska Mainline. During the line-fill phase and during the start-up phase, intermittent service may be available to shippers, with priority given to firm shippers, on a pro-rata basis. The specifics of the service provided during the line-fill phase and start-up phase will be defined in the Certificate of Public Convenience and Necessity. The start-up phase will end and a ramp-up phase will begin when reliable deliveries, as determined by Transporter, for Firm Services contracted are established, at a capacity less than the full certificated capacity of the Project, currently estimated to occur in 2020. During the ramp-up phase, Firm Service begins and each Firm Shipper shall receive Firm Service at a reduced MDQ, which, for the applicable period determined by Transporter, shall be Shipper's MDQ multiplied by a fraction, the numerator of which is the available capacity for the applicable Firm Service during such period and the denominator of which is the aggregate of the non-reduced contracted MDQs for all shippers for the applicable Firm Service. If a Shipper's MDQ is reduced for one service and the reduction impacts the ability to utilize other services, the Shipper's MDQ for other services will be reduced by a corresponding amount. The rates to be charged to such shippers will be based on the facilities in service during the ramp-up phase. The ramp-up phase will end and the full-service phase will begin when Transporter determines that sufficient facilities to deliver 100% of shippers' non-reduced MDQ is available, currently estimated to occur before the end of 2022.

3. Firm Service and Rates

3.1 Shipper's MDQ, Receipt Point(s), and Delivery Point(s) under each applicable agreement for Firm Service are set forth on Exhibit A.

3.2 Shipper shall pay the Maximum Rate for the applicable Firm Service, and any other additional charges approved by FERC, as stated in Transporter's Tariff (the "<u>Recourse Rate</u>"); provided, however, Shipper and Transporter may mutually agree to a Negotiated Rate to replace the otherwise applicable Maximum Rate. The initial Recourse Rate proposed by Transporter will be based on the principles set forth in Exhibit B. Transporter may file rate cases with FERC from time to time during the term of any agreement for Firm Service and, unless Shipper and Transporter mutually agree to a Negotiated Rate, Shipper shall be responsible to pay the applicable Maximum Rate resulting from any such rate case.

3.3 If the Parties agree to a Negotiated Rate, such Negotiated Rate shall be calculated in accordance with the principles set forth in Exhibit C, and Shipper shall pay under the applicable agreements for Firm Service according to such Negotiated Rate.

3.4 The standard for review of any challenge to a Negotiated Rate, if any, will be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Sierra Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *NRG Power Marketing L.L.C. v. Maine PUC, et al.*, ___ U.S. ___ (2010) and *Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. ___ (2008).

4. Open Season, Post Open Season, and Capacity

4.1 Shipper and Transporter have entered into this Precedent Agreement as a result of the Open Season conducted by Transporter.

4.2 If Transporter receives bids for more capacity than is available in the initial Open Season, Transporter may re-design the Project to accommodate all bids accepted by Transporter for Firm Service within the feasible design capacity determined by Transporter, taking into account economic, engineering, design, capacity, and operational constraints and potential impacts on the timely development of the Project. In the event bids accepted by Transporter for Firm Service received from shippers during the initial Open Season exceed the feasible design capacity or Transporter chooses not to re-design the Project, Transporter shall award capacity in the following order:

(a) First, to conforming bids;

(b) Next, to Capacity secured in pre-subscription agreements pursuant to 18 C.F.R. § 157.34(c)(15); and

(c) Last, to non-conforming bids that are acceptable to Transporter.

Capacity awarded for each category listed above to the extent capacity exists, will be handled on a pro-rata basis among all shippers within the same category. If applicable, Transporter shall reduce each bidder's MDQs indicated on Exhibit A to the applicable precedent agreements pro rata based solely on each bidder's proportion of the total quantity of Firm Service capacity reflected in all bids accepted by Transporter in the initial Open Season for a particular category. If Shipper's MDQ is reduced for one Firm Service and the reduction impacts the ability to utilize other Firm Services, Transporter may consult with Shipper to attempt reconciliation of capacity for other Firm Services. Shipper will have 15 days to either accept or reject such allocated MDQs. In the event Shipper rejects the reduced MDQ, the returned capacity will be made available to the remaining shippers on a pro-rata basis within the same category.

4.3 Transporter shall inform shippers of the total Firm Service commitments under the executed precedent agreements within 10 days of Transporter's approval of all precedent agreements. If the sum of the total Firm Service commitments in the precedent agreements executed by Transporter in the initial Open Season results in capacity reservations at the inlet of the Alaska Mainline greater than or equal to 85% of the design capacity of the Alaska Mainline, Transporter may configure the current design to match the capacity reservation and shall inform shippers of revised rate estimates. If the sum of the total Firm Service commitments in the precedent agreements executed by Transporter in the initial Open Season results in capacity reservations at the inlet of the Alaska Mainline less than 85% of the design capacity of the Alaska Mainline, the following procedures shall apply:

(a) During the time period between the execution of this Precedent Agreement and December 31, 2011 (the "Interim Time Frame"), Transporter shall consult with shippers to determine if shippers are willing to make additional Firm Service commitments to progress the Project's development, or if shippers are interested in Transporter developing a modified project design to deliver gas to North America or to a natural gas liquefaction facility at a location to be specified by interested shippers.

(b) Should interest exist in a modified project, Transporter and Shipper may, in their discretion, undertake an engineering study or studies to estimate the cost of the modified project. Upon (1) completion of redesign studies or (2) receipt of sufficient additional commitments to allow the original Project to proceed, Transporter and Shipper may agree to proceed with a modified project or the original Project under amended precedent agreements.

(c) Denali's and Shipper's obligations under this Precedent Agreement (other than Shipper's obligations specified in Section 9.4) shall be suspended until the end of the Interim Time Frame, or until additional commitments are secured, whichever occurs first. If either sufficient commitments for the current project design are not received by Transporter or either Party does not elect to proceed under an amended Precedent Agreement for a modified project by December 31, 2011, then either Party may terminate this Precedent Agreement with at least 30 days' prior written notice to the other Party.

4.4 In the event Transporter, after establishing the design capacity based on Precedent Agreements entered as a result of the initial Open Season or thereafter, receives indications of interest for new capacity which cannot be satisfied by the 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 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. In the event a reverse open season does not provide adequate capacity, Transporter will determine if a re-design is feasible for the requested capacity taking into account economic, engineering, design, capacity, and operational constraints and potential impacts on the timely development of the Project.

4.5 In the event FERC for any reason orders Transporter to hold a revised Open Season, Shipper agrees to participate in the revised Open Season by submitting a bid reflecting the terms of this Precedent Agreement, except as those terms may have been modified by a final FERC order specifically addressing this Precedent Agreement; provided that Shipper shall not be required to bid for more or less Capacity, or to bid any rates or charges, other than as set forth in this Precedent Agreement.

5. Firm Service Commitment

Transporter shall provide Shipper, if requested on the attached Exhibit A and subject to available capacity at the requested Receipt Point(s) and Delivery Point(s), with any combination of Transmission Service under a Transmission Agreement, Gas Treating Service under a Gas Treating Agreement, Compression Service under a Compression Agreement, or Transportation Service under a Transportation Agreement, as applicable, through the elected services within the Project in accordance with and subject to the provisions of the applicable agreements for Firm Service.

6. Foundation Shippers

6.1 A Shipper qualifies as a Foundation Shipper if (i) Shipper meets the minimum creditworthiness requirements set forth in Section 9.4, (ii) Shipper's bid is for a minimum of 20 years, (iii) Shipper executes this Precedent Agreement before the close of the Open Season, and (iv) Shipper obtains all requisite internal approvals to perform its obligations under this Precedent Agreement by February 1, 2011.

6.2 If Shipper is deemed a Foundation Shipper pursuant to Section 6.1, then Shipper shall be entitled to:

(a) Negotiated Rates calculated in accordance with the principles set forth in Exhibit C;

(b) the termination rights specified in Section 11.2;

(c) a one-time option, which may be exercised by Shipper with at least 42 months' advance written notice to Transporter, to extend the term of each agreement for Firm Service entered into pursuant to this Precedent Agreement for five additional Years after the end of the primary term specified in the applicable agreement for Firm Service. Shipper shall elect one of the following rate options for the five-Year extension term:

(i) the Recourse Rate, calculated in accordance with the principles set forth in Exhibit B; or

(ii) a negotiated rate for the five-Year extension term, to be negotiated in good faith between Transporter and Shipper in the six months following receipt of Shipper's notice. The depreciation rate assigned to such negotiated rate shall be based on the remaining life of the Project. In the event the Parties are unable to agree upon a Negotiated Rate during such six-month period, and either Party does not wish to continue negotiations, Shipper may elect to accept the applicable Recourse Rate for such five-Year extension term or elect not to extend its capacity reservation for Firm Service.

(d) a most-favored nation right as follows: If Transporter, prior to the In-Service Date under Foundation Shipper's applicable Service Agreement, enters into an agreement for Firm Service on the same path with any other Shipper, at rates lower than the rates applicable to Foundation Shipper's Service Agreement, then Transporter shall so notify Foundation Shipper and Foundation Shipper, upon providing written notice to Transporter, shall have the right to receive Firm Service with respect to its MDQ specified in the applicable Service Agreement, under the same terms and conditions for the same time period. In the event Shipper's rates have been levelized for the term of the applicable agreements for Firm Service, this provision shall only apply with respect to other shippers with levelized rates who have committed to the same path for the same time period.

6.3 Foundation Shipper status is non-transferrable unless to a Person that meets the Foundation Shipper requirements set forth in this Section 6.

7. Transporter Obligations

7.1 Transporter shall use commercially reasonable efforts to file for and diligently pursue FERC authorization for the construction and operation of the Project, and shall cause Canadian Transporter to use commercially reasonable efforts to file for and diligently pursue with the National Energy Board of Canada authorization for the construction and operation of the Canada Mainline. Transporter shall provide to each Foundation Shipper an updated cost estimate and revised rates for the Firm Service awarded, together with an updated construction schedule for the Project and the Canada Mainline, no later than 30 days after:

(a) the later of (i) the conclusion of the front-end engineering and design phase for the Project or (ii) the submission of an application for a Certificate of Public Convenience and Necessity, and

(b) the later of (i) the acceptance of the Certificate of Public Convenience and Necessity or (ii) the approval of Canadian Transporter's plan, profile, and book of reference ("PPBoR") for the entire Canada Mainline by the National Energy Board of Canada.

7.2 Transporter shall tender to Shipper, no later than 60 days after the later of (i) Transporter's acceptance of a Certificate of Public Convenience and Necessity, or (ii) the approval of Canadian Transporter's PPBoR for the entire Canada Mainline by the National Energy Board of Canada, executable copies of all Service Agreements necessary as a result of Shipper's elections in Exhibit A; provided, that Transporter shall not tender any such agreement for Firm Service to Shipper prior to the date it provides to Shipper the updated information specified in Section 7.1 above.

7.3 If shippers agree on a component tracking and valuation methodology, then Transporter shall allow for the establishment and implementation of a Gas component tracking system, which may be implemented and administered by an independent third party and would be funded by the shippers.

7.4 Transporter shall discuss with Shipper other services desired by Shipper, and in the event Transporter is agreeable to providing such services, Transporter shall include such additional services in Transporter's Tariff.

8. Conditions to Transporter's Obligations

Transporter's obligations hereunder are subject to the satisfaction of the following conditions (each, a "Transporter Condition Precedent"), unless waived in a writing signed by an authorized representative of Transporter:

(a) all requisite approvals for the Project and the Canada Mainline must be obtained and maintained on terms acceptable to Transporter and Canadian Transporter, including approval of construction, operation, rates, and terms and conditions of service;

(b) in Transporter's estimate, required modifications to Transporter's application for a Certificate of Public Convenience and Necessity do not materially decrease projected revenues, or materially increase costs (without receipt of commensurate revenue), to Transporter, or materially impair recovery of costs incurred by Transporter in constructing and operating the Project;

(c) Transporter and Canadian Transporter have each received and maintained sufficient firm commitments, in their sole discretion, from Shipper and other shippers at acceptable rates to support the construction and operation of the Project and the Canada Mainline;

(d) Transporter and Canadian Transporter have received and maintained sufficient financial commitments and capital commitments, in form and substance satisfactory to them in their sole discretion, for funding the debt and equity requirements of the Project and the Canada Mainline;

(e) Shipper has entered into, and is in compliance with, precedent agreements, firm transportation service agreements, or such other agreements as necessary to secure service, with interconnecting facilities to move Shipper's MDQ on and off the Project;

(f) Transporter and Canadian Transporter have received all requisite internal approvals for the development of subscribed Project components and have received internal approvals to accept the Certificate of Public Convenience and Necessity issued by FERC (in the case of Transporter) and to accept any conditions specified by the National Energy Board of Canada with respect to the construction and operation of the Canada Mainline (in the case of Canadian Transporter), no later than one Year after issuance of such documents or authorizations;

(g) Operators of downstream and upstream facilities interconnected, or to be interconnected, with Transporter have provided notice to Transporter of receipt of all approvals (government, corporate, and other) necessary to site, construct, and operate such facilities, along with notice of secured financing, if necessary, to affect those facilities to operational status for the duration of the primary term, in substance satisfactory to Transporter; and

(h) Transporter has received reliable evidence that each condition precedent specified in this Precedent Agreement has been satisfied or waived.

9. Shipper's Obligations

9.1 Consistent with the terms of this Precedent Agreement, Shipper shall execute the applicable agreements for Firm Service, each in the applicable form attached to this Precedent Agreement, within thirty days after tender by Transporter.

9.2 Shipper shall not oppose any filing made by Transporter with FERC or any other forum in furtherance of development of the Project with respect to any of the issues addressed directly or indirectly by this Precedent Agreement or any Service Agreement; nor shall Shipper take any actions to impede or delay development of the Project. Notwithstanding the foregoing, nothing contained in this Precedent Agreement is intended to preclude Shipper from challenging the proposed size and configuration of the Project or the applicable rates for the same in any proceeding, subject to Section 3.4.

9.3 Upon request by Transporter, Shipper shall promptly provide evidence to Transporter of creditworthiness which the Transporter may share with its Lenders. Shipper shall assist Transporter in establishing financing commitments, including agreeing to the modification of agreement terms and executing consent agreements as reasonably required by the Lenders.

9.4 Creditworthiness. The following creditworthiness standards apply for purposes of this Precedent Agreement. These creditworthiness standards shall continue to apply to Shipper (or assignees) through the term of this Precedent Agreement. Transporter shall not be required to continue to perform its obligations under this Precedent Agreement for any Shipper that fails to establish and maintain creditworthiness. Transporter shall determine Shipper's creditworthiness in accordance with the following:

(a) Creditworthiness Standard.

(i) Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 9.4(a)(ii). 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 9.4(a)(i); provided that the State of Alaska must satisfy the requirements of Section 9.4(a)(ii).

Shipper's "Capital Cost Share" is its pro-rata share (determined based on the aggregate of firm capacity commitments indicated by Shipper on all of its Exhibit A's for the applicable Service compared to shippers' total firm capacity commitments for such Firm Service, excluding any firm capacity commitments secured by a shipper that fails to secure internal approvals), of the capital costs, AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's facilities.

(ii) Shipper will be deemed creditworthy so long as (1) Shipper's long-term unenhanced senior unsecured debt securities are rated no lower than its ultimate parent company and at least BBB by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least Baa2 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and (2) it meets the provisions of Section 9.4(a)(i) 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.

(iii) "Tangible Net Worth," for purposes of this Section 9.4(a), means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations Shipper is obligated to disclose to Transporter. 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.

(b) Determination of Creditworthiness. In the event Shipper does not meet the requirements specified in Section 9.4(a) above, in determining Shipper's creditworthiness Transporter may consider, in Transporter's sole discretion, in addition to the factors set forth in Section 9.4(a), one or more of the following categories of additional information and factors, but in making all creditworthiness determinations, Transporter shall act in a not unduly discriminatory manner:

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

(ii) the pro forma effect on Shipper's debt rating of execution by Shipper of any Service Agreement;

(iii) financial statements and reports;

(iv) 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;

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

(vi) 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;

(vii) 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); and

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

(c) As indicated further in Section 16 of this Precedent Agreement, the creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) of this Precedent Agreement or to any permanent release, in whole or part, pursuant to a Service Agreement.

(d) <u>Failure to Satisfy Creditworthiness – Alternatives</u>. If Shipper fails or ceases to satisfy the creditworthiness standards or criteria as described above, Shipper must provide and maintain one or more of the following credit alternatives, in lieu of the creditworthiness standard requirements outlined in Section 9.4(a):

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

(ii) Collateral:

(1) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in Transporter's sole discretion in an amount equal to Shipper's pro-rata share of all expenditures and costs projected to be incurred by Transporter related to the development of the Project between the conclusion of Transporter's Open Season and the execution of the applicable Service Agreements. If Shipper does not, at least 20 business days prior to the conclusion of the letter of credit's term, provide Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Section 9.4(d)(ii)(1), reasonably acceptable to Transporter, Transporter shall be entitled to draw upon the full value of the letter of credit;

(2) Shipper may provide a cash security deposit acceptable to Transporter in Transporter's sole discretion in an amount equal to Shipper's pro-rata share of all expenditures and costs projected to be incurred by Transporter related to the development of the Project between the conclusion of Transporter's Open Season and the execution of the applicable Service Agreements; or

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

(iii) Upon termination in whole or part of this Precedent Agreement, if not superseded by an executed 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.

(e) 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 business days of 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 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 business days of Transporter's request or occurrence of material adverse change, 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.

(f) Notification of Failure to Meet Creditworthiness. Upon notification by Transporter, in accordance with Section 20, that Shipper no longer meets Transporter's creditworthiness standards or criteria, Shipper must within fifteen business days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Section 9.4.

(i) If Shipper fails to provide one of the credit alternatives within this time period, Transporter has the right to terminate this Precedent Agreement. Transporter may, after terminating this Precedent Agreement, resell capacity previously secured by Shipper. Nothing in this paragraph limits other remedies, including actions for damages, Transporter may seek against Shipper.

(ii) If Shipper at any time fails to provide one of the credit alternatives at the time Transporter terminates this Precedent Agreement, 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 Precedent Agreement and the amounts that would be due under the Service Agreement(s) Shipper is obligated to enter into pursuant to Section 9.1; these rights shall be in addition to other rights of and remedies available to Transporter, including those set forth in Section 9.4(f)(i) and Section 11.2.

(iii) 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, and, in the event of a termination of such agreements, Transporter may set-off any amounts due by Transporter to Shipper under any such agreement.

(iv) 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 may terminate this Precedent Agreement and may exercise any other remedy available to it hereunder, at law or in equity.

10. Conditions Precedent to Shipper's Obligations

Shipper's obligations hereunder are subject to the satisfaction of the following conditions (each, a "Shipper Condition Precedent"):

(a) Shipper has, on or before February 1, 2011, obtained all requisite internal approvals to perform its obligations under this Precedent Agreement; and

(b) Exhibit D sets forth further conditions precedent, if any, agreed between the Parties.

Shipper shall by February 1, 2011, notify Transporter of the satisfaction or failure of the condition set forth in Section 10(a) and shall notify Transporter of the satisfaction, waiver, or failure of any conditions set forth in Exhibit D by the dates, if any, indicated in that Exhibit D.

11. Termination

11.1 Termination by Transporter. Transporter may terminate its obligations under this Precedent Agreement, subject to Section 20.2, following provision of notice to Shipper in accordance with Section 20, in the event that:

(a) any Transporter Condition Precedent is not satisfied or waived by the later of (i) Transporter's acceptance of a Certificate of Public Convenience and Necessity for the Project or a final decision by FERC not to issue a Certificate of Public Convenience and Necessity for the Project, and (ii) the approval of Canadian Transporter's PPBoR for the entire Canada Mainline by the National Energy

Board of Canada with respect to the Canada Mainline or a final decision by the National Energy Board of Canada not to issue a certificate of public convenience and necessity for the Canada Mainline or to approve the PPBoR for the entire Canada Mainline; provided that, Transporter may pursuant to this Section 11.1(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 8 cannot be satisfied;

(b) 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 any other nation; or

(c) Shipper fails to perform any of the covenants or obligations imposed upon it in this Precedent Agreement and Shipper has not remedied such failure within ten days (or such other period specified herein) after receiving notice from Transporter regarding such failure.

Any termination pursuant to Section 11.1(a) above shall specify the condition set forth in Section 8 that has not been or cannot be satisfied.

11.2 Termination by Shipper. Shipper may, before February 1, 2011, terminate this Precedent Agreement, subject to Section 20.2, following written notice provided to Transporter in accordance with Section 20, in the event Shipper has not before then obtained all requisite internal approvals set forth in Section 10(a). Subject to Section 11.3 and Section 20.2, Shipper may also, before the date specified for the applicable Shipper Condition Precedent in Exhibit D, if any, terminate this Precedent Agreement, upon written notice provided to Transporter in accordance with Section 20, in the event the applicable Shipper Condition Precedent has not been satisfied or waived by such date. In addition, subject to Section 11.3 and Section 20.2, Foundation Shippers may terminate this Precedent Agreement, by providing written notice to Transporter within 30 Days after receipt of any updated cost estimate and revised rates for the Firm Service awarded, together with an updated construction schedule for the Project and the Canada Mainline provided by Transporter in accordance with Section 7.1.

11.3 Effect of Termination. In the event Transporter submits a notice of termination of this Precedent Agreement pursuant to Section 11.1(a) or Section 11.1(b) or Shipper submits a notice of termination of this Precedent Agreement pursuant to Section 11.2, Shipper shall owe, and shall pay (no later than 15 business days after receipt of an invoice for the same), to Transporter a sum equal to Development Costs (as defined below); provided that such costs shall not be owed or paid if termination arises from Shipper's failure to secure requisite internal approvals prior to February 1, 2011. In the event Transporter terminates this Precedent Agreement pursuant to Section 11.1(c), Transporter shall be entitled to all available remedies at law or in equity, including, without limitation, payments for Firm Service and other damages even where such damages are in excess of the Development Costs. Except as expressly stated in this Precedent Agreement, the notice of termination, or the termination of other provisions of this Precedent Agreement 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. For purposes of this Section 11.3, "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 February 2, 2011) of all expenditures and costs incurred or committed by Transporter related to the development of the Project between the conclusion of Transporter's Open Season and the notice of termination provided by Transporter or, if applicable, by Shipper pursuant to Section 11.2 (the "Post-Open Season Development Period"); provided, however, in the event such termination results in the failure of the Project and the resulting dissolution of Transporter, Development Costs shall also include reasonable dissolution costs incurred by Transporter prior to dissolution even if incurred after the Post-Open Season Development Period. Development Costs include costs associated with preparing, filing, and prosecuting regulatory applications, including the application to FERC for a Certificate of Public Convenience and Necessity, and AFUDC and other costs incurred during the Post-Open Season Development Period even if required to be paid thereafter.

12. Anticipated Firm Service

Transporter anticipates commencing Service on the Project in 2020; however, nothing contained in this Precedent Agreement shall be construed as a guarantee that the Project will be in service by such date. Transporter shall provide shippers with annual updates regarding the estimated initial service date.

13. Authorities

Performance hereunder shall be subject to all valid laws, orders, decisions, rules, and regulations of duly constituted governmental authorities having jurisdiction or control of the matter related hereto. Should either Party, by force of any such law, order, decision, rule, or regulation, at any time during the term of this Precedent Agreement be ordered or required to do any act inconsistent with the provisions hereof, then for the period during which the requirements of such law, order, decision, rule, or regulation are applicable, this Precedent Agreement shall be deemed modified to conform with the requirement of such law, order, decision, rule, or regulation; provided, however, nothing herein shall alter, modify, or otherwise affect the respective rights of the Parties to cancel or terminate this Precedent Agreement under the terms and conditions hereof.

14. Choice of Law and Venue

As to all matters of construction and interpretation, this Precedent Agreement shall be interpreted, construed, and governed by the laws of the State of Delaware, without regard to the choice of law rules of that state, which might otherwise apply the laws of another jurisdiction. Venue for all actions brought under this Precedent Agreement shall lie in federal or state courts of competent jurisdiction in the State of Delaware.

15. Confidentiality

Due to competitive concerns of Transporter and Shipper, each Party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Precedent Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any Person without first obtaining the express written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either Party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

16. Assignment

16.1 Shipper may assign all or a portion of its rights and obligations under this Precedent Agreement to any Person; provided, however, that any such assignee satisfies the creditworthiness provisions set forth in Section 9.4 or Shipper continues to provide credit support which satisfies the creditworthiness provisions set forth in Section 9.4 for such Person's obligations under this Precedent Agreement.

16.2 In the event Shipper partially assigns its rights and obligations hereunder, Transporter and Shipper shall amend this Precedent Agreement to reflect such partial assignment and Transporter shall enter into a new Precedent Agreement with such assignee in the same form as this Precedent Agreement, which reflects the portions of Shipper's rights and obligations assigned.

16.3 Transporter may refuse to release the assigning Shipper from its obligation if an assignment is likely to have any adverse effect upon Transporter.

17. Amendments

No amendments to or modifications of this Precedent Agreement shall be effective unless agreed upon in writing by Transporter and Shipper.

18. Counterparts

This Precedent Agreement may be executed in several counterparts, including by facsimile transmission, each of which is an original and all of which shall constitute one and the same instrument.

19. Cooperation

Transporter and Shipper shall enter into such additional agreements, and perform such other acts, as may be reasonably requested by the other Party in furtherance of this Precedent Agreement, to the extent the same are not inconsistent with the provisions of this Precedent Agreement and do not expand or modify the obligations of Transporter or Shipper, or otherwise impose costs upon one or the other. Shipper shall cooperate with, and shall file an intervention in support of the Project with FERC, including providing any information that is reasonably requested by Transporter in preparing applications for a Certificate of Public Convenience and Necessity or by any governmental body in connection with such application; provided in all cases that Transporter is not acting in contravention of this Agreement.

20. Notices

20.1 All notices and other communications hereunder shall be in writing and shall be deemed given as of the date of receipt by the receiving Party at the applicable address specified below (or such other address specified in writing by a Party):

If to Transporter, addressed to:

Denali – The Alaska Gas Pipeline, LLC
188 W. Northern Lights Blvd., Suite 1300
P.O. Box 241747
Anchorage, Alaska 99524-1747
Attention: Commercial Manager

Fax: (907) 865-4304

If to Shipper, addressed to Shipper's address specified in Exhibit A.

20.2 To the extent such notice is sent to terminate this Precedent Agreement pursuant to Sections 11.1, 11.2, or 11.3, such termination shall not become effective before the later of (a) seven business days after such notice or (b) two business days after full satisfaction of Shipper's obligations under Section 11.3 of this Precedent Agreement.

20.3 Either Party may change its address by written notice to that effect to the other Party. Except as provided in Section 20.2, notices given hereunder shall be deemed effectively given upon the first business day at the recipient's office following: (i) the day of delivery to the recipient's address by registered mail, return receipt requested, or by a nationally recognized, overnight courier; or (ii) the day when the sender of the notice received confirmation from its facsimile machine or other similar device that such notice was successfully transmitted. Any notices hereunder shall first be delivered by facsimile or other similar means, in accordance with the dates and times provided therein, and shall be mailed as soon as practicable thereafter.

21. Surviving Provisions

The provisions of the following sections shall survive the termination or expiration of this Precedent Agreement and shall become conditions subsequent that apply under each Service Agreement entered into pursuant to this Precedent Agreement:

(a) Section 2.3 shall survive until such time as Transporter determines that sufficient facilities to deliver 100% of shippers' non-reduced MDQ is available;

(b) Section 8(d) shall survive, and if Shipper is a Foundation Shipper Section 6.2(d) shall survive, until the In-Service Date of the applicable Firm Service, and

(c) if Shipper is a Foundation Shipper, Section 6.2(c) shall survive for the initial term of the applicable agreement for Firm Service.

22. Entire Agreement

This Precedent Agreement contains the entire agreement between Transporter and Shipper with respect to the subject matter hereof, and supersedes any and all prior understandings and agreements, whether oral or written, concerning the subject matter hereof.

23. Third Party Beneficiaries

This Precedent Agreement shall not create any rights in any third parties, and no provision hereof shall be construed as creating any obligations for the benefit of, or right in favor of, any person or entity other than Transporter and Shipper.

24. Representations and Warranties

Each Party represents and warrants to the other Party, as of the date of this Precedent Agreement, that (a) it is duly organized, validly existing, and in good standing under the laws of its state of formation and has all requisite legal power and authority to execute this Precedent Agreement and carry out the terms, conditions and provisions hereof; (b) this Precedent Agreement constitutes the valid, legal, and binding obligation of the Party, enforceable in accordance with the terms hereof; (c) the execution, delivery, and performance of this Precedent Agreement are not inconsistent with any obligations of such Party under any other agreement; (d) there are no actions, suits, or proceedings pending or, to the Party's knowledge, threatened against or affecting the Party before any court or administrative body that might materially adversely affect the ability of the Party to meet and carry out its obligations hereunder; (e) all information provided pursuant to Section 9.4 is accurate at the time provided; and (f) the execution and delivery by the Party of this Precedent Agreement has been duly authorized by all requisite corporate, limited liability company, or partnership, as applicable, action.

25. Limitation of Liability

Except where specifically identified in this Precedent Agreement, neither Party shall be liable to the other Party under this Precedent Agreement for any special, indirect, incidental, punitive, or consequential damages of any nature, or for any lost profits, however arising, even if such Party has been made aware of the possibility of such damages or lost profits.

26. Waiver

Unless otherwise specifically indicated herein, any waiver, consent, or approval of any kind or character by a Party of any term or condition set forth in this Precedent Agreement, or for any breach or default hereunder, shall be given or withheld in the sole discretion of the waiving, consenting, or approving Party. All such waivers, consents, and approvals shall be in writing and signed by the waiving, consenting, or approving Party. No delay or omission to exercise any right, power, or remedy accruing to either Party as a result of any breach or default hereunder shall impair any such right, power, or remedy, nor shall it be construed to be a waiver of any such breach or default, or any acquiescence therein, or of any similar or breach thereafter occurring, nor shall any waiver of any single breach or default be deemed or otherwise constitute a waiver of any other breach or default theretofore or thereafter occurring.

[signature page next page]

WHEREFORE, the Parties hereto have made and executed this Precedent Agreement, signed by their duly authorized officers below.

TRANSPORTER:

DENALI – THE ALASKA GAS PIPELINE LLC

By: ____

Name: ______________________________________

Title: _______________________________________

Date: _______________________________________

SHIPPER:

____

By: ____

Name: ______________________________________

Title: _______________________________________

Date: _______________________________________

EXHIBIT A
TO
PRECEDENT AGREEMENT
BY AND BETWEEN

____
AND
DENALI – THE ALASKA GAS PIPELINE LLC

BID SHEET

This Exhibit A is binding upon Shipper, subject to the terms and conditions of the Precedent Agreement.

SHIPPER CONTACT INFORMATION:

Shipper's Legal Name: _______________________________________
Shipper's Address: _______________________________________
____
____
Shipper's Representative: _______________________________________
email address: ____________________________
Phone: __________________________________
Fax: ____________________________________

CREDITWORTHINESS INFORMATION:

Shipper must check all boxes that apply below:

☐ Shipper's Tangible Net Worth is equal to or greater than Shipper's Capital Cost Share or 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's long-term unenhanced senior unsecured debt securities are rated no lower than its ultimate parent company and at least BBB by Standard & Poor's Corporation ("S&P") or Baa2 by Moody's Investor Service ("Moody's") (in the event Shipper is rated differently by multiple agencies, the lowest rating will be used)

☐ Shipper is not under review for possible downgrade by S&P or Moody's

☐ Shipper does not meet the above requirements, but Shipper has provided the necessary details required by Section 9.4(b) of the Precedent Agreement to establish Shipper's creditworthiness

☐ Shipper does not meet the above requirements, but Shipper will provide and maintain the following credit alternative in a manner consistent with the requirements of Section 9.4(d) of the Precedent Agreement (if applicable, check one):

  ☐ a guaranty from a creditworthy guarantor (list guarantor here: ________________________)

  ☐ an irrevocable letter of credit

  ☐ a cash security deposit

  ☐ other security (identify here: ____________________________________)

SUMMARY OF FIRM SERVICES:

The following is a brief description of the Firm Services offered under the applicable Service Agreements.

- Transmission from the Central Gas Facility at Prudhoe Bay to the inlet of the GTP.
- Transmission from the Point Thomson area to the Inlet of the GTP.
- Gas Treatment Service - The GTP will remove acid gas components.
- Treated Gas Return - Clean gas suitable for use as fuel will be available at the GTP.
- Compression Service - The GTP will accept gas downstream of the Gas Treatment Service section and provide compression and chilling.
- Firm Transportation Service - Transportation from the outlet of the GTP to delivery points in Alaska and to the inlet of the Canada Mainline.

FIRM SERVICES REQUESTED:

Shipper may elect to receive optional services in addition to Transportation Service by specifying the requested Firm Service in this Exhibit A. To bid for specific Firm Service, Shipper must insert the term and requested MDQ for the applicable Receipt and Delivery Point identified for such Firm Service. In addition Shipper shall elect an applicable rate for each Firm Service for which Shipper has submitted a bid. Shipper's MDQ is exclusive of the Fuel Requirement.

REQUESTED FIRM TRANSMISSION SERVICE		
Primary Term: ___ Years (Minimum 20 Years)		
Receipt Point	**Delivery Point**	**Requested MDQ**
Prudhoe Bay Transmission Receipt Point	Inlet to Gas Treatment Plant	_______ Dth/Day
Point Thomson Transmission Receipt Point	Inlet to Gas Treatment Plant	_______ Dth/Day
Rate Election (Select One): ☐ Recourse Rate (available to all shippers) ☐ Negotiated Rate (only available to Foundation Shippers)		

REQUESTED FIRM GAS TREATING SERVICE			
Primary Term: ___ Years (Minimum 20 Years)			
	Receipt Point	**Delivery Point**	**Requested MDQ**
A	Inlet to Gas Treatment Plant	Outlet of Gas Treatment Service	_______ Dth/Day
B	Inlet to Gas Treatment Plant	Treated Gas Return Point	_______ Dth/Day
		Total Requested MDQ for Firm Gas Treating Service	**_______ Dth/Day (must equal the sum of A-B above)**

Rate Election for Gas Treating Service (Select One):

☐ Recourse Rate (available to all shippers)

☐ Negotiated Rate (only available to Foundation Shippers)

REQUESTED FIRM COMPRESSION SERVICE		
Primary Term: ___ Years (Minimum 20 Years)		
Receipt Point	**Delivery Point**	**Requested MDQ**
Outlet of Gas Treatment Service	Outlet of Compression Service	_______ Dth/Day

Rate Election for Compression Service (Select One):

☐ Recourse Rate (available to all shippers)

☐ Negotiated Rate (only available to Foundation Shippers)

REQUESTED FIRM TRANSPORTATION SERVICE			
Primary Term: ___ Years (Minimum 20 Years)			
	Receipt Point	**Delivery Point**	**Requested MDQ**
1	Outlet of Compression Service	Livengood	_______ Dth/Day
2	Outlet of Compression Service	Fairbanks	_______ Dth/Day
3	Outlet of Compression Service	Parks Highway Spur	_______ Dth/Day
4	Outlet of Compression Service	Delta Junction	_______ Dth/Day
5	Outlet of Compression Service	Tok	_______ Dth/Day
6	Outlet of Compression Service	Canada Border	_______ Dth/Day
		Total Requested MDQ for Firm Transportation Service	**_______ Dth/Day (must equal the sum of 1-6 above)**

Rate Election for Transportation Service (Select One):

☐ Recourse Rate (available to all shippers)

☐ Negotiated Rate (only available to Foundation Shippers)

WARRANTY OF TITLE:

Shipper warrants to Transporter that it will, at the time of delivery under the applicable Service Agreements, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter under such Service Agreements, free and clear of liens and encumbrances and adverse claims of every kind.

EXHIBIT B
TO
PRECEDENT AGREEMENT
BY AND BETWEEN

____
AND
DENALI – THE ALASKA GAS PIPELINE LLC

RECOURSE RATE PRINCIPLES

Transporter's proposed rates are calculated to recover Transporter's total cost of service. Transmission, treatment, compression, and transportation services will be provided in accordance with Transporter's Tariff, and the rates for such services will be will be based on the following proposed rate principles and rate calculation methodologies, among other then-applicable FERC rules and policies:

1. Estimated Cost of Service

   The annual estimated cost of service is equal to the sum of the following categories: Operations & Maintenance Expense, Administrative & General Expense, Depreciation Expense, AFUDC Equity Amortization, AFUDC Debt Amortization, Taxes Other Than Income, Income Taxes, Equity Return Allowance, Debt Return Allowance, and Deferred Cost of Service. Each of these items is described further in the table below.

Item	**Description**
Operations & Maintenance Expense	Equal to projected annual operating and maintenance expenses at actual cost.
Administrative & General Expense	Equal to projected annual administrative and general expenses at actual cost. Administrative and general expense is allocated between services using the Commission approved Kansas-Nebraska method.
Depreciation Expense	Equal to Gross Plant divided by 25 years (*i.e.*, straight-line depreciation). Transporter intends to recover the total depreciation over the depreciable life of the Project as determined by FERC.
AFUDC Equity Amortization	Equal to Total Equity AFUDC divided by 25 years (*i.e.*, straight-line amortization).
AFUDC Debt Amortization	Equal to Total Debt AFUDC divided by 25 years (*i.e.*, straight-line amortization).

Item	**Description**
Taxes Other Than Income	Equal to projected ad valorem and other non-income taxes at actual cost.
Income Taxes	Equal to (Cost of Equity + AFUDC Equity Amortization) x Income Tax Rate / (1 – Income Tax Rate). Calculated on a normalized basis using a composite federal and state income tax rate. Any changes in tax rates will be reflected in the cost of service. Income and related taxes will be calculated as if Transporter is a corporation, as long as Transporter is a pass-through entity.
Equity Return Allowance	Equal to the return on equity multiplied by the operations phase equity capitalization percentage multiplied by rate base.
Debt Return Allowance	Equal to the cost of debt multiplied by the operations phase debt capitalization percentage multiplied by rate base.
Deferred Cost of Service (applies only during ramp-up phase plus one year)	Deferred cost of service arises due to the levelization of rates. Deferred cost of service is equal to the difference between total cost of service before levelization adjustments and total cost of service after levelization adjustments.

2. Rate Base

Rate base is equal to the sum of all capital costs, debt and equity AFUDC, working capital, and line pack gas, adjusted for accumulated depreciation, accumulated deferred taxes, and regulatory assets/liabilities (*i.e.*, accumulated deferred cost of service). AFUDC is equal to the sum of interest during construction (*i.e.*, Debt AFUDC) and return on equity during construction (*i.e.*, Equity AFUDC), based on the capital costs and capitalization ratios for construction activities discussed in item (3.). Actual tax depreciation will be used to calculate deferred taxes. Tax depreciation is estimated to be seven year MACRS schedule, as published by the IRS, for all depreciable property as per provisions of Section 706 of the American Jobs Creation Act of 2004. Intangible & General Plant is allocated between services on a gas plant account basis.

3. Return on Rate Base

Return on equity of 14% for Recourse Rates. Cost of debt will be equal to Transporter's actual weighted average cost of debt, which is estimated to be 5.1%. Construction activities will be financed with a target of 70% debt and 30% equity. Long term financing for the operations phase is estimated to be equal to 75% debt and 25% equity.

4. Rate Design Billing Determinants

Recourse Rates will be calculated using the estimated Quantities of all firm shippers.

5. Rate Design and Calculation Methodology

Rates will be designed using a straight fixed–variable cost classification. Shippers will pay a reservation charge and a usage charge, calculated as follows:

- The monthly reservation charge shall be equal to the fixed revenue requirement for each service (*i.e.*, transmission, treating, compression, and transportation) divided by the daily billing determinants for that service, divided by 12. Transportation reservation rates are distance sensitive and are designed on a mileage of haul basis.

- The usage charge is equal to the variable revenue requirement for each service divided by the annual billing determinants for that service.

Transporter will provide both firm and interruptible service under the rate schedules contained in Transporter's Tariff. Interruptible and AOS rates are calculated as the 100% load factor equivalent of the firm Recourse Rate.

6. Fuel Requirement

The fuel requirement is calculated and adjusted per Transporter's Tariff.

Funds for Dismantlement, Restoration & Removal (DR&R or Negative Salvage) will be collected if approved by FERC. For indicative purposes, such funds have been estimated following guidance in Reasons for Decision – Land Matters Consultation Initiative Stream 3 RH-2-2008 issued by the National Energy Board in May 2009. An economic life consistent with that for rate design was used; abandonment costs were taken as 1.5% of pipeline investment and 8.5% of GTP investment. Abandonment collections are presented as an applicable surcharge to rates set forth in Transporter's Tariff.

EXHIBIT C
TO
PRECEDENT AGREEMENT
BY AND BETWEEN

____
AND
DENALI – THE ALASKA GAS PIPELINE LLC

NEGOTIATED RATE PRINCIPLES AND RATE CALCULATION METHODOLOGY

The Parties agree that Transporter is authorized to charge the Negotiated Rates established in this Precedent Agreement without first obtaining FERC review and approval. Changes in Transporter's operating costs will be reflected in adjustments to Transporter's rates. Transporter is authorized to collect any such adjusted rates without first obtaining FERC approval. Shipper agrees that it will not file, nor support the filing of, a Section 5 case under the Natural Gas Act to seek to modify the Negotiated Rates established by this Precedent Agreement or successor agreements entered into in accordance with this Precedent Agreement.

Transporter's rates are calculated to recover Transporter's total cost of service. Transmission, treatment, compression, and transportation services will be provided in accordance with Transporter's Tariff, and the Negotiated Rates for such services will be will be based on the following rate principles and rate calculation methodologies:

1. Estimated Cost of Service

   The annual estimated cost of service is equal to the sum of the following categories: Operations & Maintenance Expense, Administrative & General Expense, Depreciation Expense, AFUDC Equity Amortization, AFUDC Debt Amortization, Taxes Other Than Income, Income Taxes, Equity Return Allowance, Debt Return Allowance, and Deferred Cost of Service. Each of these items is described further in the table below.

Item	**Description**
Operations & Maintenance Expense	Equal to projected annual operating and maintenance expenses at actual cost.
Administrative & General Expense	Equal to projected annual administrative and general expenses at actual cost. Administrative and general expense is allocated between services using the Commission approved Kansas-Nebraska method.

Item	**Description**
Depreciation Expense	Equal to Gross Plant divided by 25 years (*i.e.*, straight-line depreciation). Transporter will recover 80% of the depreciation over the 20 year term. Transporter intends to recover the total depreciation over the depreciable life of the project as determined by FERC.
AFUDC Equity Amortization	Equal to Total Equity AFUDC divided by 25 years (*i.e.*, straight-line amortization).
AFUDC Debt Amortization	Equal to Total Debt AFUDC divided by 25 years (*i.e.*, straight-line amortization).
Taxes Other Than Income	Equal to projected ad valorem and other non-income taxes at actual cost.
Income Taxes	Equal to (Cost of Equity + AFUDC Equity Amortization) x Income Tax Rate / (1 – Income Tax Rate). Calculated on a normalized basis using a composite federal and state income tax rate. Any changes in tax rates will be reflected in the cost of service. Income and related taxes will be calculated as if Transporter is a corporation, as long as Transporter is a pass-through entity.
Equity Return Allowance	Equal to the return on equity multiplied by the operations phase equity capitalization percentage multiplied by rate base.
Debt Return Allowance	Equal to the cost of debt multiplied by the operations phase debt capitalization percentage multiplied by rate base.
Deferred Cost of Service	Deferred cost of service arises due to the levelization of rates. Deferred cost of service is equal to the difference between total cost of service before levelization adjustments and total cost of service after levelization adjustments.

2. Rate Base

Rate base is equal to the sum of all capital costs, debt and equity AFUDC, working capital, and line pack gas, adjusted for accumulated depreciation, accumulated deferred taxes, and regulatory assets/liabilities (*i.e.*, accumulated deferred cost of service). AFUDC is equal to the sum of interest during construction (*i.e.*, Debt AFUDC) and return on equity during construction (*i.e.*, Equity AFUDC), based on the capital costs and capitalization ratios for construction activities discussed in item (3.). Actual tax depreciation will be used to calculate deferred taxes. Tax depreciation is estimated to be seven year MACRS schedule, as published by the IRS, for all depreciable property as per provisions of Section 706 of the American Jobs Creation Act of 2004. Intangible & General Plant is allocated between services on a gas plant account basis.

3. Return on Rate Base

Return on equity will be 12% for Negotiated Rates. Cost of debt will be equal to Transporter's actual weighted average cost of debt, which is estimated to be 5.1%. Construction activities will be financed with a target of 70% debt and 30% equity. Long term financing for the operations phase is estimated to be equal to 75% debt and 25% equity. Negotiated Rate will be based on actual debt/equity ratios.

4. Rate Design Billing Determinants

Negotiated Rates will be calculated using the estimated Quantities of all firm shippers.

5. Rate Design and Calculation Methodology

Rates will be designed using a straight fixed–variable cost classification. Shippers will pay a reservation charge and a usage charge, calculated as follows:

- The monthly reservation charge shall be equal to the fixed revenue requirement for each service (*i.e.*, transmission, treating, compression, and transportation) divided by the daily billing determinants for that service, divided by 12. Transportation reservation rates are distance sensitive and are designed on a mileage of haul basis.

- Reservation charges will be substantially levelized over the initial contract term of not less than 20 years.

- The usage charge is equal to the variable revenue requirement for each service divided by the annual billing determinants for that service.

Transporter will provide both firm and interruptible service under the rate schedules contained in Transporter's Tariff. Interruptible and AOS rates are calculated as the 100% load-factor equivalent of the firm recourse rate.

The Parties agree that Negotiated Rates shall be recalculated annually in accordance with this Exhibit C, in order to assure that Transporter's rates recover all costs of providing Firm Service.

6. Fuel Requirement

The fuel requirement is calculated and adjusted per Transporter's Tariff.

Funds for Dismantlement, Restoration & Removal (DR&R or Negative Salvage) will be collected. For indicative purposes, such funds have been estimated following guidance in Reasons for Decision – Land Matters Consultation Initiative Stream 3 RH-2-2008 issued by the National Energy Board in May 2009. An economic life consistent with that for rate design was used; abandonment costs were taken as 1.5% of pipeline investment and 8.5% of GTP investment. Abandonment collections are presented as an applicable surcharge to rates set forth in Transporter's Tariff.

EXHIBIT D
TO
PRECEDENT AGREEMENT
BY AND BETWEEN

____
AND
DENALI – THE ALASKA GAS PIPELINE LLC

ADDITIONAL SHIPPER CONDITIONS PRECEDENT

EXHIBIT E
TO
PRECEDENT AGREEMENT
BY AND BETWEEN
____
AND
DENALI – THE ALASKA GAS PIPELINE LLC

Service Agreement No. _______

FORM OF TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FTR

THIS TRANSMISSION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of _______, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ______________, a ______________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Transmission on a firm basis plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper shall not oppose any filing made by Transporter with FERC or any other forum in furtherance of development of Transporter's Facilities with respect to any of the issues addressed directly or indirectly by this Agreement; nor shall Shipper take any actions to impede or delay development of Transporter's Facilities. Notwithstanding the foregoing, nothing contained in this Agreement is intended to preclude Shipper from challenging the proposed size and configuration of Transporter's Facilities or the applicable recourse rates for the same in any proceeding, or enforcing a provision of this Agreement.

2.4 During the term of this Agreement, Shipper shall comply with the following creditworthiness standards. Transporter shall not be required to continue to perform its obligations under this 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 in accordance with the following:

(a) Creditworthiness Standard.

(i) Subject to Transporter's analysis of factors set forth below in Section 2.4(b), Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 2.4(a)(ii). 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 2.4(a)(i); provided that Shipper still must satisfy the requirements of Section 2.4(a)(ii).

Shipper's "Capital Cost Share" is its pro-rata share (determined based on the aggregate of firm capacity commitments indicated by Shipper on all of its Attachment 1's for the applicable Service compared to shippers' total firm capacity commitments for such Service of the capital costs (net of cumulative depreciation collected), AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's facilities.

(ii) Shipper will be deemed creditworthy so long as (1) Shipper's long-term unenhanced senior unsecured debt securities are rated no lower than its ultimate parent company and at least BBB by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least Baa2 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and (2) it meets the provisions of Section 2.4(a)(i) 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.

(iii) "Tangible Net Worth," for purposes of this Section 2.4(a), means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations Shipper is obligated to disclose to Transporter. 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.

(b) Determination of Creditworthiness. In evaluating Shipper's creditworthiness, Transporter may consider, in Transporter's sole discretion, in addition to the factors set forth in Section 2.4(a), one or more of the following categories of additional information and factors, but in making all creditworthiness determinations, Transporter shall act in a not unduly discriminatory manner:

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

(ii) the pro forma effect on Shipper's debt rating of execution by Shipper of any Service Agreement;

(iii) financial statements and reports;

(iv) 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;

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

(vi) 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;

(vii) 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); and

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

(c) The creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) of this Agreement.

(d) Failure to Satisfy Creditworthiness – Alternatives. If Shipper fails or ceases to satisfy the creditworthiness standards 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 2.4(a):

(i) Guaranty: Shipper may provide a guaranty that is sufficient to cover its contractual obligations to Transporter in a form satisfactory to Transporter

in Transporter's sole discretion, from a guarantor who meets the creditworthiness standards or criteria described above; or

(ii) Collateral:

(1) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in Transporter's sole discretion in an amount equal to a rolling 36 Months of charges under this Agreement (re-calculated semi-annually), but in no event greater than Shipper's remaining contractual obligations to Transporter. If Shipper does not, at least 20 business days prior to the conclusion of the letter of credit's term, provide Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Section 2.4(d)(ii)(1), reasonably acceptable to Transporter, Transporter shall be entitled to draw upon the full value of the letter of credit;

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

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

(iii) Upon termination of all executed Service Agreements, 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.

(e) <u>Ongoing Creditworthiness Review</u>. 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 business days of 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 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 Business Days of Transporter's request or occurrence of material adverse change, 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.

(f) <u>Notification of Failure to Meet Creditworthiness</u>. Upon notification by Transporter that Shipper no longer meets Transporter's creditworthiness standards

or criteria, Shipper must within fifteen Business Days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Section 2.4.

(i) If Shipper fails to provide one of the credit alternatives within this time period following the commencement of the primary term of this Agreement, Transporter may provide Notice to Shipper of its intention to suspend Service in five 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 Business Days of suspension of its Service, Transporter may initiate termination of Service proceedings with FERC and provide such Notice to Shipper and any replacement shipper(s).

(ii) 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 Agreement; these rights shall be in addition to other rights of and remedies available to Transporter, including those set forth in Section 2.4(f)(i).

(iii) 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, and, in the event of a termination of such agreements, Transporter may set-off any amounts due by Transporter to Shipper under any such agreement.

(iv) 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 may suspend or terminate Service. Transporter also may exercise any other remedy available to it hereunder, at law or in equity.

2.5 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

2.6 Transporter shall solicit bids for line fill from Shippers who have been awarded bids from the 2010 open season, under the presumption that Shippers can sell Transporter line fill in proportion to their MDQ relative to the service capacity. Where Transporter can accelerate the in-service date utilizing line fill from both northern and southern receipt points, and Shippers cannot provide southern receipt point Quantities, Transporter may

solicit bids from the marketplace. Where Shipper bids are not deemed competitive, or if Shipper declines to participate in the bidding process, Transporter may purchase line fill from other natural gas provider(s).

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FTR, as such rates and charges and Rate Schedule FTR may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with Transporter's FERC Gas Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of Transporter's FERC Gas Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FTR. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 After the initial successful Open Season and acceptance by Transporter of a Certificate of Public Convenience and Necessity, Transporter shall solicit interest in capacity expansion every two years. Should interest in expansion be received and before seeking FERC approval for a physical expansion of the facilities, Transporter shall provide existing Firm Shippers, on a non-discriminatory basis, the opportunity to reduce their capacity sufficient to otherwise accommodate the expansion Quantities. In the event Transporter, after establishing the design capacity based on Precedent Agreements entered as a result of the initial Open Season or any thereafter, receives indications of interest for new

capacity, which cannot be satisfied by the 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 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. If it is determined that an expansion is warranted, Transporter may undertake the expansion after securing financial commitments from expansion shippers unless such needs cannot be accommodated due to financial, economic, engineering, design, capacity, or operational constraints or unless the new request would adversely impact the timely development of Transporter's Facilities. Transporter shall not propose a rate structure for expansions that requires existing shippers to subsidize expansion shippers.

4.5 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for 20 years following the commencement date of reliable deliveries for Firm Services, as determined by Transporter, but such deliveries may be at less than the full MDQ of the Shipper. This agreement may continue past the initial term, subject to exercise of applicable extension and/or Right of First Refusal rights.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - _____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Firm Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Firm Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper may assign all or a portion of its rights and obligations under this Agreement to any Person; provided, however, that any such assignee satisfies the creditworthiness provisions set forth in Section 2.4 or Shipper continues to provide credit support which satisfies the creditworthiness provisions set forth in Section 2.4 for such Person's obligations under this Agreement.

In the event Shipper partially assigns its rights and obligations hereunder prior to the in-service date of Transporter's Facilities, Transporter and Shipper agree to amend this Agreement to reflect such partial assignment and Transporter shall enter into a new Agreement with such assignee in the same form as this Agreement, which reflects the portions of Shipper's rights and obligations assigned.

After the in-service date of Transporter's Facilities, any transfer of Capacity rights must be accomplished through the Capacity Release provisions of Transporter's approved FERC Gas Tariff. Transporter may refuse to release Shipper from its obligation if assignment is likely to have any adverse effect upon Transporter.

8.6 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter's Facilities, export and/or import licenses, market fluctuations, provision of gas to meet MDQ, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of costs required to be paid by Shipper pursuant to this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.7 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

8.8 Interpretive Conventions. Unless otherwise specifically provided, the following interpretative conventions apply to the interpretation of this Agreement:

(a) *Gender*. A reference to one gender includes the others.

(b) *References.* A reference to a "Article," "Section," or "Attachment" is to an Article, Section, or Attachment, as the case may be, of this Agreement.

(c) *Conjunctions*.

(i) And. The word "and" can have two different connotations:

(1) the several "and": A and B, jointly or severally; or

(2) the joint "and": A and B, jointly but not severally.

In this Agreement, "and" should be interpreted in the joint sense, uniting things as a whole group, not in the several sense.

(ii) Or. The word "or" can have two different connotations:

(1) the inclusive "or": A or B, or both; or

(2) the exclusive "or": A or B, but not both.

In this Agreement, "or" should be interpreted in the inclusive sense, not in the exclusive sense. If "or" is used in the exclusive sense, it is written as "either A or B" or other phrase indicating the exclusive connotation.

(d) *Singular/Plural.* A word denoting the singular only includes the plural, or vice versa, where the context requires.

(e) *Amended Statutes & Regulations.* A reference to a statue or regulation is a reference to the law as later changed or a change caused by a change to another law.

(f) *Amended Agreement.* A reference to an agreement is a reference to the agreement as later changed.

(g) *Include.* The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(h) *Headings.* The headings in this Agreement are included for convenience and do not affect the construction of this Agreement.

(i) *Drafting Construction.* Each party has had the opportunity to consult attorneys and other advisors in connection with entering into this Agreement, and as a consequence the rule calling for an agreement to be construed against the drafter does not apply.

(j) *May.* The word "may" means "is authorized or permitted to in its sole discretion," while "may not" means "is not authorized or permitted to."

(k) *Successor/Assigns.* A references to a Person includes that Person's permitted successors and assigns and, in the case of any governmental Person, the Person succeeding to the relevant functions of that governmental Person.

(l) *References to Agencies or Officials.* A reference to a governmental department, division, agency, or official continues to apply regardless of any changes in name or title, and applies to the successor department, division, agency, or official to which the referenced responsibilities or functions may be transferred. A reference to a government official includes the official's designee.

(m) *Successor Publications.* Where this Agreement references information or uses an information source that is no longer available, the parties shall reference information or use an information source that is substantially similar.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ____________________________	Title: ____________________________

Appendix A
Precedent Agreement

ATTACHMENT 1 TO
TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FTR

Receipt Point(s), Delivery Point(s), and MDQ

Receipt Point	Delivery Point	MDQ*
Prudhoe Bay Transmission Receipt Point	Inlet to Gas Treatment Plant	________ Dth/day
AND/OR		
Point Thomson Transmission Receipt Point	Inlet to Gas Treatment Plant	________ Dth/day

*Stated MDQ is an annual average. Reference Transporter's Tariff for additional information on treatment of MDQ.

**ATTACHMENT 2 TO
TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FTR**

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter's FERC Gas Tariff.

**EXHIBIT F
TO
PRECEDENT AGREEMENT
BY AND BETWEEN**

____

**AND
DENALI – THE ALASKA GAS PIPELINE LLC**

Service Agreement No. _______

**FORM OF GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE FGT**

THIS GAS TREATING SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of _______, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ______________, a ______________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for treating on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper shall not oppose any filing made by Transporter with FERC or any other forum in furtherance of development of Transporter's Facilities with respect to any of the issues addressed directly or indirectly by this Agreement; nor shall Shipper take any actions to impede or delay development of Transporter's Facilities. Notwithstanding the foregoing,

nothing contained in this Agreement is intended to preclude Shipper from challenging the proposed size and configuration of Transporter's Facilities or the applicable recourse rates for the same in any proceeding, or enforcing a provision of this Agreement.

2.4 During the term of this Agreement, Shipper shall comply with the following creditworthiness standards. Transporter shall not be required to continue to perform its obligations under this 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 in accordance with the following:

(a) Creditworthiness Standard.

(i) Subject to Transporter's analysis of factors set forth below in Section 2.4(b), Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 2.4(a)(ii). 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 2.4(a)(i); provided that Shipper still must satisfy the requirements of Section 2.4(a)(ii).

Shipper's "Capital Cost Share" is its pro-rata share (determined based on the aggregate of firm capacity commitments indicated by Shipper on all of its Attachment 1's for the applicable Service compared to shippers' total firm capacity commitments for such Service of the capital costs (net of cumulative depreciation collected), AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's facilities.

(ii) Shipper will be deemed creditworthy so long as (1) Shipper's long-term unenhanced senior unsecured debt securities are rated no lower than its ultimate parent company and at least BBB by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least Baa2 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and (2) it meets the provisions of Section 2.4(a)(i) 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.

(iii) "Tangible Net Worth," for purposes of this Section 2.4(a), means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations Shipper is obligated to disclose to Transporter. 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.

(b) Determination of Creditworthiness. In evaluating Shipper's creditworthiness, Transporter may consider, in Transporter's sole discretion, in addition to the factors set forth in Section 2.4(a), one or more of the following categories of additional information and factors, but in making all creditworthiness determinations, Transporter shall act in a not unduly discriminatory manner:

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

(ii) the pro forma effect on Shipper's debt rating of execution by Shipper of any Service Agreement;

(iii) financial statements and reports;

(iv) 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;

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

(vi) 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;

(vii) 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); and

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

(c) The creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) of this Agreement.

(d) Failure to Satisfy Creditworthiness – Alternatives. If Shipper fails or ceases to satisfy the creditworthiness standards 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 2.4(a):

(i) Guaranty: Shipper may provide a guaranty that is sufficient to cover its contractual obligations to Transporter in a form satisfactory to Transporter

in Transporter's sole discretion, from a guarantor who meets the creditworthiness standards or criteria described above; or

(ii) Collateral:

(1) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in Transporter's sole discretion in an amount equal to a rolling 36 Months of charges under this Agreement (re-calculated semi-annually), but in no event greater than Shipper's remaining contractual obligations to Transporter. If Shipper does not, at least 20 business days prior to the conclusion of the letter of credit's term, provide Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Section 2.4(d)(ii)(1), reasonably acceptable to Transporter, Transporter shall be entitled to draw upon the full value of the letter of credit;

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

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

(iii) Upon termination of all executed Service Agreements, 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.

(e) 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 business days of 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 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 Business Days of Transporter's request or occurrence of material adverse change, 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.

(f) Notification of Failure to Meet Creditworthiness. Upon notification by Transporter that Shipper no longer meets Transporter's creditworthiness standards

or criteria, Shipper must within fifteen Business Days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Section 2.4.

(i) If Shipper fails to provide one of the credit alternatives within this time period following the commencement of the primary term of this Agreement, Transporter may provide Notice to Shipper of its intention to suspend Service in five 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 Business Days of suspension of its Service, Transporter may initiate termination of Service proceedings with FERC and provide such Notice to Shipper and any replacement shipper(s).

(ii) 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 Agreement; these rights shall be in addition to other rights of and remedies available to Transporter, including those set forth in Section 2.4(f)(i).

(iii) 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, and, in the event of a termination of such agreements, Transporter may set-off any amounts due by Transporter to Shipper under any such agreement.

(iv) 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 may suspend or terminate Service. Transporter also may exercise any other remedy available to it hereunder, at law or in equity.

2.5 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

2.6 Transporter shall solicit bids for line fill from Shippers who have been awarded bids from the 2010 open season, under the presumption that Shippers can sell Transporter line fill in proportion to their MDQ relative to the service capacity. Where Transporter can accelerate the in-service date utilizing line fill from both northern and southern receipt points, and Shippers cannot provide southern receipt point Quantities, Transporter may

solicit bids from the marketplace. Where Shipper bids are not deemed competitive, or if Shipper declines to participate in the bidding process, Transporter may purchase line fill from other natural gas provider(s).

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s), and Acid Gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Acid Gas Delivery Point at Transporter's line pressure existing at the Acid Gas Delivery Point. Shipper is responsible for disposal of delivered acid gas.

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FGT, as such rates and charges and Rate Schedule FGT may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with Transporter's FERC Gas Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of Transporter's FERC Gas Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FGT. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 After the initial successful Open Season and acceptance by Transporter of a Certificate of Public Convenience and Necessity, Transporter shall solicit interest in capacity expansion every two years. Should interest in expansion be received and before seeking FERC approval for a physical expansion of the facilities, Transporter shall provide existing Firm

Shippers, on a non-discriminatory basis, the opportunity to reduce their capacity sufficient to otherwise accommodate the expansion Quantities. In the event Transporter, after establishing the design capacity based on Precedent Agreements entered as a result of the initial Open Season or any thereafter, receives indications of interest for new capacity, which cannot be satisfied by the 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 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. If it is determined that an expansion is warranted, Transporter may undertake the expansion after securing financial commitments from expansion shippers unless such needs cannot be accommodated due to financial, economic, engineering, design, capacity, or operational constraints or unless the new request would adversely impact the timely development of Transporter's Facilities. Transporter shall not propose a rate structure for expansions that requires existing shippers to subsidize expansion shippers.

4.5 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for 20 years following the commencement date of reliable deliveries for Firm Services, as determined by Transporter, but such deliveries may be at less than the full MDQ of the Shipper. This agreement may continue past the initial term, subject to exercise of applicable extension and/or Right of First Refusal rights.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]______________________
[Shipper address]____________________
[Shipper address]____________________
[City, State Zip Code]________________
Attention: [Shipper Designee]__________
Fax: (___) ____ - _____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Firm Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Firm Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper may assign all or a portion of its rights and obligations under this Agreement to any Person; provided, however, that any such assignee satisfies the creditworthiness provisions set forth in Section 2.4 or Shipper continues to provide credit support which satisfies the creditworthiness provisions set forth in Section 2.4 for such Person's obligations under this Agreement.

In the event Shipper partially assigns its rights and obligations hereunder prior to the in-service date of Transporter's Facilities, Transporter and Shipper agree to amend this Agreement to reflect such partial assignment and Transporter shall enter into a new Agreement with such assignee in the same form as this Agreement, which reflects the portions of Shipper's rights and obligations assigned.

After the in-service date of Transporter's Facilities, any transfer of Capacity rights must be accomplished through the Capacity Release provisions of Transporter's approved FERC Gas Tariff. Transporter may refuse to release Shipper from its obligation if assignment is likely to have any adverse effect upon Transporter.

8.6 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter's Facilities, export and/or import licenses, market fluctuations, provision of gas to meet MDQ, disposition of Acid Gas, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of costs required to be paid by Shipper pursuant to this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.7 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

8.8 Interpretive Conventions. Unless otherwise specifically provided, the following interpretative conventions apply to the interpretation of this Agreement:

(a) *Gender*. A reference to one gender includes the others.

(b) *References.* A reference to a "Article," "Section," or "Attachment" is to an Article, Section, or Attachment, as the case may be, of this Agreement.

(c) *Conjunctions*.

(i) And. The word "and" can have two different connotations:

(1) the several "and": A and B, jointly or severally; or

(2) the joint “and”: A and B, jointly but not severally.

In this Agreement, “and” should be interpreted in the joint sense, uniting things as a whole group, not in the several sense.

(ii) Or. The word “or” can have two different connotations:

(1) the inclusive “or”: A or B, or both; or

(2) the exclusive “or”: A or B, but not both.

In this Agreement, “or” should be interpreted in the inclusive sense, not in the exclusive sense. If “or” is used in the exclusive sense, it is written as “either A or B” or other phrase indicating the exclusive connotation.

(d) *Singular/Plural.* A word denoting the singular only includes the plural, or vice versa, where the context requires.

(e) *Amended Statutes & Regulations.* A reference to a statue or regulation is a reference to the law as later changed or a change caused by a change to another law.

(f) *Amended Agreement.* A reference to an agreement is a reference to the agreement as later changed.

(g) *Include.* The words “including,” “includes,” and “include” are deemed to be followed by the words “without limitation.”

(h) *Headings.* The headings in this Agreement are included for convenience and do not affect the construction of this Agreement.

(i) *Drafting Construction.* Each party has had the opportunity to consult attorneys and other advisors in connection with entering into this Agreement, and as a consequence the rule calling for an agreement to be construed against the drafter does not apply.

(j) *May.* The word “may” means “is authorized or permitted to in its sole discretion,” while “may not” means “is not authorized or permitted to.”

(k) *Successor/Assigns.* A references to a Person includes that Person’s permitted successors and assigns and, in the case of any governmental Person, the Person succeeding to the relevant functions of that governmental Person.

(l) *References to Agencies or Officials.* A reference to a governmental department, division, agency, or official continues to apply regardless of any changes in name or title, and applies to the successor department, division, agency, or official to which the referenced responsibilities or functions may be transferred. A reference to a government official includes the official’s designee.

(m) *Successor Publications*. Where this Agreement references information or uses an information source that is no longer available, the parties shall reference information or use an information source that is substantially similar.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ____________________________	Title: ____________________________

Appendix A
Precedent Agreement

ATTACHMENT 1 TO
GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE FGT

Receipt Point(s), Delivery Point(s), and MDQ

	Receipt Point	**Delivery Point**	**MDQ***
A	Inlet to Gas Treatment Plant	Outlet of Gas Treatment Service	________ Dth/day
B	Inlet to Gas Treatment Plant	Treated Gas Return Point	________ Dth/day
		Total MDQ for Firm Gas Treating Service	**________ Dth/day (must equal the sum of A-B above)**

*Stated MDQ is an annual average. Reference Transporter's Tariff for additional information on treatment of MDQ.

ATTACHMENT 2 TO
GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE FGT

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter's FERC Gas Tariff.

EXHIBIT G
TO
PRECEDENT AGREEMENT
BY AND BETWEEN

____
AND
DENALI – THE ALASKA GAS PIPELINE LLC

Service Agreement No. _______

FORM OF COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FC

THIS COMPRESSION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of _______, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ______________, a ______________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for compression on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper shall not oppose any filing made by Transporter with FERC or any other forum in furtherance of development of Transporter's Facilities with respect to any of the issues addressed directly or indirectly by this Agreement; nor shall Shipper take any actions to impede or delay development of Transporter's Facilities. Notwithstanding the foregoing,

nothing contained in this Agreement is intended to preclude Shipper from challenging the proposed size and configuration of Transporter's Facilities or the applicable recourse rates for the same in any proceeding, or enforcing a provision of this Agreement.

2.4 During the term of this Agreement, Shipper shall comply with the following creditworthiness standards. Transporter shall not be required to continue to perform its obligations under this 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 in accordance with the following:

(a) Creditworthiness Standard.

(i) Subject to Transporter's analysis of factors set forth below in Section 2.4(b), Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 2.4(a)(ii). 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 2.4(a)(i); provided that Shipper still must satisfy the requirements of Section 2.4(a)(ii).

Shipper's "Capital Cost Share" is its pro-rata share (determined based on the aggregate of firm capacity commitments indicated by Shipper on all of its Attachment 1's for the applicable Service compared to shippers' total firm capacity commitments for such Service of the capital costs (net of cumulative depreciation collected), AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's facilities.

(ii) Shipper will be deemed creditworthy so long as (1) Shipper's long-term unenhanced senior unsecured debt securities are rated no lower than its ultimate parent company and at least BBB by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least Baa2 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and (2) it meets the provisions of Section 2.4(a)(i) 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.

(iii) "Tangible Net Worth," for purposes of this Section 2.4(a), means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations Shipper is obligated to disclose to Transporter. 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.

(b) Determination of Creditworthiness. In evaluating Shipper's creditworthiness, Transporter may consider, in Transporter's sole discretion, in addition to the factors set forth in Section 2.4(a), one or more of the following categories of additional information and factors, but in making all creditworthiness determinations, Transporter shall act in a not unduly discriminatory manner:

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

(ii) the pro forma effect on Shipper's debt rating of execution by Shipper of any Service Agreement;

(iii) financial statements and reports;

(iv) 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;

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

(vi) 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;

(vii) 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); and

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

(c) The creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) of this Agreement.

(d) Failure to Satisfy Creditworthiness – Alternatives. If Shipper fails or ceases to satisfy the creditworthiness standards 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 2.4(a):

(i) Guaranty: Shipper may provide a guaranty that is sufficient to cover its contractual obligations to Transporter in a form satisfactory to Transporter

in Transporter's sole discretion, from a guarantor who meets the creditworthiness standards or criteria described above; or

(ii) Collateral:

(1) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in Transporter's sole discretion in an amount equal to a rolling 36 Months of charges under this Agreement (re-calculated semi-annually), but in no event greater than Shipper's remaining contractual obligations to Transporter. If Shipper does not, at least 20 business days prior to the conclusion of the letter of credit's term, provide Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Section 2.4(d)(ii)(1), reasonably acceptable to Transporter, Transporter shall be entitled to draw upon the full value of the letter of credit;

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

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

(iii) Upon termination of all executed Service Agreements, 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.

(e) <u>Ongoing Creditworthiness Review</u>. 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 business days of 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 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 Business Days of Transporter's request or occurrence of material adverse change, 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.

(f) <u>Notification of Failure to Meet Creditworthiness</u>. Upon notification by Transporter that Shipper no longer meets Transporter's creditworthiness standards

or criteria, Shipper must within fifteen Business Days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Section 2.4.

(i) If Shipper fails to provide one of the credit alternatives within this time period following the commencement of the primary term of this Agreement, Transporter may provide Notice to Shipper of its intention to suspend Service in five 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 Business Days of suspension of its Service, Transporter may initiate termination of Service proceedings with FERC and provide such Notice to Shipper and any replacement shipper(s).

(ii) 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 Agreement; these rights shall be in addition to other rights of and remedies available to Transporter, including those set forth in Section 2.4(f)(i).

(iii) 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, and, in the event of a termination of such agreements, Transporter may set-off any amounts due by Transporter to Shipper under any such agreement.

(iv) 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 may suspend or terminate Service. Transporter also may exercise any other remedy available to it hereunder, at law or in equity.

2.5 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

2.6 Transporter shall solicit bids for line fill from Shippers who have been awarded bids from the 2010 open season, under the presumption that Shippers can sell Transporter line fill in proportion to their MDQ relative to the service capacity. Where Transporter can accelerate the in-service date utilizing line fill from both northern and southern receipt points, and Shippers cannot provide southern receipt point Quantities, Transporter may

solicit bids from the marketplace. Where Shipper bids are not deemed competitive, or if Shipper declines to participate in the bidding process, Transporter may purchase line fill from other natural gas provider(s).

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FC, as such rates and charges and Rate Schedule FC may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with Transporter's FERC Gas Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of Transporter's FERC Gas Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FC. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 After the initial successful Open Season and acceptance by Transporter of a Certificate of Public Convenience and Necessity, Transporter shall solicit interest in capacity expansion every two years. Should interest in expansion be received and before seeking FERC approval for a physical expansion of the facilities, Transporter shall provide existing Firm Shippers, on a non-discriminatory basis, the opportunity to reduce their capacity sufficient to otherwise accommodate the expansion Quantities. In the event Transporter, after establishing the design capacity based on Precedent Agreements entered as a result of the initial Open Season or any thereafter, receives indications of interest for new

capacity, which cannot be satisfied by the 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 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. If it is determined that an expansion is warranted, Transporter may undertake the expansion after securing financial commitments from expansion shippers unless such needs cannot be accommodated due to financial, economic, engineering, design, capacity, or operational constraints or unless the new request would adversely impact the timely development of Transporter's Facilities. Transporter shall not propose a rate structure for expansions that requires existing shippers to subsidize expansion shippers.

4.5 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for 20 years following the commencement date of reliable deliveries for Firm Services, as determined by Transporter, but such deliveries may be at less than the full MDQ of the Shipper. This agreement may continue past the initial term, subject to exercise of applicable extension and/or Right of First Refusal rights.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments:	as directed on the applicable invoice
Notices:	as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - _____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Firm Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Firm Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper may assign all or a portion of its rights and obligations under this Agreement to any Person; provided, however, that any such assignee satisfies the creditworthiness provisions set forth in Section 2.4 or Shipper continues to provide credit support which satisfies the creditworthiness provisions set forth in Section 2.4 for such Person's obligations under this Agreement.

In the event Shipper partially assigns its rights and obligations hereunder prior to the in-service date of Transporter's Facilities, Transporter and Shipper agree to amend this Agreement to reflect such partial assignment and Transporter shall enter into a new Agreement with such assignee in the same form as this Agreement, which reflects the portions of Shipper's rights and obligations assigned.

After the in-service date of Transporter's Facilities, any transfer of Capacity rights must be accomplished through the Capacity Release provisions of Transporter's approved FERC Gas Tariff. Transporter may refuse to release Shipper from its obligation if assignment is likely to have any adverse effect upon Transporter.

8.6 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter's Facilities, export and/or import licenses, market fluctuations, provision of gas to meet MDQ, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of costs required to be paid by Shipper pursuant to this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.7 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

8.8 Interpretive Conventions. Unless otherwise specifically provided, the following interpretative conventions apply to the interpretation of this Agreement:

(a) *Gender*. A reference to one gender includes the others.

(b) *References.* A reference to a "Article," "Section," or "Attachment" is to an Article, Section, or Attachment, as the case may be, of this Agreement.

(c) *Conjunctions*.

(i) And. The word "and" can have two different connotations:

(1) the several "and": A and B, jointly or severally; or

(2) the joint "and": A and B, jointly but not severally.

In this Agreement, "and" should be interpreted in the joint sense, uniting things as a whole group, not in the several sense.

(ii) Or. The word "or" can have two different connotations:

(1) the inclusive "or": A or B, or both; or

(2) the exclusive "or": A or B, but not both.

In this Agreement, "or" should be interpreted in the inclusive sense, not in the exclusive sense. If "or" is used in the exclusive sense, it is written as "either A or B" or other phrase indicating the exclusive connotation.

(d) *Singular/Plural.* A word denoting the singular only includes the plural, or vice versa, where the context requires.

(e) *Amended Statutes & Regulations.* A reference to a statue or regulation is a reference to the law as later changed or a change caused by a change to another law.

(f) *Amended Agreement.* A reference to an agreement is a reference to the agreement as later changed.

(g) *Include.* The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(h) *Headings.* The headings in this Agreement are included for convenience and do not affect the construction of this Agreement.

(i) *Drafting Construction.* Each party has had the opportunity to consult attorneys and other advisors in connection with entering into this Agreement, and as a consequence the rule calling for an agreement to be construed against the drafter does not apply.

(j) *May.* The word "may" means "is authorized or permitted to in its sole discretion," while "may not" means "is not authorized or permitted to."

(k) *Successor/Assigns.* A references to a Person includes that Person's permitted successors and assigns and, in the case of any governmental Person, the Person succeeding to the relevant functions of that governmental Person.

(l) *References to Agencies or Officials*. A reference to a governmental department, division, agency, or official continues to apply regardless of any changes in name or title, and applies to the successor department, division, agency, or official to which the referenced responsibilities or functions may be transferred. A reference to a government official includes the official's designee.

(m) *Successor Publications*. Where this Agreement references information or uses an information source that is no longer available, the parties shall reference information or use an information source that is substantially similar.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: _____________________________	Title: _____________________________

Appendix A
Precedent Agreement

**ATTACHMENT 1 TO
COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FC**

Receipt Point(s), Delivery Point(s), and MDQ

Receipt Point	**Delivery Point**	**MDQ***
Outlet of Gas Treatment Service	Outlet of Compression Service	________ Dth/day

*Stated MDQ is an annual average. Reference Transporter's Tariff for additional information on treatment of MDQ.

**ATTACHMENT 2 TO
COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FC**

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter's FERC Gas Tariff.

**EXHIBIT H
TO
PRECEDENT AGREEMENT
BY AND BETWEEN**

**________________________________
AND
DENALI – THE ALASKA GAS PIPELINE LLC**

Service Agreement No. _______

**FORM OF TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT**

THIS TRANSPORTATION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of _______, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ______________, a ______________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Transportation on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper shall not oppose any filing made by Transporter with FERC or any other forum in furtherance of development of Transporter's Facilities with respect to any of the issues addressed directly or indirectly by this Agreement; nor shall Shipper take any actions to impede or delay development of Transporter's Facilities. Notwithstanding the foregoing,

nothing contained in this Agreement is intended to preclude Shipper from challenging the proposed size and configuration of Transporter's Facilities or the applicable recourse rates for the same in any proceeding, or enforcing a provision of this Agreement.

2.4 During the term of this Agreement, Shipper shall comply with the following creditworthiness standards. Transporter shall not be required to continue to perform its obligations under this 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 in accordance with the following:

(a) Creditworthiness Standard.

(i) Subject to Transporter's analysis of factors set forth below in Section 2.4(b), Shipper will be deemed creditworthy if (i) its Tangible Net Worth is, in Transporter's assessment, equal to or greater than Shipper's Capital Cost Share as defined below; and (ii) it satisfies the requirements of Section 2.4(a)(ii). 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 2.4(a)(i); provided that Shipper still must satisfy the requirements of Section 2.4(a)(ii).

Shipper's "Capital Cost Share" is its pro-rata share (determined based on the aggregate of firm capacity commitments indicated by Shipper on all of its Attachment 1's for the applicable Service compared to shippers' total firm capacity commitments for such Service of the capital costs (net of cumulative depreciation collected), AFUDC, and other expenditures incorporated into rate base incurred or to be incurred by Transporter, in Transporter's estimation, in developing Transporter's facilities.

(ii) Shipper will be deemed creditworthy so long as (1) Shipper's long-term unenhanced senior unsecured debt securities are rated no lower than its ultimate parent company and at least BBB by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or at least Baa2 by Moody's Investors Service, Inc. ("Moody's"), in each case with a stable or better outlook, and (2) it meets the provisions of Section 2.4(a)(i) 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.

(iii) "Tangible Net Worth," for purposes of this Section 2.4(a), means total assets, less total liabilities, less intangible assets, less off-balance sheet obligations Shipper is obligated to disclose to Transporter. 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.

(b) Determination of Creditworthiness. In evaluating Shipper's creditworthiness, Transporter may consider, in Transporter's sole discretion, in addition to the factors set forth in Section 2.4(a), one or more of the following categories of additional information and factors, but in making all creditworthiness determinations, Transporter shall act in a not unduly discriminatory manner:

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

(ii) the pro forma effect on Shipper's debt rating of execution by Shipper of any Service Agreement;

(iii) financial statements and reports;

(iv) 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;

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

(vi) 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;

(vii) 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); and

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

(c) The creditworthiness requirements applicable to Shipper shall apply to any assignee pursuant to an assignment (in whole or part) of this Agreement.

(d) Failure to Satisfy Creditworthiness – Alternatives. If Shipper fails or ceases to satisfy the creditworthiness standards 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 2.4(a):

(i) Guaranty: Shipper may provide a guaranty that is sufficient to cover its contractual obligations to Transporter in a form satisfactory to Transporter

in Transporter's sole discretion, from a guarantor who meets the creditworthiness standards or criteria described above; or

(ii) Collateral:

(1) Shipper may provide an irrevocable standby letter of credit in a form and from a financial institution acceptable to Transporter in Transporter's sole discretion in an amount equal to a rolling 36 Months of charges under this Agreement (re-calculated semi-annually), but in no event greater than Shipper's remaining contractual obligations to Transporter. If Shipper does not, at least 20 business days prior to the conclusion of the letter of credit's term, provide Transporter with a replacement letter of credit, or alternate security that meets the requirements set out in this Section 2.4(d)(ii)(1), reasonably acceptable to Transporter, Transporter shall be entitled to draw upon the full value of the letter of credit;

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

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

(iii) Upon termination of all executed Service Agreements, 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.

(e) 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 business days of 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 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 Business Days of Transporter's request or occurrence of material adverse change, 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.

(f) Notification of Failure to Meet Creditworthiness. Upon notification by Transporter that Shipper no longer meets Transporter's creditworthiness standards

or criteria, Shipper must within fifteen Business Days provide additional payment, guaranty, collateral, or other mutually agreed security sufficient to meet the creditworthiness requirements set forth in this Section 2.4.

(i) If Shipper fails to provide one of the credit alternatives within this time period following the commencement of the primary term of this Agreement, Transporter may provide Notice to Shipper of its intention to suspend Service in five 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 Business Days of suspension of its Service, Transporter may initiate termination of Service proceedings with FERC and provide such Notice to Shipper and any replacement shipper(s).

(ii) 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 Agreement; these rights shall be in addition to other rights of and remedies available to Transporter, including those set forth in Section 2.4(f)(i).

(iii) 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, and, in the event of a termination of such agreements, Transporter may set-off any amounts due by Transporter to Shipper under any such agreement.

(iv) 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 may suspend or terminate Service. Transporter also may exercise any other remedy available to it hereunder, at law or in equity.

2.5 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

2.6 Transporter shall solicit bids for line fill from Shippers who have been awarded bids from the 2010 open season, under the presumption that Shippers can sell Transporter line fill in proportion to their MDQ relative to the service capacity. Where Transporter can accelerate the in-service date utilizing line fill from both northern and southern receipt points, and Shippers cannot provide southern receipt point Quantities, Transporter may

solicit bids from the marketplace. Where Shipper bids are not deemed competitive, or if Shipper declines to participate in the bidding process, Transporter may purchase line fill from other natural gas provider(s).

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FT, as such rates and charges and Rate Schedule FT may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with Transporter's FERC Gas Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of Transporter's FERC Gas Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FT. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 After the initial successful Open Season and acceptance by Transporter of a Certificate of Public Convenience and Necessity, Transporter shall solicit interest in capacity expansion every two years. Should interest in expansion be received and before seeking FERC approval for a physical expansion of the facilities, Transporter shall provide existing Firm Shippers, on a non-discriminatory basis, the opportunity to reduce their capacity sufficient to otherwise accommodate the expansion Quantities. In the event Transporter, after establishing the design capacity based on Precedent Agreements entered as a result of the initial Open Season or any thereafter, receives indications of interest for new

capacity, which cannot be satisfied by the 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 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. If it is determined that an expansion is warranted, Transporter may undertake the expansion after securing financial commitments from expansion shippers unless such needs cannot be accommodated due to financial, economic, engineering, design, capacity, or operational constraints or unless the new request would adversely impact the timely development of Transporter's Facilities. Transporter shall not propose a rate structure for expansions that requires existing shippers to subsidize expansion shippers.

4.5 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for 20 years following the commencement date of reliable deliveries for Firm Services, as determined by Transporter, but such deliveries may be at less than the full MDQ of the Shipper. This agreement may continue past the initial term, subject to exercise of applicable extension and/or Right of First Refusal rights.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments:	as directed on the applicable invoice
Notices:	as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]______________________
[Shipper address]____________________
[Shipper address]____________________
[City, State Zip Code]________________
Attention: [Shipper Designee]__________
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Firm Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Firm Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper may assign all or a portion of its rights and obligations under this Agreement to any Person; provided, however, that any such assignee satisfies the creditworthiness provisions set forth in Section 2.4 or Shipper continues to provide credit support which satisfies the creditworthiness provisions set forth in Section 2.4 for such Person's obligations under this Agreement.

In the event Shipper partially assigns its rights and obligations hereunder prior to the in-service date of Transporter's Facilities, Transporter and Shipper agree to amend this Agreement to reflect such partial assignment and Transporter shall enter into a new Agreement with such assignee in the same form as this Agreement, which reflects the portions of Shipper's rights and obligations assigned.

After the in-service date of Transporter's Facilities, any transfer of Capacity rights must be accomplished through the Capacity Release provisions of Transporter's approved FERC Gas Tariff. Transporter may refuse to release Shipper from its obligation if assignment is likely to have any adverse effect upon Transporter.

8.6 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter's Facilities, export and/or import licenses, market fluctuations, provision of gas to meet MDQ, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of costs required to be paid by Shipper pursuant to this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.7 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

8.8 Interpretive Conventions. Unless otherwise specifically provided, the following interpretative conventions apply to the interpretation of this Agreement:

(a) *Gender*. A reference to one gender includes the others.

(b) *References.* A reference to a "Article," "Section," or "Attachment" is to an Article, Section, or Attachment, as the case may be, of this Agreement.

(c) *Conjunctions*.

(i) And. The word "and" can have two different connotations:

(1) the several "and": A and B, jointly or severally; or

(2) the joint "and": A and B, jointly but not severally.

In this Agreement, "and" should be interpreted in the joint sense, uniting things as a whole group, not in the several sense.

(ii) Or. The word "or" can have two different connotations:

(1) the inclusive "or": A or B, or both; or

(2) the exclusive "or": A or B, but not both.

In this Agreement, "or" should be interpreted in the inclusive sense, not in the exclusive sense. If "or" is used in the exclusive sense, it is written as "either A or B" or other phrase indicating the exclusive connotation.

(d) *Singular/Plural.* A word denoting the singular only includes the plural, or vice versa, where the context requires.

(e) *Amended Statutes & Regulations.* A reference to a statue or regulation is a reference to the law as later changed or a change caused by a change to another law.

(f) *Amended Agreement.* A reference to an agreement is a reference to the agreement as later changed.

(g) *Include.* The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(h) *Headings.* The headings in this Agreement are included for convenience and do not affect the construction of this Agreement.

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(j) *May.* The word "may" means "is authorized or permitted to in its sole discretion," while "may not" means "is not authorized or permitted to."

(k) *Successor/Assigns.* A references to a Person includes that Person's permitted successors and assigns and, in the case of any governmental Person, the Person succeeding to the relevant functions of that governmental Person.

(l) *References to Agencies or Officials*. A reference to a governmental department, division, agency, or official continues to apply regardless of any changes in name or title, and applies to the successor department, division, agency, or official to which the referenced responsibilities or functions may be transferred. A reference to a government official includes the official's designee.

(m) *Successor Publications*. Where this Agreement references information or uses an information source that is no longer available, the parties shall reference information or use an information source that is substantially similar.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: _____________________________	Title: _____________________________

ATTACHMENT 1 TO
TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT

Receipt Point(s), Delivery Point(s), and MDQ

	Receipt Point(s)	Delivery Point(s)	MDQ*
1	Outlet of Compression Service	Livengood	_______ Dth
2	Outlet of Compression Service	Fairbanks	_______ Dth
3	Outlet of Compression Service	Parks Highway Spur	_______ Dth
4	Outlet of Compression Service	Delta Junction	_______ Dth
5	Outlet of Compression Service	Tok	_______ Dth
6	Outlet of Compression Service	Canada Border	_______ Dth
		Total MDQ for Firm Transportation Service	**_______ Dth (must equal the sum of 1-6 above)**

*Stated MDQ is an annual average. Reference Transporter's Tariff for additional information on treatment of MDQ.

ATTACHMENT 2 TO
TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter’s FERC Gas Tariff.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

DENALI – THE ALASKA GAS PIPELINE LLC	)))	DOCKET NO. PF08-26-001

OPEN SEASON PLAN DOCUMENTS
SUBMITTED IN CONJUNCTION WITH DENALI'S
REQUEST FOR COMMISSION APPROVAL OF PLAN
<u>FOR CONDUCTING AN OPEN SEASON</u>

Volume II of III

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

Patrick J. Coughlin
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Counsel for DENALI – THE ALASKA GAS PIPELINE LLC

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Exhibit N: Estimated Negotiated Rates

Appendix B

In-State Needs Study

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
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Appendix B
In-State Needs Study

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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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.

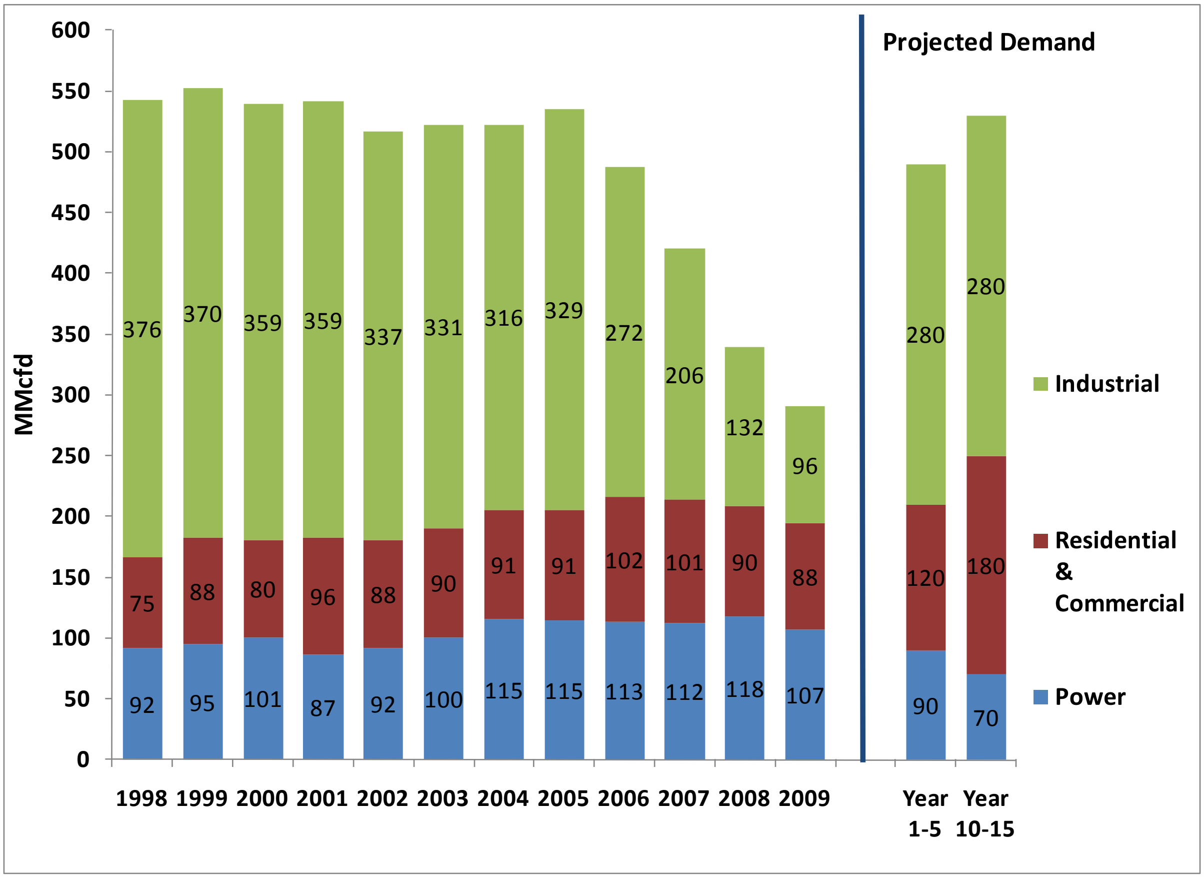
Table ES-1. Total In-State Natural Gas Demand Estimates for Three Scenarios, Alberta Project (MMcfd)

	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

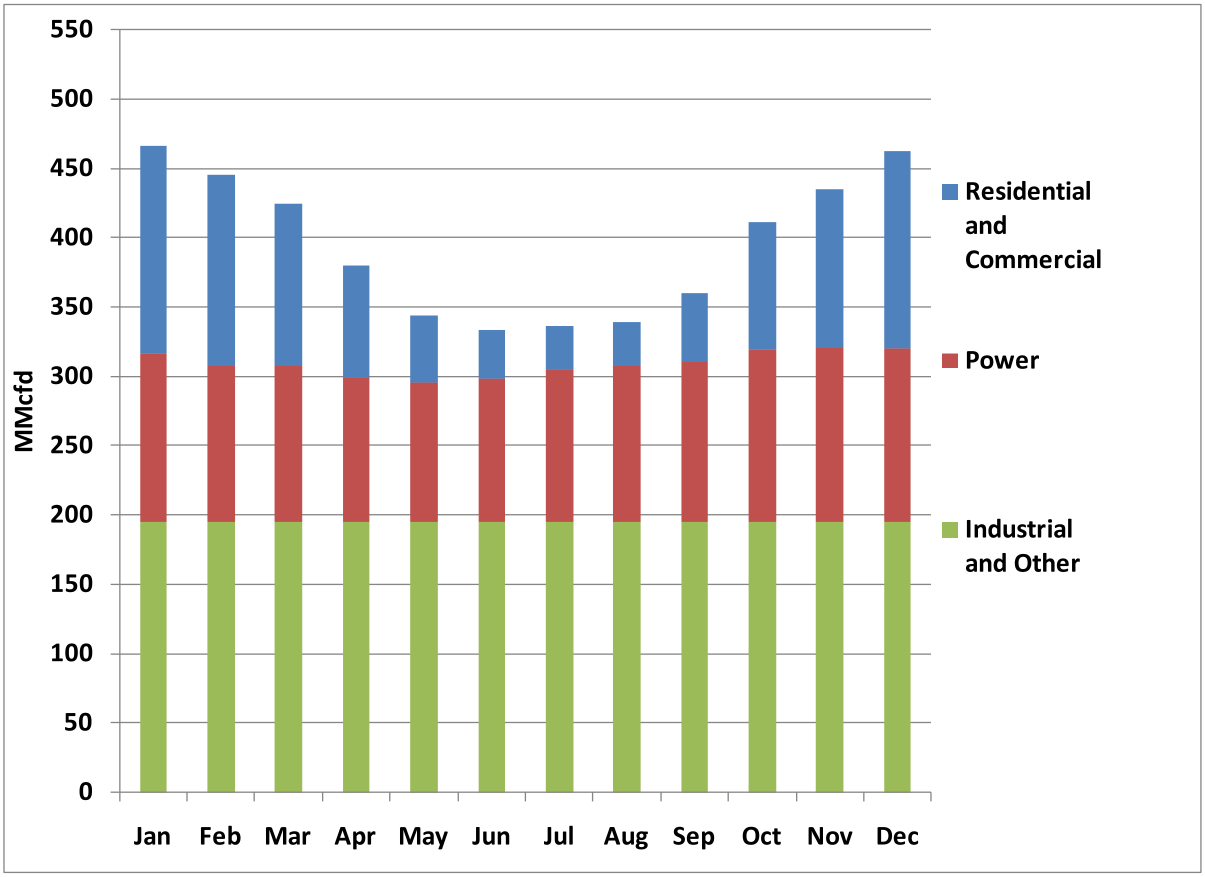


Source: Historical data are from the Division of Oil and Gas, Alaska Department of Natural Resources. Projected demand in Year 1 to 5 and Year 10 to 15 of pipeline operations are based on the results of this study.

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.

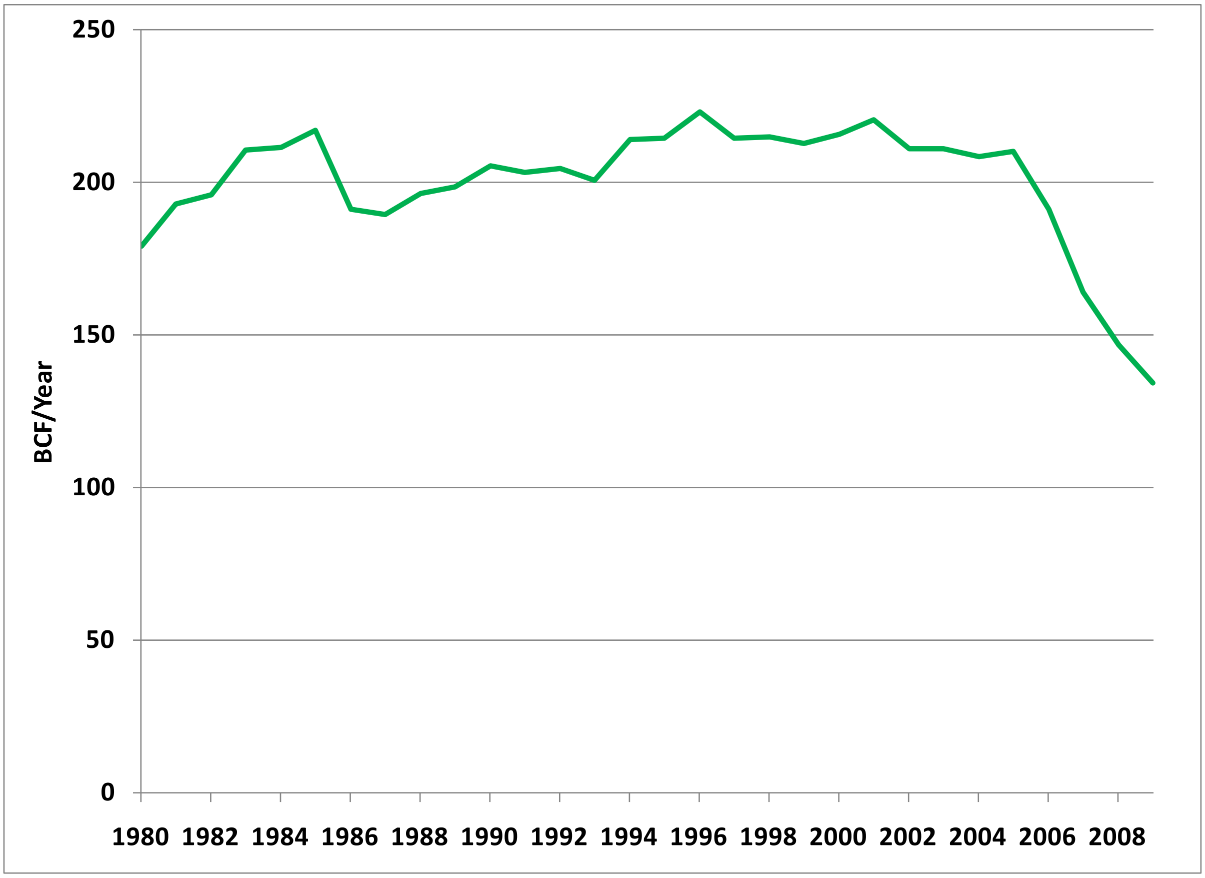
Note: Industrial demand above excludes historical gas volumes used for field operations and for fertilizer production at the Agrium plant.

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.

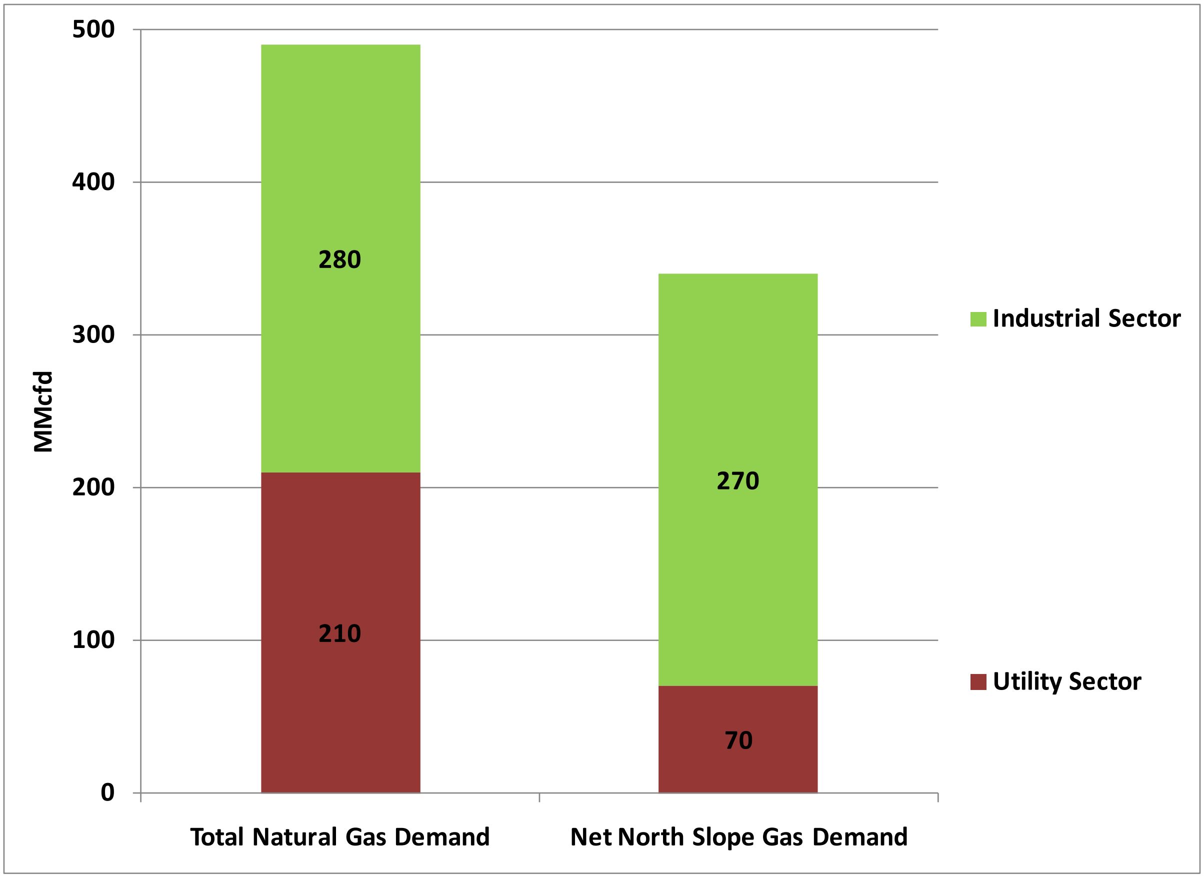
After the proposed spur line to Southcentral Alaska is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence 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

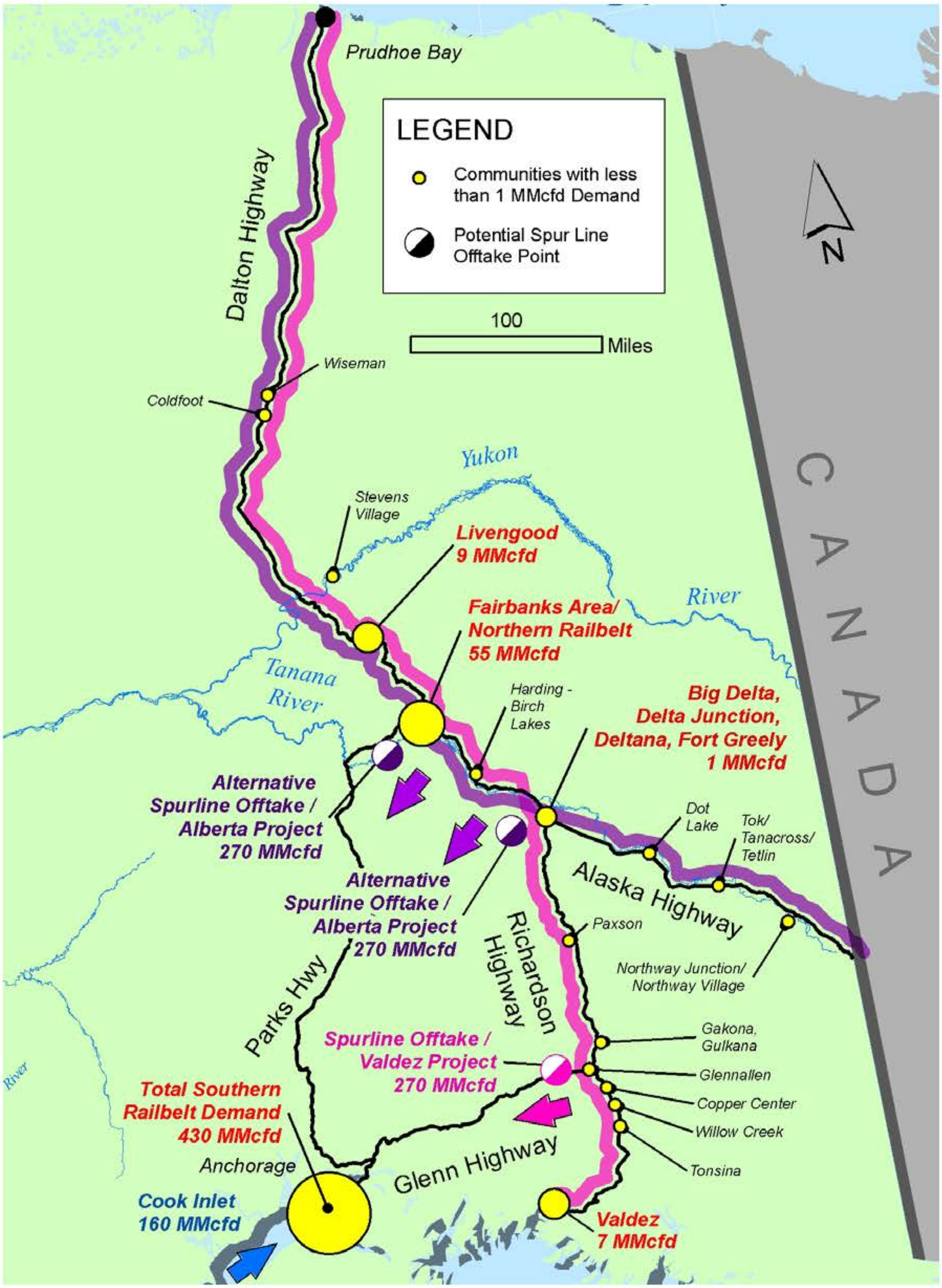
The natural gas stream in the main gas pipeline will contain large volumes of propane and other natural gas liquids; energy needs outside of the Railbelt could be supplied with propane. It is anticipated that the propane will be less expensive than distillate fuels on an energy-equivalent basis in many 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.

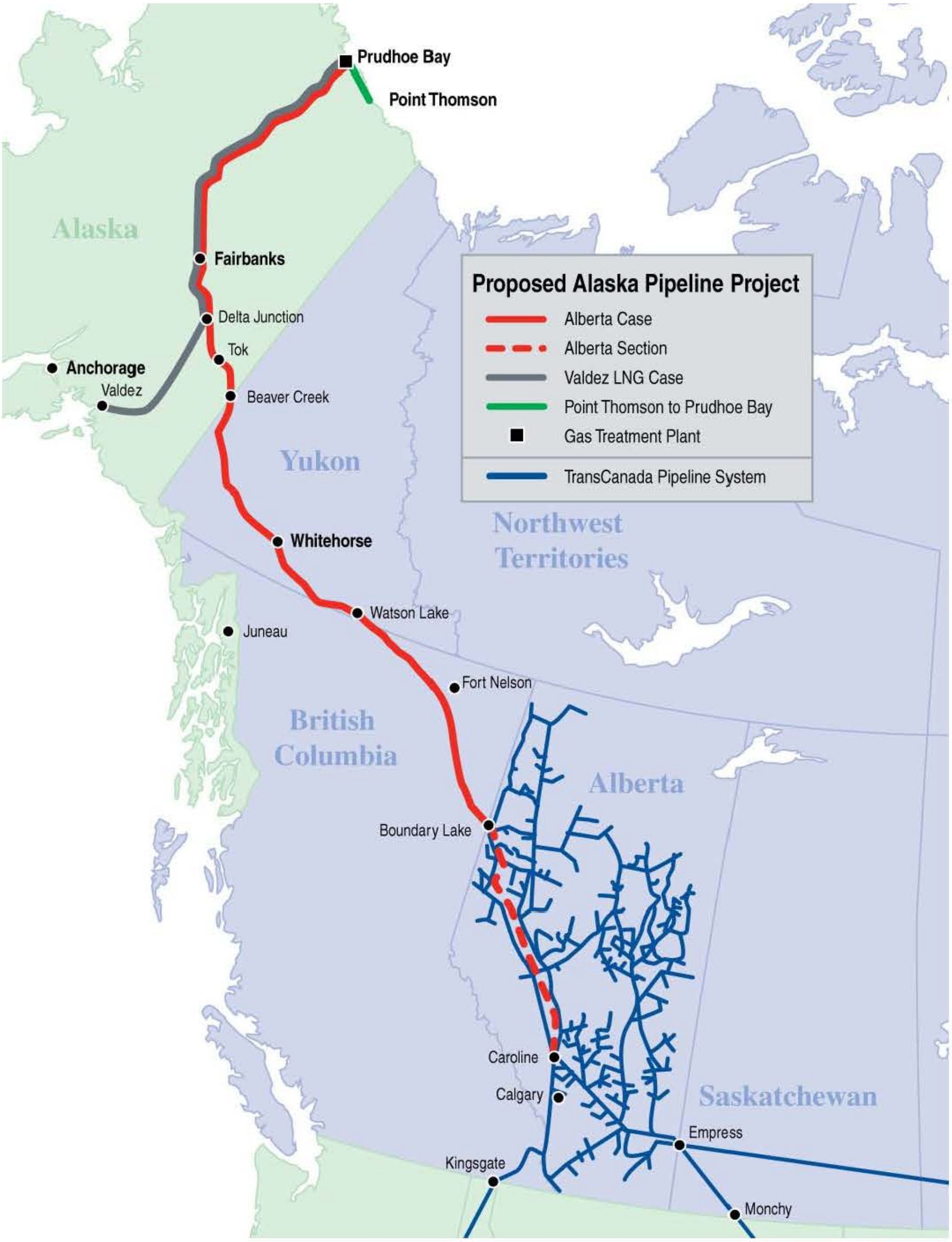
1.2 Study Scope

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

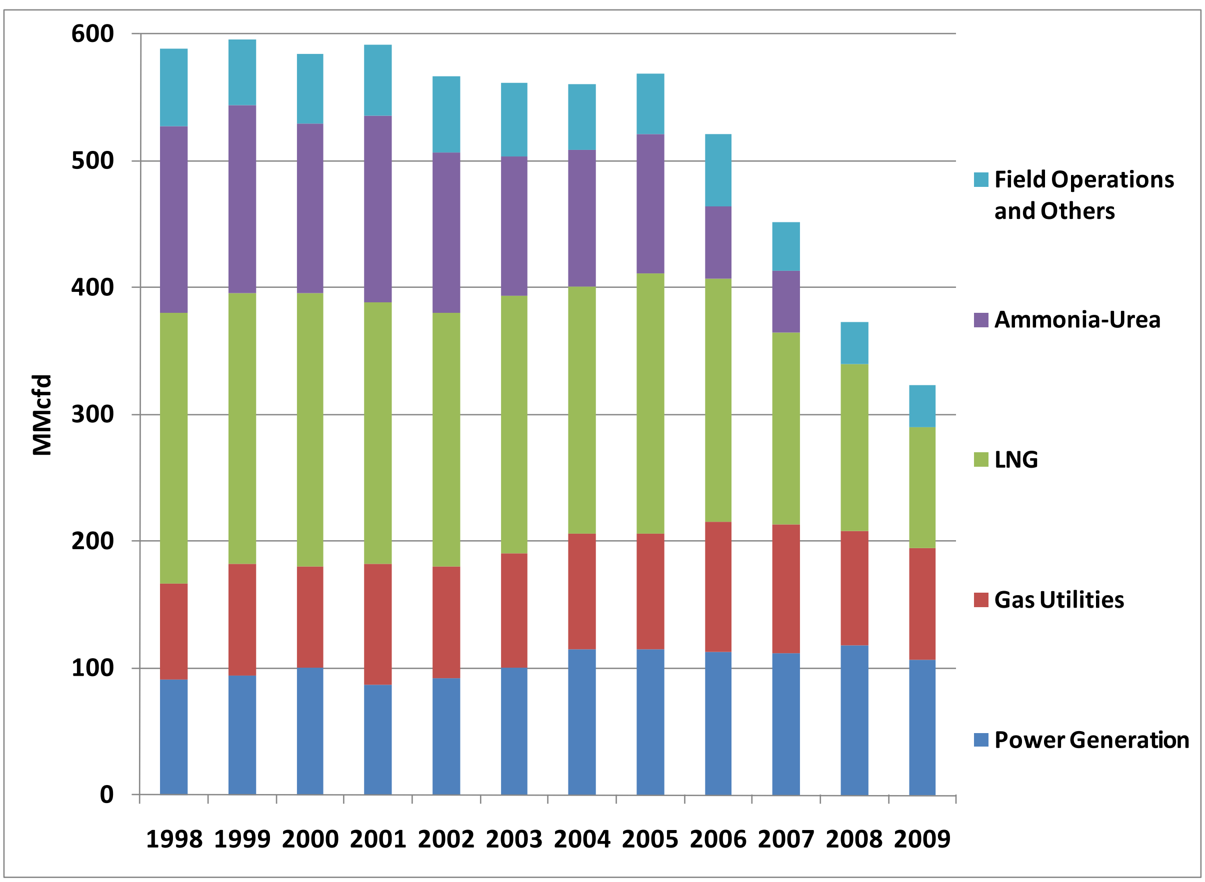
2 The Evolving Energy Picture in Alaska

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.

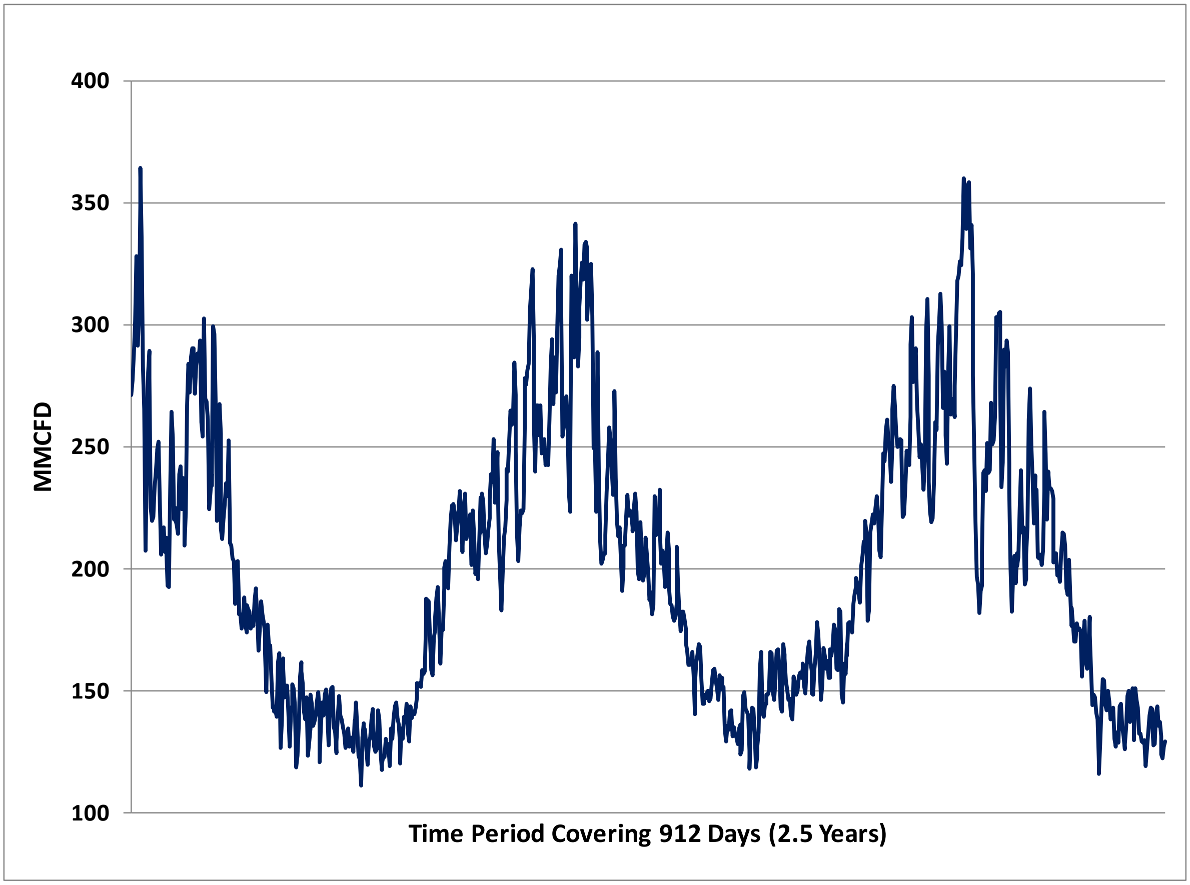
The future of the ConocoPhillips-Marathon LNG plant is uncertain beyond 2011, when its LNG export permit expires. The facility owners could apply for an extension on their permit, but a condition to the U.S. Department of Energy's approval of an export permit extension requires a showing that the permit 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



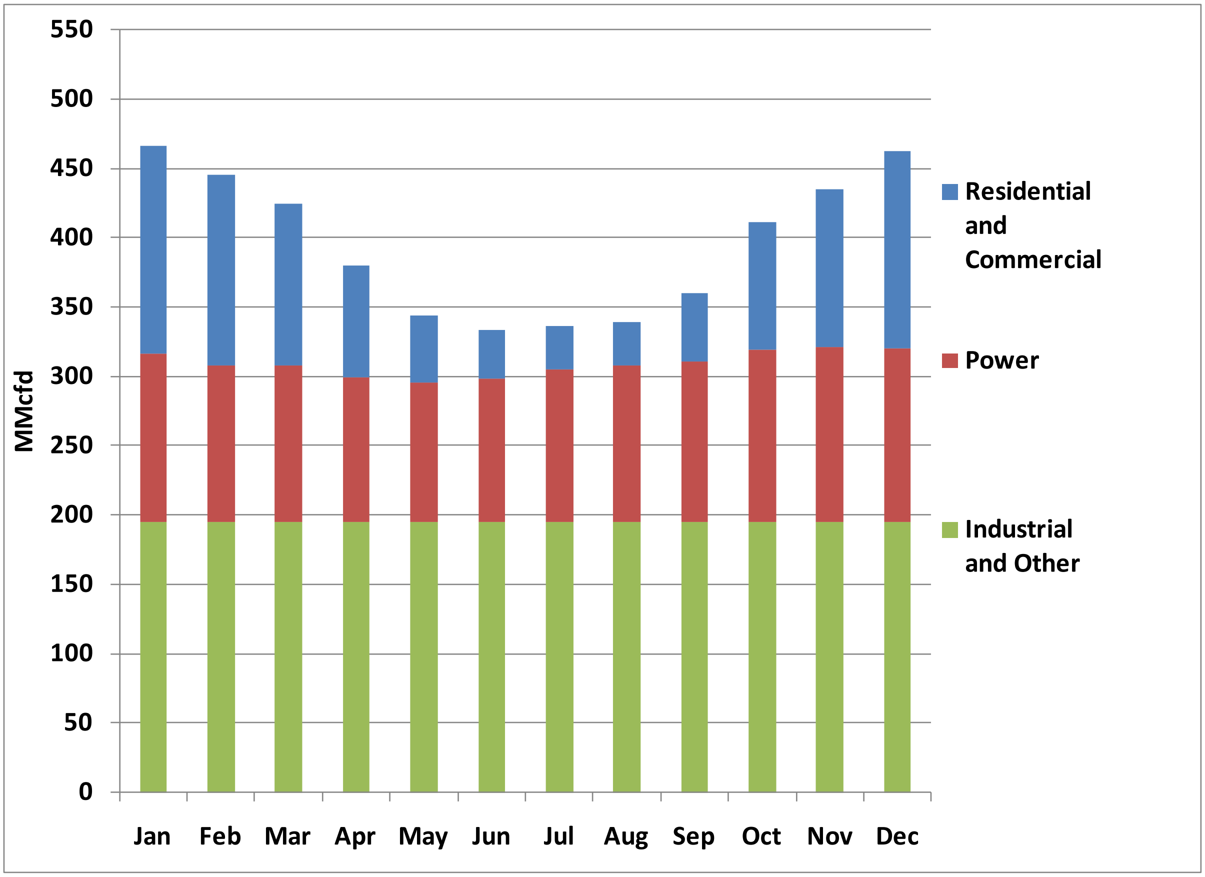
Source: Alaska Department of Natural Resources, (2009)

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).

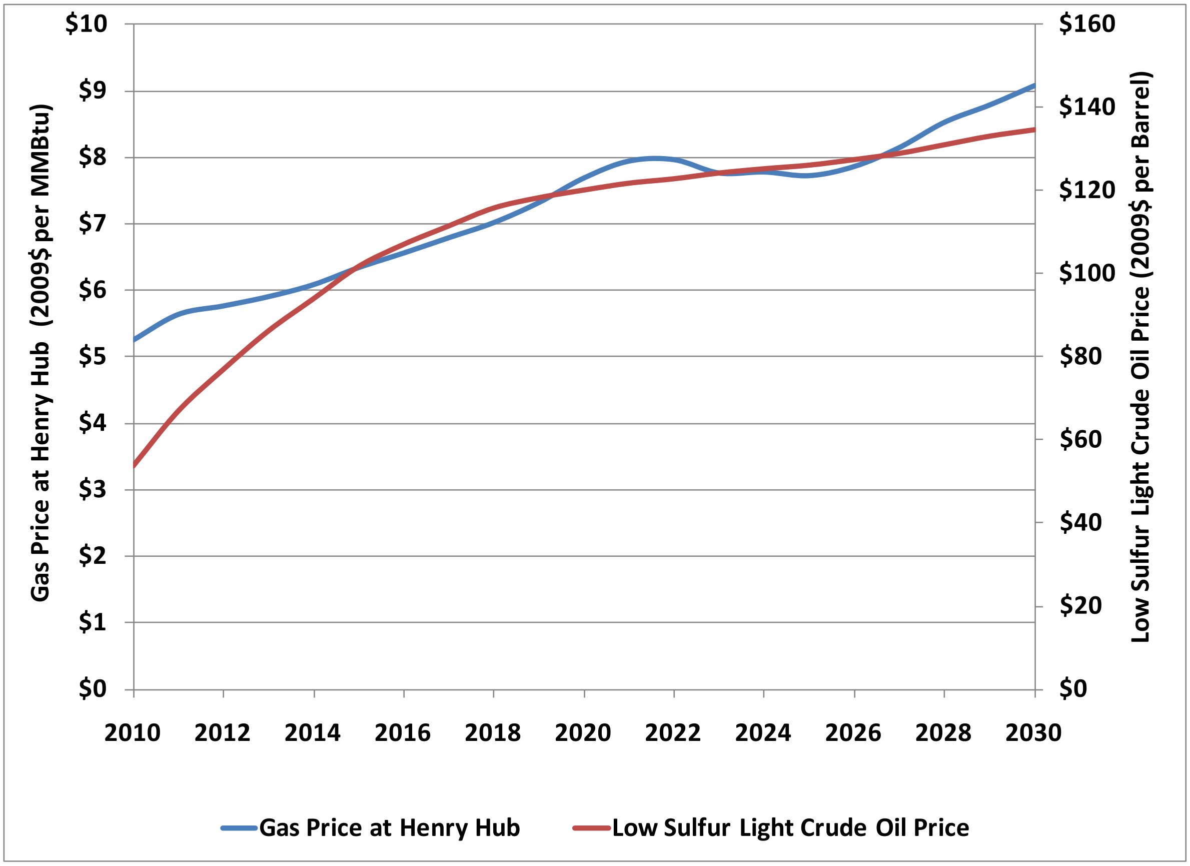
The economic and demographic model projects an average annual growth in wage and salary jobs between 2010 and 2030 of 1.3 percent based on a large number of assumptions contained in an *Economic Development Scenario* (See Appendix A). The highlights of that *Scenario* are as follows:

- 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.

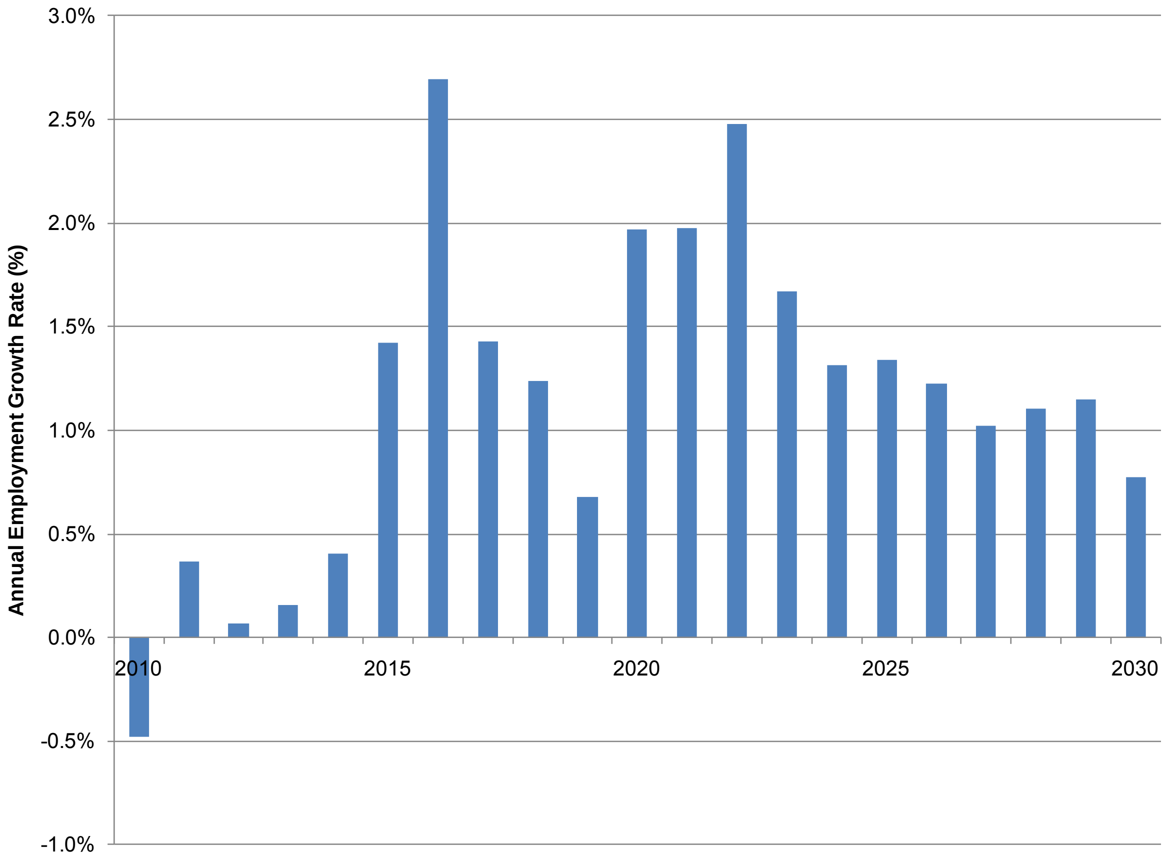
These assumptions result in a pattern of employment growth that begins with a slow recovery from the current recession (see Figure 7). This slow recovery is followed by an acceleration of growth associated primarily with construction of the gas pipeline. There is then a slowdown followed in the next 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.

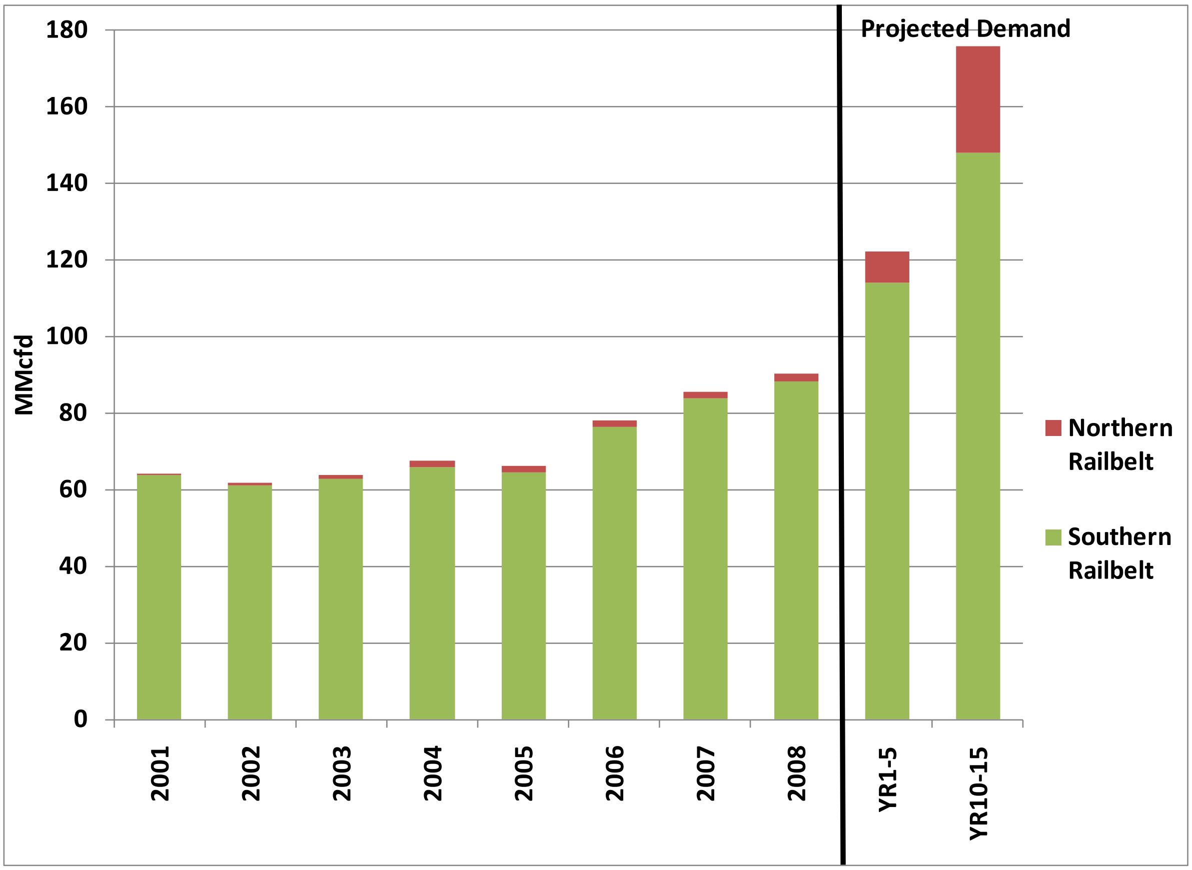
Figure 8 summarizes the findings of this section. Figure 8 shows the historical and the estimated natural gas consumption by region in the two future timeframes under consideration: Year 1 to 5 and Year 10 to 15 of pipeline operations. As shown in the figure, residential and commercial sector demand 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.

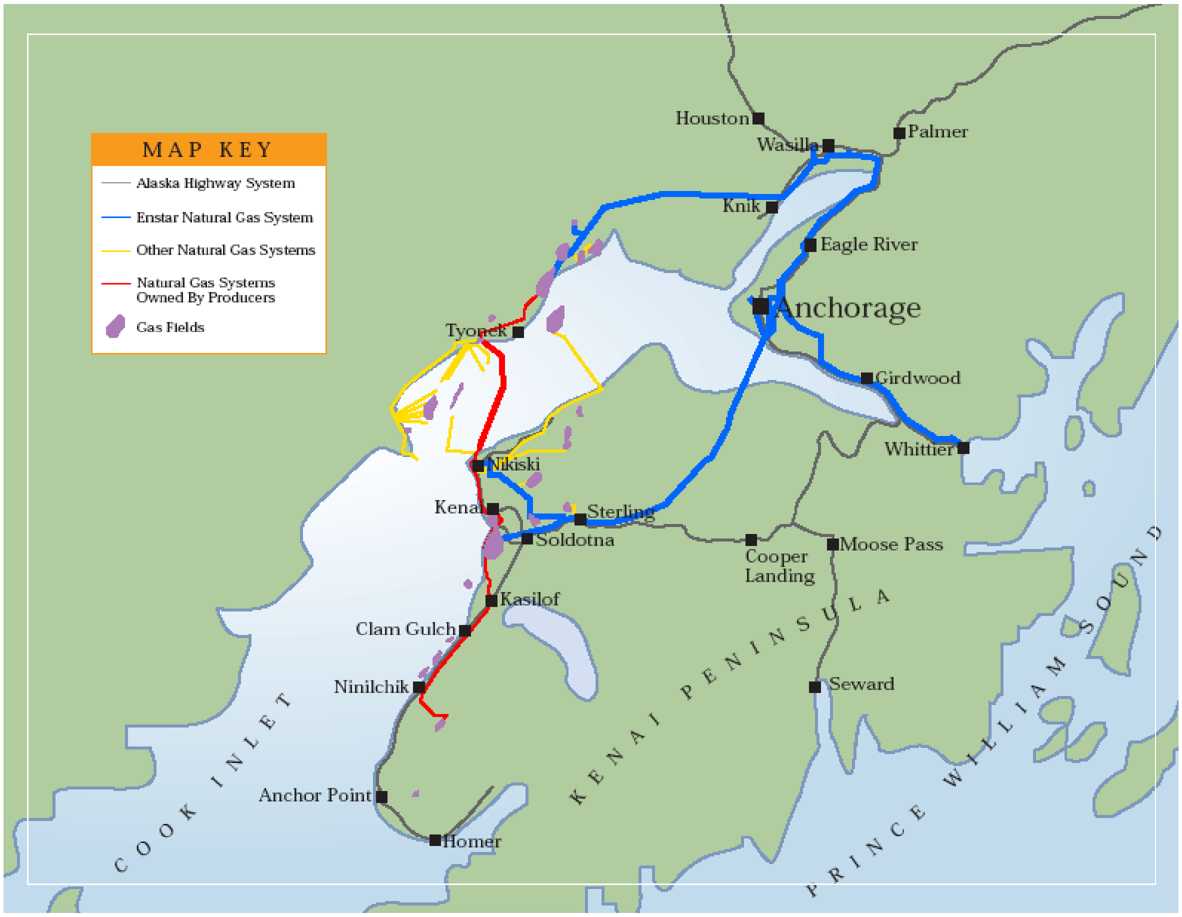
4.1.1 Southern Railbelt Region

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.

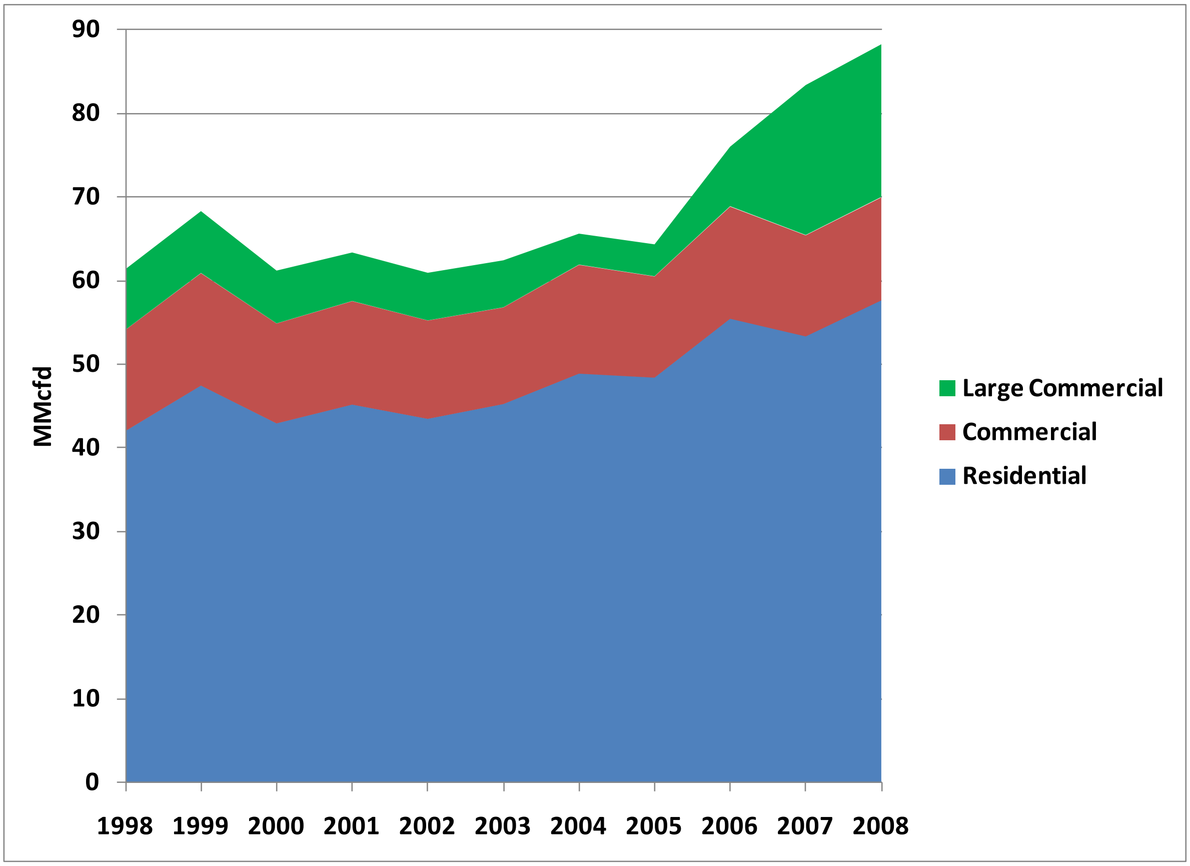
Figure 9. Southcentral, Alaska Gas Distribution System



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.

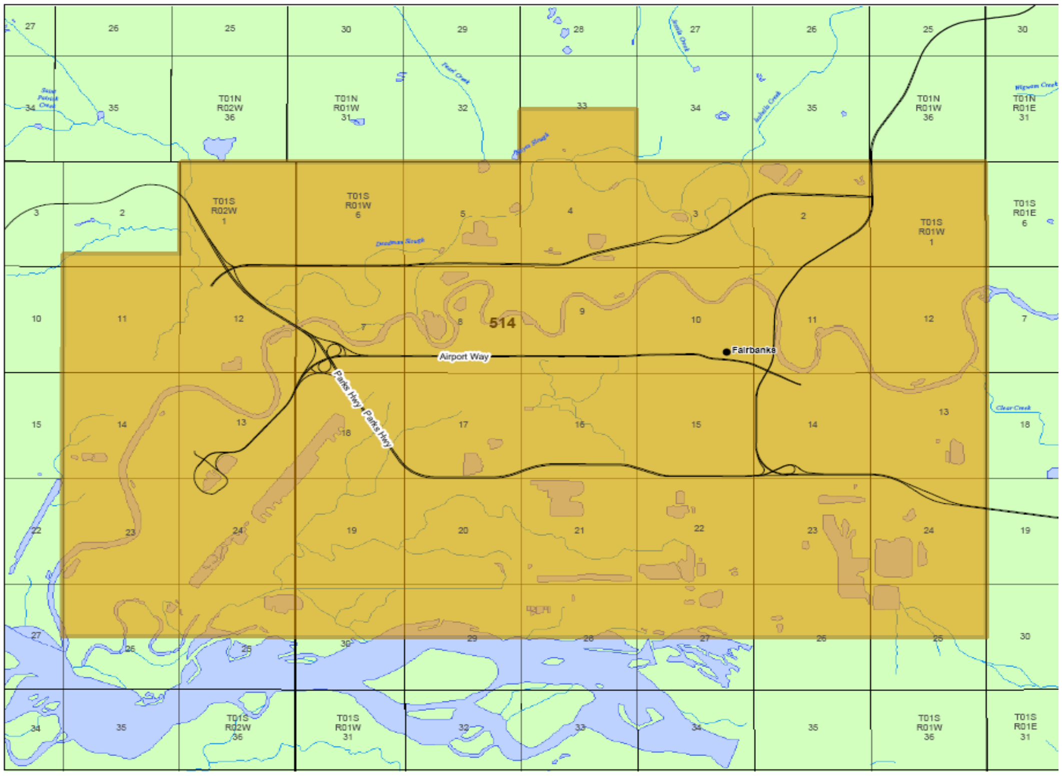
4.1.2 Northern Railbelt Region (Fairbanks North Star Borough)

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.

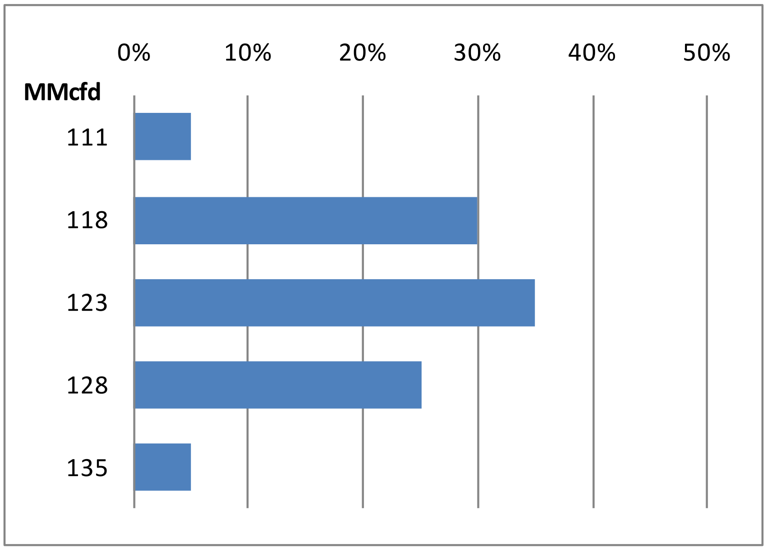
4.2.2.3 Valdez-Cordova Region

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

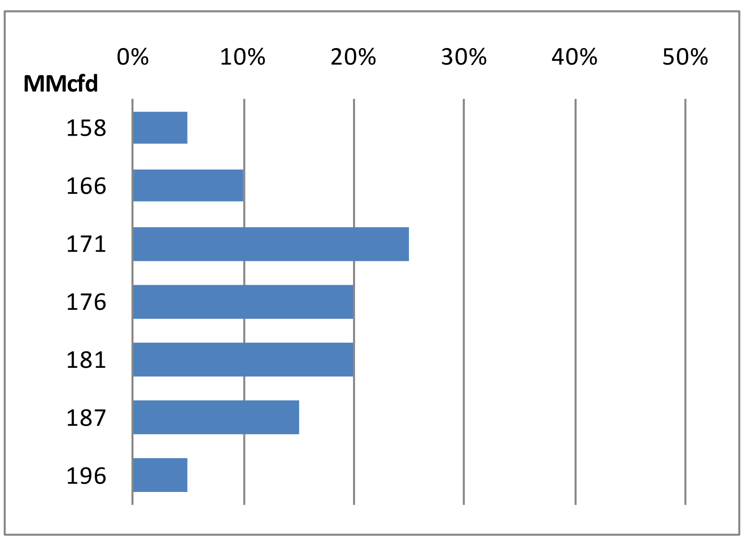
Figure 12 and Figure 13 provide a different perspective (probabilistic analysis) on the estimated demand for residential and commercial sector in the state for the Alberta Line during the two time periods. Both figures show the percent probability that demand will fall within one of the demand categories 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

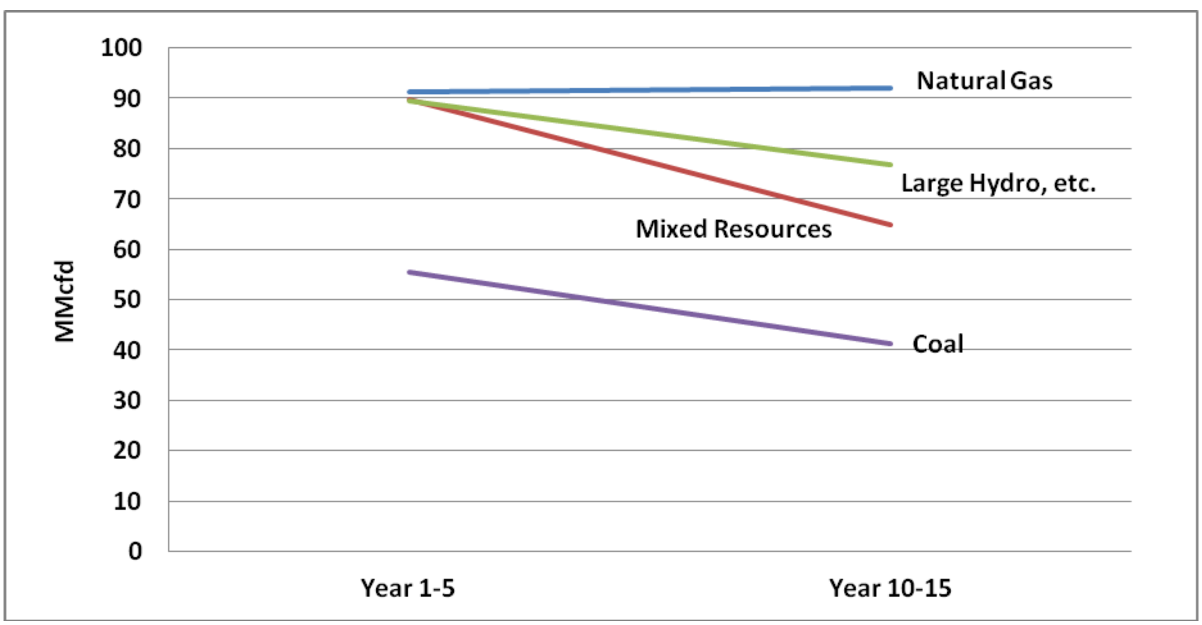
Table 11 provides the projection of average daily future natural gas demand in the two future timeframes for the Fairbanks area and the Southcentral area of the Railbelt and the total Railbelt power sector under these four scenarios. Figure 14 and Figure 15 display the projected change in total power 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**

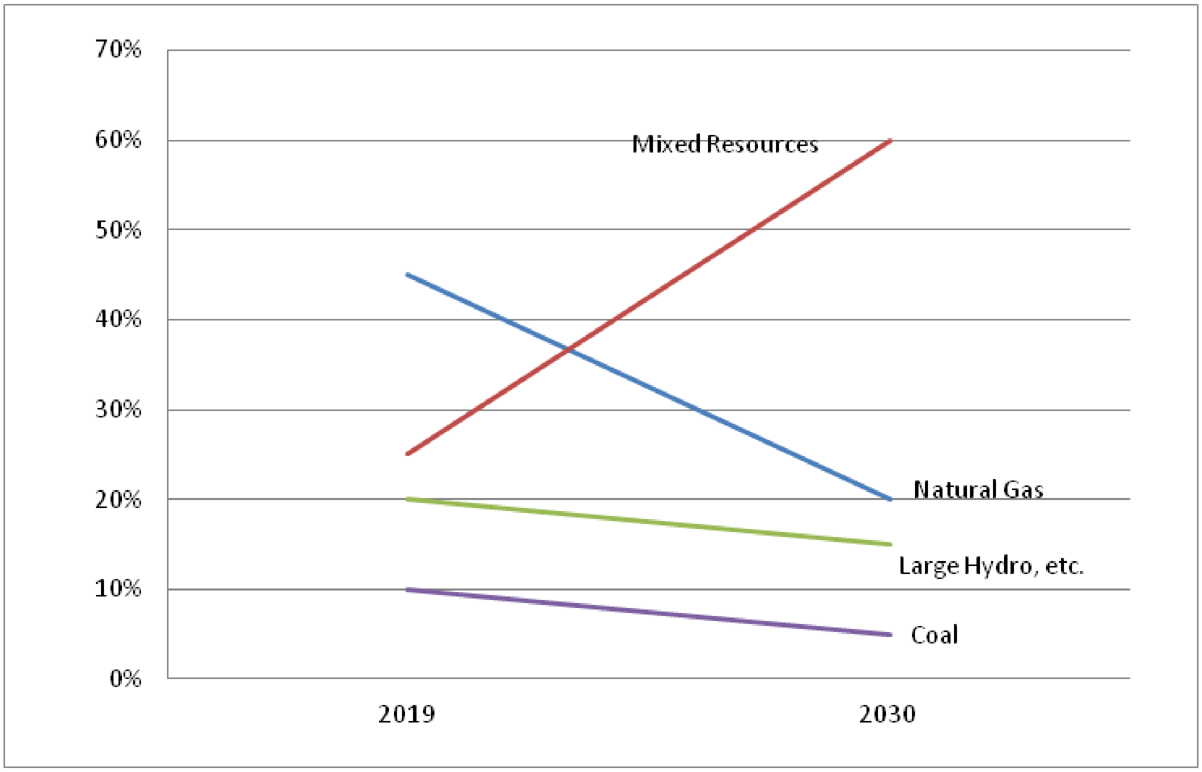
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study- Final Report," September 12, 2008 and SAIC.

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



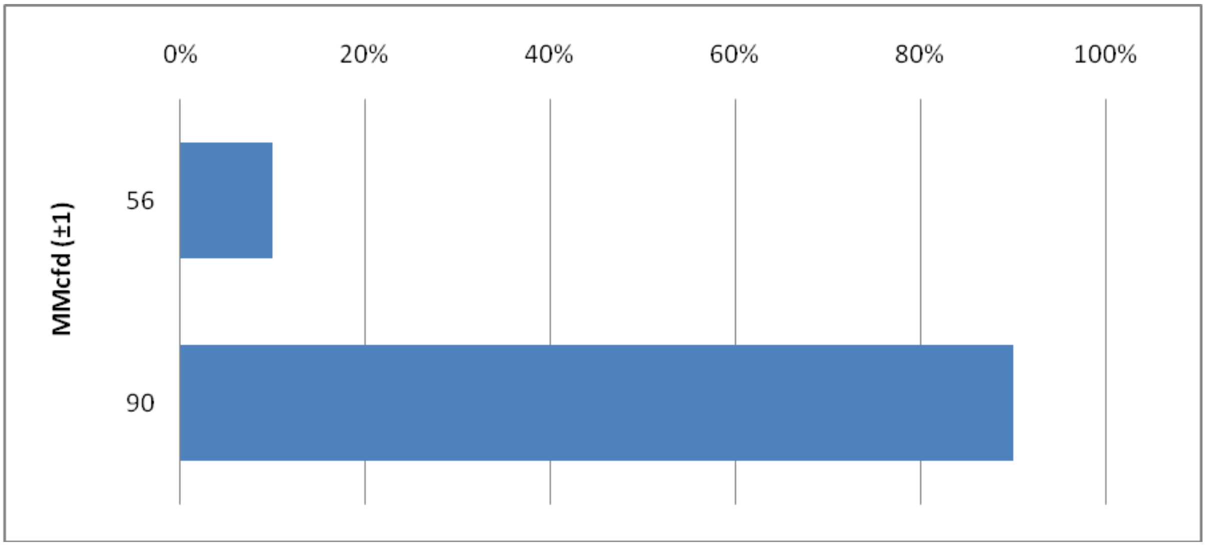
Source: SAIC, Inc., 2009.

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.

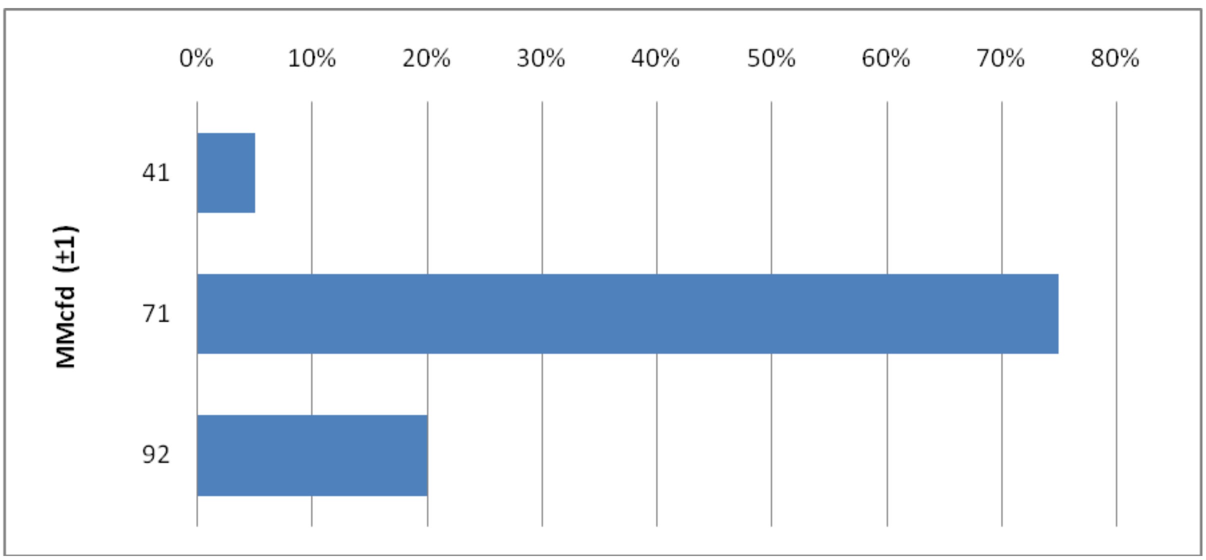
Figure 16 and Figure 17 show the chance of occurrence that demand will approximate the volumes shown on the vertical axis. For example, in the first five years of operation, there is about a 90 percent chance that demand will be about 90 MMcfd, and a 10 percent chance that demand will be about 56 MMcfd. 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.

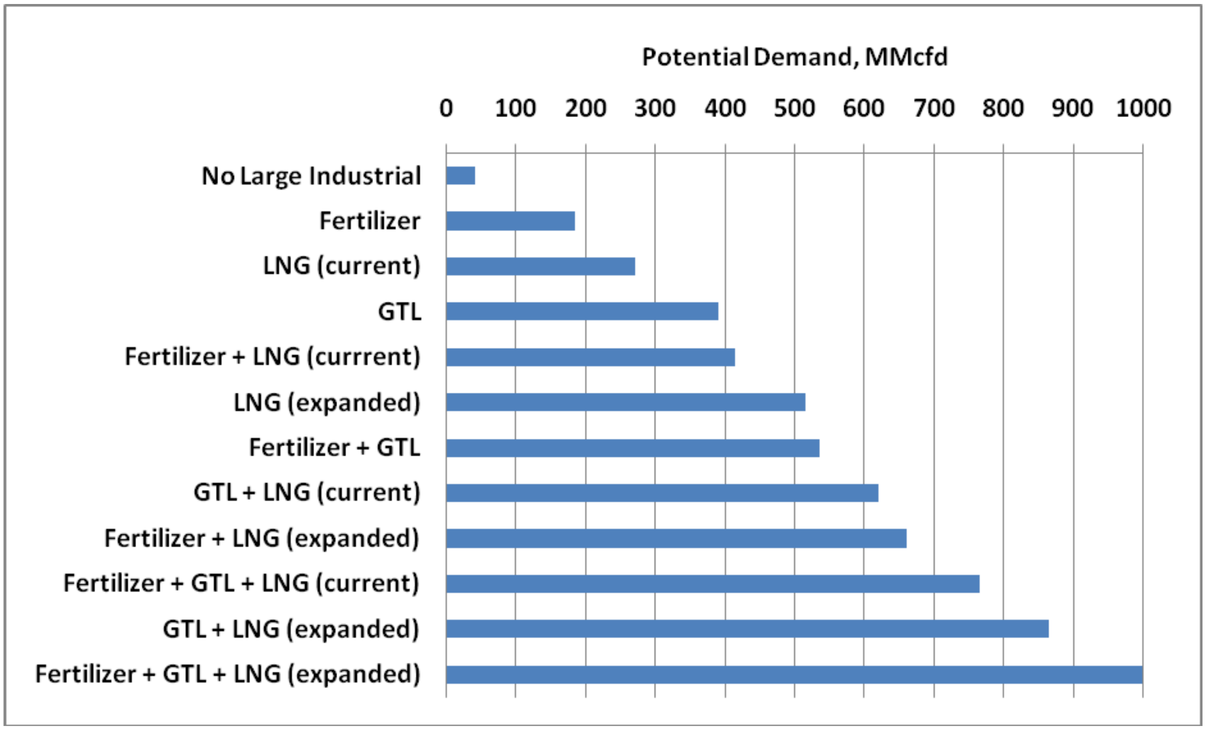
The example projects analyzed and their associated natural gas demand are as follows:

- 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.

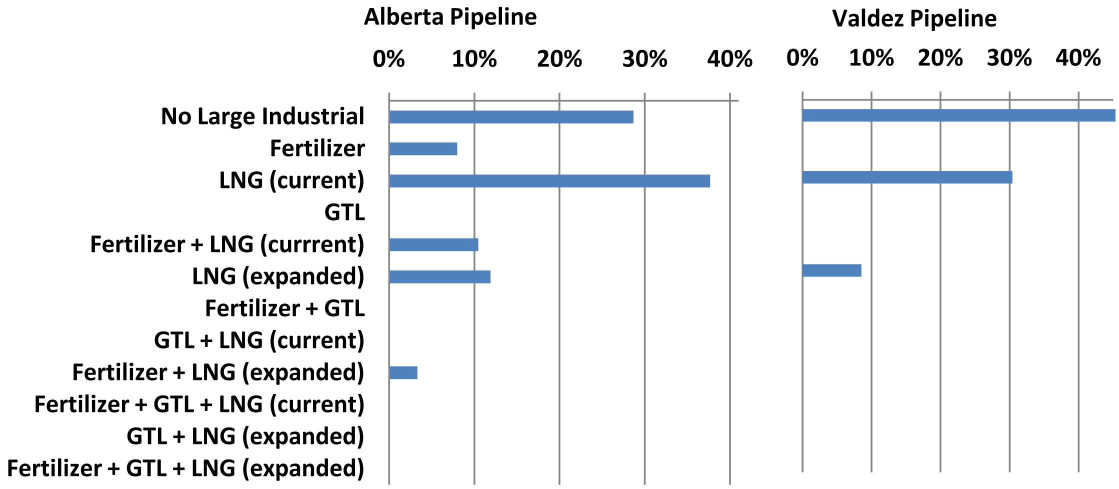
6.2.3 Total Industrial Demand for Natural Gas

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.

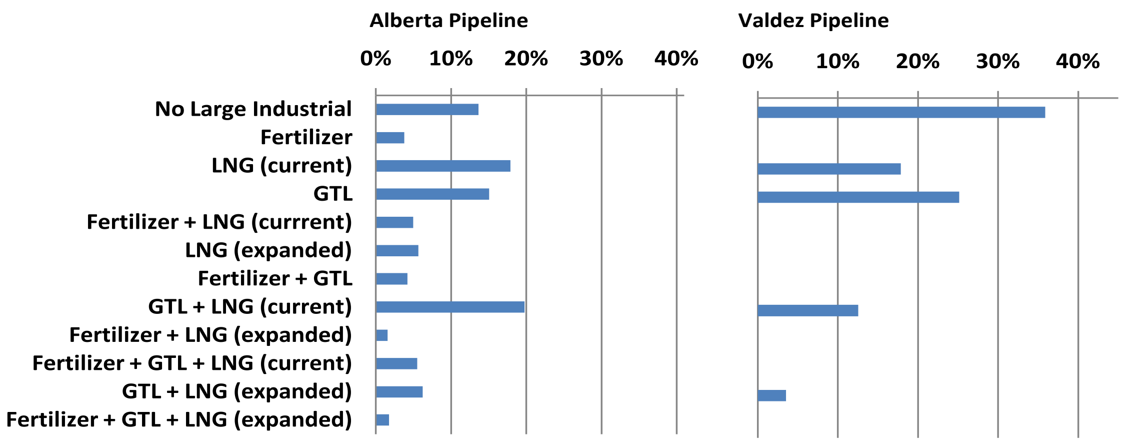
Furthermore, as indicated in Figure 20, the economic feasibility of the assessed fertilizer project (i.e., renovation of the Agrium plant in Nikiski) is relatively unlikely under the Alberta pipeline project, and has virtually no chance of realization under the higher Southern Railbelt gas prices of 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).

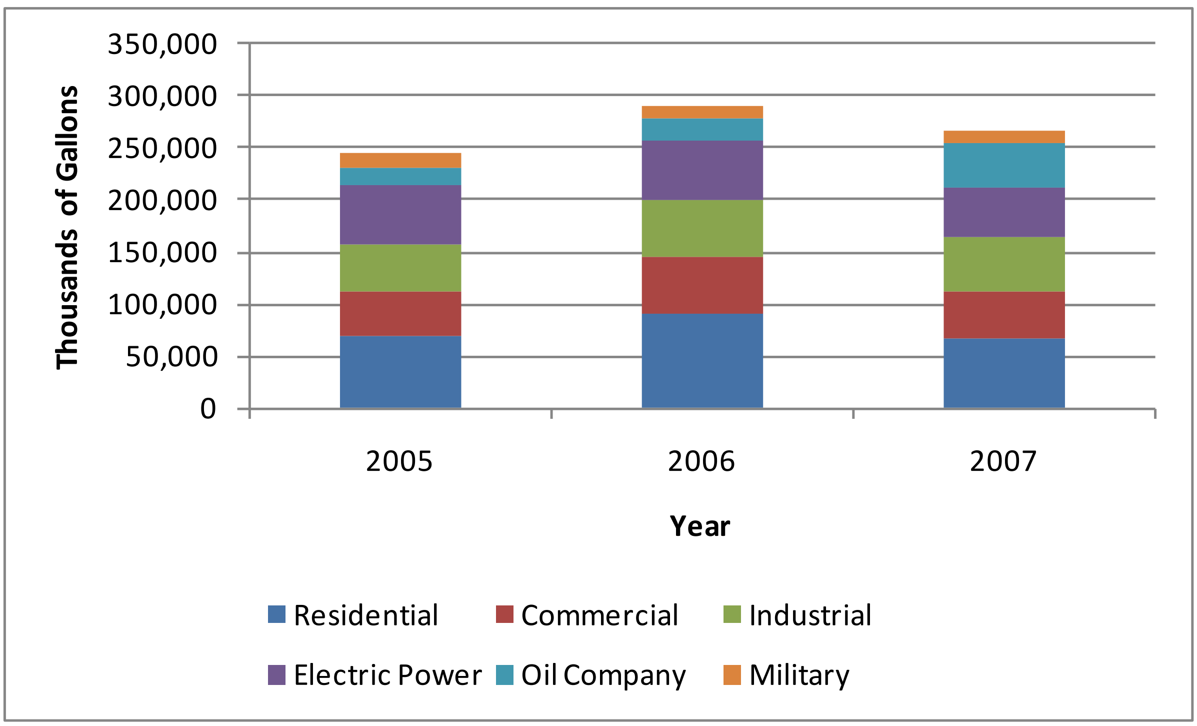
The EIA provides annual estimates of total distillate fuels by end use (Energy Information Administration, 2008). Total distillate consumption has ranged from about 565 million gallons in 2005 to 622 million in 2006 (See Table 15). Propane is not anticipated to replace distillates used in transportation. 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	2005	2006	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.

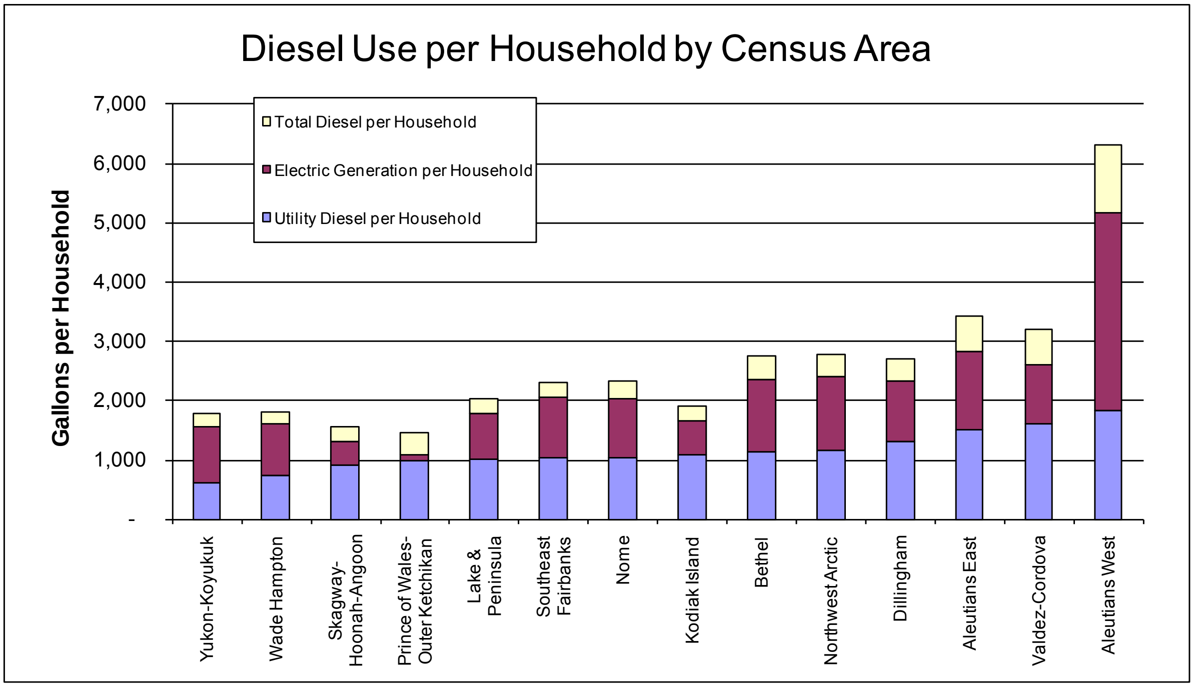
8.2.2 Residential and Commercial Demand

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)

	Years		
Region	**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.

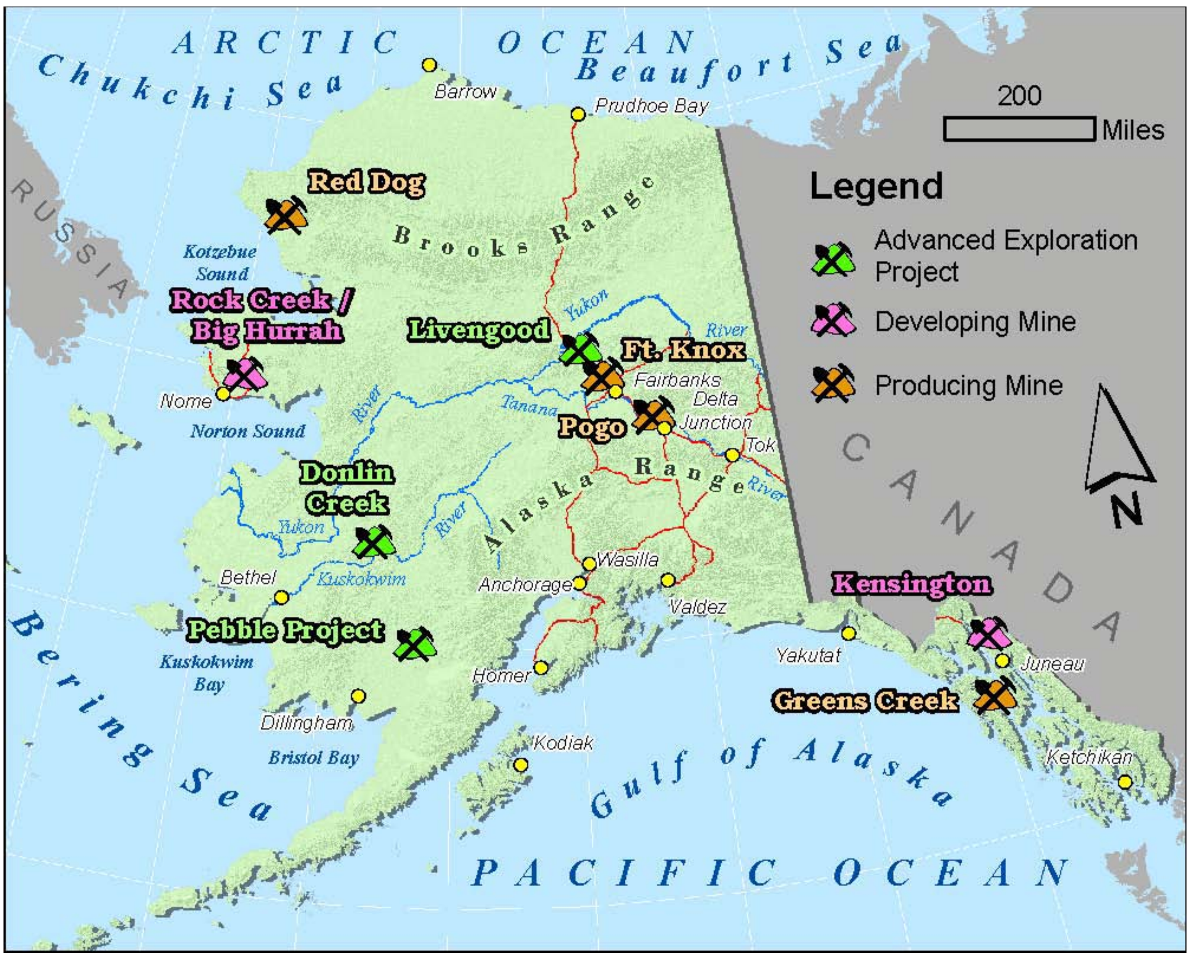
8.2.4 Industrial Demand

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.

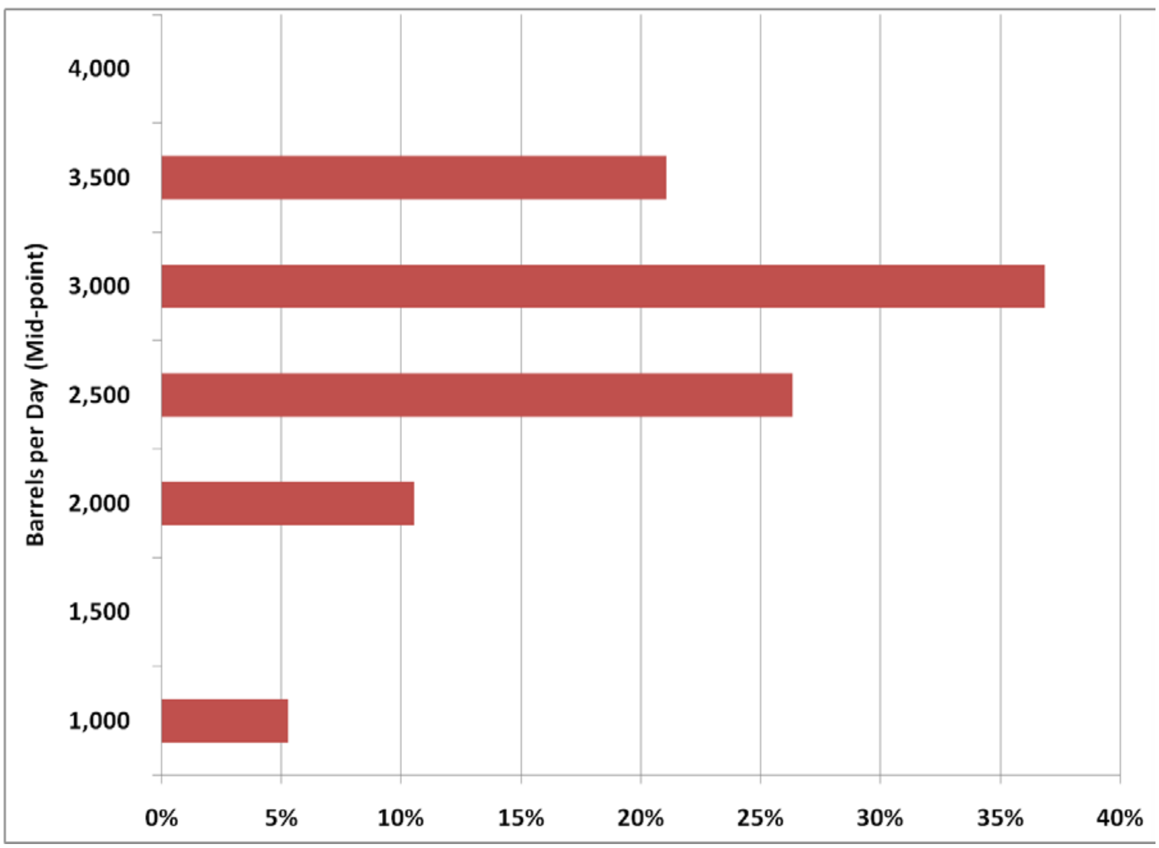
The results presented here anticipate that propane extraction facilities would be built in the Fairbanks area and in either Cook Inlet or Valdez, depending on the ultimate route. The capital cost for small propane extraction plants is very large compared to the throughput and a comparison of the potential 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.

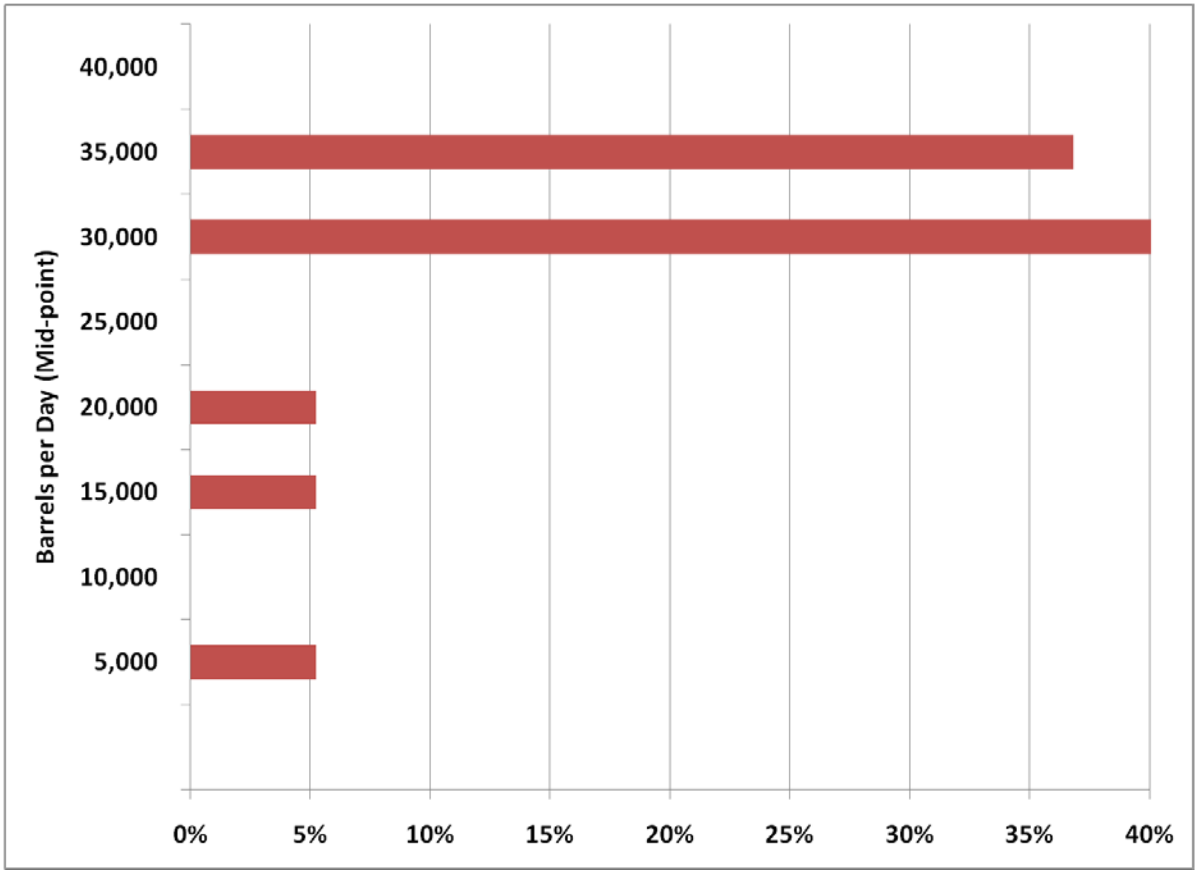
Figure 24 and Figure 25 show the percent probability that demand will fall within one of the demand categories shown on the vertical axis. For example, Figure 24 shows that there is a 37 percent chance that the actual demand will fall within 2,751 to 3,250 barrels of propane per day, and a 26 percent 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

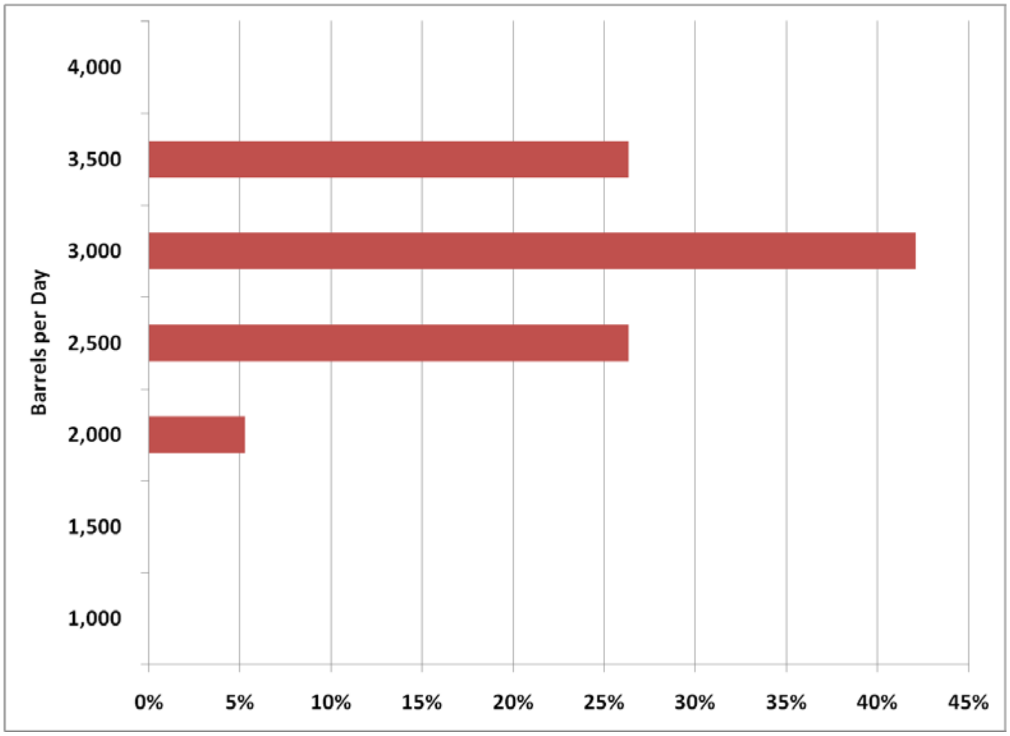


Source: Northern Economics, Inc.

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.

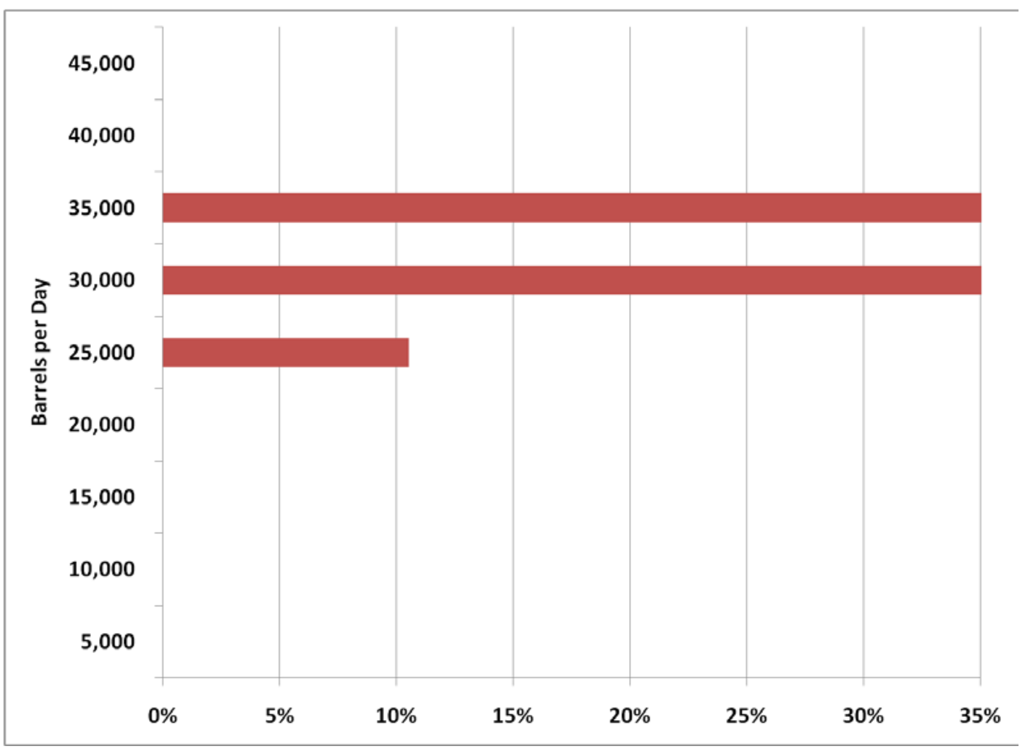
The propane composition of the North Slope gas could range from 1.7 to 3.6 percent per volume. A pipeline with 4.5Bcf per day of North Slope gas would be transporting about 21,000 to 47,000 bpd so the propane demand in years 1-5 could readily be met with the anticipated propane volumes. Demand in years 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,

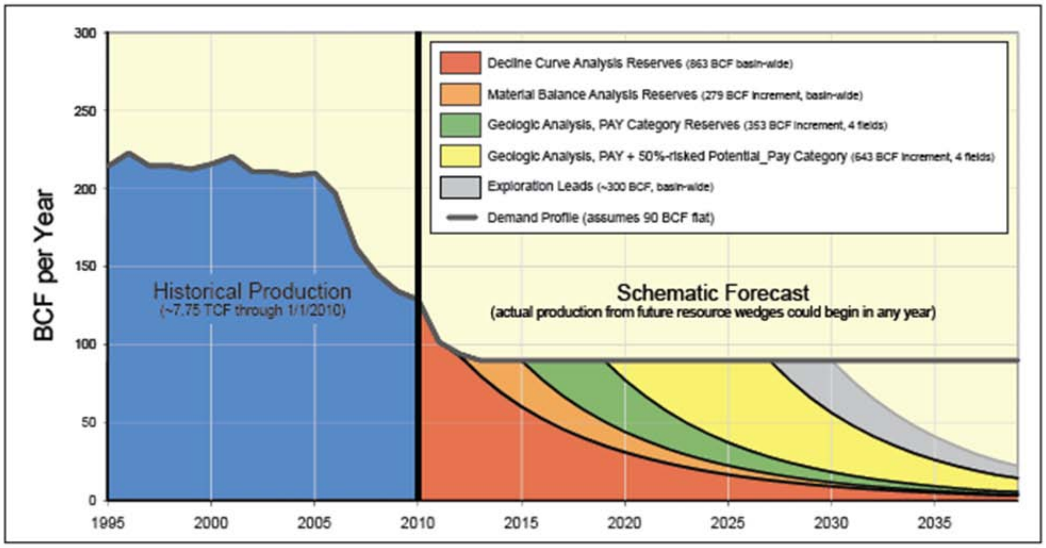

Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative 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.

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[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

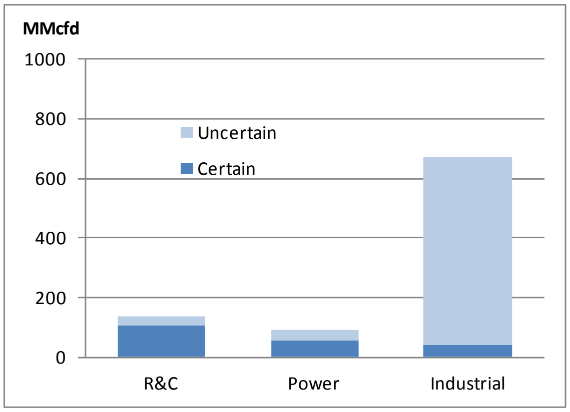
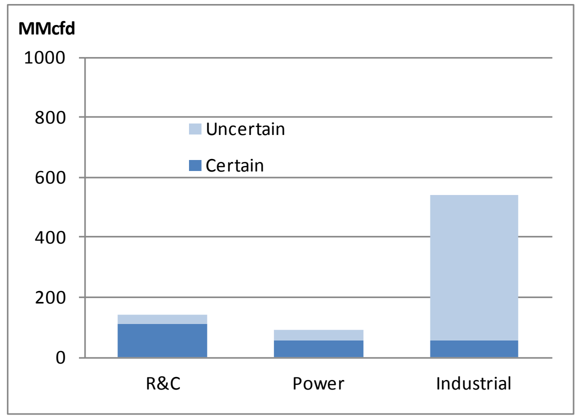


Figure 30. Projected Annual Average Daily Demand by Sector, Year 1 to5, Valdez Project



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

Figure 31. Projected Annual Average Daily Demand by Sector, Year 10 to15, Alberta Project

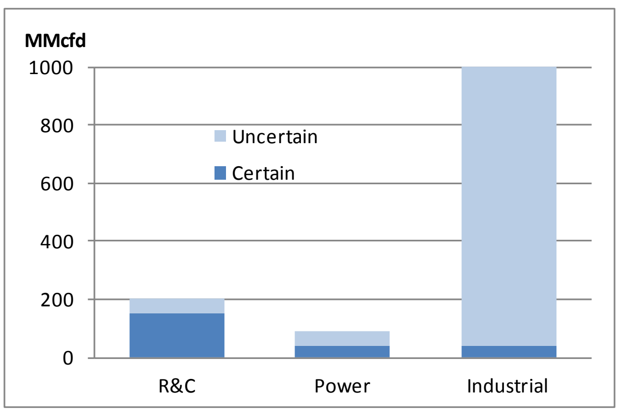
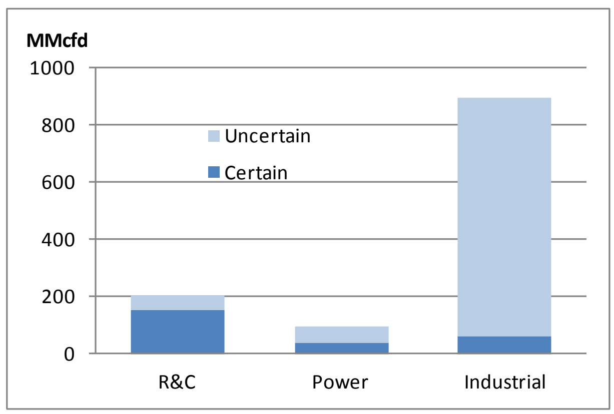


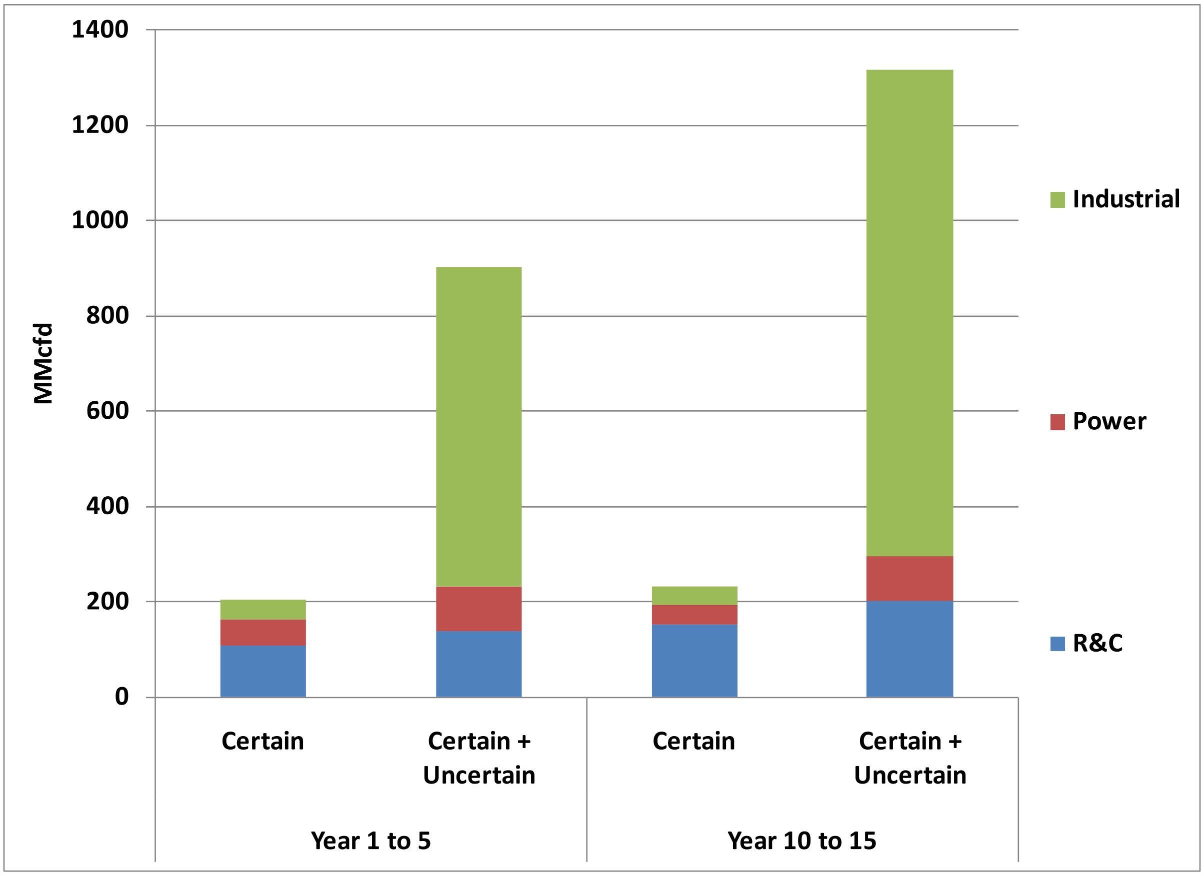
Figure 32. Projected Annual Average Daily Demand by Sector, Year 10 to15, Valdez Project



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

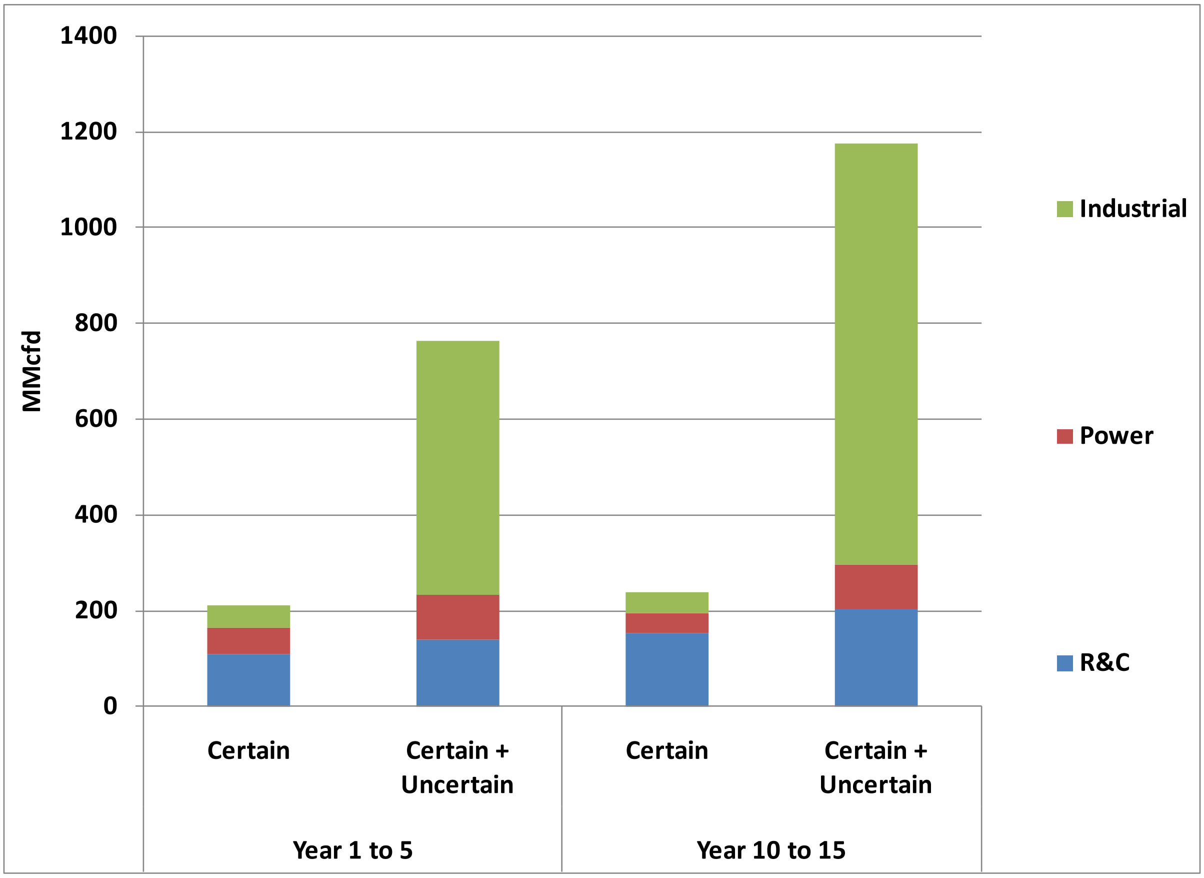
Figure 33 and Figure 34 present the range of certain and uncertain demand by sector in a different manner as the figures above, for both the Alberta and Valdez projects.

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.

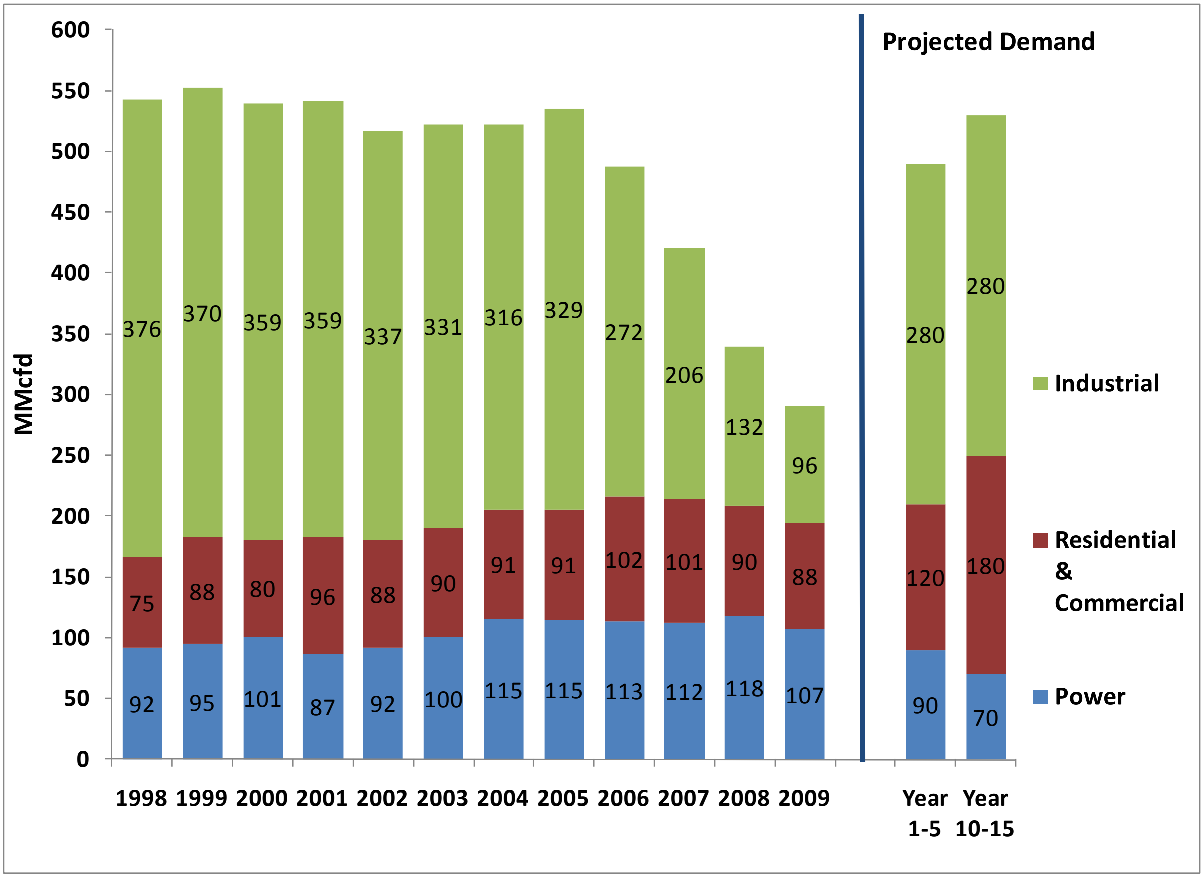
10.3 Summary of Projected Demand in the Current Industry Case

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.

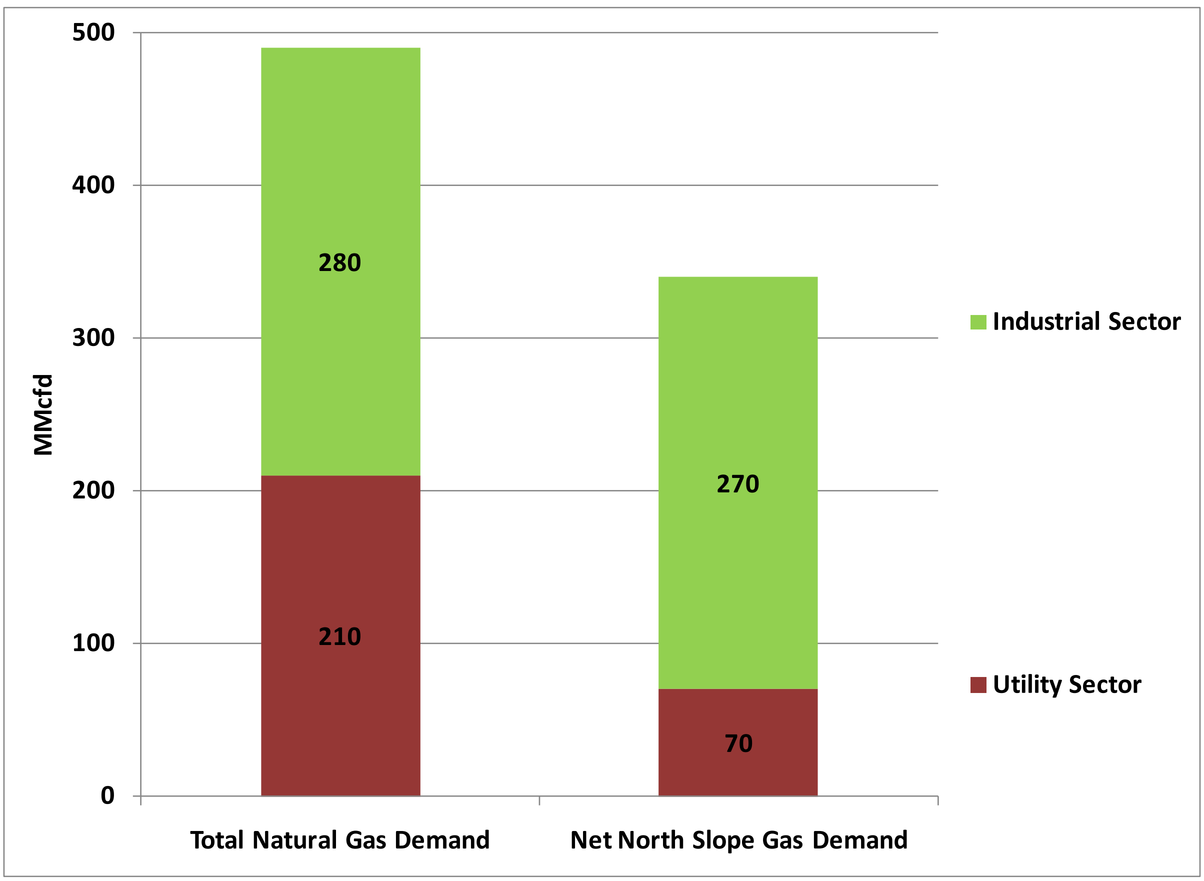
10.4 Net North Slope Natural Gas Demand

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.

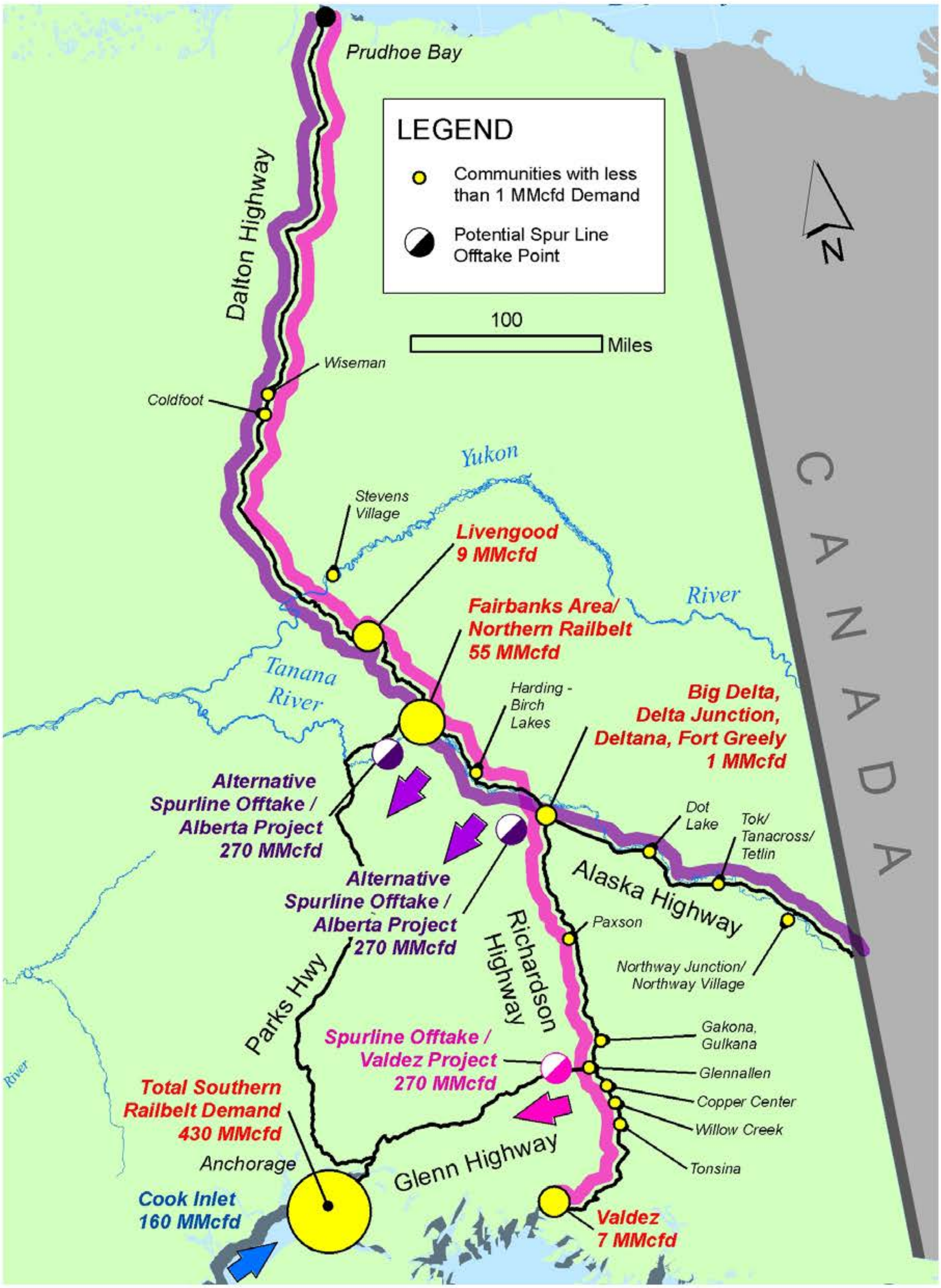
The projected demand (for the take-off volumes) for the Southern Railbelt and Valdez represent the results of the Current Industry demand scenario in the Year 1 to 5 timeframe as modeled in the combined demand probability analysis described in the previous section.

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

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

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.

[1] http://www.akenergyauthority.org/EnergyPolicyTaskForce/FinalNonRailbeltReport.pdf

[2] Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008.

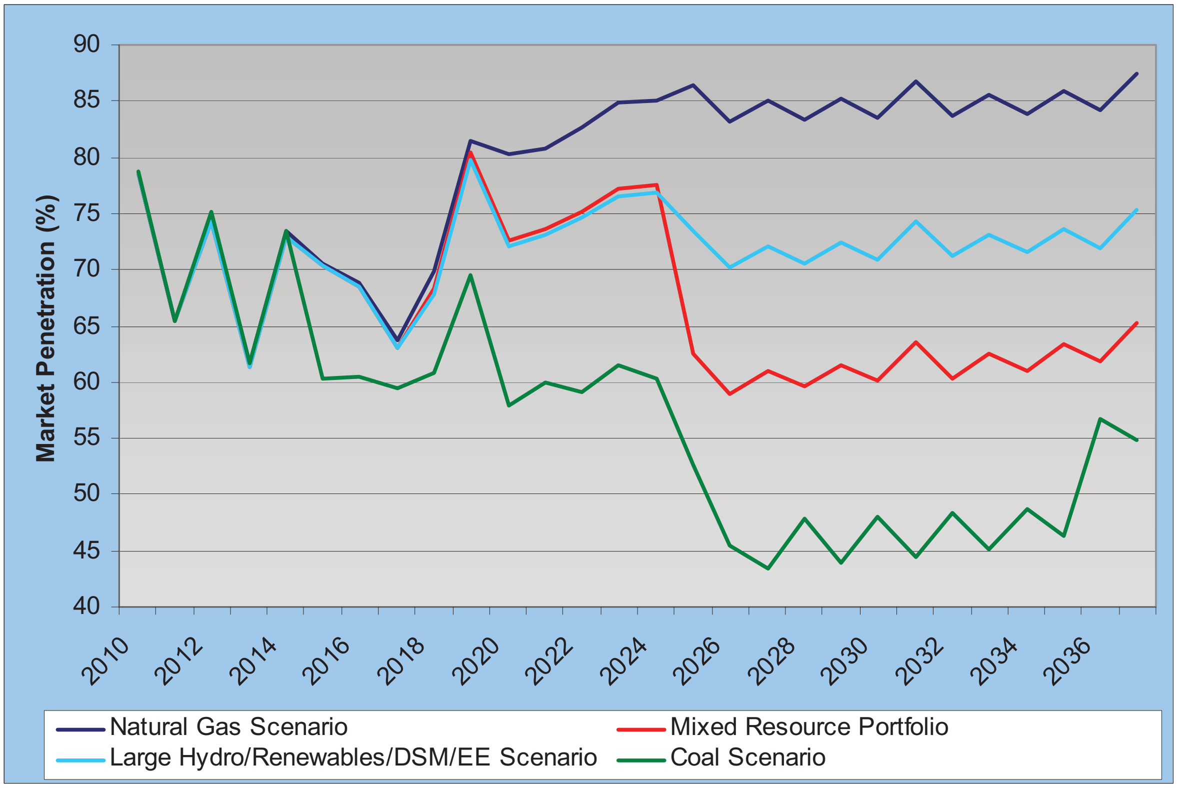
Table 1. Projected Future Natural Gas and Propane Demand for the Railbelt Utilities

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

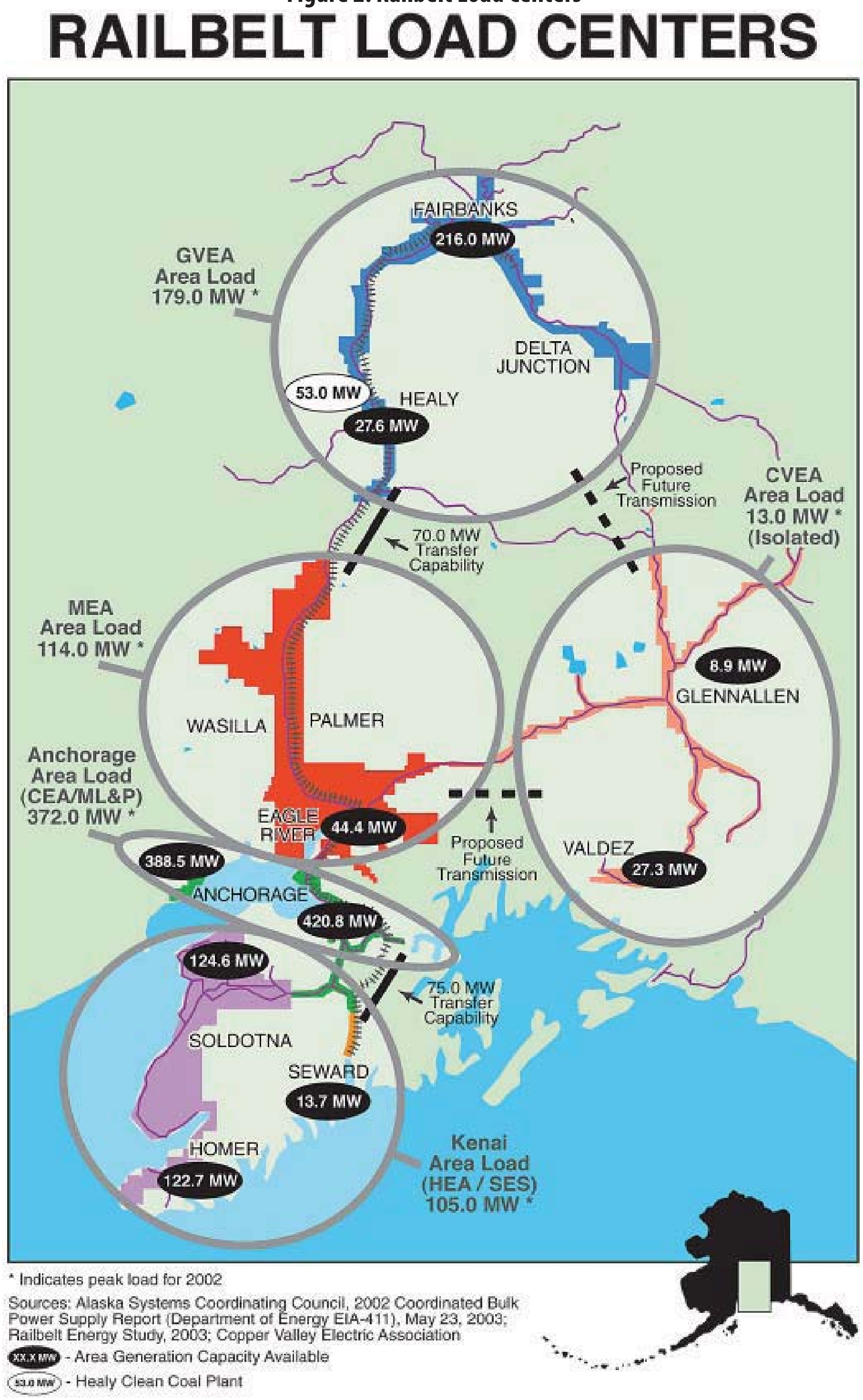
[4] 2008 Chugach Electric Annual Report, http://www.chugachelectric.com/pdfs/2008_annual_report.pdf

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.

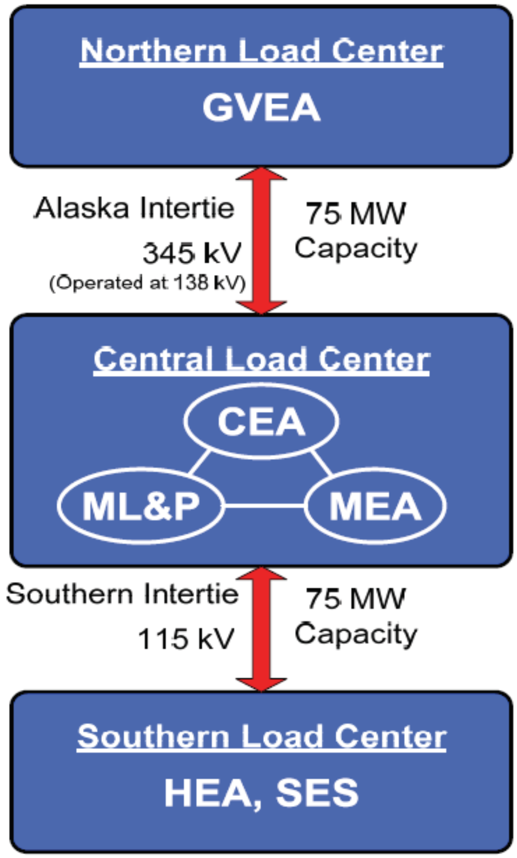
Figure 3 shows the region's three load centers and the existing transfer capability.

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

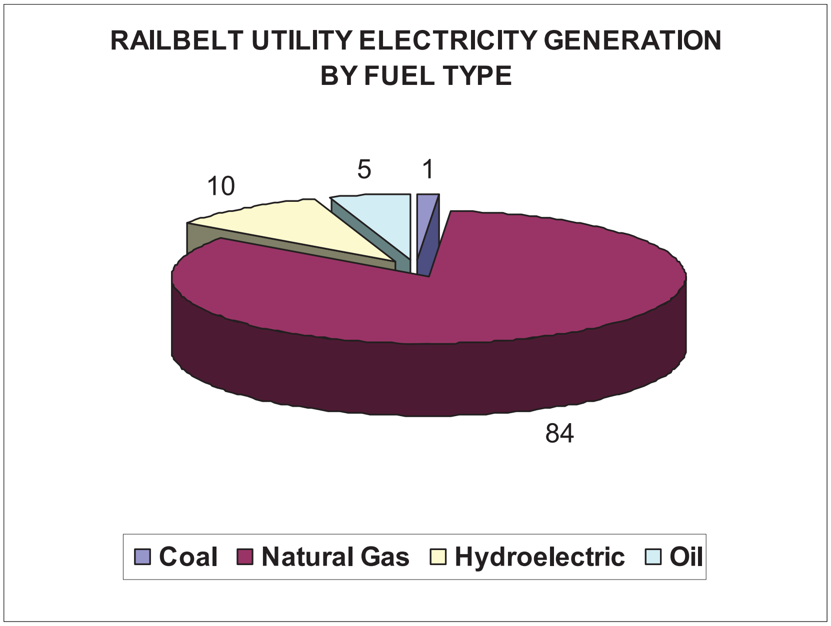


Source: Black and Veatch, “Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report,” 9-12-2008.

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%.

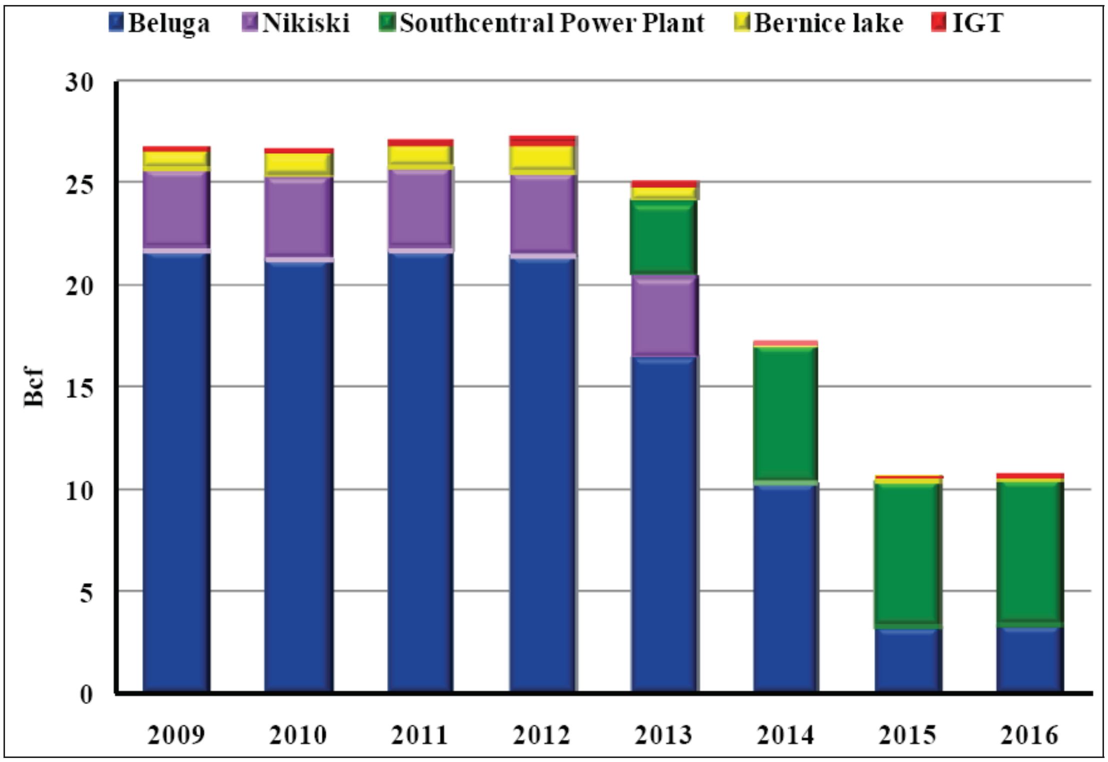
Figure 5 projects a breakdown of Chugach's requirements by generation facility for 2009 through 2016. Note that during the next seven years, the gas usage of various plants is expected to change as more efficient generation is brought on line in mid 2013. Consequently the delivery points and transportation 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).

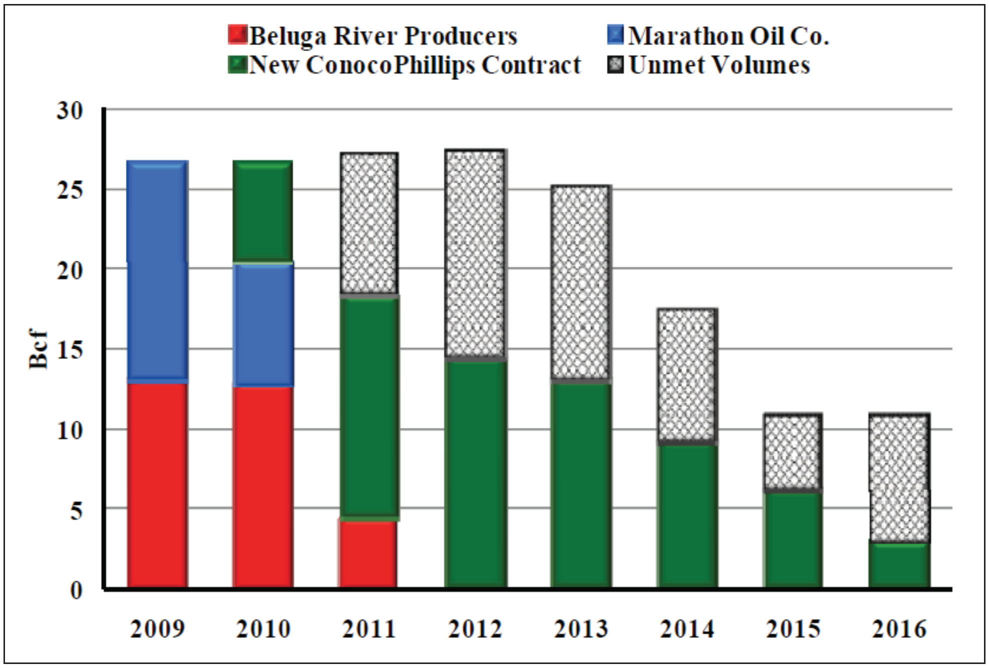
Figure 5. CEA Projection of Natural Gas Required by Plant[6]



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.

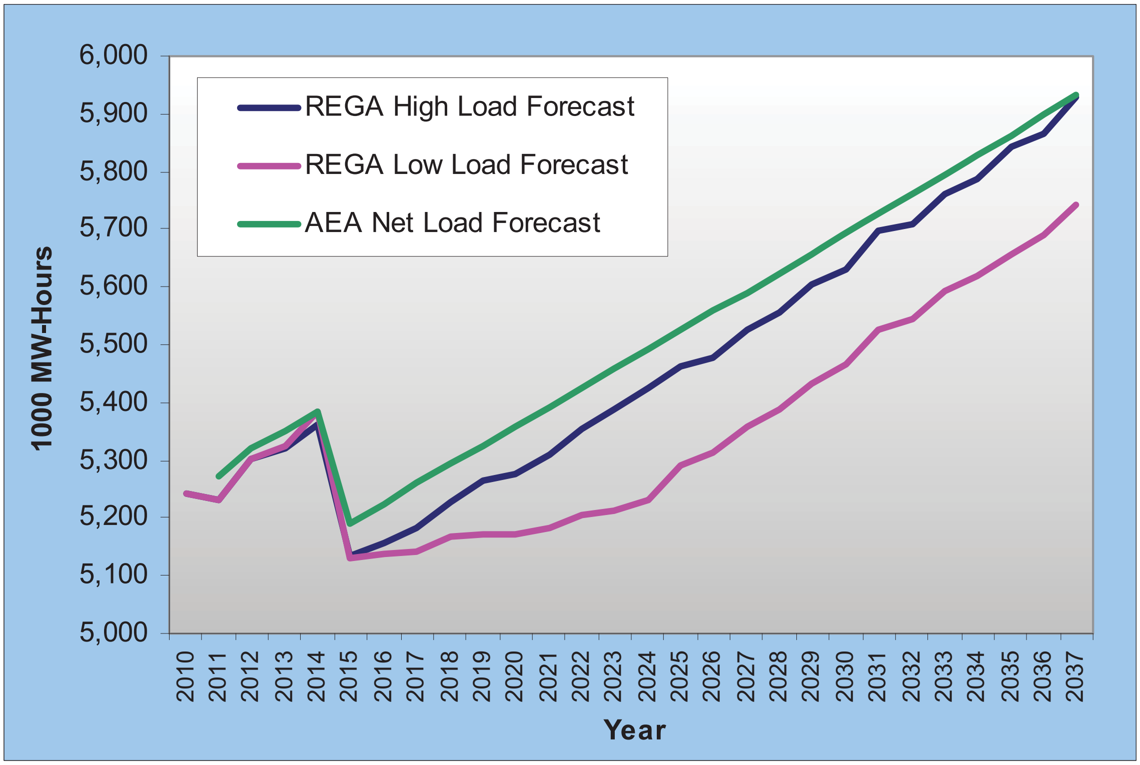
Table 13 lists the total Railbelt load forecast by generation (MW-Hours/Year) for each scenario and compares these values with the Alaska Energy Agency's (AEA) "utility net energy for load forecast"; the latter are generally less than 1% greater than the B&V "High Load Forecast" and up to 4.7% greater 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
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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

⚠ 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.

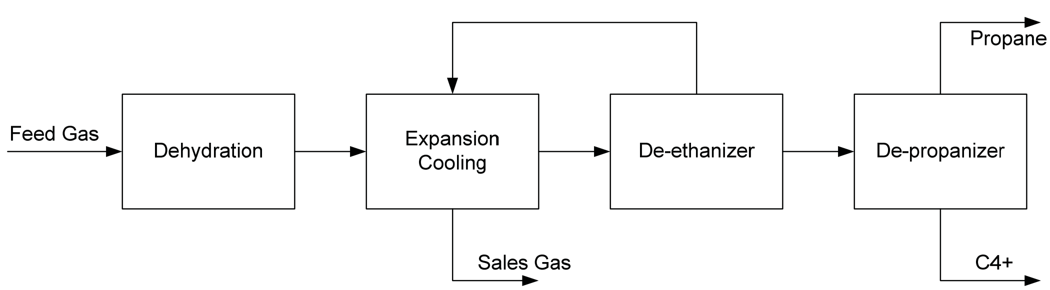
Subsidiaries of TransCanada Corporation have been awarded a license from the State of Alaska (December 5, 2008) for the Alaska Pipeline Project (APP) under the Alaska Gasline Inducement Act (AGIA) and has reached an agreement with ExxonMobil (June 11, 2009) to work together on the project. Following 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.



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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.).

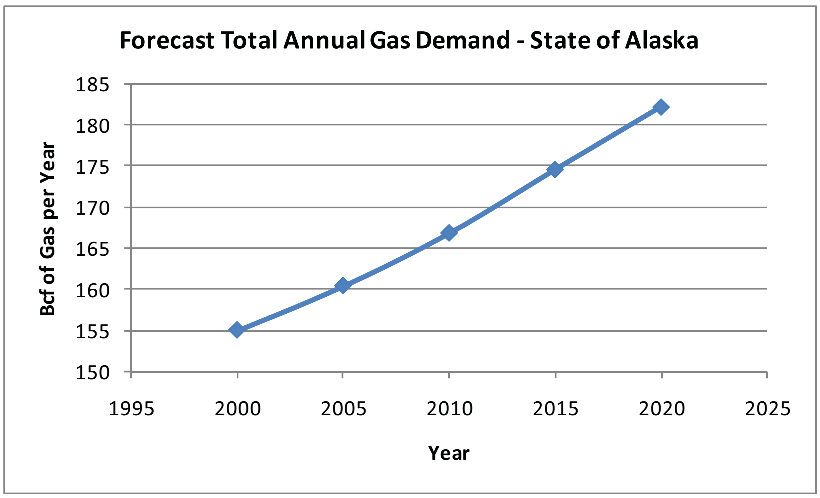
Assuming construction of the Alaska gas pipeline, the most preferred routes to obtaining propane for communities along the pipeline route would be to use so-called "straddle" plants to recover propane and sales quality natural gas from a slipstream taken from the main pipeline. Unwanted residual gas 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.

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

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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.

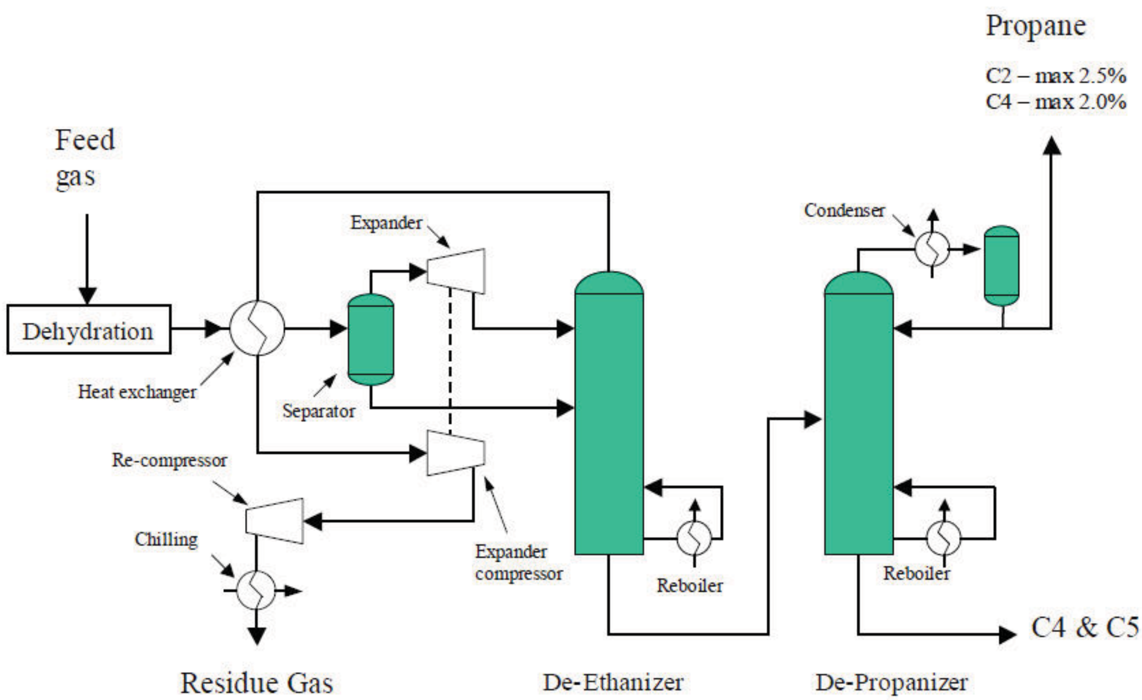
In 2007, ANGDA produced a series of three reports dealing with the subjects of propane/NGL recovery. The first of these reports addressed a potential 1000 barrel per day (BPD) propane extraction plant to be located at the junction of the Dalton highway and Yukon River.[9] In a second 2007 report, ANGDA 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.

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.

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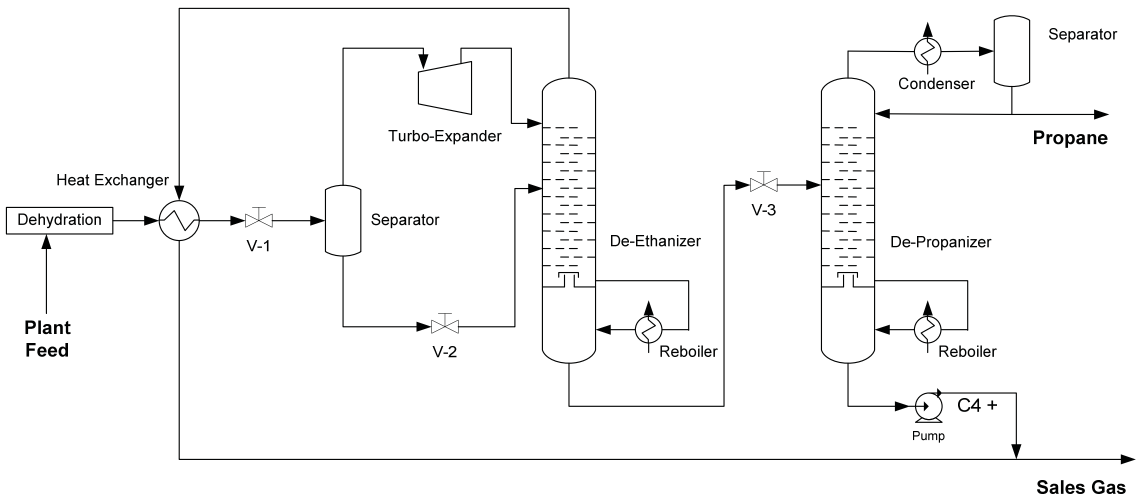
3.1 0.5 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Tok, Alaska

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.

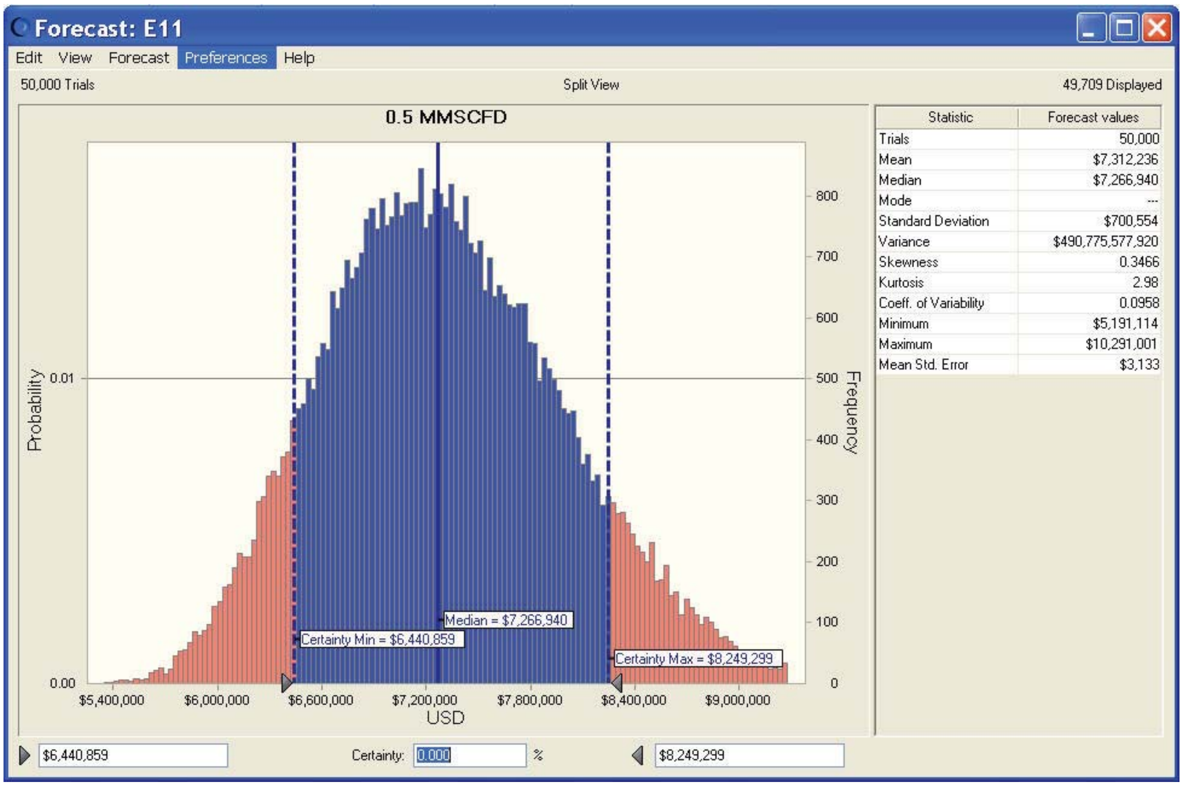
The Owner’s Cost estimate was set as described in Note 8, above.

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;

(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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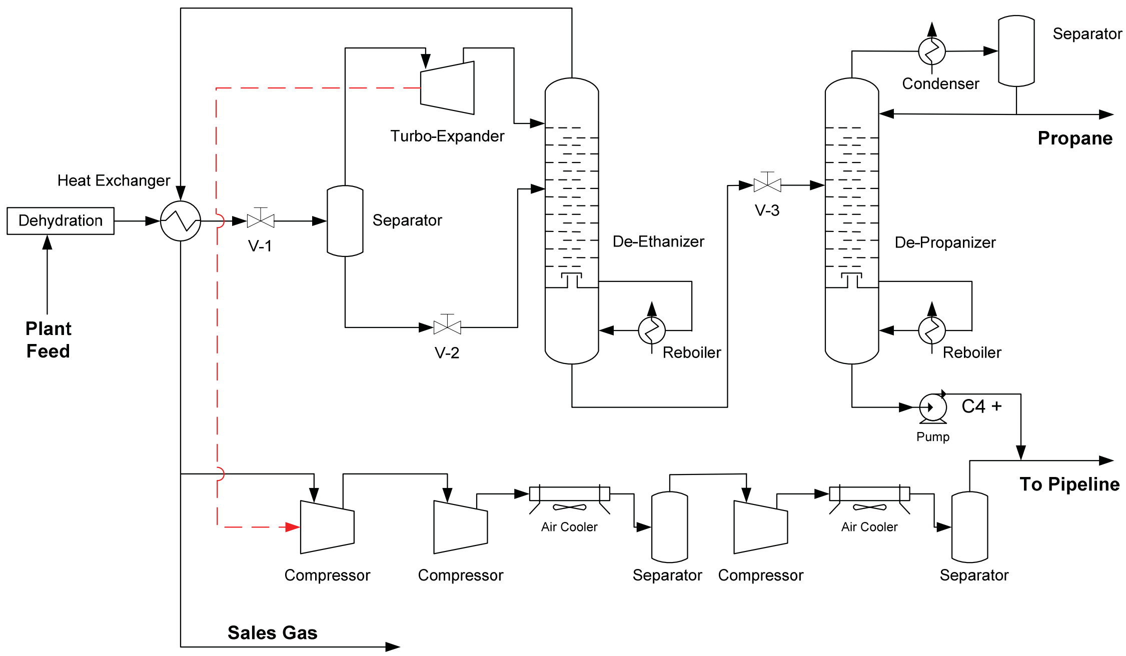
3.2 65 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Fairbanks, Alaska

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

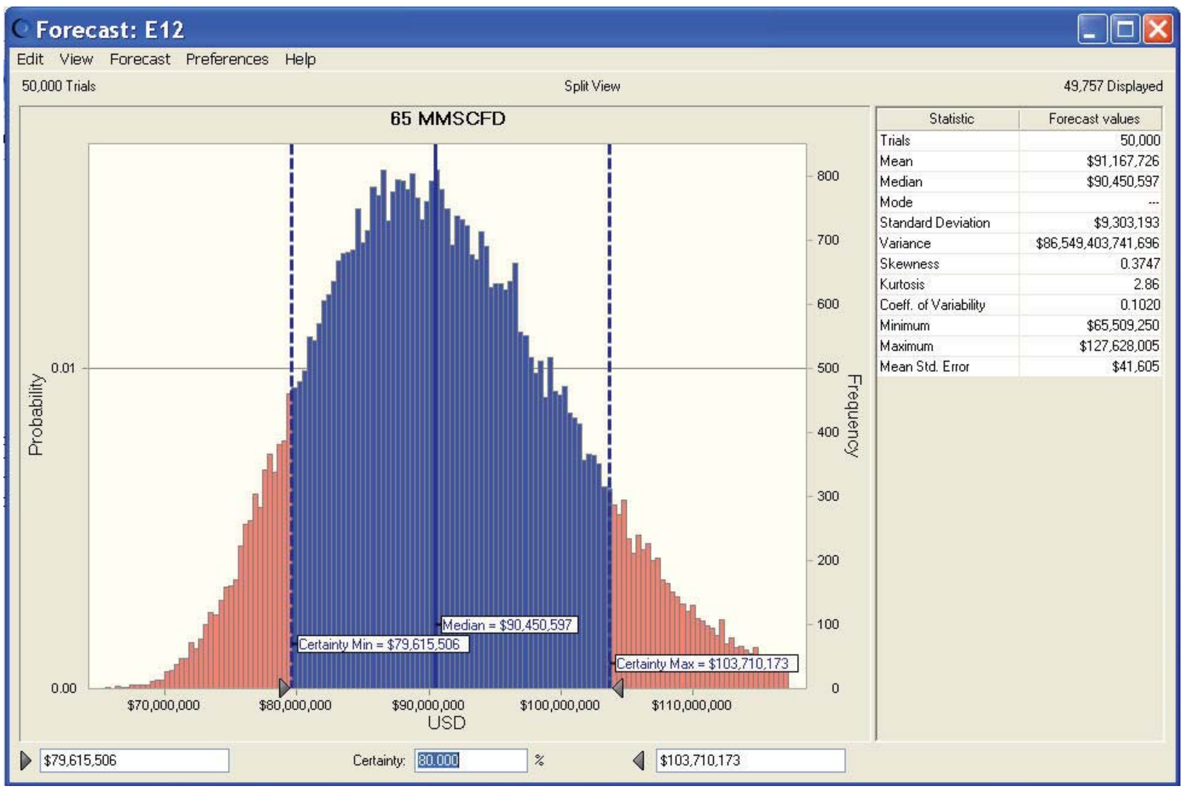
Notes:

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.

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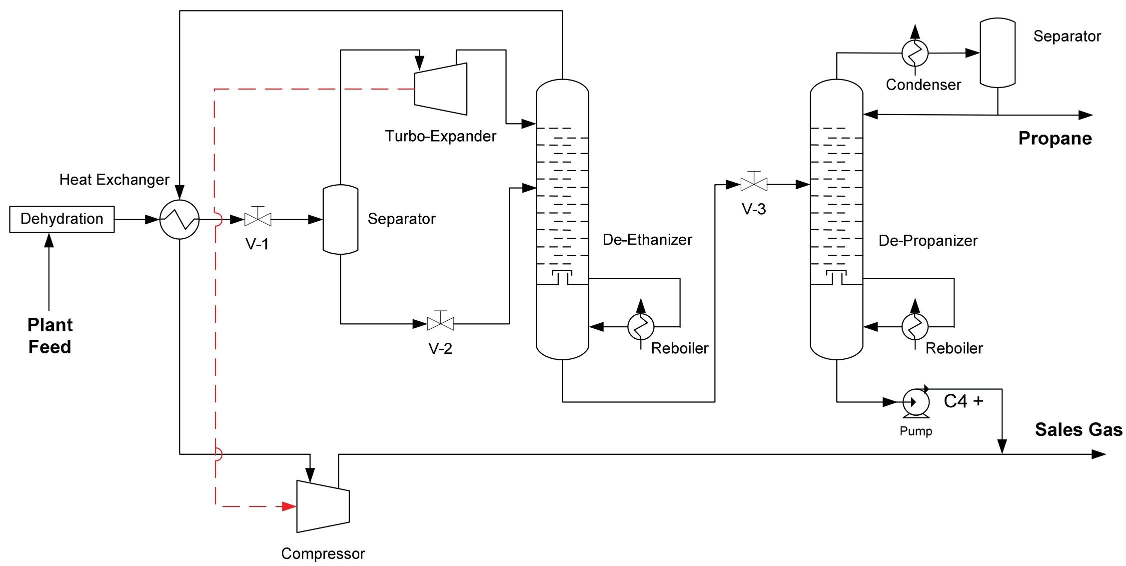
3.3 300 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Anchorage, Alaska

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

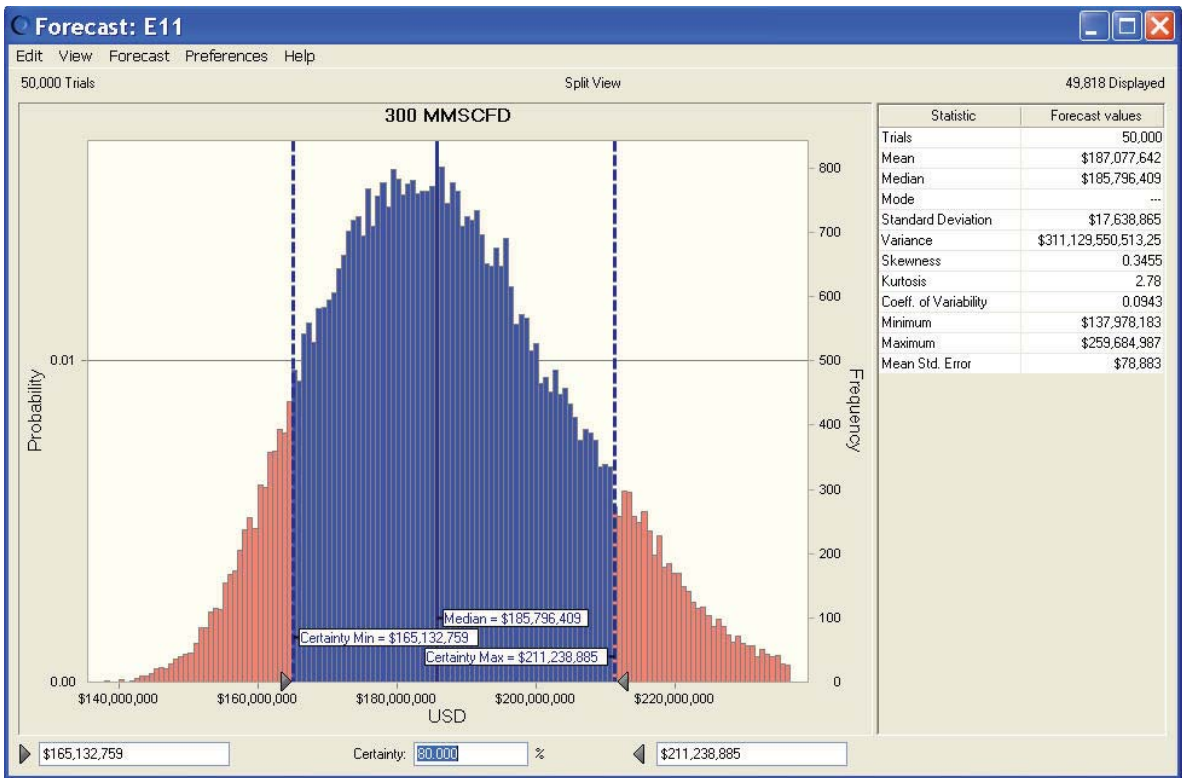
Notes:

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).

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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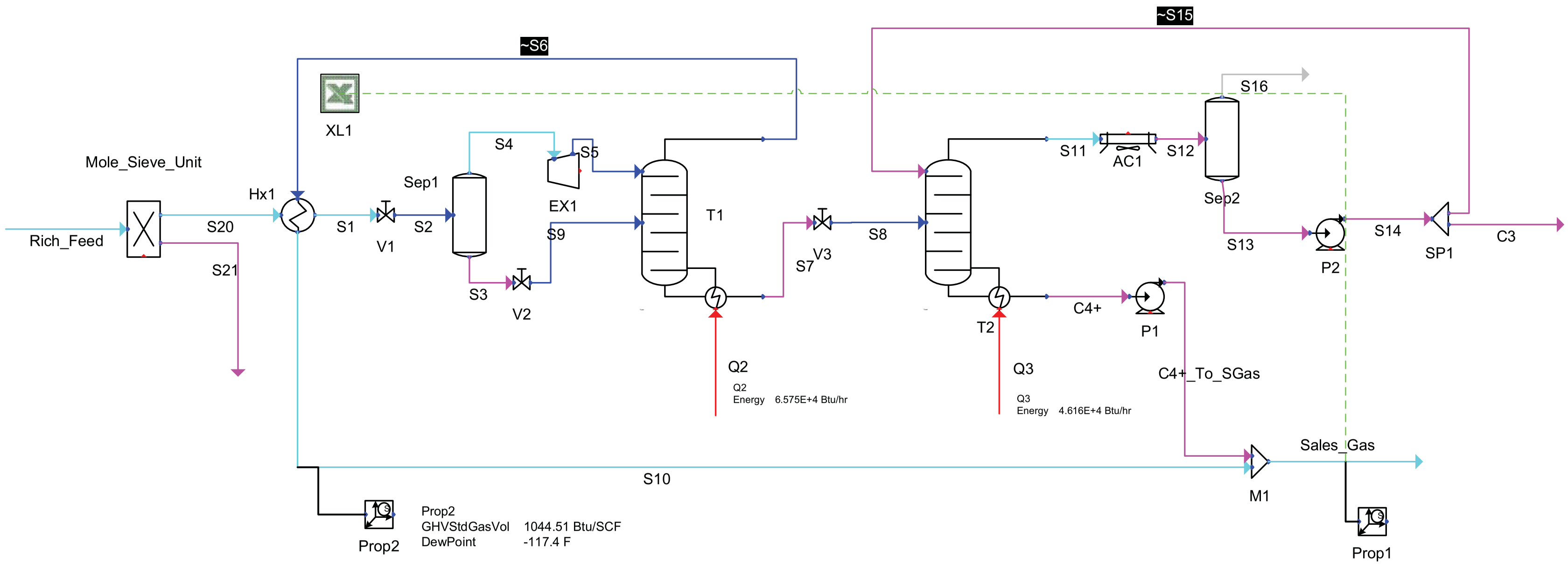
APPENDIX 1

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



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+	Sales_Gas	C4+_To_SGas	S20	S21	S9	S10	S11	S12	S13	S14	S15	S16
VapFrac	1	1	0.76995	0	1	0.94248	0.99999	0	0.05319	0	0	1	0	1	0	0.26163	1	1	0	0	0	0	1
T [F]	28	-31.3	-97.7	-97.7	-97.7	-146.8	-116.7	125.6	116.7	100.9	200.8	21	201.2	28	28	-135.8	23	103.9	100	100	100.9	100.9	100
P [psia]	1500	1499	500	500	500	230	225	230	205	250	205	220	225	1500	1500	230	220	200	200	200	250	250	200
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	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]	1037.07	1037.06	1037.06	315.84	721.22	721.22	925.14	111.94	111.94	86.1	25.81	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	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0	0.0156	0	0.015	0	0.0273	0.0157	0	0	0	0	0	0
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0	0.0062	0	0.006	0	0.0013	0.0063	0	0	0	0	0	0
METHANE	0.864	0.864	0.864	0.6001	0.9429	0.9429	0.9034	0	0	0	0	0.896	0	0.864	0	0.6001	0.9034	0	0	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	0.0729	0	0.071	0	0.1973	0.0735	0.019	0.019	0.019	0.019	0.019	0.0493
PROPANE	0.036	0.036	0.036	0.1402	0.0049	0.0049	0.0011	0.8012	0.8012	0.9748	0.0135	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	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0039	0.363	0.003	0.363	0.003	0	0.0126	0	0.0039	0.0039	0.0039	0.0039	0.0039	0.0017
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.4966	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	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1269	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

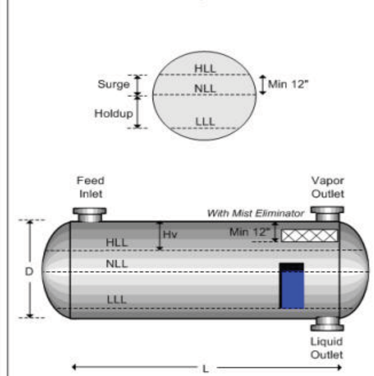
Summary of Plant Unit Design Information

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

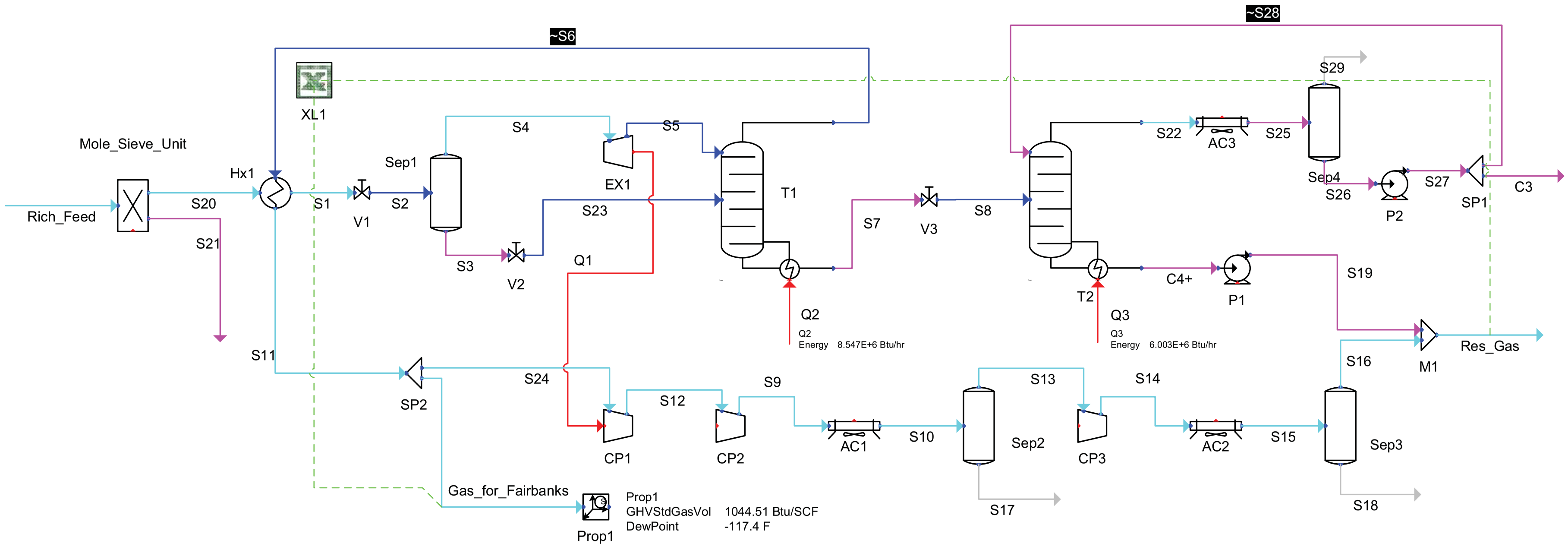
mbouchard@kilowatts.com

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

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	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	S9	S10	S13	S14
VapFrac	1	1	0.76995	0	1	0.94248	0.99999	0	0.05319	0	0	1	1	1	1	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	207.1	104	104	243.6
P [psia]	1500	1499	500	500	500	230	225	230	205	250	205	220	303.50186	682.87919	677.87919	677.87919	1510
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	4080.83	4080.83	4080.83	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	71902.44	71902.44	71902.44	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	3.72E+01	3.72E+01	3.72E+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	0.0157	0.0157	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	0.0063	0.0063	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	0.9034	0.9034	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	0.0735	0.0735	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	0.0011	0.0011	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	0	0	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	0	0	0	0
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1267	0	0	0	0	0	0

Name	S15	S16	S17	S18	S19	Res_Gas	S20	S21	S23	S24	Gas_for_Fairbanks	S22	S25	S26	S27	S28	S29
VapFrac	1	1	0	0	0	1	1	0	0.26163	1	1	1	0	0	0	0	[illegible]
T [F]	104	104	104	104	221.5	104.4	28	28	-135.8	23	23	103.9	100	100	100.9	100.9	100
P [psia]	1505	1505	677.87919	1505	1505	1505	1500	1500	230	220	220	200	200	200	250	250	200
MoleFlow [lbmole/h]	4080.83	4080.83	0	0	56.22	4137.05	7136.92	0.03	1641.88	4080.83	2744.98	1019.77	1019.77	1019.77	1019.77	764.85	0
MassFlow [lb/h]	71902.44	71902.44	0	0	3356.62	75259.06	134818.21	0.46	41059.34	71902.44	48365.27	44784.72	44784.72	44784.72	44784.72	33589.69	0
StdGasVolumeFlow [MMSCFD]	3.72E+01	3.72E+01	2.01E-42	2.01E-42	5.12E-01	3.77E+01	6.50E+01	2.35E-04	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-4[illegible]
MoleFraction [Fraction]																	
CARBON DIOXIDE	0.0157	0.0157	0.0157	0.0157	0	0.0155	0.015	0	0.0273	0.0157	0.0157	0	0	0	0	0	0
NITROGEN	0.0063	0.0063	0.0063	0.0063	0	0.0062	0.006	0	0.0013	0.0063	0.0063	0	0	0	0	0	0
METHANE	0.9034	0.9034	0.9034	0.9034	0	0.8911	0.864	0	0.6001	0.9034	0.9034	0	0	0	0	0	0
ETHANE	0.0735	0.0735	0.0735	0.0735	0	0.0725	0.071	0	0.1973	0.0735	0.0735	0.019	0.019	0.019	0.019	0.019	0.049[illegible]
PROPANE	0.0011	0.0011	0.0011	0.0011	0.0135	0.0013	0.036	0	0.1402	0.0011	0.0011	0.9748	0.9748	0.9748	0.9748	0.9748	0.948[illegible]
ISOBUTANE	0	0	0	0	0.3633	0.0049	0.003	0	0.0126	0	0	0.0039	0.0039	0.0039	0.0039	0.004	0.001[illegible]
n-BUTANE	0	0	0	0	0.4965	0.0067	0.004	0	0.017	0	0	0.0023	0.0023	0.0023	0.0023	0.0022	0.00[illegible]
n-PENTANE	0	0	0	0	0.1267	0.0017	0.001	0	0.0043	0	0	0	0	0	0	0	0

APPENDIX 6

Major Equipment List
65 MMSCFD Propane Fractionation Facility

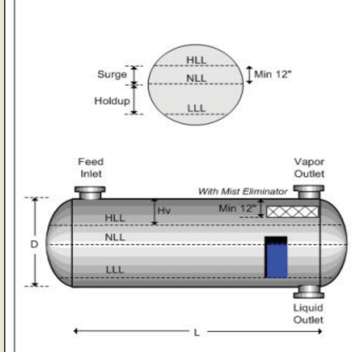
Summary of Plant Unit Design Information					
65 MMSCFD Facility					
Unit	**Water Removal Rate (lb/h)**				
Molecular Sieve	0.4645				
Hx 1	Name		**Value**		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**317242.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-8987220.9**		
	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

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

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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

7.6.0.1	Company: Enerflex	Customer:	Gas Liquids Engineering
	Quote:	Inquiry:	
	Case 1:	Project:	Residue Gas

Compressor Data: **Driver 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)

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		
Frame:	JGZ/4	Stroke, in:	6.75	Rod Dia, in:	2.875		
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000		
Rated RPM:	1000	Rated BHP:	5200.0	Rated PS FPM:	1125.0		
Calc RPM:	1000.0	BHP:	3630	Calc PS FPM:	1125.0		

Driver Data:

Type:	Nat. Gas
Mfg:	Caterpillar
Model:	G3612LE L 90
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

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		
Frame:	JGZ/4	Stroke, in:	6.75	Rod Dia, in:	2.875		
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000		
Rated RPM:	1000	Rated BHP:	5200.0	Rated PS FPM:	1125.0		
Calc RPM:	885.0	BHP:	3603	Calc PS FPM:	995.6		

Driver Data:

Type:	Unselected
Mfg:	
Model:	
BHP:	0
Avail:	0 (0)

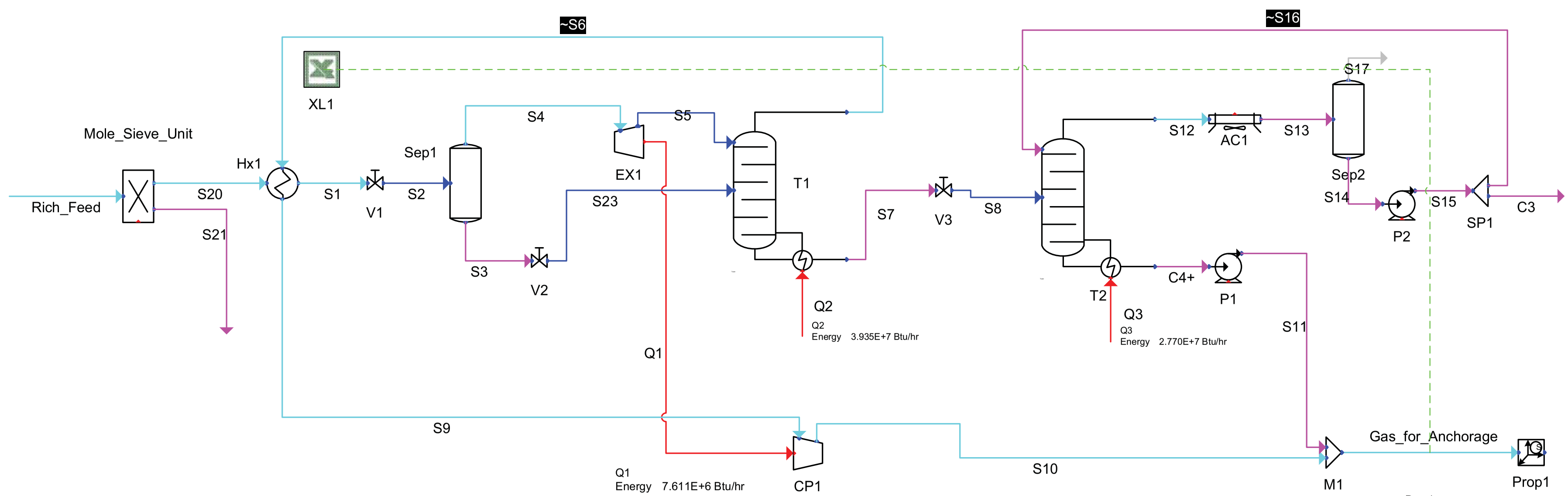
Services	**Service 1**			
Stage Data:	**1**	---	**2**	**3**
Flow Req'd, MMSCFD	37.200	---	37.200	37.200
Flow Calc, MMSCFD	37.200	---	37.200	37.200
Cyl BHP per Stage	1382.9	---	906.2	1273.1
Specific Gravity	0.6083	---	0.6083	0.6083
Ratio of Sp Ht (N)	1.2955	---	1.2988	1.3038
Comp Suct (Zs)	0.9459	---	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	10[illegible]
P [psia]	1500	1500	230	273.5475	224.92144	273.5475	275	200	200	200	250	250	20[illegible]
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	0.948[illegible]
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

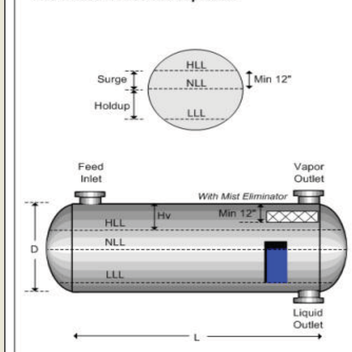
Summary of Plant Unit Design Information

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

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			
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

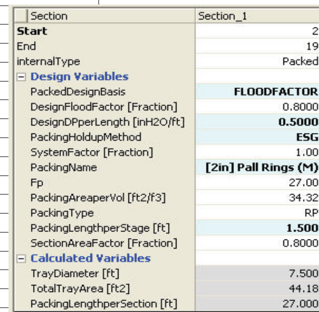
Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

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.

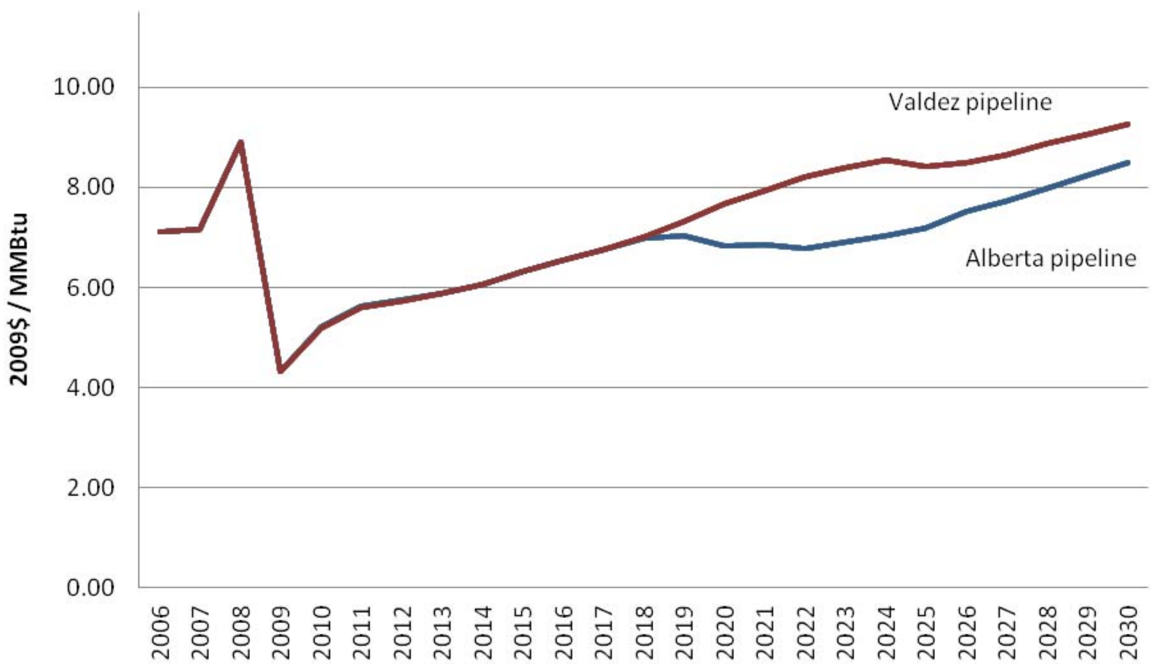
A high fuel price scenario was developed based on another NEMS run with the similar inputs as applied for the EIA “high price” scenario, but with incorporation of ARRA. Under this scenario, the NEMS calculates that the Alaska pipeline will be operational in 2020. To roughly reflect commencement of pipeline 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



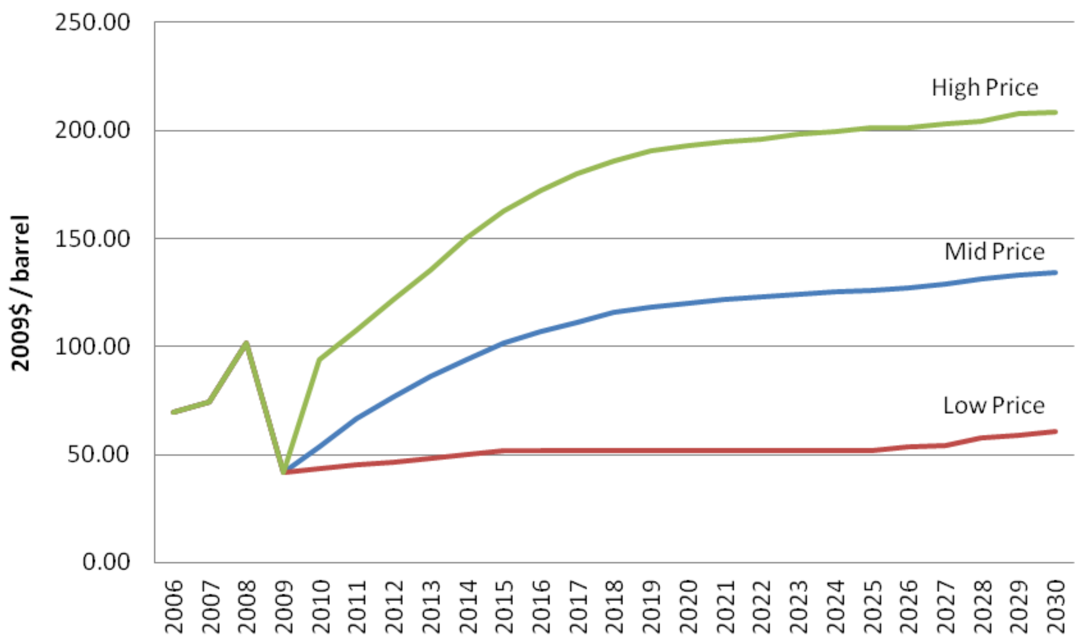
1.2 Petroleum Liquid Fuel Prices

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

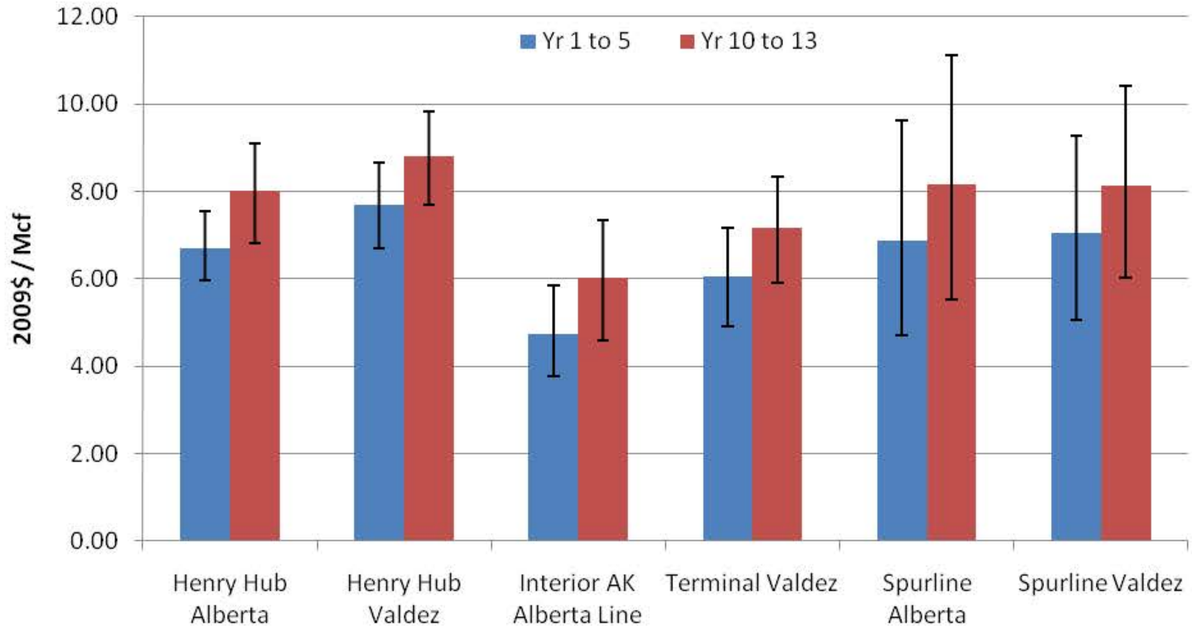
2.2 Average Study-Period Prices

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.

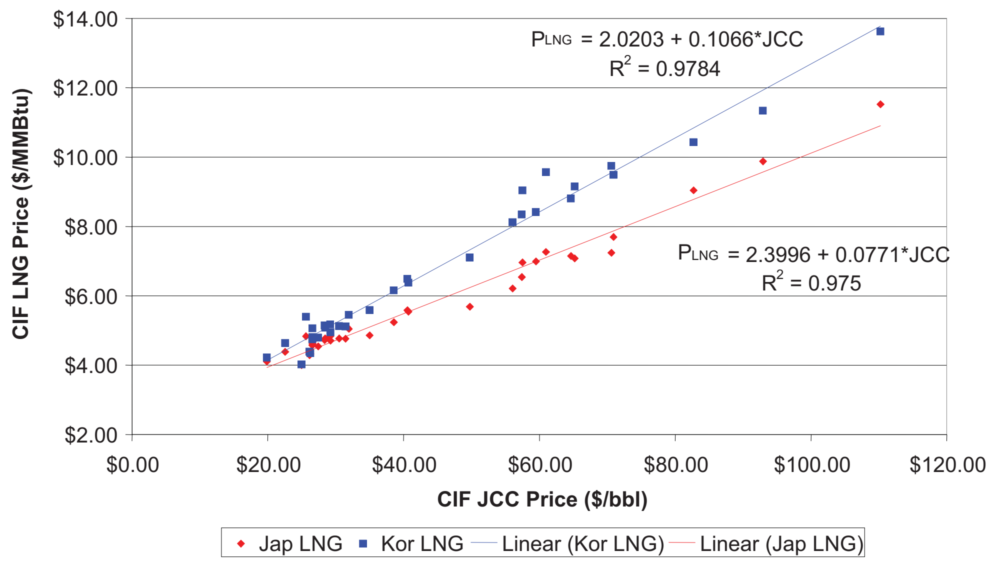
Different LNG contracts employ different pricing formulae, which are rarely disclosed, but it is widely known that Japanese and Korean contracts are linked to the "Japanese Crude Cocktail" (JCC) price, which is a weighted-average of all crude import prices reported by the Japanese Customs office. East 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



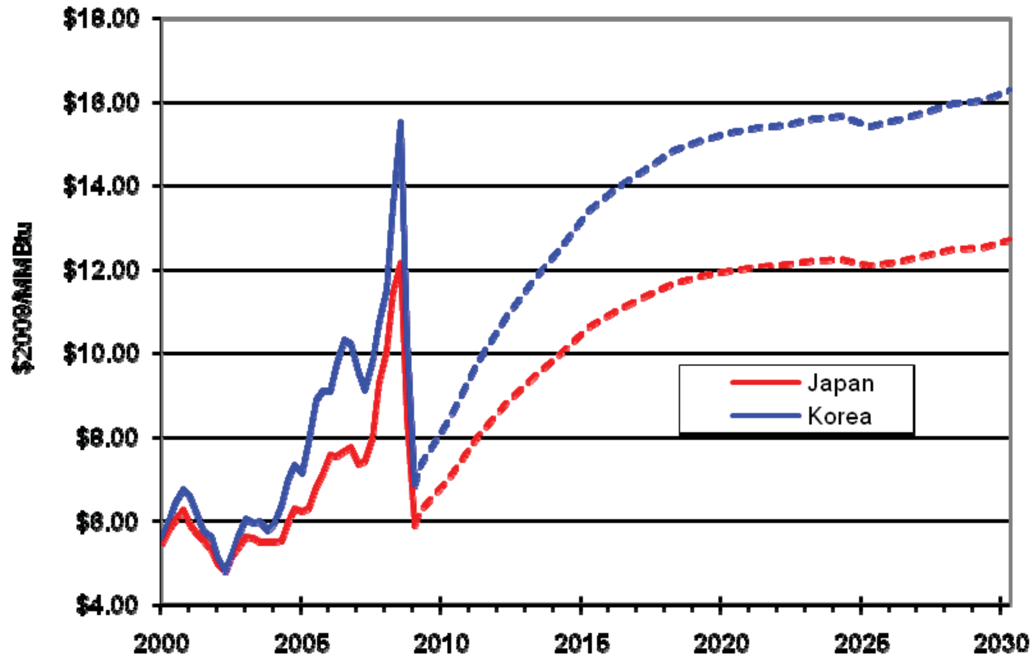
Source: SAIC, derived from Japanese Customs office and Korean Customs office data

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

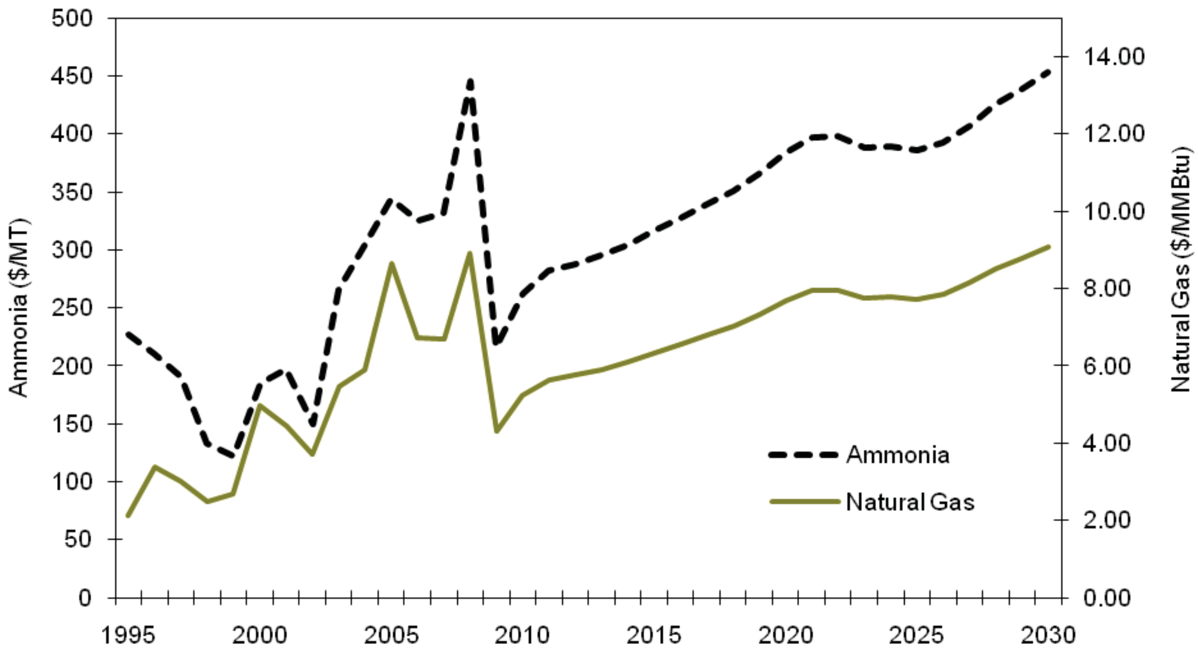
The figure above shows that East Asian LNG prices peaked in the third quarter of 2008 at more than $12 per MMBtu in Japan and more than $15 per MMBtu in Korea. Estimated average LNG prices fell sharply along with crude prices in the fourth quarter of 2008, reaching lows in the first quarter of 2009 of 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.

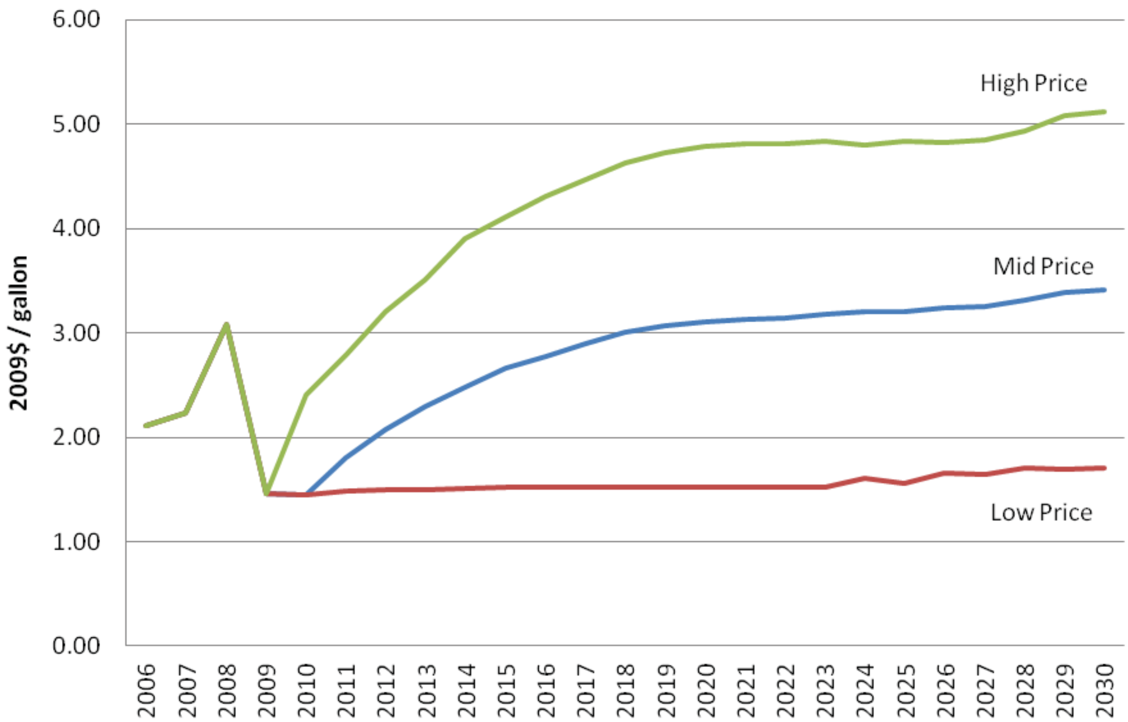
3 Jet Fuel Price Forecast

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 Availability Letter

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

SEAN PARNELL, GOVERNOR

☐ 550 WEST 7TH AVENUE, SUITE 1400
ANCHORAGE, ALASKA 99501-3650
PHONE: (907) 269-8431
FAX: (907) 269-8918

October 30, 2009

Mr. Bud Fackrell, President
Denali Pipeline Project
188 W. Northern Lights Blvd., 13th Floor
PO Box 241747
Anchorage, AK 99524-1747

Dear Mr. Fackrell:

I am in receipt of your October 20, 2009 letter concerning the adoption of an appropriate In-State Gas Usage Study as required in FERC's Open Season regulations. I appreciate your inquiry on this matter as it is important to continue communications as we proceed forward on an Alaska gas pipeline project.

As stated in your recent correspondence, FERC Open Season Regulations require that when an applicant makes a filing prior to conducting an Open Season the applicant also include a study of both gas consumption needs and prospective points of delivery within the state. Further, the regulation states, specifically, that the application "*shall consist of a study conducted, approved, or otherwise sanctioned by an appropriate governmental agency, office or commission of the State of Alaska*. The Commissioners of the Departments of Revenue and Natural Resources will jointly consider any request to approve or sanction an In-state Gas Demand Study to fulfill this requirement of FERC.

The 2006 study conducted by the National Energy Technology Laboratory that you've cited is no longer up-to-date and insufficient to use in 2009–2010 for this purpose. New data should be utilized when evaluating such in-state demand. If submitted for state approval or sanction, an In-State demand study will be evaluated based on the timeliness of its data, the comprehensiveness of its scope, and the methodology used for ensuring the accuracy of the data.

We anticipate the Alaska Pipeline Project sponsors will submit a study for state sanction prior to their Open Season filing at the end of January 2010. If the state sanctions this study it would be available for use by other Alaska gas pipeline sponsors, such as Denali.

Again, thank you for contacting us on this matter.

Sincerely,

for Thomas E. Irwin
Commissioner

"Develop, Conserve, and Enhance Natural Resources for Present and Future Alaskans"

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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☐ *P.O. Box 110400*
JUNEAU, AK 99811-0400
PHONE: (907) 465-2300
FAX: (907) 465-2389

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

DENALI – THE ALASKA GAS PIPELINE LLC	)))	DOCKET NO. PF08-26-001

OPEN SEASON PLAN DOCUMENTS
SUBMITTED IN CONJUNCTION WITH DENALI'S
REQUEST FOR COMMISSION APPROVAL OF PLAN
<u>FOR CONDUCTING AN OPEN SEASON</u>

Volume III of III

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

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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 paragraph (b) of this section;"

Proposed Project and Route in Alaska

Denali's FERC-jurisdictional Alaska Project consists of two transmission lines to deliver gas from North Slope fields, a Gas Treatment Plant (GTP) to condition the gas, and a pipeline with its ancillary facilities (Alaska Mainline) to transport gas within and through Alaska to the international border between Alaska and Canada (Alaska-Canada Border). At the Alaska-Canada Border, gas from the Alaska Mainline will be delivered to the proposed National Energy Board (NEB) regulated Denali Canada pipeline with its ancillary facilities (Canada Mainline). In Alaska, Denali has plans for six in-state gas delivery points including one at the GTP to provide treated, low-carbon dioxide fuel gas for North Slope consumers.

Transmission Lines - The two proposed transmission pipelines will deliver gas to the GTP. One of these is a 36-inch diameter, 62-mile pipeline that will deliver gas from the Point Thomson area (PT). The PT transmission line will generally run west to the Badami field and then parallel the Badami and Endicott oil pipelines into the Prudhoe Bay Unit (PBU) and on to the GTP. The other transmission line will be a 60-inch diameter, 1.2-mile pipeline that will deliver gas from the PBU. The routes of both transmission lines and the location of the GTP are shown in Exhibit A.

GTP - The GTP will be located within the boundaries of the PBU and will be the largest processing plant of its kind in the world. The GTP will consist of four processing trains of activated amine to remove carbon dioxide, hydrogen sulfide, and other impurities and to dehydrate, compress, and chill the treated gas. Denali's GTP services are unbundled, and Denali offers separate rates for gas treating service and compression service (including chilling).

Alaska Mainline - The Alaska Mainline will begin at the GTP and generally follow the Dalton Highway and other Alaska state highways to Delta Junction, Alaska. From there, the route will generally parallel the Alaska Highway to the Alaska-Canada Border. The Alaska Mainline route will cover a total of approximately 730 miles. The general route of the Alaska Mainline in Alaska is shown in Exhibit B.

Alternative Routes - No alternative routes are under consideration at this time. However, if Denali does not receive commitments for at least 85 percent of the design capacity at open season, Denali has provided a framework for Shippers and Denali to work together to consider a scaled down project, a different project such as a pipeline to an LNG facility, or to generate additional commitments to allow the original Project to proceed.

Proposed Alaska Receipt and Delivery Points

Denali will provide for six delivery points inside Alaska. Specifically, Denali will provide for a delivery point at the outlet of the GTP treating facilities prior to final compression (to provide treated, low-carbon dioxide gas for North Slope users), as well as five additional delivery points along the Alaska Mainline as identified in the In-State Gas Demand Study[1] approved by the State of Alaska. During the open season process, shippers may express interest in other receipt points or delivery points. If interest is expressed in other receipt or delivery points, Denali will consider including such requests in its plans. The table on the following page summarizes the proposed receipt and delivery points for the Alaska Project.

Canada Mainline Route

The Canada Mainline will begin at the Alaska-Canada border and generally follow the Alaska Highway through the Yukon Territory and northeast British Columbia (BC) to a point near Liard Hot Springs. From Liard Hot Springs, the route will deviate from the highway and run south and east through British Columbia to Boundary Lake, Alberta (AB). In British Columbia and Alberta, Denali Canada will offer connections to multiple pipeline systems, allowing shippers options for transporting gas to North American markets. At Boundary Lake, the line diameter will be reduced from 48 inches to 36 inches, and the pipeline will continue in a southerly direction to its final terminus near Blueberry Hill, AB. The Canada Mainline route will cover a total of approximately 1020 miles. Denali Canada has designed for intermediate receipt/delivery points. Based upon input from shippers in the Canadian open season, Denali Canada may modify its planned receipt and delivery points on the Canada Mainline. The general route of the Denali Canada Mainline is shown in Exhibit C.

[1] "In-State Gas Demand Study" by Northern Economics, January 2010 (In-State Gas Demand Study). As required by the Commission's regulations, Denali has adopted and relied upon this study in developing the contents of this Notice. 18 C.F.R. § 157.34(b).

Proposed Alaska Receipt and Delivery Points

The receipt and delivery points listed below represent proposed points where gas may be accepted into or taken off of Denali's Alaska Project.

Location	Receipt Point	Delivery Point
Central Gas Facility, Prudhoe Bay – Transmission Line to GTP	X	
Point Thomson area – Transmission Line to GTP	X	
Inlet to the GTP	X	
Inlet to GTP Compression/Chilling[1]	X	
GTP Treated Gas Return[2]		X
Inlet to the Alaska Mainline (Outlet of Compression Service)	X	
Livengood[3]		X
Parks Highway Spur[3]		X
Fairbanks[3]		X
Delta Junction[3]		X
Tok[3]		X
Alaska-Canada Border (delivery to the Canada Mainline)		X

[1] Intermediate GTP location downstream of acid gas removal/dehydration and upstream of the compression/chilling facilities.

[2] Treated, low-carbon dioxide gas off-take upstream of compression/chilling facilities.

[3] Delivery Points identified by the In-State Gas Demand Study.

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 paragraph (c)(1) of this section 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;"

The proposed Alaska Project will have the size and design capacities as summarized below. The design throughputs stated below represent annual averages.

Including the GTP Treated Gas delivery point identified in Item 1, Denali is proposing six delivery points for in-state consumers. The delivery volumes from the In-State Gas Demand Study have been incorporated in the table below. Actual in-state receipt/delivery points and associated volumes will be determined in the course of the open season.

Section of the Project	**Design Parameter**	**Value**
Point Thomson Transmission Line	Pipeline Diameter (inches)	36
	Pipeline Grade	X70
	Pipeline Length (miles)	62
	Pipeline Capacity (Bscf/d)	1.1
Prudhoe Bay Transmission Line	Pipeline Diameter (inches)	60
	Pipeline Grade	X65
	Pipeline Length (miles)	1.2
	Pipeline Capacity (Bscf/d)	4.6

Section of the Project	Design Parameter	Value
Gas Treatment Plant	Total Processing Capacity (Bscf/d)	5.8
	Acid Gas Processing Capacity (CO_2 & H_2S, Bscf/d)	0.7
	GTP Treated Gas Return (Bscf/d)	0.3
	Delivered sales gas[1] to Alaska Mainline (Bscf/d)	4.5
	Inlet gas receipt temperature (min-max F)	45- 80
	Outlet CO_2 temperature (min-max F)	100-150
Alaska Mainline	Pipeline Diameter (inches)	48
	Pipeline Grade	X80
	Pipeline Length Alaska (miles)	730
	Pipeline capacity – sales gas (Bscf/d)	4.5
	Inlet Gas receipt temperature (F)	<30
	Outlet gas delivery point Livengood (MMscf/d)	9
	Outlet gas delivery point Parks Highway Spur (MMscf/d)	270[2]
	Outlet gas delivery point Fairbanks (MMscf/d)	55
	Outlet gas delivery point Delta Junction (MMscf/d)	272[2]
	Outlet gas delivery point Tok (MMscf/d)	1
	Outlet gas delivery point Alaska-Canada Border (Bscf/d)	4.5[3]

[1] The term "sales gas" as used in this Appendix C refers to pipeline-quality gas owned by shippers and transported on the Alaska Project (exclusive of fuel and lost and unaccounted for gas related to the Project).

[2] Deliveries will only be provided at one of these locations to provide gas to a spur line to the Southcentral region in Alaska. The location of the spur line interconnection will determine where this capacity will be utilized.

[3] Actual deliveries will be dependent on Alaska in-state gas off-take.

Designs for Initial and Potential Expanded Capacity

The Alaska Project will be capable of delivering an annual average of 4.5 Bscf/d of sales gas to the Canada Mainline and will be expandable up to 5.6 Bscf/d. The initial Alaska Project capacity may be adjusted based upon the results of the open season. After the acceptance of a Certificate of Public Convenience and Necessity (CPCN), Denali will solicit interest in capacity expansion every two years. Should interest in expansion be received, and before seeking FERC approval for a physical expansion of the facilities, Denali will provide existing Firm shippers, on a non-discriminatory basis, the opportunity to reduce their capacity sufficient to accommodate the expansion volumes. If it is determined that an expansion is warranted, Denali may undertake the expansion after securing financial commitments from expansion shippers unless such requests cannot be accommodated due to financial, economic, engineering, design, capacity, or operational constraints or unless the new request would adversely impact the timely development of the Project. In the event Denali seeks an expansion of capacity, Denali will not propose a rate structure for expansions that will require existing shippers to subsidize expansion shippers.

The following sections summarize the design premise and expansion capabilities that are included in the Project design. In general, the capacity of the Transmission Lines and the Alaska and Canada Mainlines can be significantly increased through increased compression. Significant capacity increases in the GTP will require the addition of new gas treating, compression, and chilling facilities.

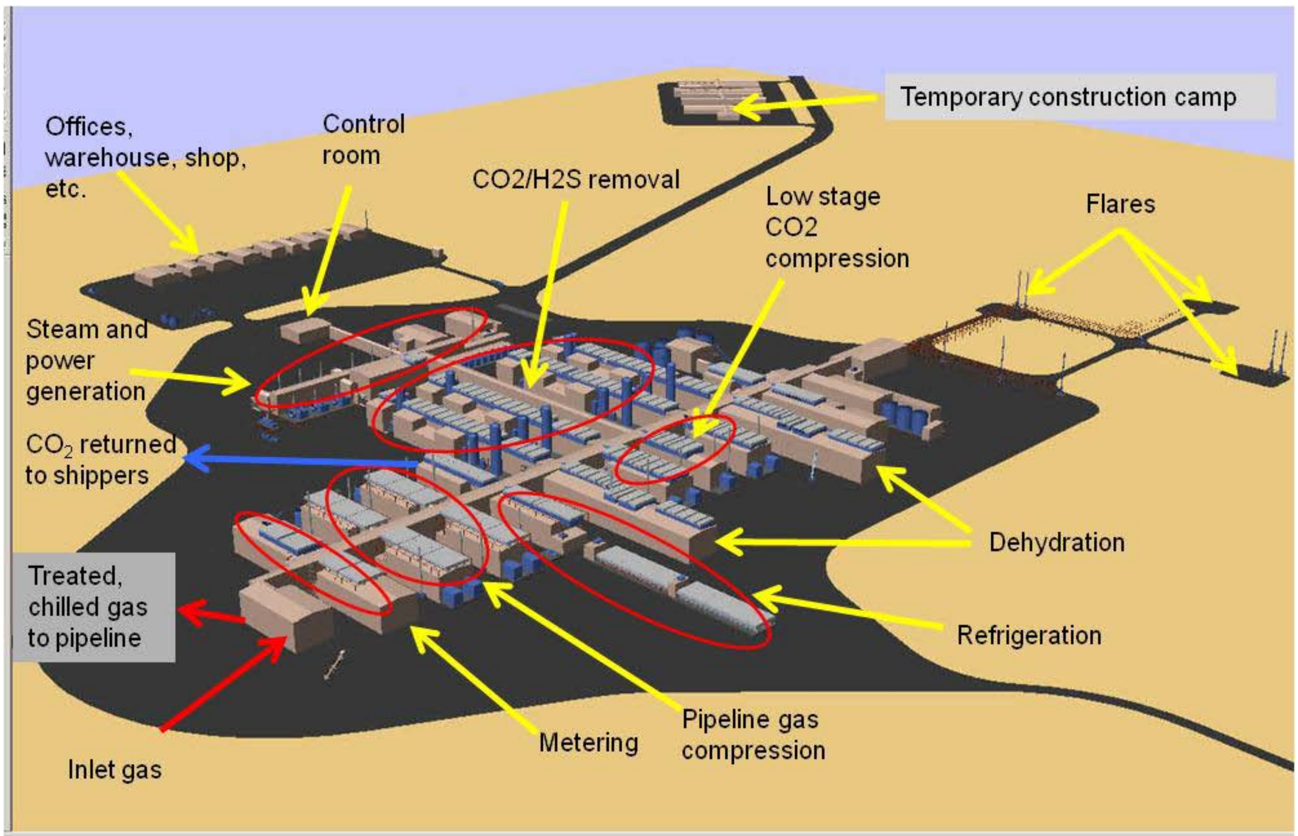
Point Thomson Transmission Line – The design premise for the Point Thomson Transmission Line is a 36-inch diameter, 62-mile, X70 pipeline capable of transporting 1.1 Bscf/d to the inlet of the Gas Treatment Plant (GTP) at a Transmission Line inlet pressure of approximately 1,000 psig. The capacity of the Point Thomson Transmission Line can be increased to 1.5 Bscf/d by increasing the inlet pressure to 1,220 psig.

Prudhoe Bay Transmission Line – The design premise for the Prudhoe Bay Transmission Line is a 60-inch diameter, 1.2-mile, X65 pipeline capable of transporting 4.6 Bscf/d to the inlet of the GTP at a Transmission Line inlet pressure of approximately 615 psig. The capacity of the Prudhoe Bay Transmission Line can be increased to 5.4 Bscf/d by increasing the inlet pressure to approximately 620 psig.

GTP – The GTP is an integral part of the Project and is designed to process North Slope natural gas to meet the Alaska and Canada Mainline gas specifications. The GTP inlet capacity will be approximately 5.8 Bscf/d of gas at an inlet pressure of 600 psig. The GTP is designed to remove carbon dioxide, hydrogen sulfide, and other impurities, and to dehydrate, compress, and chill the gas to pipeline specifications. Four gas treating trains are included in the design. The GTP will deliver 4.5 Bscf/d of sales gas to the Alaska Mainline for transportation. Recovered carbon dioxide, hydrogen sulfide, and other impurities (up to 13% of the feed gas volumes or approximately 700 MMscf/d) will be dehydrated, compressed, and returned for disposition to shippers at the GTP boundary. Denali will provide a delivery point downstream of the GTP treating facilities for delivery of treated, low-carbon dioxide gas for use by North Slope consumers.

In the event that market demand supports the expansion of the GTP, the GTP can be debottlenecked for minor capacity increases. Incremental gas treating trains along with other related facilities can increase the GTP gas delivery capacity to the Alaska Mainline by up to 1.3 Bscf/d for a total of 5.8 Bscf/d.

The following figure illustrates the proposed configuration of the GTP.



Alaska Mainline – The design capacity of the 48-inch Alaska Mainline is approximately 4.5 Bscf/d. The base design includes six compressor stations located roughly equidistant along the Alaska Mainline. All six stations are designed to have refrigeration systems to chill the gas below 32 degrees Fahrenheit to prevent thawing of the permafrost. The design for the Alaska Mainline includes provisions for up to seven additional refrigerated compressor stations to increase capacity to approximately 5.6 Bscf/d.

Canada Mainline – The Canada Mainline has size and design capacities consistent with the Alaska Mainline. The Canada Mainline includes nine compressor stations in the base design (approximately 4.5 Bscf/d) and a provision to add nine additional compressors to increase capacity to approximately 5.6 Bscf/d.

Item 3 - Operating Pressures

18 C.F.R. § 157.34(c)(3): "Maximum allowable operating pressure and expected actual operating pressure;"

Transmission Lines and Alaska Mainline

Section of the Project	Location	Maximum Allowable Operating Pressure (psig)	Expected Actual Operating Pressure (psig)
Point Thomson Transmission Line	Inlet	1,480	1,000
	Outlet	1,480	600
Prudhoe Bay Transmission Line	Inlet	740	615
	Outlet	740	600
Alaska Mainline	Inlet	2,500	2,500
	Outlet	2,500	2,250

Gas Treatment Plant

Section of the Project	Location	Maximum Operating Pressure (psig)	Expected Actual Operating Pressure (psig)
Gas Treatment Plant (GTP)	Inlet	650	600
	Outlet (Recovered CO_2, H_2S, and other impurities)	4,000	3,900
	Inlet to Compression and Treated Gas Return	650	500
	Outlet (Compressed Gas to Mainline)	2,500	2,500

Item 4 – Delivery Pressures

18 C.F.R. § 157.34(c)(4): "Delivery pressure at all delivery points named in paragraph (c)(1) of this section;"

In-State Delivery Points	Average Delivery Pressure (psig)
GTP Treated Gas Return	500
Livengood	2,100
Parks Highway Spur	1,850
Fairbanks	1,800
Delta Junction	1,900
Tok	1,950
Alaska-Canada Border (delivery to the Canada Mainline)	2,250

Item 5 - Estimated In-Service Date

18 C.F.R. § 157.34(c)(5): "Projected in-service date;"

The projected in-service date is 2020. Firm service will begin at that time at adjusted contract levels. The Project is estimated to reach full certificated capacity in 2022.

Item 6 - Estimated Transportation and Treating Rates

18 C.F.R. § 157.34(c)(6): "An estimated unbundled transportation rate for each delivery point named in paragraph (c)(1) of this section, 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 the Annual Charge Adjustment (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);"

Estimated unbundled recourse rates on a thermal basis for each service and delivery point named in Item 1 are shown in the following tables. Negotiated rates are presented in Item 9.

To provide a stable recourse rate during the early years of operations, recourse rates are presented for two periods of operation. Period One will begin when Denali determines that reliable deliveries for contracted firm services can be delivered at a capacity less than the full certificated capacity of the Project. Period One will continue until one year after Firm services for all contracted quantities are available. In total, Period One is projected to last three years. The recourse rates applicable during Period One will be calculated on a substantially levelized basis over the duration of the period.

Period Two will commence after Period One has ended. Recourse rates during Period Two will not be levelized. Estimated cost of service and rate design details for Period One and Period Two recourse rates are presented in Item 7.

All estimated rates are exclusive of any applicable charges or surcharges the Commission may allow.

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE FTR – FIRM TRANSMISSION

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)	Fuel Retention Percentage
Prudhoe Bay to GTP:				
Maximum Rate:	$0.26	0.00¢	0.85¢	0.0%
Minimum Rate:	$0.00	0.00¢	0.00¢	0.0%
Point Thomson to GTP:				
Maximum Rate:	$16.85	0.03¢	55.42¢	0.0%
Minimum Rate:	$0.00	0.03¢	0.03¢	0.0%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Prudhoe Bay to GTP: 0.003¢

Point Thomson to GTP: 0.24¢

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE ITR – INTERRUPTIBLE TRANSMISSION

	¢/Dth	Fuel Retention Percentage
Prudhoe Bay to GTP:		
Maximum Rate:	0.85¢	0.0%
Minimum Rate:	0.00¢	0.0%
Point Thomson to GTP:		
Maximum Rate:	55.42¢	0.0%
Minimum Rate:	0.03¢	0.0%

Dismantlement, Restoration, Removal Surcharge (¢/Dth)

Prudhoe Bay to GTP: 0.003¢

Point Thomson Bay to GTP: 0.24¢

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE FGT – FIRM GAS TREATMENT

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate ($/Dth)
Maximum Rate:	$36.87	3.75¢	$1.2496
Minimum Rate:	$0.00	3.75¢	$0.0375

Fuel Retention Percentage: 2.7786%

Dismantlement, Restoration, and Removal Surcharge: 3.70¢/Dth

Note 1: This rate also applies to the gas delivered to the GTP Treated Gas Return delivery point identified in Item 1.

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE IGT – INTERRUPTIBLE GAS TREATMENT

Maximum Rate: $1.2496/Dth

Minimum Rate: $0.0375/Dth

Fuel Retention Percentage: 2.7786%

Dismantlement, Restoration, and Removal Surcharge: 3.70¢/Dth

Note 1: This rate also applies to the gas delivered to the GTP Treated Gas Return delivery point identified in Item 1.

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE FC – FIRM COMPRESSION

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)
Maximum Rate:	$12.40	0.80¢	41.57¢
Minimum Rate:	$0.00	0.80¢	0.80¢

Fuel Retention Percentage: 1.6061%

Dismantlement, Restoration, and Removal Surcharge: 0.44¢/Dth

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE IC – INTERRUPTIBLE COMPRESSION

Maximum Rate: 41.57¢/Dth

Minimum Rate: 0.80¢/Dth

Fuel Retention Percentage: 1.6061%

Dismantlement, Restoration, and Removal Surcharge: 0.44¢/Dth

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE FT – FIRM TRANSPORTATION

Note: Receipt Point means the inlet to the Alaska Mainline

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate ($/Dth)	Fuel Retention Percentage
Receipt Point to Livengood:				
Maximum Rate:	$27.76	0.50¢	$0.9175	0.6724%
Minimum Rate:	$0.00	0.50¢	$0.0050	0.6724%
Receipt Point to Parks Highway Spur:				
Maximum Rate:	$31.02	0.56¢	$1.0253	0.7539%
Minimum Rate:	$0.00	0.56¢	$0.0056	0.7539%
Receipt Point to Fairbanks:				
Maximum Rate:	$31.25	0.56¢	1.0331¢	0.7599%
Minimum Rate:	$0.00	0.56¢	0.0056¢	0.7599%
Receipt Point to Delta Junction:				
Maximum Rate:	$37.21	0.68¢	$1.2300	0.9084%
Minimum Rate:	$0.00	0.68¢	$0.0068	0.9084%
Receipt Point to Tok:				
Maximum Rate:	$44.40	0.81¢	$1.4679	1.0874%
Minimum Rate:	$0.00	0.81¢	$0.0081	1.0874%
Receipt Point to Alaska-Canada Border:				
Maximum Rate:	$50.37	0.92¢	$1.6653	1.2353%
Minimum Rate:	$0.00	0.92¢	$0.0092	1.2353%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Receipt Point to Livengood: 0.36¢

Receipt Point to Parks Highway Spur: 0.41¢

Receipt Point to Fairbanks: 0.41¢

Receipt Point to Delta Junction: 0.49¢

Receipt Point to Tok: 0.59¢

Receipt Point to Canadian Border: 0.67¢

ESTIMATED PERIOD ONE RECOURSE RATES

RATE SCHEDULE IT – INTERRUPTIBLE TRANSPORTATION

Note: Receipt Point means the inlet to the Alaska Mainline

	$/Dth	Fuel Retention Percentage
Receipt Point to Livengood:		
Maximum Rate:	$0.9175	0.6724%
Minimum Rate:	$0.0050	0.6724%
Receipt Point to Parks Highway Spur:		
Maximum Rate:	$1.0253	0.7539%
Minimum Rate:	$0.0056	0.7539%
Receipt Point to Fairbanks:		
Maximum Rate:	$1.0331	0.7599%
Minimum Rate:	$0.0056	0.7599%
Receipt Point to Delta Junction:		
Maximum Rate:	$1.2300	0.9084%
Minimum Rate:	$0.0068	0.9084%
Receipt Point to Tok:		
Maximum Rate:	$1.4679	1.0874%
Minimum Rate:	$0.0081	1.0874%
Receipt Point to Alaska-Canada Border:		
Maximum Rate:	$1.6653	1.2353%
Minimum Rate:	$0.0092	1.2353%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Receipt Point to Livengood: 0.36¢

Receipt Point to Parks Highway Spur: 0.41¢

Receipt Point to Fairbanks: 0.41¢

Receipt Point to Delta Junction: 0.49¢

Receipt Point to Tok: 0.59¢

Receipt Point to Canadian Border: 0.67¢

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE FTR – FIRM TRANSMISSION

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)	Fuel Retention Percentage
Prudhoe Bay to GTP:				
Maximum Rate:	$0.17	0.00¢	0.57¢	0.0%
Minimum Rate:	$0.00	0.00¢	0.00¢	0.0%
Point Thomson to GTP:				
Maximum Rate:	$11.13	0.03¢	36.61¢	0.0%
Minimum Rate:	$0.00	0.03¢	0.03¢	0.0%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Prudhoe Bay to GTP: 0.003¢

Point Thomson to GTP: 0.19¢

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE ITR – INTERRUPTIBLE TRANSMISSION

	¢/Dth	Fuel Retention Percentage
Prudhoe Bay to GTP:		
Maximum Rate:	0.57¢	0.0%
Minimum Rate:	0.00¢	0.0%
Point Thomson to GTP:		
Maximum Rate:	36.61¢	0.0%
Minimum Rate:	0.03¢	0.0%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Prudhoe Bay to GTP: 0.003¢

Point Thomson to GTP: 0.19¢

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE FGT – FIRM GAS TREATMENT

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate ($/Dth)
Maximum Rate:	$28.69	3.51¢	$0.9782
Minimum Rate:	$0.00	3.51¢	$0.0351

Fuel Retention Percentage: 2.5662%

Dismantlement, Restoration, and Removal Surcharge: 2.96¢/Dth

Note: This rate also applies to the gas delivered to the GTP Treated Gas Return delivery point identified in Item 1.

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE IGT – INTERRUPTIBLE GAS TREATMENT

Maximum Rate: $0.9782/Dth

Minimum Rate: $0.0351/Dth

Fuel Retention Percentage: 2.5662%

Dismantlement, Restoration, and Removal Surcharge: 2.96¢/Dth

Note: This rate also applies to the gas delivered to the GTP Treated Gas Return delivery point identified in Item 1.

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE FC – FIRM COMPRESSION

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)
Maximum Rate:	$10.07	0.80¢	33.91¢
Minimum Rate:	$0.00	0.80¢	0.80¢

Fuel Retention Percentage: 1.5794%

Dismantlement, Restoration, and Removal Surcharge: 0.38¢/Dth

DENALI
the alaska gas pipeline

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE IC – INTERRUPTIBLE COMPRESSION

Maximum Rate: 33.91¢/Dth

Minimum Rate: 0.80¢/Dth

Fuel Retention Percentage: 1.5794%

Dismantlement, Restoration, and Removal Surcharge: 0.38¢/Dth

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE FT – FIRM TRANSPORTATION

Note: Receipt Point means the inlet to the Alaska Mainline

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate ($/Dth)	Fuel Retention Percentage
Receipt Point to Livengood:				
Maximum Rate:	$19.69	0.50¢	$0.6523	0.8424%
Minimum Rate:	$0.00	0.50¢	$0.0050	0.8424%
Receipt Point to Parks Highway Spur:				
Maximum Rate:	$21.98	0.56¢	$0.7281	0.9444%
Minimum Rate:	$0.00	0.56¢	$0.0056	0.9444%
Receipt Point to Fairbanks:				
Maximum Rate:	$22.14	0.56¢	0.7336¢	0.9518%
Minimum Rate:	$0.00	0.56¢	0.0056¢	0.9518%
Receipt Point to Delta Junction:				
Maximum Rate:	$26.32	0.67¢	$0.8720	1.1374%
Minimum Rate:	$0.00	0.67¢	$0.0067	1.1374%
Receipt Point to Tok:				
Maximum Rate:	$31.37	0.81¢	$1.0393	1.3609%
Minimum Rate:	$0.00	0.81¢	$0.0081	1.3609%
Receipt Point to Alaska-Canada Border:				
Maximum Rate:	$35.55	0.92¢	$1.1780	1.5454%
Minimum Rate:	$0.00	0.92¢	$0.0092	1.5454%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Receipt Point to Livengood: 0.31¢

Receipt Point to Parks Highway Spur: 0.35¢

Receipt Point to Fairbanks: 0.35¢

Receipt Point to Delta Junction: 0.42¢

Receipt Point to Tok: 0.50¢

Receipt Point to Canadian Border: 0.57¢

ESTIMATED PERIOD TWO RECOURSE RATES

RATE SCHEDULE IT – INTERRUPTIBLE TRANSPORTATION

Note: Receipt Point means the inlet to the Alaska Mainline

	$/Dth	Fuel Retention Percentage
Receipt Point to Livengood:		
Maximum Rate:	$0.6523	0.8424%
Minimum Rate:	$0.0050	0.8424%
Receipt Point to Parks Highway Spur:		
Maximum Rate:	$0.7281	0.9444%
Minimum Rate:	$0.0056	0.9444%
Receipt Point to Fairbanks:		
Maximum Rate:	$0.7336	0.9518%
Minimum Rate:	$0.0056	0.9518%
Receipt Point to Delta Junction:		
Maximum Rate:	$0.8720	1.1374%
Minimum Rate:	$0.0067	1.1374%
Receipt Point to Tok:		
Maximum Rate:	$1.0393	1.3609%
Minimum Rate:	$0.0081	1.3609%
Receipt Point to Alaska-Canada Border:		
Maximum Rate:	$1.1780	1.5454%
Minimum Rate:	$0.0092	1.5454%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Receipt Point to Livengood: 0.31¢

Receipt Point to Parks Highway Spur: 0.35¢

Receipt Point to Fairbanks: 0.35¢

Receipt Point to Delta Junction: 0.42¢

Receipt Point to Tok: 0.50¢

Receipt Point to Canadian Border: 0.57¢

Item 7 - Estimated 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;"

This item addresses recourse rates. Negotiated rates are presented in Item 9.

The estimated capital cost of the facilities in billions of 2009 U.S. dollars is shown in the following table.

Estimated Capital Cost of Facilities (Billions of 2009 U.S. Dollars)

	Transmission Lines		**GTP**	**Mainline**		**Total, GTP + Mainline**
	Prudhoe Bay Transmission Line	Point Thomson Transmission Line		Alaska	Canada	
Estimated Capital Cost	0.1	0.8	**12.2**	**10.4**	**12.5**	**35.1**

The estimated cost of service is detailed in Exhibit H.

The estimated rate of return and capitalization are detailed in Exhibit I.

The estimated rate design volumes represent a 100% load factor and are detailed in Exhibit J.

Rates for Alaska Mainline transportation are distance-sensitive and reasonably reflect material variations in the cost of providing service due to the distance over which transportation service will be provided (*see* 18 C.F.R. § 284.10(c)(3)).

The recourse rate principles and calculation methodology are shown in Exhibit B to the Proposed Precedent Agreement (Appendix A). Intangible and General Plant (capital) is allocated among services on a gas plant account basis. Administrative & General Expense is allocated among services using the Commission-approved Kansas-Nebraska method.

Item 8 - Estimated 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 paragraph (c)(1) of this section, 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;"

Estimated unbundled distance-sensitive transportation rates for delivery points within the State of Alaska are presented in Item 6 for recourse rates and in Item 9 for negotiated rates.

Cost of service and rate design details supporting recourse rates are presented in Item 7.

Cost of service and rate design details supporting negotiated rates are presented in Item 9.

These estimated transportation rates are based on the costs to make such in-state deliveries and do not include costs to make deliveries outside the State of Alaska.

Item 9 - Negotiated and Other Rate Options

18 C.F.R. § 157.34(c)(9): "Negotiated rate and other rate options under consideration, including any rates and terms of any precedent agreement with prospective anchor shippers that have been negotiated or agreed to outside of the open season process prescribed in this section;"

Denali is offering a negotiated rate option as an alternative to recourse rates. Denali intends that these rates will recover all of Denali's annual cost of service. Denali will recover 80% of the depreciation over the initial 20-year term. Denali intends to recover the total depreciation over the depreciable life of the project as determined by FERC.

Estimated cost of service is detailed in Exhibit K.

Estimated rate of return and capitalization is detailed in Exhibit L.

Estimated rate design volumes represent a 100% load factor and are detailed in Exhibit M.

Estimated negotiated reservation rates, usage rates, fuel retention percentages and other applicable charges and surcharges are detailed in the following pages. Estimated negotiated reservation rates, usage rates, fuel retention percentages, and other applicable charges and surcharges for all contract years are detailed in Exhibit N.

The rates presented in this Item 9 and attached exhibits are estimates of negotiated rates. Actual negotiated rates will be designed in accordance with the negotiated rate principles described in Exhibit C to the Proposed Precedent Agreement (Appendix A).

As of the date of this filing, Denali has not entered into any pre-subscription agreements.

ESTIMATED NEGOTIATED RATES

RATE SCHEDULE FTR – FIRM TRANSMISSION

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)	Fuel Retention Percentage
Prudhoe Bay to GTP:				
Rate:	$0.15	0.00¢	Note 1	0.0%
Point Thomson to GTP:				
Rate:	$9.54	0.03¢	Note 1	0.0%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Prudhoe Bay to GTP: 0.003¢

Point Thomson to GTP: 0.19¢

Note 1: The negotiated AOS rate shall be the recourse AOS rate.

ESTIMATED NEGOTIATED RATES

RATE SCHEDULE FGT – FIRM GAS TREATMENT

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate ($/Dth)
Rate:	$23.09	3.51¢	Note 1

Fuel Retention Percentage: 2.5662%

Dismantlement, Restoration, and Removal Surcharge: 2.96¢/Dth

Note 1: The negotiated AOS rate shall be the recourse AOS rate.

Note 2: This rate also applies to the gas delivered to the GTP Treated Gas Return delivery point identified in Item 1.

ESTIMATED NEGOTATIATED RATES

RATE SCHEDULE FC – FIRM COMPRESSION

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)
Rate:	$8.08	0.80¢	Note 1

Fuel Retention Percentage: 1.5794%

Dismantlement, Restoration, and Removal Surcharge: 0.38¢/Dth

Note 1: The negotiated AOS rate shall be the recourse AOS rate.

ESTIMATED NEGOTIATED RATES

RATE SCHEDULE FT – FIRM TRANSPORTATION

Note: Receipt Point means the inlet to the Alaska Mainline

	Monthly Reservation Rate ($/Dth/Month)	Usage Rate (¢/Dth)	AOS Rate ($/Dth)	Fuel Retention Percentage
Receipt Point to Livengood:				
Rate:	$16.49	0.50¢	Note 1	0.8424%
Receipt Point to Parks Highway Spur:				
Rate:	$18.39	0.56¢	Note 1	0.9444%
Receipt Point to Fairbanks:				
Rate:	$18.52	0.56¢	Note 1	0.9518%
Receipt Point to Delta Junction:				
Rate:	$21.99	0.67¢	Note 1	1.1374%
Receipt Point to Tok:				
Rate:	$26.18	0.81¢	Note 1	1.3609%
Receipt Point to Alaska-Canada Border:				
Rate:	$29.66	0.92¢	Note 1	1.5454%

Dismantlement, Restoration, and Removal Surcharge (¢/Dth)

Receipt Point to Livengood: 0.31¢

Receipt Point to Parks Highway Spur: 0.35¢

Receipt Point to Fairbanks: 0.35¢

Receipt Point to Delta Junction: 0.42¢

Receipt Point to Tok: 0.50¢

Receipt Point to Canadian Border: 0.57¢

Note 1: The negotiated AOS rate shall be the recourse AOS rate.

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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;"

A key feature of Denali's design is the unbundling of its services. As illustrated in the table of specifications below, Denali will take gas at the inlet to the transmission lines, at the inlet to the GTP, at the inlet to the compression and chilling section of the GTP (for those Shippers who do not require gas treating), and directly into the mainline (for those Shippers who do not require any GTP services). Shippers will pay for only those services they require. The specifications for receipt of gas into Denali's facilities are summarized in the tables below.

The gas specifications shown below for the inlet to the GTP gas treating facilities have a carbon dioxide limit of 13 mole %. However, Denali will accept gas with a higher percentage of carbon dioxide on an as-available basis.

Denali will not require potential shippers to process or treat their gas at any designated plant or facility, including the Denali GTP. For complete Tariff provisions related to gas quality, refer to the Indicative FERC Gas Tariff (Exhibit G).

Prudhoe Bay and Point Thomson Transmission Lines

Characteristic of Received Gas	Maximum Value	Minimum Value
The Gas shall be commercially free from dust, sand, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the Transmission Line, regulators, meters, or other equipment.	NA	NA
Hydrogen Sulfide	90 ppmv	NA
Other Sulfur Compounds, with Gas composition adjusted to 2 mole % Carbon Dioxide	12 ppmv	NA

Characteristic of Received Gas	Maximum Value	Minimum Value
Methyl Mercaptan (included in Other Sulfur Compounds), with Gas composition adjusted to 2 mole % Carbon Dioxide	0.22 grains per Ccf	NA
Oxygen	0.1 mole %	NA
Carbon Dioxide[1]	13.0 mole %	NA
Total Inert Substances (other than Carbon Dioxide), with Gas composition adjusted to 2 mole % Carbon Dioxide	2.0 mole %	NA
Water Vapor	0.3 pounds per MMscf	NA
C6+ Hydrocarbon Components	0.05 mole %	NA
Cricondenbar	1,200 psia	NA
Temperature – Prudhoe Bay Transmission Line	80 Degrees F	45 degrees F
Temperature – Point Thomson Transmission Line	100 Degrees F	90 degrees F
Gross Heating Value, with composition adjusted to 2 mole % Carbon Dioxide	NA	967 Btu per scf
The Gas shall not contain any component or mix of components that may cause the presence of any liquid anywhere in the Denali's facilities under normal operating conditions.	NA	NA

[1] Gas with Carbon Dioxide content in excess of 13 mole % will be accepted into the Transmission Lines and GTP at Denali's discretion, applied in a not unduly discriminatory manner, to the extent GTP treating capacity is available without pro-rating shippers who meet the carbon dioxide inlet specifications.

Gas Treatment Plant (Inlet to Treating Service)

Characteristic of Received Gas	Maximum Value	Minimum Value
The Gas shall be commercially free from dust, sand, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the Gas Treatment Plan, regulators, meters, or other equipment.	NA	NA
Hydrogen Sulfide	90 ppmv	NA
Other Sulfur Compounds, with Gas composition adjusted to 2 mole % Carbon Dioxide	12 ppmv	NA
Methyl Mercaptan (included in Other Sulfur Compounds), with Gas composition adjusted to 2 mole % Carbon Dioxide	0.22 grains per Ccf	NA
Oxygen	0.1 mole %	NA
Carbon Dioxide[1]	13.0 mole %	NA
Total Inert Substances (other than Carbon Dioxide), with Gas composition adjusted to 2 mole % Carbon Dioxide	2.0 mole %	NA
C6+ Hydrocarbon Components	0.05 mole %	NA
Cricondenbar	1,200 psia	NA
Temperature	80 Degrees F	45 degrees F
Gross Heating Value, with composition adjusted to 2 mole % Carbon Dioxide	NA	967 Btu per scf

[1] Gas with Carbon Dioxide content in excess of 13 mole % will be accepted into the Transmission Lines and GTP at Denali's discretion, applied in a not unduly discriminatory manner, to the extent GTP treating capacity is available without pro-rating shippers who meet the carbon dioxide inlet specifications.

Gas Treatment Plant (Inlet to Compression Service) and Alaska Mainline

Characteristic of Received Gas	Maximum Value	Minimum Value
The Gas shall be commercially free from dust, sand, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the Gas Treatment Plant, pipeline, regulators, meters, or other equipment.	NA	NA
Hydrogen Sulfide	4 ppmv	NA
Total Sulfur	16 ppmv	NA
Methyl Mercaptan (included in Total Sulfur	0.22 grains per Ccf	NA
Oxygen	0.4 mole %	NA
Carbon Dioxide	2.0 mole %	NA
Total Inert Substances (including Carbon Dioxide)	4.0 mole %	NA
Water Vapor	0.8 pounds per MMscf	NA
C6+ Hydrocarbon Components	0.05 mole %	NA
Cricondenbar	1,200 psia	NA
Temperature – Inlet to GTP Compression	80 Degrees F	45 degrees F
Temperature – Alaska Mainline Downstream of GTP	30 Degrees F	20 degrees F
Gross Heating Value	NA	967 Btu per scf
The Gas shall not contain any component or mix of components that may cause the presence of any liquid anywhere in the Denali's facilities under normal operating conditions.	NA	NA

Item 11 - Terms and Conditions

18 C.F.R. § 157.34(c)(11): "Terms and conditions for each service offered;"

Denali's terms and conditions for each service offered are specified in the Indicative FERC Gas Tariff (Appendix C, Exhibit G).

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;"

Denali's creditworthiness standards are specified in Section 9.4 of the Proposed Precedent Agreement (Appendix A). Among other things, the creditworthiness provisions of the Proposed Precedent Agreement require shippers to meet tangible net worth and minimum credit rating requirements or provide collateral. In the event the shipper is the State of Alaska or is otherwise supported by the full faith and credit of the State of Alaska, the shipper will be deemed to have satisfied the tangible net worth requirement so long as the State of Alaska satisfies the applicable credit rating requirements.

Denali believes these creditworthiness standards along with no minimum volume requirement will encourage maximum participation by producers and explorers in Denali's open season.

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 sign binding precedent agreements before the close of the open season and obtain all requisite internal approvals to perform their obligations under the Precedent Agreement by February 1, 2011. After all potential shippers that have submitted signed Precedent Agreements provide evidence of all requisite internal approvals related to the Precedent Agreements, Denali intends to execute such Precedent Agreements within 30 days.

Item 14 - Bid Valuation

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;"

All conforming bids for firm service accepted by Denali in this open season will be valued on an equal basis for the purposes of awarding capacity. Denali will not differentiate among conforming bids for purposes of valuation on the basis of chosen delivery points within or outside the State of Alaska.

Denali may choose to accept non-conforming bids in a not unduly discriminatory manner if capacity is available. Denali will provide an explanation to any prospective shipper who submits a non-conforming bid rejected by Denali.

Item 15 – Oversubscription Allocation

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;"

If Denali receives bids for more capacity than is available in the open season, Denali may re-design the Alaska Project to accommodate all bids accepted by Denali for firm service within the feasible design capacity determined by Denali, taking into account economic, engineering, design, capacity, and operational constraints and potential impacts on the timely development of the Alaska Project. In the event bids accepted by Denali for firm service received from shippers during the open season exceed the feasible design capacity or Denali chooses not to re-design the Alaska Project, Denali shall award capacity in the following order:

- First, to conforming bids;
- Next, to capacity secured in pre-subscription agreements pursuant to 18 C.F.R. § 157.34(c)(15); and
- Last, to non-conforming bids that are acceptable to Denali.[1]

Capacity awarded for each category listed above, to the extent capacity exists, will be handled on a pro-rata basis among all prospective shippers within the same category. Section 4.2 of the Proposed Precedent Agreement (Appendix A) describes the allocation process in further detail.

As of the date of this filing, Denali has not entered into any pre-subscription agreements with any prospective shippers.

[1] For purposes of the requirement that all capacity subject to the terms and conditions of pre-subscription agreements be allocated prior to allocating capacity bid for in the open season, Denali will consider capacity awarded to non-conforming bids as capacity awarded outside the open season process.

Item 16 – Bid Requirements and Post-Open Season Process

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 binding Precedent Agreements from shippers for firm service for natural gas transportation, optional transmission, and optional GTP services.

Required Bid Information

The bidding shipper shall submit the information required in Exhibit A of the Proposed Precedent Agreement (Appendix A). Required bid information is applicable to all prospective shippers.

Binding or Non-Binding

Bids submitted in Denali's open season are binding commitments.

Receipt and Delivery Point Requirements

Receipt and delivery point requirements are described in the Proposed Precedent Agreement (Appendix A). To the extent a shipper desires receipt or delivery points other than those listed in Exhibit A to the Proposed Precedent Agreement, all such points and the MDQ for each point must be specified. For Shipper delivery and receipt points not identified on Exhibit A to the Precedent Agreement, Shipper should indicate whether or not the Precedent Agreement is contingent upon Denali's accommodation of such selected points. Denali will inform the requesting shipper whether Denali can accommodate such requested points and, in Denali's sole discretion, may accept or reject, in whole or in part, any bid which contains such contingencies. Denali's acceptance or rejection will be made in a not unduly discriminatory manner.

Precedent Agreements

The Proposed Precedent Agreement is attached in Appendix A of Denali's Open Season Plan filing. Potential shippers must sign binding Precedent Agreements before the close of the open season and must obtain all requisite internal approvals to perform their obligations under the Precedent Agreement by February 1, 2011.

Conforming and Non-Conforming Bids

In order to qualify as a conforming bid, a shipper's bid must include a signed Precedent Agreement with the information required by Exhibit A of the Precedent Agreement and must be received by Denali by the close of the open season.

A shipper may add conditions precedent to the Precedent Agreement without necessarily rendering a bid non-conforming. Any bid not meeting the above requirements or containing conditions precedent that materially change the terms of the Precedent Agreement will be considered a non-conforming bid. Shippers submitting non-conforming bids will be contacted within 10 days of submission of the bid information to confirm the nature of non-conformance.

Post-Open Season Process

Denali will issue indicative open season results to all shippers 30 days after the close of open season.

If required, post open season discussions with shippers will continue for up to 90 days after the close of the open season, at which time final Precedent Agreements will be issued to shippers, including capacity reservations. Shippers must obtain all requisite internal approvals to perform their obligations under the Precedent Agreement by February 1, 2011. After all shippers that have submitted signed Precedent Agreements provide evidence of all requisite internal approvals related to the Precedent Agreements, Denali intends to execute such Precedent Agreements within 30 days.

Denali reserves the right to change the timing described above on a not unduly discriminatory basis.

Item 17 – Project Certificate Application Date

18 C.F.R. § 157.34(c)(17): "The projected date for filing an application with the Commission;"

Denali's projected date for filing its application is the 4^{th} quarter of 2013.

Item 18 - Information Disclosure and Data Room Procedures

18 C.F.R. § 157.34(c)(18): "All information that the prospective applicant has in its possession pertaining to the proposed 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 any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;"

Denali has established Shipper Reading Rooms that will contain information regarding the initial Project, including the information required by 18 C.F.R. § 157.34(c)(18). Denali will have the SRR in Anchorage open on April 12, 2010 and will have the SRRs in Calgary and Houston open shortly thereafter.

The Shipper Reading Rooms will contain information that Denali has in its possession pertaining to the proposed services to be offered, projected Alaska Mainline capacity and design, proposed tariff provisions, and cost projections that Denali has made available to, or obtained from, any potential shipper, including any affiliates of Denali, prior to the issuance of the Denali Open Season Notice. The Shipper Reading Rooms will also include information on the Canada Mainline.

In addition to the Shipper Reading Rooms, Denali's public website (www.denalipipeline.com) will contain public information related to Denali's open season and is accessible by any interested person.

Due to the sensitive nature of the information placed in the Shipper Reading Rooms, all information in the Shipper Reading Rooms that is not in the public domain must be treated as confidential. Access to the Shipper Reading Rooms will be limited to representatives of regulatory agencies with jurisdiction over this open season process and potential shippers and their reviewers. Potential shippers who have not executed a Confidentiality Agreement with Denali that would apply to the information in the Shipper Reading Rooms must sign Denali's Shipper Reading Room Confidentiality Agreement (Exhibit E), and each potential shipper or regulatory agency representative seeking access to the Shipper Reading Rooms must comply with the applicable Denali Shipper Reading Room Procedures (Exhibit F) to gain access to the Shipper Reading Rooms.

For ease of use, Denali has structured its Shipper Reading Rooms through a dual virtual and physical room approach. A Virtual Shipper Reading Room (maintained by a third party custodian) will contain Denali's Open Season Plan materials, the Implementation Procedures for Standards of Conduct, as well as Denali's communications with potential shippers. Three separate and geographically dispersed Physical Shipper Reading Rooms will contain additional information.

- **Public Website –** Public information will be accessible through Denali's public internet website (www.denalipipeline.com) and will be available for review by interested persons. The available information will include the Denali Open Season Plan and the Implementation Procedures for Standards of Conduct.

- **Virtual Shipper Reading Room –** Potential shippers and their reviewers who have signed Denali's Shipper Reading Room Confidentiality Agreement and comply with Denali's Shipper Reading Room Procedures may request access to the Virtual Shipper Reading Room. The Virtual Shipper Reading Room will contain Denali's communications with potential shippers as well as the Denali Open Season Plan and the Implementation Procedures for Standards of Conduct.

- **Physical Shipper Reading Rooms –** Potential shippers and their reviewers who have signed Denali's Shipper Reading Room Confidentiality Agreement and comply with Denali's Shipper Reading Room Procedures may request access to three Physical Shipper Reading Rooms. The Physical Shipper Reading Rooms will contain information in electronic format and hard copy.

The Physical Shipper Reading Rooms will contain both public and commercially sensitive information, including historical reference data, technical work product documents, design basis information, cost estimates, and affiliate email correspondence. All of the Physical Shipper Reading Rooms will contain the same information.

- **Third-Party Confidentiality Restrictions -** Certain information in the Physical Shipper Reading Rooms is subject to third-party confidentiality restrictions. This information will only be made available to those who have obtained a release from, or signed a confidentiality agreement with, such third parties.

- **Physical Shipper Reading Room Locations –** Physical Shipper Reading Rooms will be located in Anchorage, Alaska; Calgary, Alberta; and Houston, Texas.

Information regarding scheduling appointments to visit the Physical Shipper Reading Rooms or obtaining access to the Virtual Shipper Reading Room is contained in the Denali Shipper Reading Room Procedures (Exhibit F).

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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 affiliates involved in the production of natural gas in the State of Alaska. Affiliated unit means 'Affiliate' as defined in § 358.3(a) of this chapter. Marketing units and or affiliates are those conducting a 'marketing function' as defined in section 358.3(c) of this chapter, except that the exemption in 358.3(c(2)(iii) shall not apply;"

The prospective applicant is Denali – The Alaska Gas Pipeline LLC (Denali). Denali is a Delaware limited liability company jointly and equally owned by BP Alaska Gas Pipelines LLC and ConocoPhillips Denali Company. The names and addresses of Denali's affiliated sales and marketing units and affiliates involved in the production of natural gas in the State of Alaska are identified below.

Affiliates Involved in the Production of Natural Gas in the State of Alaska:

BP Exploration (Alaska) Inc.
900 E. Benson Blvd.
Anchorage, AK 99508

ConocoPhillips Alaska, Inc.
700 G Street
P.O. Box 100360
Anchorage, AK 99510

Sales and Marketing Units:

BP America Production Company
501 Westlake Park Boulevard
Houston, Texas 77079

BP Energy Company
501 Westlake Park Boulevard
Houston, TX 77079

BP Canada Energy Company
240 4th Avenue S.W.
Calgary, Alberta T2P 4H4

BP Canada Energy Marketing Corp.
4101 Winfield Road
Warrenville, IL 60555

BP Canada Energy Resources Company
240 – 4th Avenue S.W.
Calgary, Alberta T2P 4H4

IGI Resources, Inc.
501 Westlake Park Boulevard
Houston, TX 77079

ConocoPhillips Company
Global Gas & Power and Global Strategy and Commercial
600 North Dairy Ashford Road
Houston, TX 77079

ConocoPhillips Canada Marketing and Trading ULC
1600, 401- 9th Avenue SW
Calgary, AB   T2P 3C5
Canada

ConocoPhillips Western Canada
1600, 401- 9th Avenue SW
Calgary, AB   T2P 3C5
Canada

ConocoPhillips Canada Energy Partnership
1600, 401- 9th Avenue SW
Calgary, AB   T2P 3C5
Canada

ConocoPhillips Canada (BRC) Partnership
1600, 401- 9th Avenue SW
Calgary, AB   T2P 3C5
Canada

ConocoPhillips Canada Surmont Partnership
1600, 401- 9th Avenue SW
Calgary, AB   T2P 3C5
Canada

ConocoPhillips Canada Resources Corp.
1600, 401- 9th Avenue SW
Calgary, AB T2P 3C5
Canada

ConocoPhillips Canada Operations, Ltd.
1600, 401- 9th Avenue SW
Calgary, AB T2P 3C5
Canada

Phillips Petroleum Resources, Ltd.
1600, 401- 9th Avenue SW
Calgary, AB T2P 3C5
Canada

Phillips Petroleum Canada Ltd.
1600, 401- 9th Avenue SW
Calgary, AB T2P 3C5
Canada

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 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 affiliates involved in the production of natural gas in the State of Alaska;"

Denali's parent corporations are BP Alaska Gas Pipelines LLC and ConocoPhillips Denali Company.

The corporate structure of the marketing and sales units and affiliates involved in the production of natural gas in the State of Alaska or the marketing or sales of natural gas are identified below in Table A-1 for BP Alaska Gas Pipelines LLC and Table A-2 for ConocoPhillips Denali Company.

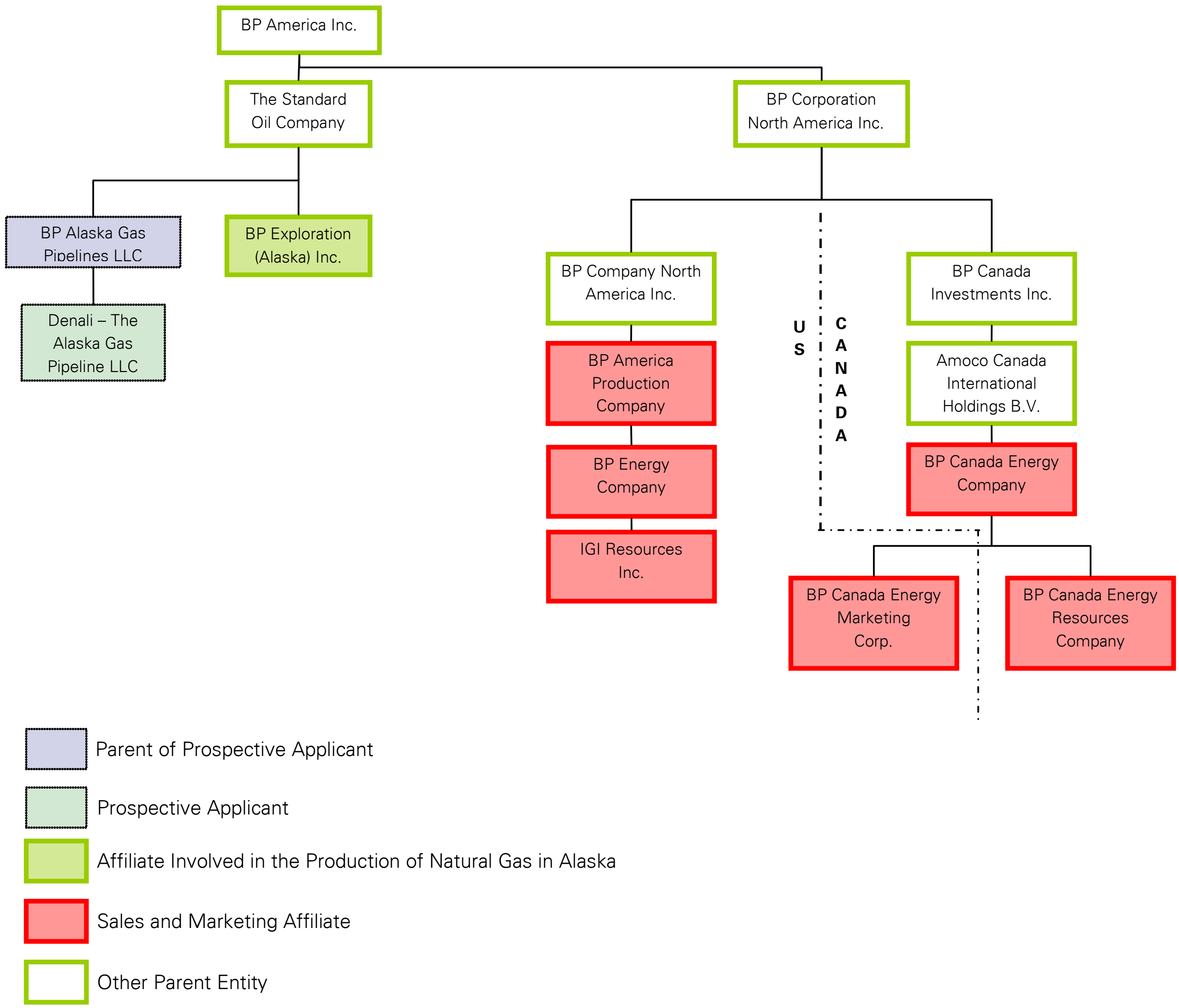
The job titles and descriptions, and chain of command for all officers and directors of Denali's affiliated marketing and sales units and production affiliates involved in the production of natural gas in the State of Alaska are identified below in Table B-1A (Production Affiliate) and Table B-1B (Marketing and Sales Units) for BP Alaska Gas Pipelines LLC and Table B-2A (Production Affiliate) and B-2B (Marketing and Sales Units) for ConocoPhillips Denali Company.

Table A-1

Corporate Structure of BP Marketing and Sales Units

And Production Affiliates

[18 CFR §157.34 (c) (20) (i)]

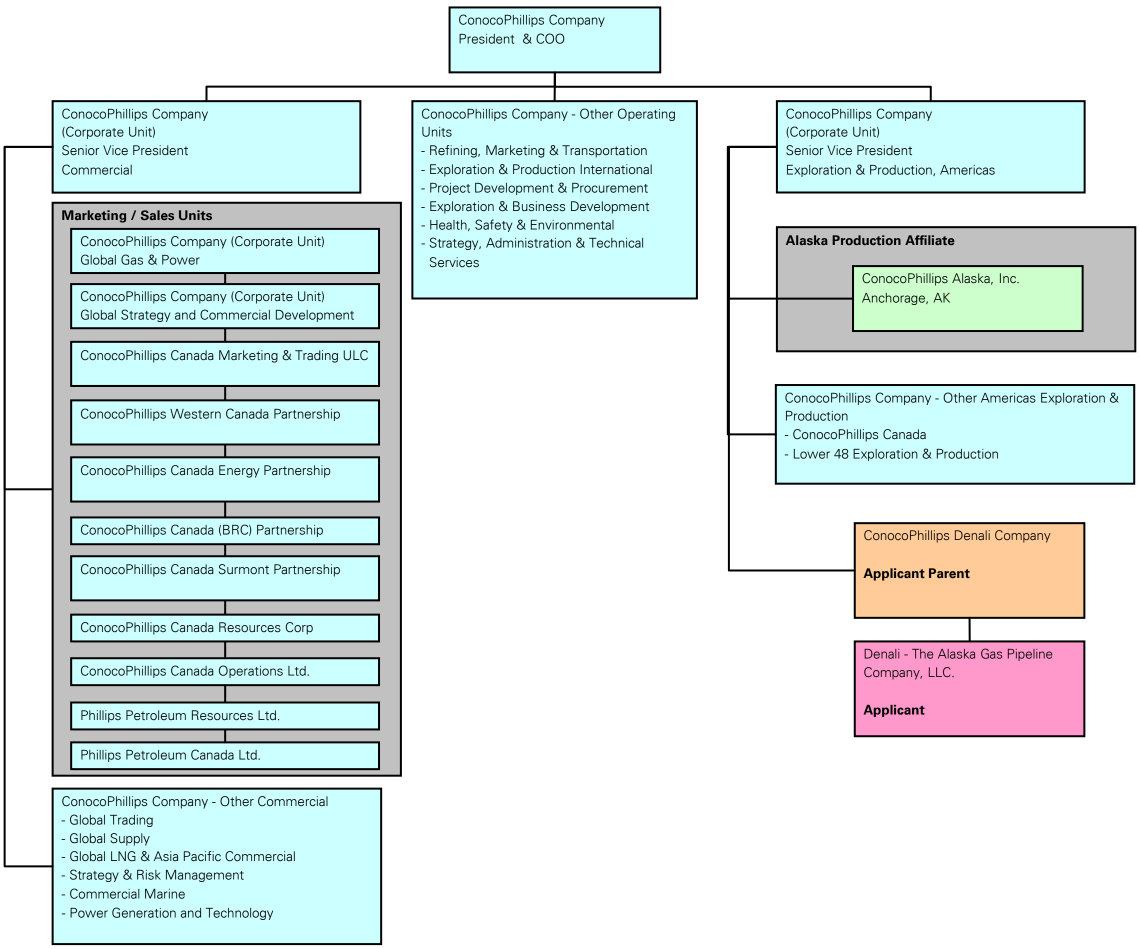


Notes: BP Exploration (Alaska) Inc. is involved in the sale of de minimus volumes of natural gas for local use on the North Slope. Arrangements for the transportation and marketing of gas produced by BP's Alaska production affiliate, which may be shipped through Denali, are being handled by BP's marketing affiliates. With the exception of a small number of employees within BP's Alaska production affiliate, who support BP's marketing affiliate in this effort and are considered as marketing function employees, none of the other employees of BP's Alaska production affiliate are marketing function employees.

This organization structure was implemented prior to the adoption of Order 2005-B and the issuance of the Commission's subsequent order providing additional clarification of its intent in Docket No. PF 09-11-001 (March 31, 2010). This structure may be more restrictive in some ways than would be required if wholly fashioned to correspond to the employee functional approach that now applies to conducting Alaska open seasons. In any case, BP's implementation will follow the applicable Standards of Conduct as now imposed in Order 2005-B, as further clarified in the March 31 and any subsequent orders.

Table A-2

Corporate Structure of ConocoPhillips Marketing and Sales Units and Production Affiliates
[18 CFR §157.34 (c) (20) (i)]
ConocoPhillips Affiliate Structure, Chain of Command



Notes:
All of the North Slope production is produced and owned by ConocoPhillips Alaska, Inc. ConocoPhillips Alaska, Inc. also sells de minimus volumes of gas for local use on the North Slope of Alaska and ConocoPhillips Company also produces and sells some gas volumes from leases it owns in the Cook Inlet in Alaska.

Marketing function of ConocoPhillips Canada reports functionally through Global Gas and Power. Arrangements for the transportation and marketing of gas produced by ConocoPhillips Alaska, Inc., which may be shipped through Denali, are being coordinated by ConocoPhillips marketing affiliates. A small number of employees within ConocoPhillips Alaska, Inc. support ConocoPhillips marketing affiliates with this effort.

This organization structure was implemented prior to the effectiveness of Order 2005-B and the Commission's subsequent order providing additional clarification of its intent in Docket No. PF09-11-001 dated March 31, 2010 and may be more restrictive in some ways than would be required if wholly fashioned to correspond to the employee functional approach that now applies to conducting open seasons. In any case, ConocoPhillips Company intends to fully comply with the applicable Standards of Conduct in the FERC Open Season Rules as modified by Order 2005-B and clarified by FERC's March 31, 2010 order in Docket No. PF09-11-001.

Table B-1A
BP Alaska Production Affiliate
Job Titles, Descriptions, and Chain of Command [18 CFR §157.34 (c) (20) (ii)]
BP Exploration (Alaska) Inc.

Officers	
Title	**Job Description**
President	SPUL / President, BPXA
Sr. Vice President	VP HSSE & Engineering
Sr. Vice President	VP Resource
Sr. Vice President	CFO, Alaska SPU
Sr. Vice President	VP Operations
Vice President	VP of Developments
Vice President	Senior Attorney, US Corporate Secretary
Vice President	Senior Attorney
Vice President & Chief Financial Officer	VP, Structured Finance, Western Hemisphere & CFO, BP America
Vice President & General Tax Officer	Vice President & General Tax Officer
Vice President	Vice President C&EA
Vice President	VP Drilling & Completions
Treasurer	Director, Operations
Secretary	Paralegal
Tax and Royalty Officer	Senior Tax Manager - E&P
Tax Officer	Head of US Income Tax Compliance, Audit and Financial Reporting
Tax Officer	Manager, Tax Planning
Tax Officer	Manager NA Production Taxes & Royalties
Tax Officer	Assoc. Gen. Tax Counsel-Corp, State & Intl. Plan
Tax Officer	Manager, Production Tax & Royalties Alaska
Assistant Secretary	Senior Paralegal
Assistant Secretary	Sr. Environmental Attorney
Assistant Secretary	Sr. Paralegal
Assistant Secretary	Assistant General Counsel
Assistant Treasurer	Manager Treasury Ops
Assistant Treasurer	Manager, Cash and Banking Services Operations
Assistant Treasurer	Manager, Treasury Operations
Assistant Treasurer	Senior Operations Manager
Assistant Treasurer	Project Manager
Assistant Treasurer	Manager, Treasury Services
Directors	
Title	**Job Description**
Director	Senior Attorney, US Corporate Secretary
Director	Paralegal
Director	Senior Paralegal

Table B-1B

BP Sales and Marketing Units and Affiliates
Job Titles, Descriptions and Chain of Command [18 CFR §157.34 (c) (20) (ii)][11]

BP Energy Company

Officers	
Title	**Job Description**
President	Head of Supply & Trading
Vice President	Chief Commercial Officer
Vice President & General Tax Officer	Senior Tax Manager- E&P
Vice President	Head of Marketing & Trading, South
Vice President	Chief Commercial Officer
Vice President	SVP Midwest Marketing & Origination
Vice President	CCO- LNG Americas, SVP- NGL M&O
Vice President	Senior Vice President- Marketing & Origination
Vice President	Vice President of Business Development
Vice President	COO- NGLs, Power and Financial Products
Vice President	Senior Attorney, US Corporate Secretary
Vice President	Senior Attorney
Chief Financial Officer	CFO- IST Gas SPU
Treasurer	Director, Operations
Secretary	Paralegal
Tax Officer	Head of US Income Tax Compliance, Audit and Financial Reporting
Assistant Secretary	Senior Paralegal
Assistant Secretary	Managing Attorney
Assistant Secretary	Assistant General Counsel, IST, N.A
Assistant Secretary	Managing Attorney
Assistant Treasurer	Manager, Cash and Banking Services
Assistant Treasurer	Manager, Treasury Operations
Directors	
Title	**Job Description**
Director	Senior Attorney, US Corporate Secretary
Director	Paralegal
Director	Senior Paralegal

[11] 18 C.F.R. §157.34(c)(20)(ii) requires the listing of the job titles and descriptions, and chain of command of the prospective applicant's marketing and sales units. BP Energy Company is a sales and marketing unit of BP, not the prospective applicant, however this information is provided for completeness.

Table B-1C

BP Sales and Marketing Units and Affiliates

Job Titles, Descriptions, and Chain of Command [18 CFR 157.34(c) (20) (ii)][12]

BP Canada Energy Company

Officers	
Title	**Job Description**
President and Chief Executive Officer	President & CEO
Chief Operating Officer	Chief Operating Officer
Senior Vice President	COO North American Gas, Calgary (Designate, Calgary)
Senior Vice President	SVP WCan M&O
Senior Vice President	SVP Midwest Marketing & Origination
Senior Vice President	SVP, Global Oil Trading Canada
Vice President	VP Operation
VP, NGL Business Development & Integration	VP NGL Business Development & Integration
Vice President	VP Transportation and Operations
Vice President	VP, Origination
Vice President	Commercial Manager – NAGP
Vice President	Canada NGL Manager
Vice President	Vice President, Oil Sands
Chief Financial Officer	CFO
Corporate Secretary	Senior Legal Counsel
Assistant Corporate Secretary	Sr Legal Counsel
Assistant Corporate Secretary	Senior Legal Counsel
Assistant Corporate Secretary	Corporate Paralegal
Directors	
Title	**Job Description**
Director	Senior Legal Counsel

[12] 18 C.F.R. §157.34(c)(20)(ii) requires the listing of the job titles and descriptions, and chain of command of the prospective applicant's marketing and sales units. BP Canada Energy Company is a sales and marketing unit of BP, not the prospective applicant, however this information is provided for completeness.

Table B-1D

BP Sales and Marketing Units and Affiliates

Job Titles, Descriptions and Chain of Command [18 CFR §157.34 (c) (20) (ii)][13]

BP Canada Energy Resources Company

Officers	
Title	**Job Description**
President and Chief Executive Officer	President & CEO
Chief Operating Officer	Chief Operating Officer
Senior Vice President	COO North American Gas, Calgary (Designate, Calgary)
Vice President	VP of Operations
VP, NGL Business Development & Integration	VP, NGL Business Development & Integration
Vice President	CCO - LNG Americas, SVP - NGL M&O
Vice President	Canada NGL Manager
Vice President	Vice President, Oil Sands
Chief Financial Officer	CFO
Corporate Secretary	Senior Legal Counsel
Assistant Corporate Secretary	Sr Legal Counsel
Assistant Corporate Secretary	Senior Legal Counsel
Assistant Corporate Secretary	Corporate Paralegal
Directors	
Title	**Job Description**
Director	Senior Legal Counsel

[13] 18 C.F.R. §157.34(c)(20)(ii) requires the listing of the job titles and descriptions, and chain of command of the prospective applicant's marketing and sales units. BP Canada Energy Resources Company is a sales and marketing unit of BP, not the prospective applicant, however this information is provided for completeness.

Table B-1E

BP Sales and Marketing and Units and Affiliates

Job Titles, Descriptions and Chain of Command [18 CFR §157.34(c) (20) (ii)][14]

BP Canada Energy Marketing Corp.

Officers	
Title	**Job Description**
President	COO North American Gas, Calgary(Designate, Calgary)
Senior Vice President	SVP WCan M&O
Senior Vice President	SVP, Global Oil Trading Canada
Vice President	Head of Marketing & Trading, South
Vice President	Senior Attorney, US Corporate Secretary
Vice President	VP Operation
Vice President	Senior Attorney
Vice President	Senior Attorney
VP, NGL Business Development & Integration	VP NGL Business Development & Integration
Vice President	VP Transportation and Operations
Vice President	VP, Origination
Vice President	SVP Midwest Marketing & Origination
Vice President	President - Midwest Region
Vice President	Director of Sulphur Sales
Vice President	CCO - LNG Americas, SVP - NGL M&O
Vice President	Canada NGL Manager
Vice President	COO-NGLs, Power & Financial Products
US Tax Officer Compliance, Audit Reporting	Head of US Income Tax Compliance, Audit and Financial Reporting
Commercial Manager	Commercial Manager – NAGP
Secretary	Paralegal
Assistant Secretary	Sr. Paralegal
Assistant Secretary	Managing Attorney
Assistant Secretary	Senior Paralegal
Assistant Secretary	North Region Finance Manager
Assistant Secretary	Managing Attorney
Directors	
Title	**Job Description**
Director	Senior Attorney, US Corporate Secretary

[14] 18 C.F.R. §157.34(c)(20)(ii) requires the listing of the job titles and descriptions, and chain of command of the prospective applicant's marketing and sales units. BP Canada Energy Marketing Corp. is a sales and marketing unit of BP, not the prospective applicant, however this information is provided for completeness.

Table B-1F

BP Sales and Marketing Units and Affiliates

Job Titles, Descriptions and Chain of Command [18 CFR §157.34(c) (20) (ii)][15]

IGI Resources, Inc.

Officers	
Title	**Job Description**
President	President IGI Resources, Inc.
Vice President & Chief Financial Officer	VP, Structured Finance, Western Hemisphere & CFO, BP America
Vice President & General Tax Officer	Vice President & General Tax Officer
Vice President, Marketing & Operations	Vice President - Marketing & Risk Mgmt
Vice President	Head of Marketing & Trading, South
Vice President	Head of Supply & Trading
Vice President	Senior Vice President - Mktg & Origination
Vice President	Senior Attorney, US Corporate Secretary
Vice President	Senior Attorney
Treasurer	Director, Operations
Assistant Secretary	Controller
Tax Officer	Head of US Income Tax Compliance, Audit and Financial Reporting
Tax Officer	Senior Tax Manager - E&P
Tax Officer	Assoc. Gen. Tax Counsel - Corp, State & Intl. Plan
Secretary	Paralegal
Assistant Secretary	Sr. Paralegal
Assistant Secretary	Managing Attorney
Assistant Secretary	Senior Paralegal
Assistant Secretary	Assistant General Counsel, IST, N.A.
Assistant Secretary	Controller
Assistant Secretary	Managing Attorney
Assistant Treasurer	Mgr Treasury Operations
Assistant Treasurer	Manager, Cash and Banking Services
Assistant Treasurer	Manager, Treasury Operations
Assistant Treasurer	Senior Operations Manager
Assistant Treasurer	Project Manager
Assistant Treasurer	Manager, Treasury Services
Directors	
Title	**Job Description**
Director	Senior Attorney, US Corporate Secretary
Director	Paralegal
Director	Senior Paralegal

[15] 18 C.F.R. §157.34(c)(20)(ii) requires the listing of the job titles and descriptions, and chain of command of the prospective applicant's marketing and sales units. IGI Resources, Inc. is a sales and marketing unit of BP, not the prospective applicant, however this information is provided for completeness.

Table B-1G

BP Sales and Marketing Units and Affiliates

Job Titles, Descriptions and Chain of Command [18 CFR §157.34(c) (20) (ii)][16]

BP America Production Company

Officers	
Title	**Job Description**
President	Head of Portfolio & Technology
Vice President & Chief Financial Officer	VP, Structured Finance, Western Hemisphere & CFO, BP America
Vice President & General Tax Officer	Vice President & General Tax Officer
Vice President	Head of Marketing & Trading, South
Vice President	Senior Vice President – GoM SPU
Vice President	Vice President Project Appraisal
Vice President	Global Product Control Head
Vice President	SPUL Southern Cone
Vice President	Chief Information Officer
Vice President	VP, Westlake Property Management
Vice President	Assistant General Counsel, North America Gas
Vice President	Head of Supply and Trading
Vice President	Vice President – GoM Production
Vice President	Gasoline Global Commodity Head
Vice President	CFO, North America Gas
Vice President	Head of Supply and Trading
Vice President	Technology VP Research
Vice President	Vice President
Vice President	Chief Operating Officer - Developments
Vice President	Chief Operating Officer - Production
Vice President	Director GOI Americas
Vice President	Sr. Vice President – North America Gas
Vice President	Technology Vice President
Vice President	Chief Financial Officer – GoM SPU
Vice President	Senior Attorney, US Corporate Secretary
Vice President	Senior Attorney
Vice President	Head of Origination & Marketing
Treasurer	Director, Operations

[16] 18 C.F.R. §157.34(c)(20)(ii) requires the listing of the job titles and descriptions, and chain of command of the prospective applicant's marketing and sales units. BP America Production Company is a sales and marketing unit of BP, not the prospective applicant, however this information is provided for completeness.

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the alaska gas pipeline

Table B-1Continued

Officers	
Title	**Job Description**
Secretary	Paralegal
Tax Officer	Head of US Income Tax Compliance, Audit and Financial Reporting
Tax Officer	Manager, US Tax Audits and Appeals
Tax Officer	Manager, North America Production Tax & Royalties
Tax Officer	Senior Tax Manager - E&P
Assistant Secretary	Senior Paralegal
Assistant Secretary	Manager, Excise Tax
Assistant Secretary	Managing Attorney – Global Corporate (M&A)
Assistant Secretary	Sr. Paralegal
Assistant Secretary	Assistant General Counsel, IST, N.A.
Assistant Secretary	Assistant General Counsel
Assistant Secretary	Managing Attorney
Assistant Secretary	Managing Attorney
Assistant Secretary	Managing Attorney
Assistant Treasurer	Manager, Treasury Operations
Assistant Treasurer	Manager, Cash and Banking Services
Assistant Treasurer	Manager, Treasury Operations
Assistant Treasurer	Senior Operations Manager
Assistant Treasurer	Project Manager
Assistant Treasurer	Manager, Treasury Services
Directors	
Title	**Job Description**
Director	Senior Attorney, US Corporate Secretary
Director	Paralegal
Director	Senior Paralegal

Table B-2A

ConocoPhillips Alaska Production Affiliate

Job Titles and Descriptions for Officers and Directors [18 CFR 157.34(c) (20) (ii)]

ConocoPhillips Alaska, Inc.

Officers	
Title	**Job Description**
President	President
Vice President	General Counsel
Vice President	North Slope Development and Operations
Vice President	Human Resources
Vice President	Commercial Assets
Vice President	External Affairs
Vice President	Exploration
Vice President	Finance
Vice President	Health, Safety and Environment
General Counsel	Attorney
Vice President and Treasurer	Treasurer
Assistant Treasurer	Treasury
Assistant Treasurer	Treasury
General Tax Officer	General Tax Officer
Tax Administration Officer	Tax Compliance
Assistant Tax Administration Officer	Tax Compliance
Secretary	Paralegal
Assistant Secretary (8)	Paralegals/Administrative Assistants
Directors	
Title	**Job Description**
Director	President
Director	Vice President
Director	Vice President

Table B-2B

ConocoPhillips Marketing and Sales Units and Affiliates

Job Titles and Descriptions for Officers and Directors [18 CFR 157.34(c) (20) (ii)]

ConocoPhillips Company

Officers	
Title	**Job Description**
President	President
Manager	Global Strategy & Commercial Development
Manager	US Gas Marketing & Trading
Manager	US Power Marketing & Trading
Manager	Origination
Manager	Canadian Gas & Power
Manager	European Gas & Power

ConocoPhillips Canada Marketing and Trading ULC

Officers	
Title	**Job Description**
President	President
Vice President	Canadian Gas and Power
Vice President	Crude Oil Marketing and Supply
Vice President	Western Canada Gas
Vice President	Finance
Vice President	General Counsel
Vice President	Strategy and Portfolio Management
Vice President and Treasurer	Treasurer
Assistant Treasurer (6)	Treasury
Controller	Controller
Secretary	Paralegal
Assistant Secretary (2)	Paralegals/Administrative Assistants
Directors	
Title	**Job Description**
Director	President
Director	Vice President
Director	Vice President
Director	Vice President
Director	Vice President

ConocoPhillips Western Canada Partnership

Managing Partner
ConocoPhillips Canada Resources Corp.

ConocoPhillips Canada Energy Partnership

Managing Partner
ConocoPhillips Canada Resources Corp.

ConocoPhillips Canada (BRC) Partnership

Managing Partner
ConocoPhillips Canada Operations Ltd.

ConocoPhillips Canada Surmont Partnership

Managing Partner
ConocoPhillips Canada Resources Corp.

ConocoPhillips Canada Resources Corp.

Officers	
Title	**Job Description**
President	President
Vice President	Crude Oil Marketing and Supply
Vice President	Western Canada Gas
Vice President	Finance
Vice President	General Counsel
Vice President	Strategy and Portfolio Management
Vice President	Exploration
Vice President	Canadian Arctic
Vice President	Canadian Capital Projects
Vice President	Human Resources
Vice President	Oil Sands
Vice President	Health, Safety and Environment
Vice President	Environment and Sustainable Development
Vice President and Treasurer	Treasurer
Assistant Treasurer (6)	Treasury
Controller	Controller
Secretary	Paralegal
Assistant Secretary (8)	Paralegals/Administrative Assistants
Directors	
Title	**Job Description**
Director	President
Director	Vice President
Director	Vice President
Director	Vice President
Director	Vice President

ConocoPhillips Canada Operations, Ltd.

Officers	
Title	**Job Description**
President	President
Vice President	Crude Oil Marketing and Supply
Vice President	Western Canada Gas
Vice President	Canadian Gas and Power
Vice President	Finance
Vice President	General Counsel
Vice President	Strategy and Portfolio Management
Vice President	Exploration
Vice President	Canadian Arctic
Vice President	Canadian Capital Projects
Vice President	Human Resources
Vice President	Oil Sands
Vice President	Health, Safety and Environment
Vice President	Environment and Sustainable Development
Vice President and Treasurer	Treasurer
Assistant Treasurer (6)	Treasury
Controller	Controller
Secretary	Paralegal
Assistant Secretary (8)	Paralegals/Administrative Assistants
Directors	
Title	**Job Description**
Director	President
Director	Vice President
Director	Vice President
Director	Vice President
Director	Vice President

Phillips Petroleum Resources, Ltd.

Officers	
Title	**Job Description**
President	President
Vice President	Canadian Gas and Power
Vice President	Western Canada Gas
Vice President	Finance
Vice President	General Counsel
Vice President	Strategy and Portfolio Management
Vice President and Treasurer	Treasurer
Assistant Treasurer (4)	Treasury
Controller	Controller
Secretary	Paralegal
Assistant Secretary (2)	Paralegals/Administrative Assistants
Directors	
Title	**Job Description**
Director	President
Director	Vice President
Director	Vice President
Director	Vice President

Phillips Petroleum Canada, Ltd.

Officers	
Title	**Job Description**
President	President
Vice President	Western Canada Gas
Vice President	Finance
Vice President	General Counsel
Vice President	Strategy and Portfolio Management
Vice President and Treasurer	Treasurer
Assistant Treasurer (4)	Treasury
Controller	Controller
Secretary	Paralegal
Assistant Secretary (2)	Paralegals/Administrative Assistants
Directors	
Title	**Job Description**
Director	President
Director	Vice President
Director	Vice President
Director	Vice President
Director	Vice President

Item 21 - Officer and Director Statement

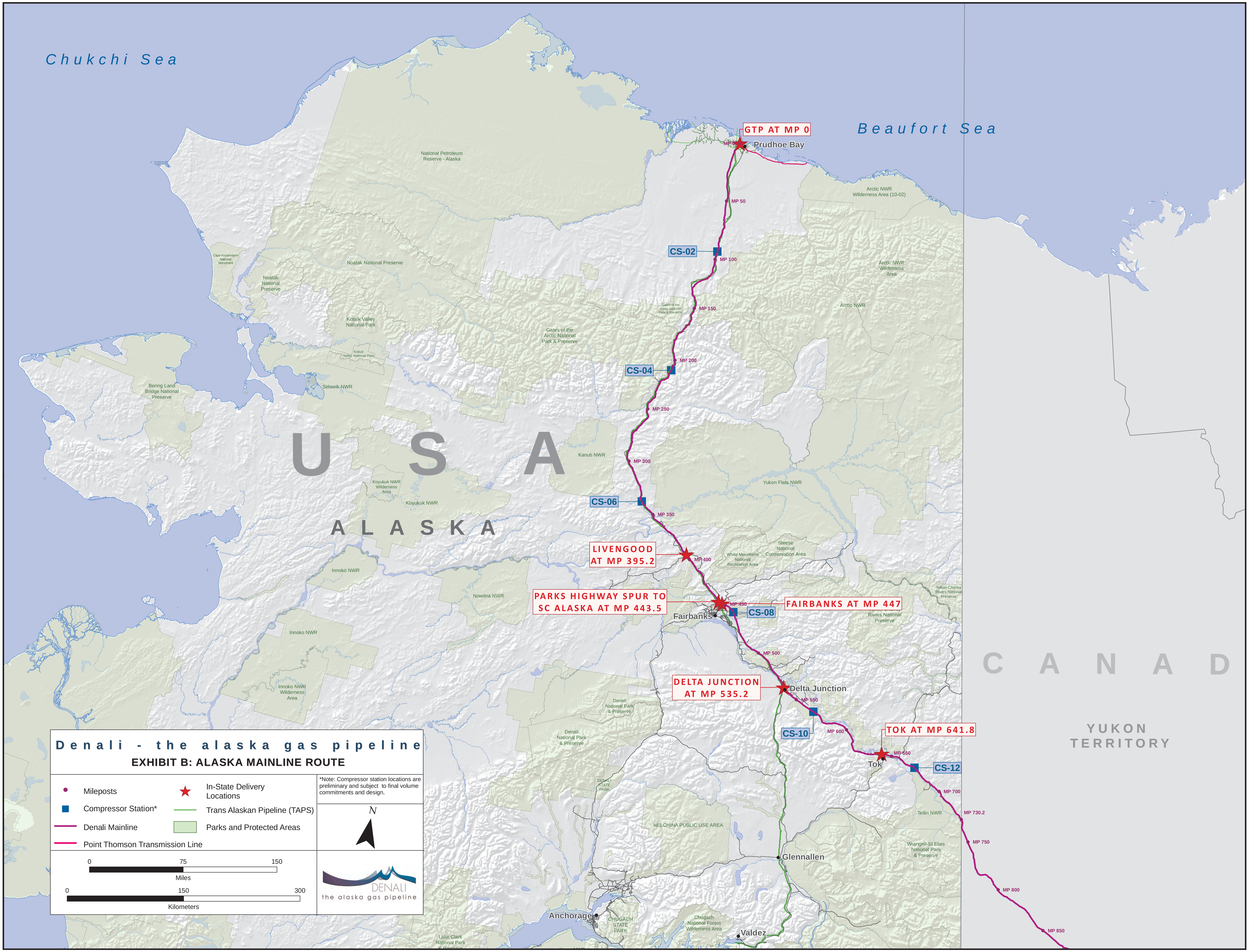
18 C.F.R. § 157.34(c)(21): "A statement that any officers and directors of the prospective applicant's affiliated sales and marketing units and affiliates involved in the production of natural gas in the State of Alaska named in paragraph (c)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the open season Internet website or that is otherwise also available to the general public or other participants in the open season."

BP America Inc. (BP) and ConocoPhillips Denali Company (ConocoPhillips), on behalf of themselves and Denali's affiliated sales and marketing units and affiliates involved in the production of natural gas in the State of Alaska have taken action to implement compliance procedures and Standards of Conduct to fully comply with FERC Orders 2005 et al. and ensure that proprietary information about the conduct of the open season and allocation of capacity is managed appropriately.

Specifically, officers and directors of BP's and ConocoPhillips' affiliated sales and marketing units and affiliates involved in the production of natural gas in Alaska named in response to 18 CFR §157.34(c)(19), 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 otherwise also available to the general public or other participants in the open season.[17]

[17] In the context of FERC Order No. 2005-B, BP and ConocoPhillips understand this statement to require that BP and ConocoPhillips implement procedures which prohibit those officers and directors, as well as other employees, who are "marketing function employees," as that term is defined in the Commission's regulations, 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 otherwise also available to the general public or other participants in the open season.

Denali - the alaska gas pipeline
EXHIBIT A: GTP AND TRANSMISSION LINES
Mileposts
Denali Mainline
Point Thomson Transmission Line
Prudhoe Bay Transmission Line
Gas Treatment Plant
Proposed GTP Access Road
North Slope Infrastructure
Existing Pipelines
Primary Road
Secondary Roads
Pad Outline
N
DENALI
the alaska gas pipeline
Miles
0
2.5
5
10
Kilometers
0
5
10
20
Miles
0
0.5
1
2
Kilometers
0
1
2
4
Prudhoe Bay
WDSP
NORTH PRUDHOE BAY 2
ABEL STATE 1
TERM WELL A
WEST BEACH STATE
AGI
LGI
DSL1
K PAD
DISCOVERY WELL PB STATE 1
WGI
NGI
CGF
CCP
EAST DOCK
MP 0
PRUDHOE BAY TRANSMISSION LINE
MP 62
MP 61
MP 1
POINT THOMSON TRANSMISSION LINE
DSL2
T3C
DS18
PUT 23 MINE SITE
DS15
MP 60
MP 2
GTP
MP 5
MP 10
Foggy Island Bay
Mikkelsen Bay
POINT THOMSON TRANSMISSION LINE
POINT THOMSON UNIT #1
POINT THOMSON UNIT #3
NORTHSTAR
RESOLUTION ISLAND
ENDEAVOR ISLAND MPI
DENALI



Chukchi Sea
Beaufort Sea
GTP AT MP 0
Prudhoe Bay
MP 50
CS-02
MP 100
MP 150
CS-04
MP 200
MP 250
MP 300
CS-06
MP 350
LIVENGOOD AT MP 395.2
MP 400
PARKS HIGHWAY SPUR TO SC ALASKA AT MP 443.5
FAIRBANKS AT MP 447
MP 450
CS-08
Fairbanks
MP 500
DELTA JUNCTION AT MP 535.2
Delta Junction
MP 550
CS-10
MP 600
TOK AT MP 641.8
MP 650
Tok
CS-12
MP 700
MP 730.2
MP 750
MP 800
MP 850
Glennallen
Anchorage
Valdez
USA
ALASKA
CANADA
YUKON TERRITORY
National Petroleum Reserve - Alaska
Noatak National Preserve
Noatak National Preserve
Kobuk Valley National Park
Gates of the Arctic National Park & Preserve
Bering Land Bridge National Preserve
Selawik NWR
Kanuti NWR
Koyukuk NWR
Innoko NWR
Nowitna NWR
Innoko NWR Wilderness Area
Yukon Flats NWR
Arctic NWR
Arctic NWR Wilderness Area
Arctic NWR Wilderness Area (10-02)
Steese National Conservation Area
White Mountains National Recreation Area
Denali National Park & Preserve
Denali National Park & Preserve
NELCHINA PUBLIC USE AREA
Tetlin NWR
Wrangell-St Elias National Park & Preserve
Chugach National Forest Wilderness Area
CHUGACH STATE PARK
Lake Clark National Park & Preserve
Denali - the alaska gas pipeline
EXHIBIT B: ALASKA MAINLINE ROUTE
Mileposts
In-State Delivery Locations
Compressor Station*
Trans Alaskan Pipeline (TAPS)
Denali Mainline
Parks and Protected Areas
Point Thomson Transmission Line
*Note: Compressor station locations are preliminary and subject to final volume commitments and design.
N
0
75
150
Miles
0
150
300
Kilometers
DENALI
the alaska gas pipeline

Denali - the alaska gas pipeline
EXHIBIT C: CANADA MAINLINE ROUTE
Mileposts
Kilometer Post
Compressor Station
Denali Mainline
Park Boundaries
DENALI
the alaska gas pipeline
0
75
150
Miles
0
150
300
Kilometers
N
CANADA
YUKON TERRITORY
NORTHWEST TERRITORIES
BRITISH COLUMBIA
Gulf of Alaska
Fishing Branch
Tombstone
Ddhaw Ghro
Kluane Wildlife Sanctuary
Kluane National Park
Kusawa
Tatshenshini-Alsek Park
Atlin Park
Wood Buffalo (Alberta Portion)
Caribou Mountains Wildland
Northern Rocky Mountains Park
Denetiah Park
Dune Za Keyih Park
Muskwa-Kechika Management Area
Kwadacha Wilderness Park
Stikine River Park
Mount Edziza Park
Spatsizi Plateau Wilderness Park
Tatlatui Park
Chinchaga Wildland
HAINES JUNCTION
WHITEHORSE
WATSON LAKE
FORT NELSON
FORT ST JOHN
DAWSON CREEK
MP 700
KP 0
MP 750
CS-14
KP 100
MP 800
MP 850
KP 200
CS-16
MP 900
KP 300
MP 950
KP 400
MP 1000
CS-18
KP 500
MP 1050
MP 1100
CS-20
KP 600
MP 1150
KP 700
CS-22
MP 1200
MP 1250
KP 800
CS-24
KP 900
MP 1300
MP 1350
KP 1000
CS-26
MP 1400
KP 1100
MP 1450
CS-28
KP 1200
MP 1500
KP 1300
MP 1550
CS-30
MP 1600
KP 1400
MP 1650
KP 1500
MP 1700
KP 1600
MP 1750

Exhibit D
Denali Preliminary Finance Plan

Denali's finance plan covers three phases: development phase, construction phase and post-completion phase. Denali intends to finance the entire project, including the Transmission Lines, Gas Treatment Plant and the Mainline.

The development phase will be equity financed by the Denali owners, and during this phase Denali will focus on managing up-front risks including project risk, right-of-way access risk, capital access risk and credit risk. The goal of credit risk management is to minimize the cost of credit by targeting a long-term project rating of at least A-/A3. This is accomplished primarily by ensuring satisfactory creditworthiness of shippers making firm commitments to the project. To this end, Denali will require shippers to maintain a credit rating equal to or greater than BBB and meet an acceptable tangible net worth threshold.

During the construction phase, Denali intends to issue sufficient debt via securing bank commitments and issuing bonds which will bridge through to commercial operation and financial completion. Equity will be placed pro-rata with debt to fund the capital expenditures, providing an overall target debt equity ratio of 70/30 during the construction phase. At this stage, no distinction is made between financing the U.S. and the Canadian portions of the project. Once Denali completion has been achieved, the bank loan(s) are assumed to be taken out by issuances of bond debt. Denali will retain a short-term revolving credit facility to manage working capital, as necessary. Indications from financial institutions suggest that bank debt will be limited in terms of capacity and tenor.

Post-completion, the finance plan assumes Denali will be project-financed on a limited recourse basis to the Sponsors, with a leverage of 75/25 debt to equity.

The finance plan intends to optimize use the US Department of Energy (DOE) Federal Loan Guarantee (FLG) program enacted by the Alaska Natural Gas Pipeline Act of 2004 (ANGPA), assuming the terms and conditions, including costs, of the government guarantees are acceptable to Denali. Alternative sources of funding will be explored, such as Export Credit Agencies financing, US tax exempt financing and such other funding which may be available and cost efficient to the project. Intercreditor requirements and restrictions will be taken into account in developing the final debt profile.

Financing will rely heavily on the depth and capacity of the bond capital markets. To manage the bond portfolio and minimize negative carry, a multi-year bond program – consisting of numerous tranches of various tenors is likely to be used. Due to the limited capacity of FLGs under the current law compared with total forecasted project costs, some of the project bonds will not be covered by the guarantee and, accordingly, the related debt will carry a higher cost.

Interest rate assumptions in the finance 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

The specific credit terms, tenor, and rates associated with Denali's contemplated debt financing will depend upon financial market conditions at the time the debt is raised. In developing this finance plan, Denali has reviewed current financial market conditions, consulted with representatives of the banking community, and held discussions with various relevant government agencies. As issues associated with each element of the finance plan continue to be progressed, modifications to the finance plan may be required.

DENALI SHIPPER READING ROOM CONFIDENTIALITY AGREEMENT

This Denali Shipper Reading Room Confidentiality Agreement ("Agreement") is entered into between Denali - The Alaska Gas Pipeline, LLC ("Denali"), and ______________________ as a prospective qualified Alaska natural gas shipper

Shipper is seeking access to Denali's Shipper Reading Rooms (SRR). Denali and Shipper are individually called a "Party" and collectively called the "Parties."

Background

1. Denali is proposing to build an Alaska natural gas transportation project that will carry Alaska North Slope gas to North American natural gas markets (Project).

2. Shipper is interested in seeking additional information regarding Denali's open season and the Project and seeks access to Denali's SRR.

3. Denali has placed certain confidential information in its SRR and requires completion of this Confidentiality Agreement before access to the SRR will be granted.

Terms

Denali and Shipper agree as follows:

ARTICLE I – USE OF INFORMATION

Section 1.01. Permitted Use. Shipper may use Confidential Information only to evaluate Shipper's possible participation in the open season being conducted by Denali (Permitted Use). Without limiting the generality of the foregoing sentence, it is not a Permitted Use for Shipper to disclose any Confidential Information to:

(a) an Other Alaska Project;
(b) a Representative of such an entity; or
(c) a Representative of any political subdivision, department, institution, board, commission, division, authority, public corporation, council, committee, or other instrumentality of the State of Alaska or one of its municipalities that is involved in the oversight or development of a project licensed under the Alaska Gas Inducement Act.

ARTICLE II – CONFIDENTIALITY

Section 2.01. Obligation to Maintain Confidentiality. During the term of this Agreement, Shipper shall, and shall use reasonable efforts to cause its Representatives to, keep Confidential

Information confidential. Without limiting the effect of the previous sentence, Shipper shall not, and shall use reasonable efforts to cause its Representatives not to:

(a) disclose any of the Confidential Information to any person, except
  (i) with the prior written consent of Denali; or
  (ii) as permitted by Section 2.03; or

(b) use any of the Confidential Information in any way other than in connection with the Permitted Use.

Section 2.02. Unauthorized Use. Shipper shall give prompt notice to Denali of any unauthorized use or disclosure of Confidential Information and shall assist Denali in remedying the unauthorized use or disclosure. Any assistance does not waive any breach of this Agreement by a Shipper, nor does acceptance of the assistance constitute a waiver of any breach of this Agreement.

Section 2.03. Permitted Disclosees. Shipper may disclose Confidential Information only to a Representative who:

(a) requires the Confidential Information for the Permitted Use; and
(b) is informed of the confidential nature of the Confidential Information.

Section 2.04. Exceptions to Obligation to Maintain Confidentiality. Shipper is not required to keep confidential any Confidential Information that:

(a) was or becomes generally publicly available other than as a result of a disclosure by a Shipper or any of its Representatives in breach of this Agreement;
(b) was in the lawful possession of a Shipper or any of its Representatives before its provision by or on behalf of Denali; or
(c) was or becomes available to a Shipper or any of its Representatives on a non-confidential basis from a third party that is not bound by a similar obligation of confidentiality (contractual, legal, fiduciary, or otherwise).

Section 2.05. No License or Interest in Information. Nothing in this Agreement is to be interpreted or construed as a grant or as an intention to grant any right, title, license, or interest in or to any Confidential Information provided under this Agreement.

Section 2.06. Shipper Representative SRR Access. Any representative of Shipper who wishes to access Denali's SRRs must sign the Denali Shipper Reading Room Confidentiality Acknowledgment attached as Attachment 1 and comply with the Denali Shipper Reading Room Procedures attached as Attachment 2

Section 2.07. Critical Energy Infrastructure Information. Certain documents in Denali's SRR contain Critical Energy Infrastructure Information. Shipper acknowledges that it has a valid or legitimate need for the Critical Energy Infrastructure Information, which may only be used for the Permitted Use, and shall be kept confidential in accordance with the terms of this Agreement.

ARTICLE III – TERM, TERMINATION, AND SURVIVAL

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Section 3.01. Term. This Agreement is effective upon signature. Except as otherwise agreed by the Parties in writing, this Confidentiality Agreement terminates on October 31, 2020.

ARTICLE IV – INDEMNITY, DISPUTES, REMEDIES

Section 4.01. Indemnity. Shipper shall indemnify and defend Denali, any of its Affiliates, and any of Denali's and its Affiliates' Representatives against all damages, losses, claims, costs, liabilities, obligations, or expenses (including reasonable legal fees and the reasonable cost of enforcing this indemnity) made by a third party against Denali, arising out of or relating to any unauthorized use or threatened use or disclosure or threatened disclosure by Shipper or any of its Representatives of the Confidential Information or any other breach of this Agreement.

Section 4.02. Governing Law and Venue.

(a) *Governing Law.* The laws of the State of Alaska (without giving effect to its conflict of laws principles) govern all matters arising out of or relating to this Agreement, including its interpretation, construction, performance, and enforcement.

(b) *Venue.* A Party may bring any action under this Agreement only in the Superior Court for the State of Alaska, Third Judicial District, at Anchorage, Alaska.

Section 4.03. Disclaimer of Warranties. The Confidential Information is made available on an "as is" basis. Denali makes no express warranty, and disclaims all implied warranties, regarding the Confidential Information, including any warranty about the accuracy or completeness of the Confidential Information. Shipper fully releases Denali for all damages, losses, claims, costs, liabilities, obligations, or expenses (including reasonable legal fees) incurred as a result of its reliance upon, or any action or inaction by Shipper or any of its Representatives regarding, the Confidential Information. Nothing contained in the Confidential Information is to be, or may be, relied upon as a promise or representation or warranty, whether about the past, present or future.

Section 4.04. Injunctive Relief. Shipper acknowledges that:

(a) an award of money damages is inadequate for any breach of this Agreement by a Shipper or any of its Representatives; and
(b) any breach causes Denali irreparable harm.

Accordingly, if Shipper or any of its Representatives breaches or threatens to breach this Agreement, Denali is entitled to equitable relief, including injunctive relief and specific performance, without the posting of a bond or other security and without proof of actual damages. Denali may pursue injunctive relief in addition to any other remedies at law or equity for the breach of this Agreement.

Section 4.05. Limitation on Damages. In no event is any Party liable to any other Party for the following damages, however caused, that arise out of or relate to this Agreement or any breach of it:

(a) any consequential or incidental damages, including lost profits; or

(b) any special or punitive damages.

A Party shall neither claim nor, if awarded, collect any of these prohibited damages from any other Party in any proceeding arising out of or relating to this Agreement or any breach of it.

ARTICLE V – RELATIONSHIP AND COMMUNICATIONS BETWEEN THE PARTIES

Section 5.01. Relationship of the Parties and Non-Binding Nature.

(a) *No Partnership or Joint Venture.* Nothing in this Agreement or any action by the Parties under this Agreement alone or in conjunction with any other agreement, document, or course of conduct constitutes, or may be construed to constitute, a partnership, joint venture, or any other cooperative relationship, including a fiduciary relationship between the Parties.

(b) *Non-Binding Nature.* Furnishing Confidential Information does not constitute an offer by either Party to enter into an agreement to transport gas on the Project. Nothing in this Agreement is to be interpreted or construed to create any obligation to:

(i) enter into any business dealings;

(ii) negotiate in good faith;

(iii) use any efforts to enter into any agreement; or

(iv) hold or continue to hold discussions regarding the Project.

Section 5.02. Announcements. Neither Party may make a public announcement or press release about this Agreement without the other's written approval.

ARTICLE VI – PARTS OF THE AGREEMENT

Section 6.01. Amendments. The Parties may amend this Agreement only by a written document that identifies itself as an amendment to this Agreement and that is signed by each of the Parties.

Section 6.02. No Waiver. A Party may consent to or waive any breach or default by another Party only by Notice. The Notice does not operate as a consent or waiver of any future default by the same Party.

Section 6.03. Severability. If any part of this Agreement is held indefinite, invalid, or otherwise unenforceable, the rest of the Agreement terminates, and none of the other parts of this Agreement is enforceable against any Party except as provided in Article IV.

Section 6.04. Complete Agreement. This Agreement constitutes the final agreement between the Parties. It is the complete and exclusive expression of the Parties' agreement on the matters contained in this Agreement. All prior and contemporaneous negotiations and agreements between the Parties on the matters contained in this Agreement are merged into and superseded by this Agreement.

Section 6.05. Counterparts. This Agreement may be executed in identical counterpart originals, each of which constitutes an original, and all of which, collectively, constitute only one agreement.

Section 6.06. Attachments. Any Attachment to this Agreement is fully incorporated into this Agreement.

Section 6.07. Defined Terms. Defined terms have the meaning described in Attachment 3.

ARTICLE VII – INTERPRETATION OF THE AGREEMENT

Section 7.01. Construction Against the Drafter. In entering into this Agreement, no Party has relied upon any statement, representation, warranty, or agreement of any other Party except for those provided in this Agreement. This Agreement is the product of the Parties' joint efforts, and it is not to be construed against any Party as drafter.

Section 7.02. Captions. The descriptive captions of the articles, sections, and subsections of this Agreement are for convenience only and do not constitute part of this Agreement. They do not affect this Agreement's construction or interpretation and do not indicate that all of the provisions of this Agreement relating to any topic are to be found in any particular article, section, or subsection.

Denali – The Alaska Gas Pipeline LLC

By: ______________________________

Name: ___________________________

Title: ____________________________

Date: ____________________________

Shipper

By: ____________________________

Name: __________________________

Title: ___________________________

Date: ___________________________

ATTACHMENT 1

**DENALI SHIPPER READING ROOM
CONFIDENTIALITY ACKNOWLEDGMENT**

To: Denali – The Alaska Gas Pipeline LLC (Denali)

I, ____________________ (Reviewer) acknowledge that during my review of the Denali Shipper Reading Room (SRR) materials associated with the open season being conducted by Denali (Open Season Review), I will have access, directly and indirectly, to Confidential Information.

I. Use and Confidentiality of Information

1. I acknowledge that I have read and understand the Confidentiality Agreement between Denali and Shipper (Confidentiality Agreement).

2. 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 that I represent, specifically ____________________ (Shipper).

3. I shall hold all Confidential Information I obtain in the course of my Open Season Review confidential until October 31, 2020. I shall not disclose Confidential Information to any person that is not a permitted disclosee under the Confidentiality Agreement. But I may disclose Confidential Information if I demonstrate it is publicly available as of the date of this Acknowledgment other than as a result of a disclosure in violation of this Acknowledgment.

4. Without Denali's prior written consent, I may use Confidential Information only to evaluate Shipper's possible participation in the open season being conducted by Denali.

5. Certain documents in Denali's SRR contain Critical Energy Infrastructure Information. I acknowledge that I have a valid or legitimate need for the Critical Energy Infrastructure Information which I shall keep confidential in accordance with the terms of this Acknowledgment.

II. Competitive Advantage

I acknowledge that Confidential Information which I obtain may consist of confidential commercial, technical, or financial information that enables Denali to obtain or maintain a competitive position. If I am unsure whether any information is subject to this

Acknowledgment, I will ask Denali to determine the applicability of this Acknowledgment to the information and I shall abide by Denali's determination.

III. Damages for Breach of Confidentiality

I acknowledge that an award of money damages is inadequate for any breach of the confidentiality provisions of this Acknowledgment and any breach causes Denali irreparable harm. Accordingly, if I breach or threaten to breach this Acknowledgment, Denali is entitled to equitable relief, including injunctive relief and specific performance, without the posting of a bond or other security and without proof of actual damages. Denali may pursue injunctive relief in addition to any other remedies at law or equity for the breach of this Acknowledgment.

In no event is any Party liable to any other Party for the following damages, however caused, that arise out of or relate to this Acknowledgement or any breach of it:

(a) any consequential or incidental damages, including lost profits; or

(b) any special or punitive damages.

A Party shall neither claim nor, if awarded, collect any of these prohibited damages from any other Party in any proceeding arising out of or relating to this Acknowledgment or any breach of it.

IV. Disclaimer of Warranties

I acknowledge that the Confidential Information is made available on an "as is" basis. Denali makes no express warranty, and disclaims all implied warranties, regarding the Confidential Information, including any warranty about the accuracy or completeness of the Confidential Information. Shipper fully releases Denali for all damages, losses, claims, costs, liabilities, obligations, or expenses (including reasonable legal fees) incurred as a result of its reliance upon, or any action or inaction by Shipper or any of its representatives regarding, the Confidential Information. Nothing contained in the Confidential Information is to be, or may be, relied upon as a promise or representation or warranty, whether about the past, present or future.

V. Further Undertaking

During the course of my Open Season Review, I agree to be bound by and to conduct my review in accordance with the Denali Shipper Reading Room Procedures, attached as Attachment 2.

By: ________________________________

Printed Name: _______________________

Title: ________________________________

Representing: ________________________

Date: ________________________________

ATTACHMENT 2

Denali Shipper Reading Room Procedures

Eligible Parties

1. A potential shipper (Shipper) is eligible to access a Denali Shipper Reading Room if it meets the following creditworthiness standards:
   a) the Shipper's long-term unenhanced senior unsecured debt securities are rated at least BBB by Standard & Poor's, or at least Baa2 by Moody's Investors Service, Inc., in each case with a stable or better outlook, or
   b) the Shipper has a tangible net worth of at least $300 million.
2. If the Shipper is the State of Alaska (State), is guaranteed by the State, or otherwise is supported by the full faith and credit of the State, the Shipper is deemed to have satisfied the tangible net worth requirement set forth in Section 1.b); provided that the State satisfies the requirements of Section 1.a).
3. A Shipper who cannot meet the creditworthiness standards stated in Sections 1.a) or 1.b) may provide a guarantee or collateral in a form acceptable to Denali at Denali's sole discretion.
4. Regulatory agencies with jurisdiction over the Open Season process are eligible to access a Denali Shipper Reading Room.

General Requirements

1. To access a Denali Shipper Reading Room (SRR) (either Virtual or Physical), an eligible party (described above) must submit all required documents via email to lieza.wilcox@denalipipeline.com or via regular mail to the following address:

   Denali Commercial Department
   188 Northern Lights Boulevard. Suite 1300
   P.O. Box 241747
   Anchorage, AK 99524-1747.

   The required documents are:
   a) An executed Confidentiality Agreement between Shipper and Denali, which requires Shipper to maintain the confidentiality of the information in the SRR;
   b) Documents for each of the eligible party's reviewers (Reviewer):
      (1) An executed acknowledgment wherein the Reviewer agrees to maintain the confidentiality of the information in the SRR in accordance with the terms of the Confidentiality Acknowledgement specified above, and
      (2) Contact information, including each Reviewer's first and last name, title, address, phone number, and email address; and
   c) Documents showing the Shipper's creditworthiness qualifications (not applicable to regulatory agencies).

Eligible parties may contact the Denali Commercial department with questions about the SRRs at (907) 865-4759.

2. After reviewing the required documents and performing any due diligence required, the Denali Commercial Department will notify the Shipper when the Shipper and its Reviewers have been approved to access the SRR and will provide contact information for the Reading Room Coordinators (RRC).

Physical SRRs

1. A Reviewer must call a RRC to schedule access to a Physical SRR. The Physical SRRs are located in Anchorage, Calgary, and Houston and may be accessed only during normal weekday business hours (8:00 AM – 4:30 PM local time) excluding holidays.

2. Each Reviewer must present a government-issued photo ID.

3. The RRC will issue each Reviewer a visitor label, which must be worn in a visible location.

4. Each Reviewer must check in and out with the RRC. Each Reviewer must notify the RRC when leaving the Physical SRR.

5. No photographs, video, copying, or other imaging of the contents of the Physical Reading Room will be allowed (*e.g.*, no use of cameras, copiers, scanners, portable faxes or similar technologies).

6. External network access, including wireless internet access, is prohibited.

7. Each Physical SRR can accommodate up to ten Reviewers at a time. Only one Shipper team will be allowed access to a Physical SRR at a time.

Virtual SRR

1. The Virtual SRR provider will send an email to each Reviewer. The email will contain the website address and the username and password needed to access the Virtual SRR via the internet. The username and password are specific to each Reviewer and cannot be used by any other person.

2. Confidential documents in the Virtual SRR will not be available for copying, downloading, or printing.

3. The Virtual SRR is available 24 hours per day, 7 days per week (except during system maintenance).

4. The Virtual SRR provides contact information for technical assistance.

ATTACHMENT 3

DEFINITIONS

Affiliate means a company, limited liability company, partnership, or other legal entity that Controls, is Controlled by, or is Controlled by an entity which Controls, a Party.

Confidential Information means:

(a) any information placed in Denali's SRR; and

(b) Derivative Material.

Control means the ownership, directly or indirectly, of ten percent or more of the shares, voting rights, or interest in a company, limited liability company, partnership, or other legal entity.

Critical Energy Infrastructure Information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

(a) relates details about the production, generation, transmission, or distribution of energy;

(b) could be useful to a person planning an attack on critical infrastructure;

(c) is exempt from mandatory disclosure under the Freedom of Information Act; and

(d) does not simply give the general location of the critical infrastructure.

Derivative Material means any note, analysis, study, summary, correspondence, or other material, however documented, containing or prepared from, in whole or in part, using any information defined in part (a) of the definition of Confidential Information.

Effective Date of the Agreement is the date upon which the Agreement is signed by the Shipper..

Other Alaska Project means any person or entity that has Control or a direct or indirect interest in an Alaska natural gas transportation project, other than the Denali Project, that will carry Alaska North Slope gas to North American natural gas markets, including any project licensed under the Alaska Gasline Inducement Act and any of the following legal entities or any of their Affiliates:

(a) Exxon Mobil Corporation, excluding the following of its divisions: ExxonMobil Gas & Power Marketing Company and ExxonMobil Production Company;
(b) TransCanada Corporation; and
(c) Alaska Gasline Port Authority.

Permitted Use means to evaluate Shipper's possible participation in the open season being conducted by Denali.

Representative means a reviewer, employee, secondee, agent, consultant, contractor, or other representative.

Exhibit F
Denali Shipper Reading Room Procedures

Eligible Parties

1. A potential shipper (Shipper) is eligible to access a Denali Shipper Reading Room if it meets the following creditworthiness standards:
   a) the Shipper's long-term unenhanced senior unsecured debt securities are rated at least BBB by Standard & Poor's, or at least Baa2 by Moody's Investors Service, Inc., in each case with a stable or better outlook, or
   b) the Shipper has a tangible net worth of at least $300 million.
2. If the Shipper is the State of Alaska (State), is guaranteed by the State, or otherwise is supported by the full faith and credit of the State, the Shipper is deemed to have satisfied the tangible net worth requirement set forth in Section 1.b); provided that the State satisfies the requirements of Section 1.a).
3. A Shipper who cannot meet the creditworthiness standards stated in Sections 1.a) or 1.b) may provide a guarantee or collateral in a form acceptable to Denali at Denali's sole discretion.
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   a) An executed Confidentiality Agreement between Shipper and Denali, which requires Shipper to maintain the confidentiality of the information in the SRR;
   b) Documents for each of the eligible party's reviewers (Reviewer):
      (1) An executed acknowledgment wherein the Reviewer agrees to maintain the confidentiality of the information in the SRR in accordance with the terms of the Confidentiality Acknowledgement specified above, and
      (2) Contact information, including each Reviewer's first and last name, title, address, phone number, and email address; and
   c) Documents showing the Shipper's creditworthiness qualifications (not applicable to regulatory agencies).

Eligible parties may contact the Denali Commercial department with questions about the SRRs at (907) 865-4759.

2. After reviewing the required documents and performing any due diligence required, the Denali Commercial Department will notify the Shipper when the Shipper and its Reviewers have been approved to access the SRR and will provide contact information for the Reading Room Coordinators (RRC).

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2. Each Reviewer must present a government-issued photo ID.

3. The RRC will issue each Reviewer a visitor label, which must be worn in a visible location.

4. Each Reviewer must check in and out with the RRC. Each Reviewer must notify the RRC when leaving the Physical SRR.

5. No photographs, video, copying, or other imaging of the contents of the Physical Reading Room will be allowed (*e.g.*, no use of cameras, copiers, scanners, portable faxes or similar technologies).

6. External network access, including wireless internet access, is prohibited.

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2. Confidential documents in the Virtual SRR will not be available for copying, downloading, or printing.

3. The Virtual SRR is available 24 hours per day, 7 days per week (except during system maintenance).

4. The Virtual SRR provides contact information for technical assistance.

Appendix C
Exhibit G

INDICATIVE FERC GAS TARIFF

of

DENALI – THE ALASKA GAS PIPELINE LLC

Filed with the

FEDERAL ENERGY REGULATORY COMMISSION

Communications Concerning this Tariff
Should Be Addressed to:

[Name]
[Title]
Denali - The Alaska Gas Pipeline LLC
188 W. Northern Lights Blvd., Suite 1300
P. O. Box 241747
Anchorage, Alaska 99524-1747
Telephone: (907) ___-_____
Facsimile: (907) ___-____

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PRELIMINARY STATEMENT

Denali – The Alaska Gas Pipeline LLC ("Transporter") operates an Alaska natural gas transportation system that treats and carries Alaska natural gas in interstate commerce to various points in the State of Alaska and to the border between Alaska and Canada, and includes all related facilities (such as the Gas Treatment Plant and any transmission lines) that are subject to the jurisdiction of the Federal Energy Regulatory Commission.

Transporter operates pursuant to one or more Certificates of Public Convenience and Necessity issued by the Commission. The currently effective Rate Schedules, General Terms and Conditions, and forms of Service Agreement applicable to the jurisdictional Services performed by Transporter are contained herein.

SYSTEM MAP

[System Map to be Provided]

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE FT – FIRM TRANSPORTATION)[1]

	Monthly Reservation Rate ($/Dth)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)	Fuel Requirement
Receipt Point to Livengood:				
Maximum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Minimum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Receipt Point to Parks Highway Spur:				
Maximum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Minimum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Receipt Point to Fairbanks:				
Maximum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Minimum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Receipt Point to Delta Junction:				
Maximum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Minimum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Receipt Point to Tok:				
Maximum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Minimum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Receipt Point to Canada Border:				
Maximum Rate:	$x.xx	x.x¢	x.x¢	x.x%
Minimum Rate:	$x.xx	x.x¢	x.x¢	x.x%

A rate in excess of the Maximum Rate shown above may be charged and collected for qualifying releases of firm Capacity pursuant to Article 23 (Capacity Release) of the General Terms and Conditions.

Rates under Rate Schedule FT are charged on the basis of Shipper’s MDQ and the Quantity of Gas delivered for Shipper’s Account (less the applicable Fuel Requirement) under the applicable Firm Transportation Agreement.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE IT – INTERRUPTIBLE TRANSPORTATION)[1]

Rate	Per Dth	Fuel Requirement
Receipt Point to Livengood:		
Maximum Rate:	xx.x¢	x.x%
Minimum Rate:	xx.x¢	x.x%
Receipt Point to Parks Highway Spur:		
Maximum Rate:	xx.x¢	x.x%
Minimum Rate:	xx.x¢	x.x%
Receipt Point to Fairbanks:		
Maximum Rate:	xx.x¢	x.x%
Minimum Rate:	xx.x¢	x.x%
Receipt Point to Delta Junction:		
Maximum Rate:	xx.x¢	x.x%
Minimum Rate:	xx.x¢	x.x%
Receipt Point to Tok:		
Maximum Rate:	xx.x¢	x.x%
Minimum Rate:	xx.x¢	x.x%
Receipt Point to Canada Border:		
Maximum Rate:	xx.x¢	x.x%
Minimum Rate:	xx.x¢	x.x%

Rates under Rate Schedule IT are charged on the basis of the Quantity of Gas delivered for Shipper’s Account (less the applicable Fuel Requirement) under the applicable Interruptible Service Agreement.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE FGT – FIRM GAS TREATING)[1]

	Monthly Reservation Rate ($/Dth)	AOS Rate (¢/Dth)	Usage Rate (¢/Dth)
Maximum Rate:	$x.xx	xx.x¢	xx.x¢
Minimum Rate:	$x.xx	xx.x¢	xx.x¢

Fuel Requirement: x.xx%

Rates under Rate Schedule FGT are charged on the basis of Shipper's MDQ and the Quantity of Gas delivered for Shipper's Account (less the applicable Fuel Requirement) under the applicable Gas Treating Agreement.

A rate in excess of the Maximum Rate shown above may be charged and collected for qualifying releases of firm Capacity pursuant to Article 23 (Capacity Release) of the General Terms and Conditions.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE IGT – INTERRUPTIBLE GAS TREATING)[1]

Maximum Rate: xx.xx¢/Dth

Minimum Rate: xx.xx¢/Dth

Fuel Requirement: x.xx%

Rates under Rate Schedule IGT are charged on the basis of the Quantity of Gas delivered for Shipper’s Account (less the applicable Fuel Requirement) under the applicable Gas Treating Agreement.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE FC – FIRM COMPRESSION)[1]

	Monthly Reservation Rate ($/Dth)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)
Maximum Rate:	$x.xx	x.x¢	x.x¢
Minimum Rate:	$x.xx	x.x¢	x.x¢

Fuel Requirement: x.x%

Rates under Rate Schedule FC are charged on the basis of Shipper's MDQ and the Quantity of Gas delivered for Shipper's Account (less the applicable Fuel Requirement) under the applicable Compression Agreement.

A rate in excess of the Maximum Rate shown above may be charged and collected for qualifying releases of firm Capacity pursuant to Article 23 (Capacity Release) of the General Terms and Conditions.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE IC – INTERRUPTIBLE COMPRESSION)[1]

Maximum Rate: xx.xx¢/Dth

Minimum Rate: xx.xx¢/Dth

Fuel Requirement: x.x%

Rates under Rate Schedule IC are charged on the basis of the Quantity of Gas delivered for Shipper’s Account (less the applicable Fuel Requirement) under the applicable Compression Agreement.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE FTR – FIRM TRANSMISSION)[1],[2]

	Monthly Reservation Rate ($/Dth)	Usage Rate (¢/Dth)	AOS Rate (¢/Dth)
Prudhoe Bay Transmission Receipt Point			
Maximum Rate:	$x.xx	x.x¢	x.x¢
Minimum Rate:	$x.xx	x.x¢	x.x¢
Point Thomson Transmission Receipt Point			
Maximum Rate:	$x.xx	x.x¢	x.x¢
Minimum Rate:	$x.xx	x.x¢	x.x¢

Fuel Requirement: x.x%

Rates under Rate Schedule FTR are charged on the basis of Shipper’s MDQ and the Quantity of Gas delivered for Shipper’s Account (less the applicable Fuel Requirement) under the applicable Transmission Agreement.

A rate in excess of the Maximum Rate shown above may be charged and collected for qualifying releases of firm Capacity pursuant to Article 23 (Capacity Release) of the General Terms and Conditions.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

[2] Rates for Transmission Service are charged on a postage-stamp basis.

CURRENTLY EFFECTIVE RATES
(RATE SCHEDULE ITR – INTERRUPTIBLE TRANSMISSION)[1],[2]

Prudhoe Bay Transmission Receipt Point

Maximum Rate: xx.xx¢/Dth

Minimum Rate: xx.xx¢/Dth

Fuel Retention Percentage: x.x%

Point Thomson Transmission Receipt Point

Maximum Rate: xx.xx¢/Dth

Minimum Rate: xx.xx¢/Dth

Fuel Requirement: x.x%

Rates under Rate Schedule ITR are charged on the basis of the Quantity of Gas delivered for Shipper’s Account (less the applicable Fuel Requirement) under the applicable Transmission Agreement.

[1] The charges shall be increased to include any applicable surcharges, including the Annual Charge Adjustment (ACA) pursuant to Article 29 (Annual Charge Adjustment) of the General Terms and Conditions, at a current rate of $0.000 per Dth.

[2] Rates for Transmission Service are charged on a postage-stamp basis.

STATEMENT OF NEGOTIATED RATES[1],[2],[3]

Shipper Name	Agreement Number	Rate Schedule	Contract MDQ	Reservation Rate	Usage Rate	AOS Rate	Receipt Point	Delivery Point	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 this 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 Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

Sheet Nos. 15-30 Are Reserved for Future Use

RATE SCHEDULE FT
FIRM TRANSPORTATION SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) Transporter’s existing facilities have sufficient capacity for the requested duration of Service and are able to provide such Transportation Service;

(b) Shipper has met Transporter’s creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Firm Transportation Agreement for Service under this Rate Schedule FT.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its system in order to provide Service hereunder to any Shipper.

RATE SCHEDULE FT (Contd.)

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule FT is available on any Day as provided herein, in Shipper's Firm Transportation Agreement, and in the General Terms and Conditions. Nominations for Service shall be made pursuant to Article 13 (Nominations) of the General Terms and Conditions. Service shall be on a firm basis and shall not be subject to interruption or curtailment except as provided herein or in the General Terms and Conditions.

2.2 Transporter is not obligated to provide Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Transporter will receive Daily Quantities of Gas for Shipper's Account for Transportation hereunder up to Shipper's MDQ, plus Make-Up Quantities up to Shipper's available balance of Deficient Quantities, plus AOS scheduled for Shipper's Account in accordance with Article 14 (Scheduling) of the General Terms and Conditions, and plus the applicable Fuel Requirement. Such MDQ shall be specified in Shipper's Firm Transportation Agreement.

2.4 Transporter will transport and deliver for Shipper's Account at the Delivery Point(s) Equivalent Quantities of Gas to the Gas received by Transporter at the Receipt Point from or on behalf of Shipper in accordance with Section 2.3 above.

2.5 Transporter shall periodically determine and post on the EDM the amount of capacity available as AOS. The AOS shall be available to all Shippers that have executed Firm Transportation Agreements. AOS shall only be available to each Shipper to the extent the Shipper's balance of Deficient Quantities is less than the otherwise applicable AOS allocation. AOS shall be allocated in accordance with the provisions of Article 14 (Scheduling) of the General Terms and Conditions. The actual capacity available for AOS will vary Daily depending on Shipper nominations for Firm Service and the capability of Transporter's system to provide Transportation.

RATE SCHEDULE FT (Contd.)

ARTICLE 3 REQUESTS FOR SERVICE

3.1 Any party requesting Transportation Service under this Rate Schedule FT must provide to Transporter the information required by Article 2 (Requests for Service) of the General Terms and Conditions.

3.2 Transporter may, in its sole discretion, waive the required prepayment described in Subsection 2.3 of Article 2 (Requests for Service) of the General Terms and Conditions, on a not unduly discriminatory basis. In the event such prepayment is waived, Transporter will provide a written waiver to Shipper.

RATE SCHEDULE FT (Contd.)

ARTICLE 4 RATES AND CHARGES

4.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 5 of this Tariff's currently effective rates for Rate Schedule FT and are incorporated herein.

4.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum and Maximum Rates as set forth on Sheet No. 5 of this Tariff's currently effective rates for Rate Schedule FT, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

4.3 For each Month, Transporter shall charge and Shipper shall pay an amount equal to the sum of:

(a) the applicable Reservation Rate, multiplied by (i) Shipper's MDQ specified in the applicable Service Agreement under this Rate Schedule FT, and (ii) the number of Days in the applicable Month;

(b) the applicable Usage Rate, multiplied by the total Quantity of Gas actually received from Shipper during the Month (less the applicable Fuel Requirement); and

(c) the applicable AOS Rate, multiplied by the total Quantity of Gas actually received from Shipper above Shipper's MDQ as AOS during the Month (less the applicable Fuel Requirement).

4.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 5 of this Tariff's currently effective rates for Rate Schedule FT, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) any applicable penalties determined pursuant to Article 16 (Resolution of Imbalances and Adjustment) of the General Terms and Conditions;

RATE SCHEDULE FT (Contd.)
ARTICLE 4 RATES AND CHARGES (Contd.)
4.4 (Contd.)

(d) any unpaid Reservation Charges for Released Capacity, as determined under Article 23 (Capacity Release) of the General Terms and Conditions;

(e) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for the incremental receipt, measurement, or transportation of Gas for Shipper’s Account, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter’s scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(f) any other generally applicable charge imposed for the Service provided hereunder.

4.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule FT, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE FT (Contd.)
ARTICLE 4 RATES AND CHARGES (Contd.)

4.6 The sum of the amounts set forth in Sections 4.3 and 4.4 above shall be reduced by the sum of the credits set forth below:

(a) any credits attributable to the applicable Firm Transportation Agreement for Released Capacity determined under Article 23 (Capacity Release) of the General Terms and Conditions;

(b) Shipper’s share of revenue credits attributable to the applicable Firm Transportation Agreement determined pursuant to Article 20 (Crediting of Revenue) of the General Terms and Conditions; and

(c) any applicable penalties attributable to the applicable Firm Transportation Agreement in favor of Shipper as determined pursuant to Article 16 (Resolution of Imbalances and Adjustment) of the General Terms and Conditions.

RATE SCHEDULE FT (Contd.)

ARTICLE 5 DEFERRED FIRM SERVICE

5.1 Shipper shall continue to pay all applicable Reservation Charges under this Rate Schedule FT even if Transporter is unable, for any reason, including an event of Force Majeure or issuance of an OFO, to provide Firm Service under this Rate Schedule FT; provided, however, in the event Deficient Quantities accrue to Shipper's Account under this Rate Schedule FT pursuant to Section 17.5 of Article 17 (Curtailment) of the General Terms and Conditions, Shipper shall be entitled to receive deferred Firm Service as described in Article 17 (Curtailment) of the General Terms and Conditions.

RATE SCHEDULE FT (Contd.)

ARTICLE 6 RECEIPT AND DELIVERY POINT(S)

6.1 Transporter shall receive Gas for Transportation hereunder at the Receipt Point for Transportation Service set forth in Exhibit A of this Tariff, and such Receipt Point shall be designated as the Receipt Point in Shipper’s Firm Transportation Agreement.

6.2 The points at which Transporter shall deliver Gas to Shipper or to Shipper’s Account shall be the points designated as Delivery Point(s) in Shipper’s Firm Transportation Agreement.

6.3 When entering into a Firm Transportation Agreement, Shipper shall elect Delivery Point(s) from the Delivery Point(s) listed on Exhibit B of this Tariff, subject to availability. Transporter shall approve such elections based on availability of capacity at the selected points, based on Shipper’s election and the similar elections of other Shippers.

6.4 Shippers may request changes to their Delivery Point(s), including increases or decreases to Shipper’s MDQ at the Delivery Point(s), or requesting deliveries to a different Delivery Point that is located inside such Shipper’s existing path, by submitting a written request to Transporter, so long as such changes will not have a negative financial impact upon Transporter.

RATE SCHEDULE FT (Contd.)
ARTICLE 6 RECEIPT AND DELIVERY POINT(S) (Contd.)

6.5 If adequate capacity is available to accommodate a request to change a Delivery Point, the request will be approved and Transporter shall notify Shipper of such approval via the EDM. Shipper shall then identify the point from which the available amount of capacity is to be transferred. If adequate capacity is not available to accommodate the requested change, Transporter shall advise Shipper as to the amount of capacity, if any, that can be accommodated and Shipper shall have the option to either (a) withdraw its request, or (b) identify the point from which the available amount of capacity is to be transferred. Attachment 1 of Shipper's Service Agreement shall be amended by the Parties to reflect any change approved by Transporter under this Article 6.

6.6 Transporter shall maintain a queue of requests from Shippers under Rate Schedule FT requesting to either add Delivery Point(s) or increase their contracted capacity at a Delivery Point and such queue, based on the date and time each request was received by Transporter, shall establish the priority in which Transporter will accommodate such requests.

RATE SCHEDULE FT (Contd.)

ARTICLE 7 SIMULTANEOUS RECEIPT AND DELIVERY OF GAS

7.1 Services hereunder will be provided on the basis that Gas will be received and delivered by Transporter on a simultaneous basis. Transporter’s obligation to deliver Gas to, or for the account of, Shipper on any Day is limited to making available to Shipper Equivalent Quantities of Gas at the Delivery Point(s).

7.2 It is recognized that because of scheduling and other variations, certain minor imbalances may occur between the Daily Quantities of Gas received by Transporter and the Daily Quantities of Gas delivered by Transporter. Shipper and Transporter shall use every reasonable effort to ensure that receipts and deliveries remain in balance on a uniform basis.

RATE SCHEDULE FT (Contd.)

ARTICLE 8 GENERAL TERMS AND CONDITIONS

8.1 All of the General Terms and Conditions of Transporter’s Tariff of which this Rate Schedule FT is a part are applicable to Service under this Rate Schedule FT. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule FT or a Firm Transportation Agreement for Service under this Rate Schedule FT, the specific provisions of this Rate Schedule FT or such Firm Transportation Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule FT and a Firm Transportation Agreement for Service under this Rate Schedule FT, the specific provisions of such Firm Transportation Agreement shall control.

Sheet Nos. 42-50 Are Reserved for Future Use

RATE SCHEDULE IT

INTERRUPTIBLE TRANSPORTATION SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) Transporter’s existing facilities have sufficient capacity for the requested duration of Service and are able to provide such Service;

(b) Shipper has met Transporter’s creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into an Interruptible Transportation Agreement for Service under this Rate Schedule IT.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its system in order to provide Service hereunder to any Shipper.

RATE SCHEDULE IT (Contd.)

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule IT is available on an interruptible basis on any Day, as provided herein, in Shipper's Interruptible Transportation Agreement, and in the General Terms and Conditions.

2.2 Transporter is not obligated to provide Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Shipper shall be subject to interruption at any time that deliveries hereunder would in any way interfere with or restrict Transporter's ability to make deliveries under Rate Schedule FT, or for operational reasons.

2.4 Transporter will receive Daily Quantities of Gas for Shipper's Account for Transportation hereunder up to Shipper's Maximum Daily Service Quantity in accordance with Nominations accepted under Article 13 (Nominations) of the General Terms and Conditions. Transporter shall not be obligated to accept and schedule Nominations in excess of Shipper's Maximum Daily Service Quantity, but may do so subject to available pipeline capacity and in a not unduly discriminatory fashion.

2.5 Transporter will transport and deliver for Shipper's Account at the Delivery Point(s) Equivalent Quantities of Gas to the Gas received by Transporter at the Receipt Point from or on behalf of Shipper in accordance with Section 2.4 above.

2.6 Transporter is free to contract at any time with other parties to provide new Services (whether firm or interruptible) without liability to Shipper for any resulting interruption, impairment of quality of Service, or reduction of Service hereunder.

RATE SCHEDULE IT (Contd.)

ARTICLE 3 RATES AND CHARGES

3.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 6 of this Tariff's currently effective rates for Rate Schedule IT and are incorporated herein.

3.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 6 of this Tariff's currently effective rates for Rate Schedule IT, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

3.3 Transporter shall charge and Shipper shall pay Transporter each Month for Service under this Rate Schedule IT the applicable rate, multiplied by the total Quantity of Gas actually received from Shipper during the Month (expressed in Dth), less the Fuel Requirement.

RATE SCHEDULE IT (Contd.)
ARTICLE 3 RATES AND CHARGES (Contd.)

3.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 6 of this Tariff's currently effective rates for Rate Schedule IT, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) any applicable penalties determined pursuant to Article 16 (Resolution of Imbalances and Adjustment) of the General Terms and Conditions;

(d) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for the incremental receipt, measurement, or Transportation of Gas for Shipper's Account, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(e) any other generally applicable charge imposed for the Service provided hereunder.

3.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule IT, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE IT (Contd.)

ARTICLE 4 RECEIPT AND DELIVERY POINT(S)

4.1 Transporter shall receive Gas for Transportation hereunder at the Receipt Point for Transportation Service set forth in Exhibit A of this Tariff, and such Receipt Point shall be designated as the Receipt Point in Shipper’s Interruptible Transportation Agreement.

4.2 The points at which Transporter shall deliver Gas to Shipper or to Shipper’s Account shall be the points designated as Delivery Point(s) in Shipper’s Interruptible Transportation Agreement.

4.3 When entering into an Interruptible Transportation Agreement, Shipper shall elect Delivery Point(s) from the Delivery Point(s) listed on Exhibit B of this Tariff, subject to availability.

RATE SCHEDULE IT (Contd.)

ARTICLE 5 SIMULTANEOUS RECEIPT AND DELIVERY OF GAS

5.1 Services hereunder will be provided on the basis that Gas will be received and delivered by Transporter on a simultaneous basis. Transporter’s obligation to deliver Gas to, or for the account of, Shipper on any Day is limited to making available to Shipper Equivalent Quantities of Gas at the Delivery Point(s).

5.2 It is recognized that because of scheduling and other variations, certain minor imbalances may occur between the Daily Quantities of Gas received by Transporter and the Daily Quantities of Gas delivered by Transporter. Shipper and Transporter shall use every reasonable effort to ensure that receipts and deliveries remain in balance on a uniform basis.

RATE SCHEDULE IT (Contd.)

ARTICLE 6 GENERAL TERMS AND CONDITIONS

6.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule IT is a part are applicable to Service under this Rate Schedule IT. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule IT or an Interruptible Transportation Agreement, the specific provisions of this Rate Schedule IT or such Interruptible Transportation Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule IT and an Interruptible Transportation Agreement under this Rate Schedule IT, the specific provisions of such Interruptible Transportation Agreement shall control.

Sheet Nos. 58-70 Are Reserved for Future Use

RATE SCHEDULE FGT

FIRM GAS TREATING SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) the existing facilities for Acid Gas removal and dehydration have sufficient capacity for the requested duration of Service and are able to provide such Service;

(b) Shipper has met Transporter’s creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Gas Treating Agreement for Service under this Rate Schedule FGT.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its existing treatment facilities in any manner in order to provide Service hereunder to any Shipper.

RATE SCHEDULE FGT

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule FGT is available on any Day as provided herein, in Shipper’s Gas Treating Agreement, and in the General Terms and Conditions. Nominations for Service hereunder shall be made pursuant to Shipper’s Gas Treating Agreement. Service shall be on a firm basis and shall not be subject to interruption or curtailment except as provided herein or in the General Terms and Conditions.

2.2 Transporter is entitled to refuse Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Transporter will receive for treatment hereunder, Daily Quantities of Gas that have been scheduled for Shipper’s Account in accordance with Shipper’s Gas Treating Agreement and Article 14 (Scheduling) of the General Terms and Conditions.

RATE SCHEDULE FGT

2. NATURE OF SERVICE

2.4 Transporter will deliver for Shipper's Account at the Acid Gas Delivery Point all Acid Gas recovered and allocated to Shipper. Allocations of Acid Gas will be calculated as:

(a) the Volume of Shipper's Gas received at the Receipt Point for Gas Treating Service multiplied by the sum of the hydrogen sulfide content and carbon dioxide content (each expressed as a mole percentage)for such received Gas; less

(b) the Volume of Shipper's Gas delivered at the Delivery Point for Gas Treating Service multiplied by the sum of the hydrogen sulfide content and carbon dioxide content (each expressed as a mole percentage) for such delivered Gas.

Transporter will deliver at the Delivery Point for Gas Treating Service, a Quantity of Gas equal to the Quantity of Shipper's Gas received at the Gas Treating Service Receipt Point less the Quantity of Acid Gas delivered at the Acid Gas Delivery Point and less the Gas Treating Fuel Requirement.

2.5 Transporter will allocate Acid Gas to Shippers after a Month is complete and after all data required to make the necessary allocations has been received. Shipper shall arrange for the Daily disposition of its Acid Gas with the understanding that the Month-end allocation may differ slightly from estimated Daily deliveries.

2.6 If Shipper does not arrange for the Daily disposition of its Acid Gas, Transporter may refuse to receive Shipper's Gas under this Rate Schedule FGT until such time Shipper arranges for the Daily disposition of its Acid Gas. In addition, Transporter reserves the right to arrange for the disposition or sale of Acid Gas and to bill Shipper for any costs actually incurred by Transporter in making such disposition or sale, plus a return on such costs equal to Transporter's applicable return approved by the Commission. In the event Shipper does not arrange for Daily disposition of Shipper's Acid Gas and Transporter is able to sell Shipper's Acid Gas, Transporter will credit Shipper with the proceeds of such sale to the extent such proceeds exceed the sum of Transporter's costs of disposition plus a return on such costs equal to Transporter's applicable return approved by the Commission.

RATE SCHEDULE FGT (Contd.)

ARTICLE 3 RATES AND CHARGES

3.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 7 of this Tariff's currently effective rates for Rate Schedule FGT and are incorporated herein.

3.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 7 of this Tariff's currently effective rates for Rate Schedule FGT, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

3.3 For each Month, Transporter shall charge and Shipper shall pay an amount equal to the sum of:

(a) the applicable Reservation Rate, multiplied by (i) Shipper's MDQ specified in the applicable Service Agreement under this Rate Schedule FGT, and (ii) the number of Days in the applicable Month.

(b) the applicable Usage Rate, multiplied by the total Quantity of Gas actually received from Shipper under the applicable Gas Treating Agreement during the Month (less the applicable Fuel Requirement); and

(c) the applicable AOS Rate, multiplied by the total Quantity of Gas actually received from Shipper under the applicable Gas Treating Agreement above Shipper's MDQ as AOS during the Month (less the applicable Fuel Requirement).

RATE SCHEDULE FGT (Contd.)
ARTICLE 3 RATES AND CHARGES (Contd.)
3.3 (Contd.)

3.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 7 of this Tariff's currently effective rates for Rate Schedule FGT, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) any unpaid Reservation Charges for Released Capacity, as determined under Article 23 (Capacity Release) of the General Terms and Conditions;

(d) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for the incremental treatment of Gas for Shipper's Account, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(e) any other generally applicable charge imposed for the Service provided hereunder.

3.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule FGT, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Gas Treating Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE FGT (Contd.)
ARTICLE 3 RATES AND CHARGES (Contd.)

3.6 The sum of the amounts set forth in Sections 3.3 and 3.4 above shall be reduced by the sum of the credits set forth below:

(a) any credits attributable to the applicable Gas Treating Agreement for Released Capacity determined under Article 23 (Capacity Release) of the General Terms and Conditions; and

(b) Shipper’s share of any revenue credits attributable to the applicable Gas Treating Agreement determined pursuant to Article 20 (Crediting of Revenue) of the General Terms and Conditions.

RATE SCHEDULE FGT (Contd.)

ARTICLE 4 DEFERRED FIRM SERVICE

4.1 Shipper shall continue to pay all applicable Reservation Charges under this Rate Schedule FGT even if Transporter is unable, for any reason, including an event of Force Majeure or issuance of an OFO, to provide Firm Service under this Rate Schedule FGT; provided, however, in the event Deficient Quantities accrue to Shipper's Account under this Rate Schedule FGT pursuant to Section 17.5 of Article 17 (Curtailment) of the General Terms and Conditions, Shipper shall be entitled to receive deferred Firm Service as described in Article 17 (Curtailment) of the General Terms and Conditions.

RATE SCHEDULE FGT (Contd.)

ARTICLE 5 RECEIPT AND DELIVERY POINT(S)

5.1 The Receipt Point to be utilized by Shipper under this Rate Schedule FGT shall be the Receipt Point designated in Shipper’s Gas Treating Agreement.

5.2 The Delivery Point(s) to be utilized by Shipper for redelivery of Shipper’s treated Gas under this Rate Schedule FGT shall be the Delivery Point(s) designated in Shipper’s Gas Treating Agreement.

5.3 Acid Gas shall be delivered to Shipper hereunder at the Acid Gas Delivery Point, unless otherwise specified in Shipper’s Gas Treating Agreement.

RATE SCHEDULE FGT (Contd.)

ARTICLE 6 SIMULTANEOUS RECEIPT AND DELIVERY OF GAS

6.1 Service hereunder will be provided on the basis that Gas will be received and Gas and Acid Gas will be delivered by Transporter on a simultaneous basis. Transporter reserves the right to retain, without obligation to Shipper, an allocated portion of Shipper’s Gas and/or Acid Gas to serve as line fill or inventory within Transporter’s treatment facility.

RATE SCHEDULE FGT (Contd.)

ARTICLE 7 GENERAL TERMS AND CONDITIONS

7.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule FGT is a part are applicable to Service under this Rate Schedule FGT. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule FGT or a Gas Treating Agreement under this Rate Schedule FGT, the specific provisions of this Rate Schedule FGT or such Gas Treating Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule FGT and a Gas Treating Agreement under this Rate Schedule FGT, the specific provisions of such Gas Treating Agreement shall control.

Sheet Nos. 81-90 Are Reserved for Future Use

RATE SCHEDULE IGT

INTERRUPTIBLE GAS TREATING SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) the existing facilities for Acid Gas removal and dehydration have sufficient capacity for the requested duration of Service and are able to provide such Service;

(b) Shipper has met Transporter’s creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Gas Treating Agreement for Service under this Rate Schedule IGT.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its existing system in any manner in order to provide Service hereunder to any Shipper.

RATE SCHEDULE IGT

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule IGT is available on an interruptible basis on any Day, as provided herein, in Shipper's Gas Treating Agreement, and in the General Terms and Conditions.

2.2 Transporter is not obligated to provide Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Shipper shall be subject to interruption at any time that deliveries hereunder would in any way interfere with or restrict Transporter's ability to make deliveries under Rate Schedule FGT, or for operational reasons.

2.4 Transporter will receive for treatment hereunder, Daily Quantities of Gas that have been scheduled for Shipper's Account in accordance with Shipper's Gas Treating Agreement and Article 14 (Scheduling) of the General Terms and Conditions.

RATE SCHEDULE IGT

2. NATURE OF SERVICE

2.5 Transporter will deliver for Shipper's Account at the Acid Gas Delivery Point all Acid Gas recovered and allocated to Shipper. Allocations of Acid Gas will be calculated as:

(a) the Volume of Shipper's Gas received at the Receipt Point for Gas Treating Service multiplied by the sum of the hydrogen sulfide content and carbon dioxide content (each expressed as a mole percentage)for such received Gas; less

(b) the Volume of Shipper's Gas delivered at the Delivery Point for Gas Treating Service multiplied by the sum of the hydrogen sulfide content and carbon dioxide content (each expressed as a mole percentage) for such delivered Gas.

Transporter will deliver at the Delivery Point for Gas Treating Service, a Quantity of Gas equal to the Quantity of Shipper's Gas received at the Gas Treating Service Receipt Point less the Quantity of Acid Gas delivered at the Acid Gas Delivery Point and less the Gas Treating Fuel Requirement.

2.6 Transporter will allocate Acid Gas to Shippers after a Month is complete and after all data required to make the necessary allocations has been received. Shipper shall arrange for the Daily disposition of its Acid Gas with the understanding that the Month-end allocation may differ slightly from estimated Daily deliveries.

2.7 If Shipper does not arrange for the Daily disposition of its Acid Gas, Transporter may refuse to receive Shipper's Gas under this Rate Schedule IGT until such time Shipper arranges for the Daily disposition of its Acid Gas. In addition, Transporter reserves the right to arrange for the disposition or sale of Acid Gas and to bill Shipper for any costs actually incurred by Transporter in making such disposition or sale, plus a return on such costs equal to Transporter's applicable return approved by the Commission. In the event Shipper does not arrange for Daily disposition of Shipper's Acid Gas and Transporter is able to sell Shipper's Acid Gas, Transporter will credit Shipper with the proceeds of such sale to the extent such proceeds exceed the sum of Transporter's costs of disposition plus a return on such costs equal to Transporter's applicable return approved by the Commission.

RATE SCHEDULE IGT (Contd.)

ARTICLE 3 RATES AND CHARGES

3.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 8 of this Tariff's currently effective rates for Rate Schedule IGT and are incorporated herein.

3.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 8 of this Tariff's currently effective rates for Rate Schedule IGT, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

3.3 For each Month, Transporter shall charge and Shipper shall pay an amount equal to the sum of applicable rate multiplied by the total Quantity of Shipper's Gas delivered for Gas Treating Service (less the applicable Fuel Requirement).

RATE SCHEDULE IGT (Contd.)
ARTICLE 3 RATES AND CHARGES (Contd.)
3.3 (Contd.)

3.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 8 of this Tariff's currently effective rates for Rate Schedule IGT, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for the incremental treatment of Gas for Shipper's Account, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(d) any other generally applicable charge imposed for the Service provided hereunder.

3.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule IGT, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Gas Treating Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE IGT (Contd.)

ARTICLE 4 RECEIPT AND DELIVERY POINT(S)

4.1 The Receipt Point to be utilized by Shipper under this Rate Schedule IGT shall be the Receipt Point designated in Shipper’s Interruptible Gas Treating Agreement.

4.2 The Delivery Point(s) to be utilized by Shipper for redelivery of Shipper’s treated Gas under this Rate Schedule FGT shall be the Delivery Point(s) designated in Shipper’s Gas Treating Agreement.

4.3 Acid Gas shall be delivered to Shipper hereunder at the Acid Gas Delivery Point, unless otherwise specified in Shipper’s Gas Treating Agreement.

RATE SCHEDULE IGT (Contd.)

ARTICLE 5 SIMULTANEOUS RECEIPT AND DELIVERY OF GAS

5.1 Service hereunder will be provided on the basis that Gas will be received and Gas and Acid Gas will be delivered by Transporter on a simultaneous basis. Transporter reserves the right to retain, without obligation to Shipper, an allocated portion of Shipper’s Gas and/or Acid Gas to serve as line fill or inventory within Transporter’s treatment facility.

RATE SCHEDULE IGT (Contd.)

ARTICLE 6 GENERAL TERMS AND CONDITIONS

6.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule IGT is a part are applicable to Service under this Rate Schedule IGT. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule IGT or a Gas Treating Agreement under this Rate Schedule IGT, the specific provisions of this Rate Schedule IGT or such Gas Treating Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule IGT and a Gas Treating Agreement under this Rate Schedule IGT, the specific provisions of such Gas Treating Agreement shall control.

Sheet Nos. 99-110 Are Reserved for Future Use

RATE SCHEDULE FC

FIRM COMPRESSION SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) the existing First Stage Compression Facilities have sufficient capacity for the requested duration of Service and are able to provide such Service;

(b) Shipper has met Transporter's creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Compression Agreement for Service under this Rate Schedule FC.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its existing First Stage Compression Facilities in any manner in order to provide Service hereunder to any Shipper.

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule FC is available on any Day as provided herein, in Shipper's Compression Agreement, and in the General Terms and Conditions. Nominations for Service shall be made pursuant to Article 13 (Nominations) of the General Terms and Conditions. Service shall be on a firm basis and shall not be subject to interruption or curtailment except as provided herein or in the General Terms and Conditions.

2.2 Transporter is entitled to refuse Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

RATE SCHEDULE FC (Contd.)
ARTICLE 2 NATURE OF SERVICE (Contd.)

2.3 Transporter will receive for Compression Service hereunder, Daily Quantities of Gas that have been scheduled for Shipper’s Account in accordance with Shipper’s Compression Agreement and Article 14 (Scheduling) of the General Terms and Conditions.

2.4 After Compression Service has been completed, Transporter will deliver to Transporter’s pipeline facilities for Shipper’s Account a Quantity of Gas equal to the Dekatherms of Shipper’s Gas delivered into the First Stage Compression Facilities, less the Compression Fuel Requirement.

RATE SCHEDULE FC (Contd.)

ARTICLE 3 RATES AND CHARGES

3.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 9 of this Tariff’s currently effective rates for Rate Schedule FC and are incorporated herein.

3.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 9 of this Tariff’s currently effective rates for Rate Schedule FC, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

3.3 For each Month, Transporter shall charge and Shipper shall pay an amount equal to:

(a) the applicable Reservation Rate, multiplied by (i) Shipper’s MDQ specified in the applicable Service Agreement under this Rate Schedule FC, and (ii) the number of Days in the applicable Month;

(b) the applicable Usage Rate, multiplied by the total Quantity of Gas actually received from Shipper under the applicable Compression Agreement during the Month (less the applicable Fuel Requirement); and

(c) the applicable AOS Rate, multiplied by the total Quantity of Gas actually received from Shipper under the applicable Compression Agreement above Shipper’s MDQ as AOS during the Month (less the applicable Fuel Requirement).

RATE SCHEDULE FC (Contd.)

3.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 9 of this Tariff's currently effective rates for Rate Schedule FC, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) any unpaid Reservation Charges for Released Capacity, as determined under Article 23 (Capacity Release) of the General Terms and Conditions;

(d) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for incremental Compression Service related to Shipper's Gas, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(e) any other generally applicable charge imposed for the Service provided hereunder.

3.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule FC, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Compression Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE FC (Contd.)
ARTICLE 3 RATES AND CHARGES (Contd.)

3.6 The sum of the amounts set forth in Sections 3.3 and 3.4 above shall be reduced by the sum of the credits set forth below:

(a) any credits attributable to the applicable Compression Agreement for Released Capacity determined under Article 23 (Capacity Release) of the General Terms and Conditions; and

(b) Shipper’s share of any revenue credits attributable to the applicable Compression Agreement determined pursuant to Article 20 (Crediting of Revenue) of the General Terms and Conditions.

RATE SCHEDULE FC (Contd.)

ARTICLE 4 DEFERRED FIRM SERVICE

4.1 Shipper shall continue to pay all applicable Reservation Charges under this Rate Schedule FC even if Transporter is unable, for any reason, including an event of Force Majeure or issuance of an OFO, to provide Firm Service under this Rate Schedule FC; provided, however, in the event Deficient Quantities accrue to Shipper's Account under this Rate Schedule FC pursuant to Section 17.5 of Article 17 (Curtailment) of the General Terms and Conditions, Shipper shall be entitled to receive deferred Firm Service as described in Article 17 (Curtailment) of the General Terms and Conditions.

RATE SCHEDULE FC (Contd.)

ARTICLE 5 RECEIPT AND DELIVERY POINT(S)

5.1 The Receipt Point to be utilized by Shipper under this Rate Schedule FC shall be the inlet flange of Transporter's First Stage Compression Facilities, unless otherwise specified in the applicable Compression Agreement.

5.2 The Delivery Point to be utilized by Shipper under this Rate Schedule FC shall be the outlet flange of Transporter's First Stage Compression Facilities, unless otherwise specified in the applicable Compression Agreement.

RATE SCHEDULE FC (Contd.)

ARTICLE 6 GENERAL TERMS AND CONDITIONS

6.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule FC is a part are applicable to Service under this Rate Schedule FC. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule FC or a Compression Agreement under this Rate Schedule FC, the specific provisions of this Rate Schedule FC or such Compression Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule FC and a Compression Agreement under this Rate Schedule FC, the specific provisions of such Compression Agreement shall control.

Sheet Nos. 119-130 Are Reserved for Future Use

RATE SCHEDULE IC

INTERRUPTIBLE COMPRESSION SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) the existing First Stage Compression Facilities have sufficient capacity for the requested duration of Service and are able to provide such Service;

(b) Shipper has met Transporter’s creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Compression Agreement for Service under this Rate Schedule IC.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its system in any manner in order to provide Service hereunder to any Shipper.

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule IC is available on an interruptible basis on any Day, as provided herein, in Shipper’s Compression Agreement, and in the General Terms and Conditions.

2.2 Transporter is not obligated to provide Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Shipper shall be subject to interruption at any time that deliveries hereunder would in any way interfere with or restrict Transporter’s ability to make deliveries under Rate Schedule FC, or for operational reasons.

RATE SCHEDULE IC (Contd.)
ARTICLE 2 NATURE OF SERVICE (Contd.)

2.4 Transporter will receive for Compression Service hereunder, Daily Quantities of Gas that have been scheduled for Shipper's Account in accordance with Shipper's Interruptible Compression Agreement and Article 14 (Scheduling) of the General Terms and Conditions.

2.5 After Compression Service has been completed, Transporter will deliver to Transporter's pipeline facilities for Shipper's Account a Quantity of Gas equal to the Dekatherms of Shipper's Gas delivered into the First Stage Compression Facilities, less the Compression Fuel Requirement.

RATE SCHEDULE IC (Contd.)

ARTICLE 3 RATES AND CHARGES

3.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 10 of this Tariff’s currently effective rates for Rate Schedule IC and are incorporated herein.

3.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 10 of this Tariff’s currently effective rates for Rate Schedule IC, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

3.3 For each Month, Transporter shall charge and Shipper shall pay an amount equal to the applicable Compression Service rate multiplied by (i) the total Quantity of Gas received by Transporter for Compression Service under Shipper’s Compression Agreement (less the applicable Fuel Requirement), and (ii) the number of Days in the applicable Month.

RATE SCHEDULE IC (Contd.)

3.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 10 of this Tariff's currently effective rates for Rate Schedule IC, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for incremental Compression Service related to Shipper's Gas, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(d) any other generally applicable charge imposed for the Service provided hereunder.

3.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule IC, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Compression Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE IC (Contd.)

ARTICLE 4 RECEIPT AND DELIVERY POINT(S)

4.1 The Receipt Point to be utilized by Shipper under this Rate Schedule IC shall be the inlet flange of Transporter's First Stage Compression Facilities, unless otherwise specified in the applicable Compression Agreement.

4.2 The Delivery Point to be utilized by Shipper under this Rate Schedule IC shall be the outlet flange of Transporter's First Stage Compression Facilities, unless otherwise specified in the applicable Compression Agreement.

RATE SCHEDULE IC (Contd.)

ARTICLE 5 GENERAL TERMS AND CONDITIONS

5.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule IC is a part are applicable to Service under this Rate Schedule IC. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule IC or a Compression Agreement under this Rate Schedule IC, the specific provisions of this Rate Schedule IC or such Compression Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule IC and a Compression Agreement under this Rate Schedule IC, the specific provisions of such Compression Agreement shall control.

Sheet Nos. 137-150 Are Reserved for Future Use

RATE SCHEDULE FTR
FIRM TRANSMISSION SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) Transporter’s existing facilities have sufficient capacity for the requested duration of Service and are able to provide such Transmission Service;

(b) Shipper has met Transporter’s creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Transmission Agreement for Service under this Rate Schedule FTR.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its system in order to provide Service hereunder to any Shipper.

RATE SCHEDULE FTR (Contd.)

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule FTR is available on any Day as provided herein, in Shipper's Transmission Agreement, and in the General Terms and Conditions. Nominations for Service shall be made pursuant to Article 13 (Nominations) of the General Terms and Conditions. Service shall be on a firm basis and shall not be subject to interruption or curtailment except as provided herein or in the General Terms and Conditions.

2.2 Transporter is not obligated to provide Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Transporter will receive Daily Quantities of Gas for Shipper's Account for Transmission hereunder up to Shipper's MDQ, plus Make-Up Quantities up to Shipper's available balance of Deficient Quantities, plus AOS scheduled for Shipper's Account in accordance with Article 14 (Scheduling) of the General Terms and Conditions, and plus the applicable Fuel Requirement. Such MDQ shall be specified in Shipper's Transmission Agreement.

2.4 Transporter will transport and deliver for Shipper's Account at the Delivery Point Equivalent Quantities of Gas to the Gas received by Transporter at the Receipt Point from or on behalf of Shipper in accordance with Section 2.3 above.

2.5 Transporter shall periodically determine and post on the EDM the amount of capacity available as AOS. The AOS shall be available to all Shippers that have executed Transmission Agreements under this Rate Schedule FTR. AOS shall only be available to each Shipper to the extent the Shipper's balance of Deficient Quantities is less than the otherwise applicable AOS allocation. AOS shall be allocated in accordance with the provisions of Article 14 (Scheduling) of the General Terms and Conditions. The actual capacity available for AOS will vary daily depending on Shipper nominations for Firm Service and the capability of Transporter's system to provide Transmission.

RATE SCHEDULE FTR (Contd.)

ARTICLE 3 REQUESTS FOR SERVICE

3.1 Any party requesting Transmission Service under this Rate Schedule FTR must provide to Transporter the information required by Article 2 (Requests for Service) of the General Terms and Conditions.

3.2 Transporter may, in its sole discretion, waive the required prepayment described in Subsection 2.3 of Article 2 (Requests for Service) of the General Terms and Conditions, on a not unduly discriminatory basis. In the event such prepayment is waived Transporter will provide a written waiver to Shipper.

RATE SCHEDULE FTR (Contd.)

ARTICLE 4 RATES AND CHARGES

4.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 11 of this Tariff’s currently effective rates for Rate Schedule FTR and are incorporated herein.

4.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 11 of this Tariff’s currently effective rates for Rate Schedule FTR, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

4.3 For each Month, Transporter shall charge and Shipper shall pay an amount equal to the sum of:

(a) the applicable Reservation Rate, multiplied by (i) Shipper’s MDQ specified in the applicable Service Agreement under this Rate Schedule FGT, and (ii) the number of Days in the applicable Month;

(b) the applicable Usage Rate, multiplied by the total Quantity of Gas actually received from Shipper under the applicable Transmission Agreement during the Month (less the applicable Fuel Requirement); and

(c) the applicable AOS Rate, multiplied by the total Quantity of Gas actually received from Shipper under the applicable Transmission Agreement above Shipper’s MDQ as AOS during the Month (less the applicable Fuel Requirement).

RATE SCHEDULE FTR (Contd.)
ARTICLE 4 RATES AND CHARGES (Contd.)

4.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 11 of this Tariff's currently effective rates for Rate Schedule FTR, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) any applicable penalties determined pursuant to Article 16 (Resolution of Imbalances and Adjustment) of the General Terms and Conditions;

(d) any unpaid Reservation Charges for Released Capacity, as determined under Article 23 (Capacity Release) of the General Terms and Conditions;

(e) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for the incremental receipt, measurement, or Transmission of gas for Shipper's Account, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(f) any other generally applicable charge imposed for the Service provided hereunder.

4.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule FTR, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Transmission Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE FTR (Contd.)
ARTICLE 4 RATES AND CHARGES (Contd.)

4.6 The sum of the amounts set forth in Sections 4.3 and 4.4 above shall be reduced by the sum of the credits set forth below:

(a) any credits attributable to the applicable Transmission Agreement for Released Capacity determined under Article 23 (Capacity Release) of the General Terms and Conditions;

(b) Shipper’s share of revenue credits attributable to the applicable Transmission Agreement determined pursuant to Article 20 (Crediting of Revenue) of the General Terms and Conditions; and

(c) any applicable penalties attributable to the applicable Transmission Agreement in favor of Shipper as determined pursuant to Article 16 (Resolution of Imbalances and Adjustment) of the General Terms and Conditions.

RATE SCHEDULE FTR (Contd.)

ARTICLE 5 DEFERRED FIRM SERVICE

5.1 Shipper shall continue to pay all applicable Reservation Charges under this Rate Schedule FTR even if Transporter is unable, for any reason, including an event of Force Majeure or issuance of an OFO, to provide Firm Service under this Rate Schedule FTR; provided, however, in the event Deficient Quantities accrue to Shipper's Account under this Rate Schedule FTR pursuant to Section 17.5 of Article 17 (Curtailment) of the General Terms and Conditions, Shipper shall be entitled to receive deferred Firm Service as described in Article 17 (Curtailment) of the General Terms and Conditions.

RATE SCHEDULE FTR (Contd.)

ARTICLE 6 RECEIPT AND DELIVERY POINT(S)

6.1 The point at which Transporter shall receive Gas for Transmission hereunder shall be the point designated as the Receipt Point in Shipper's Firm Transmission Agreement.

6.2 The points at which Transporter shall deliver Gas to Shipper or to Shipper's Account shall be the points designated as Delivery Point(s) in Shipper's Firm Transmission Agreement.

6.3 When entering into a Transmission Agreement under this Rate Schedule FTR, Shipper shall elect the Delivery Point and Receipt Point from the Delivery and Receipt Points listed on Exhibits A and B of this Tariff, subject to availability. Transporter shall approve such elections based on availability of capacity at the selected points, based on Shipper's election and the similar elections of other Shippers.

RATE SCHEDULE FTR (Contd.)

ARTICLE 7 SIMULTANEOUS RECEIPT AND DELIVERY OF GAS

7.1 Transmission Services hereunder will be provided on the basis that Gas will be received and delivered by Transporter on a simultaneous basis. Transporter's obligation to deliver gas to, or for the account of, Shipper on any Day is limited to making available to Shipper Equivalent Quantities of Gas at the Delivery Point(s).

7.2 It is recognized that because of scheduling and other variations, certain minor imbalances may occur between the Daily Quantities of Gas received by Transporter and the Daily Quantities of Gas delivered by Transporter. Shipper and Transporter shall use every reasonable effort to ensure that receipts and deliveries remain in balance on a uniform basis.

RATE SCHEDULE FTR (Contd.)

ARTICLE 8 GENERAL TERMS AND CONDITIONS

8.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule FTR is a part are applicable to Service under this Rate Schedule FTR. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule FTR or a Transmission Agreement for Service under this Rate Schedule FTR, the specific provisions of this Rate Schedule FTR or such Transmission Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule FTR and a Transmission Agreement for Service under this Rate Schedule FTR, the specific provisions of such Transmission Agreement shall control.

Sheet Nos. 161-170 Are Reserved for Future Use

RATE SCHEDULE ITR

INTERRUPTIBLE TRANSMISSION SERVICE

ARTICLE 1 AVAILABILITY

1.1 Any Shipper shall be eligible to receive Service hereunder provided that:

(a) Transporter's existing facilities have sufficient capacity for the requested duration of Service and are able to provide such Transmission Service;

(b) Shipper has met Transporter's creditworthiness requirements pursuant to Article 9 (Creditworthiness) of the General Terms and Conditions;

(c) Shipper has complied with the requirements of Article 2 (Requests for Service) of the General Terms and Conditions; and

(d) Shipper and Transporter have entered into a Transmission Agreement for Service under this Rate Schedule ITR.

1.2 Unless lawfully required pursuant to 15 U.S.C. § 720c by the Commission, Transporter shall not be obligated to add any facilities or expand the capacity of its system in order to provide Service hereunder to any Shipper.

RATE SCHEDULE ITR (Contd.)

ARTICLE 2 NATURE OF SERVICE

2.1 Service under this Rate Schedule ITR is available on an interruptible basis on any Day, as provided herein, in Shipper's Transmission Agreement, and in the General Terms and Conditions.

2.2 Transporter is not obligated to provide Service hereunder if, and for so long as, Shipper is in default hereunder, under any Service Agreement, or under the General Terms and Conditions.

2.3 Shipper shall be subject to interruption at any time that deliveries hereunder would in any way interfere with or restrict Transporter's ability to make deliveries under Rate Schedule FTR, or for operational reasons.

2.4 Transporter will receive Daily Quantities of Gas for Shipper's Account for Transmission hereunder up to Shipper's maximum Quantity specified in Shipper's Transmission Agreement and in accordance with Nominations accepted under Article 13 (Nominations) of the General Terms and Conditions. Transporter shall not be obligated to accept and schedule Nominations in excess of Shipper's maximum Quantity specified in Shipper's Transmission Agreement, but may do so subject to available pipeline capacity and in a not unduly discriminatory fashion.

2.5 Transporter will transport and deliver for Shipper's Account at the Delivery Point(s) Equivalent Quantities of Gas to the Gas received by Transporter at the Receipt Point from or on behalf of Shipper in accordance with Section 2.4 above.

2.6 Transporter is free to contract at any time with other parties to provide new Services (whether firm or interruptible) without liability to Shipper for any resulting interruption, impairment of quality of Service, or reduction of Service hereunder.

RATE SCHEDULE ITR (Contd.)

ARTICLE 3 RATES AND CHARGES

3.1 The applicable Maximum and Minimum Rates for Service hereunder are set forth on Sheet No. 12 of this Tariff’s currently effective rates for Rate Schedule ITR and are incorporated herein.

3.2 Unless Transporter and Shipper agree in writing to either (a) a Negotiated Rate for Service provided herein or (b) a rate discount that is between the Minimum Rate and Maximum Rate as set forth on Sheet No. 12 of this Tariff’s currently effective rates for Rate Schedule ITR, the rates applicable to Shipper for Service hereunder shall be the Maximum Rates.

3.3 Transporter shall charge and Shipper shall pay Transporter each Month for Service under this Rate Schedule ITR the applicable rate, multiplied by the total Quantity of Gas actually received from Shipper during the Month (less the applicable Fuel Requirement).

RATE SCHEDULE ITR (Contd.)
ARTICLE 3 RATES AND CHARGES (Contd.)

3.4 In addition to the charges specified above, unless otherwise agreed to by Transporter in accordance with FERC regulations, Shipper shall pay to Transporter the following charges applicable to Service hereunder:

(a) an ACA Surcharge as prescribed by Article 29 (Annual Charge Adjustment) of the General Terms and Conditions and set forth on Sheet No. 12 of this Tariff's currently effective rates for Rate Schedule ITR, as said charge may be changed from time to time;

(b) any applicable late payment charges, determined pursuant to Article 18 (Billing and Payments) of the General Terms and Conditions;

(c) any applicable penalties determined pursuant to Article 16 (Resolution of Imbalances and Adjustment) of the General Terms and Conditions;

(d) all costs actually incurred by Transporter in the construction and installation, modification, and/or acquisition (including acquisition of interests in real estate and permits) of facilities for the incremental receipt, measurement, or Transmission of Gas for Shipper's Account, which Transporter, in its reasonable discretion, agrees to construct, install, modify, and/or acquire; provided that Shipper is in agreement with Transporter's scope of work and the costs projection. Unless agreed otherwise, title and ownership of such facilities shall remain with Transporter; and

(e) any other generally applicable charge imposed for the Service provided hereunder.

3.5 In addition to the charges specified above, as additional compensation for the Service provided under Rate Schedule ITR, Shipper shall deliver, or cause to be delivered, to Transporter at the Receipt Point the Transmission Fuel Requirement, calculated in accordance with Section 30.2 of Article 30 (Fuel Retention Adjustment) of the General Terms and Conditions.

RATE SCHEDULE ITR (Contd.)

ARTICLE 4 RECEIPT AND DELIVERY POINT(S)

4.1 The point at which Transporter shall receive Gas for Transmission hereunder shall be the point designated as the Receipt Point in Shipper's Transmission Agreement.

4.2 The points at which Transporter shall deliver Gas to Shipper or to Shipper's Account shall be the points designated as Delivery Point(s) in Shipper's Transmission Agreement.

4.3 When entering into a Transmission Agreement under this Rate Schedule ITR, Shipper shall elect the Delivery Point and the Receipt Point from the Delivery and Receipt Points listed on Exhibits A and B of this Tariff, subject to availability. Transporter shall approve such elections based on availability of capacity at the selected points, based on Shipper's election and the similar elections of other Shippers.

RATE SCHEDULE ITR (Contd.)

ARTICLE 5 SIMULTANEOUS RECEIPT AND DELIVERY OF GAS

5.1 Services hereunder will be provided on the basis that Gas will be received and delivered by Transporter on a simultaneous basis. Transporter’s obligation to deliver Gas to, or for the account of, Shipper on any Day is limited to making available to Shipper Equivalent Quantities of Gas at the Delivery Point(s).

5.2 It is recognized that because of scheduling and other variations, certain minor imbalances may occur between the Daily Quantities of Gas received by Transporter and the Daily Quantities of Gas delivered by Transporter. Shipper and Transporter shall use every reasonable effort to ensure that receipts and deliveries remain in balance on a uniform basis.

RATE SCHEDULE ITR (Contd.)

ARTICLE 6 GENERAL TERMS AND CONDITIONS

6.1 All of the General Terms and Conditions of Transporter's Tariff of which this Rate Schedule ITR is a part are applicable to Service under this Rate Schedule ITR. In the event of a conflict between the General Terms and Conditions and the provisions of this Rate Schedule ITR or an Interruptible Transmission Agreement, the specific provisions of this Rate Schedule ITR or such Interruptible Transmission Agreement shall control. In the event of a conflict between the provisions of this Rate Schedule ITR and an Interruptible Transmission Agreement under this Rate Schedule ITR, the specific provisions of such Transmission Agreement shall control.

Sheet Nos. 178-190 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS

ARTICLE 1 DEFINITIONS

The following terms, when used in these General Terms and Conditions and in any Service Agreement, or any Rate Schedule incorporating these General Terms and Conditions, shall have the following meanings. Each capitalized term not defined below or not defined in the specific Article of the Tariff, has the meaning ascribed to such term in the then-applicable governing NAESB standards.

"AAA" means the American Arbitration Association.

"ACA" means Annual Charge Adjustment.

"ACA Surcharge" has the meaning ascribed to such term in Section 29.1 of Article 29 (Annual Charge Adjustment) of these General Terms and Conditions.

"Acid Gas" means the stream of gas removed at the GTP consisting primarily of carbon dioxide.

"Acid Gas Delivery Point" means the point of interconnection between the GTP and the Acid Gas delivery line located just downstream of the GTP meter facilities where Acid Gas is delivered from the GTP to Shipper or its agent.

"Affiliate" when used to indicate a relationship with a specific Person, means another Person that directly, or indirectly through one or more intermediaries or otherwise, controls, is controlled by, or is under common control with, such specific Person. A corporation shall be deemed to be an Affiliate of another corporation if one directly or indirectly controls the other or if each of them is directly or indirectly controlled by the same Person.

"Alaska Natural Gas Pipeline Act" means Sections 720 through 720n of Title 15 of the United States Code, as amended or recodified from time to time.

"Approved Bidders List" means the list of those parties eligible to bid for Released Capacity pursuant to Article 23 (Capacity Release) of these General Terms and Conditions, as such list is maintained on Transporter's EDM.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"AOS" means authorized overrun service, and is defined as a Shipper's right to a pro rata share of available capacity, above its MDQ amount, that is not, from time to time, contracted for and being utilized under all agreements for Firm Service, with any allocation to those Shippers with agreements for Firm Service made pursuant to Article 14 (Scheduling) of these General Terms and Conditions.

"AOS Rate" means the AOS Rate specified in the applicable Service Agreement. If no AOS Rate is specified in the applicable Service Agreement, then the AOS Rate shall be the Maximum Rate under the column entitled AOS Rate in the applicable Schedule of Currently Effective Rates.

"Average Monthly Index Price" or "AMIP" has the meaning ascribed to such term in Subsection 16.9(b) of Article 16 (Resolution of Imbalances and Adjustment) of these General Terms and Conditions.

"Bcf" means one billion (1,000,000,000) Cubic Feet.

"Bid Limit" has the meaning ascribed to such term in Subsection 9.2(b) of Article 9 (Creditworthiness) of these General Terms and Conditions.

"Biddable" means a Capacity release transaction that is required to be posted for bidding pursuant to the Commission's Regulations.

"Bidding Period" means the period during which bids for released Capacity will be received pursuant to the provisions of Article 23 (Capacity Release) of these General Terms and Conditions.

"Bidding Shipper" means a Shipper submitting a bid for released Capacity pursuant to Article 23 (Capacity Release) of these General Terms and Conditions.

"Btu" means British thermal unit, and is defined as the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit from 59°F to 60°F, measured on a dry basis at a standard pressure of 14.73 psia.

"Business Day" means Monday through Friday, excluding U.S. federal banking holidays.

"Canada Fuel" has the meaning ascribed to such term in Section 30.1 of Article 30 (Fuel Requirement) of these General Terms and Conditions.

"Canada Mainline" means the natural gas transportation system and all related facilities owned by Canadian Transporter that carries Gas within Canada.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Canadian Transporter" means Denali Canada – The Alaska Gas Pipeline (West), Inc.

"Capacity" has the meaning ascribed to such term in Section 23.1 of Article 23 (Capacity Release) of these General Terms and Conditions.

"Central Clock Time" means central daylight time when central savings time is in effect and central standard time when central savings time is not in effect.

"Certificate of Public Convenience and Necessity" means the certificate issued by FERC authorizing Transporter to provide the Services identified in this Tariff.

"Commission" or "FERC" means the Federal Energy Regulatory Commission or any federal commission, agency, or other governmental body or bodies succeeding to, lawfully exercising, or superseding any powers which, as of the date hereof, are exercisable by the Federal Energy Regulatory Commission.

"Commission's Regulations" means the regulations promulgated by the Commission and codified at Part 284 of Title 18 of the Code of Federal Regulations, as the same may by amended or recodified from time to time.

"Compression Agreement" means an agreement for Service under Rate Schedule FC or Rate Schedule IC, pursuant to which Transporter is obligated to provide Compression Service to a Shipper.

"Compression Fuel Requirement" means the Fuel Requirement associated with providing Compression Service under Rate Schedule FC or Rate Schedule IC and allocated to Shipper based on the Quantity of Gas nominated by Shipper for such Compression Service.

"Compression Service" means compressing the Gas Under Rate Schedule FC or Rate Schedule IC at the First Stage Compression Facilities so that the Gas has a pressure and temperature sufficient to enter Transporter's pipeline facilities at the outlet of the First Stage Compression Facilities.

"Cubic Foot" means that volume of Gas occupying one cubic foot when such Gas is at a temperature of 60 degrees Fahrenheit and at a pressure of 14.73 psia.

"Daily" or "Day" means a period beginning at 9:00 a.m. Central Clock Time on a calendar day and ending at 9:00 a.m. Central Clock Time on the following calendar day, unless otherwise mutually agreed in writing by Shipper and Transporter.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Deficient Quantities" has the meaning ascribed to such term in Section 17.5 of Article 17 (Curtailment) of these General Terms and Conditions.

"Delivery Month" means any Month in which Shipper has requested and Transporter has provided Service under the applicable Service Agreement.

"Dekatherm" or "Dth" means the Quantity of energy that is equivalent to ten therms or one million (1,000,000) Btus.

"Delivery Point(s)" means the points listed on Exhibit B of this Tariff, and the applicable Service Agreement, where Transporter delivers Gas to Shippers or for Shippers' Accounts.

"Designated Allocator" means the production operator at the individual measurement point into Transporter's system, or an alternate party designated by the production operator, who will be responsible for providing Transporter with the required predetermined allocations at such measurement point.

"Elapsed Pro Rata Capacity" means that portion of the capacity that would have theoretically been available for use prior to the effective time of the Intraday recall based upon a cumulative uniform hourly use of the capacity.

"Electronic Delivery Mechanism" or "EDM" means the internet website including the interactive bulletin board and information publication system established and maintained by Transporter, as more fully described in Article 28 (Electronic Delivery Mechanism) of these General Terms and Conditions.

"Equivalent Quantities" means the Dekatherms of Gas delivered by Shipper at the applicable Receipt Point under a Service Agreement, less the applicable Fuel Requirement.

"Evening Nomination Cycle" has the meaning ascribed to such term in Subsection 13.6(b) of Article 13 (Nominations) of these General Terms and Conditions.

"Firm Service" means Service provided by Transporter where Shipper has elected to receive Firm Service under the applicable Service Agreement under Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR.

"Firm Transportation Agreement" means an agreement, in the form provided in this Tariff under Rate Schedule FT, pursuant to which Transporter is obligated to provide Firm Transportation Service to a Shipper.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Firm Transportation Service" means Transportation Service, backed by fixed capacity on Transporter's pipeline system, provided by Transporter pursuant to Rate Schedule FT.

"Firm Shippers" has the meaning ascribed to such term in Section 22.2 of Article 22 (Pre-Granted Abandonment) of these General Terms and Conditions.

"First Stage Compression Facility" means Transporter's compression facility located at, or adjacent to, the GTP where Gas is Compressed prior to entering Transporter's high-pressure pipeline system.

"Flow Control" has the meaning ascribed to such term in Article 39 (Flow Control Equipment) of these General Terms and Conditions.

"Force Majeure" has the meaning ascribed to such term in Section 12.1 of Article 12 (Force Majeure) of these General Terms and Conditions.

"Fuel" means all Gas consumed in Transporter's operations.

"Fuel Requirement" has the meaning ascribed to such term in Section 30.1 of Article 30 (Fuel Retention Adjustment) of these General Terms and Conditions.

"Gas" means methane, and such other hydrocarbon and non-hydrocarbon constituents, or a mixture of two or more of them that, in any case, meets the applicable Gas Quality Standards.

"Gas Day" means the period from 9:00 a.m. Central Clock Time on one calendar day to 9:00 a.m. Central Clock Time on the following calendar day, during which Gas is nominated, scheduled, or actually flows.

"Gas Quality Standards" means the applicable quality standards specified in Article 4 (Gas Quality) of these General Terms and Conditions.

"Gas Treating Agreement" means an agreement for Service under Rate Schedule FGT or Rate Schedule IGT, pursuant to which Transporter is obligated to provide Gas Treating Service to a Shipper.

"Gas Treating Fuel Requirement" means the Fuel Requirement associated with providing Treating Service under Rate Schedule FGT or Rate Schedule IGT and allocated to Shipper.

"Gas Treating Service" means the separation of Acid Gas from Shipper's Gas delivered into the GTP and the dehydration of Shipper's Gas under Rate Schedule FGT or Rate Schedule IGT so that it meets the Gas Quality Standards applicable for Compression Service and Transportation Service.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Gas Treatment Plant" or "GTP" means the gas treatment facility subject to the jurisdiction of the Commission under the Alaska Natural Gas Pipeline Act.

"Gross Heating Value" means the quantity of heat (excluding any such heat associated with hydrogen sulfide) in Btus liberated by the complete combustion at constant pressure, of a Cubic Foot of Gas at a temperature of 60 degrees Fahrenheit on a water-free basis and at an absolute pressure of 14.73 psia.

"General Terms and Conditions" means these General Terms and Conditions of Transporter's Tariff, as amended from time to time.

"Imbalances" has the meaning ascribed to such term in Section 16.3 of Article 16 (Resolution of Imbalances and Adjustment) of these General Terms and Conditions.

"Indemnified Person" has the meaning ascribed to such term in Subsection 10.2(a) of Article 10 (Liability of Shipper and Transporter) of these General Terms and Conditions.

"Interruptible Service" means Service provided by Transporter where Shipper has elected to receive Interruptible Service under the applicable Service Agreement under Rate Schedule IT, Rate Schedule IGT, Rate Schedule IC, or Rate Schedule ITR.

"Interruptible Service Agreement" means an agreement, in the form provided in this Tariff, pursuant to which Transporter is obligated to provide Interruptible Service to a Shipper.

"Intraday" means within a Gas Day.

"Intraday 1 Nomination Cycle" has the meaning ascribed to such term in Subsection 13.6(c) of Article 13 (Nominations) of these General Terms and Conditions.

"Intraday 2 Nomination Cycle" has the meaning ascribed to such term in Subsection 13.6(d) of Article 13 (Nominations) of these General Terms and Conditions.

"Lenders" means any Person with whom Transporter, from time to time, has entered into a debt financing arrangement or other loan or credit facility with respect to the financing of Transporter's facilities.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"LIBOR" means, with respect to any date, the "London Interbank Offered Rate" for deposits of six months as such term is quoted by IDD Information Services (as referenced in Dow Jones News Retrieval, a service of Dow Jones & Company, Inc.), with respect to such date; provided, however, that LIBOR with respect to any date that is not a Business Day shall mean LIBOR for the next succeeding Business Day.

"Lost or Unaccounted for Gas" means the Quantity of Gas reasonably determined by Transporter to be lost, or gained, during the provision of any Service, expressed as Dth, other than Gas consumed and measured in Transporter's operations.

"Make-Up Quantities" has the meaning ascribed to such term in Section 17.5 of Article 17 (Curtailment) of these General Terms and Conditions.

"Master Capacity Release Agreement" means an agreement, in the form provided on Transporter's EDM, setting forth the terms and conditions pursuant to which Transporter will provide Service to a Replacement Shipper in the event such Replacement Shipper is awarded Released Capacity pursuant to Article 23 (Capacity Release) of these General Terms and Conditions.

"Matching Period" means the period of time the applicable Pre-Arranged Replacement Shipper and the Releasing Shipper have negotiated during which the Pre-Arranged Replacement Shipper may exercise its right of first refusal.

"Maximum Daily Service Quantity" means the maximum Quantity, as specified in Shipper's Interruptible Service Agreement, which Transporter agrees to receive from Shipper or for Shipper's Account under an Interruptible Service Agreement.

"MDQ" or "Maximum Daily Quantity" means the maximum Quantity, expressed in Dth per Day, which Transporter agrees to receive from Shipper or for Shipper's Account under an agreement for Firm Service. Shipper's MDQs may vary by season, quarter, Month, or any other basis as specified in the applicable Firm Service Agreement, to the extent Transporter has agreed to such variations.

"Maximum Rate" means the applicable maximum Tariff rate Transporter can charge for Service under a Rate Schedule as shown in the currently effective rate sheets of this Tariff, as amended and approved from time to time by the Commission.

"Mcf" means one thousand (1000) Cubic Feet.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Minimum Rate" means the applicable minimum Tariff rate Transporter can charge for Service under a Rate Schedule as shown in the currently effective rate sheets of this Tariff, as amended and approved from time to time by the Commission.

"Month" or "Monthly" means a period extending from 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 succeeding calendar Month, or at such other hour as Shipper and Transporter agree upon.

"Natural Gas Act" or "NGA" means Sections 717 through 717w of Title 15 of the United States Code, as amended or recodified from time to time.

"Negotiated Rate" means a rate that Transporter and Shipper have agreed will be charged for Service under Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR, where, for all or a portion of the contract term, one or more of the individual components of such rate may exceed or otherwise deviate from Transporter's Maximum Rates.

"Negotiated Rate Agreement" has the meaning ascribed to that term in Section 38.3 of Article 38 (Negotiated Rates) of these General Terms and Conditions.

"Nomination(s)" means the information provided by Shipper to Transporter in accordance with Article 13 (Nominations) of these General Terms and Conditions.

"Nomination Party" means the Person making a Nomination.

"Non-Conforming Service Agreement" means a Service Agreement containing provisions that deviate from the provisions (other than the fill-in-the-blank provisions thereof) of the applicable form of Service Agreement attached to this Tariff.

"North American Energy Standards Board" or "NAESB" means the accredited organization established to set standards for certain natural gas industry business practices and procedures.

"NAESB WGQ" means the North American Energy Standards Board Wholesale Gas Quadrant.

"Notice" has the meaning ascribed to that term in Section 21.1 of Article 21 (Notices) of these General Terms and Conditions.

"NPV" means net present value.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Open Season" means an open season seeking Shippers to commit to Service prior to the installation of the applicable facilities, which open season shall be conducted pursuant to the Commission's Regulations.

"Operator" means Transporter or a Person retained by Transporter to operate Transporter's facilities pursuant to Article 24 (Transporter's Facility Operation and Maintenance) of these General Terms and Conditions.

"Operational Flow Order" or "OFO" has the meaning ascribed to such term in Section 31.1 of Article 31 (Operational Flow Orders) of these General Terms and Conditions.

"Permanent Release" means a release of Capacity to a Permanent Replacement Shipper for the entire remaining term of the applicable agreement for Firm Service.

"Permanent Replacement Shipper" has the meaning ascribed to such term in Section 23.21 of Article 23 (Capacity Release) of these General Terms and Conditions.

"Person" means an individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company, or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator, or other legal personal representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted.

"Pre-Arranged Release" means a Capacity release transaction pursuant to Article 23 (Capacity Release) of these General Terms and Conditions wherein the terms of the release are agreed to between the Releasing Shipper and the Replacement Shipper in advance of notifying Transporter or posting the release on Transporter's EDM.

"Pre-Arranged Replacement Shipper" means a Person acquiring Capacity through a Pre-Arranged Release under Article 23 (Capacity Release) of these General Terms and Conditions.

"Precedent Agreement" means an agreement entered into by Transporter and a Shipper as a result of an Open Season, wherein the Shipper and Transporter commit to enter into one or more Service Agreements upon the fulfillment of specified conditions.

"Predetermined Allocation" or "PDA" means the method determined by the Designated Allocator and provided to Transporter in accordance with Article 15 (Allocations) of these General Terms and Conditions to be used by Transporter in allocating the actual gas Volumes and/or Quantities delivered for the Shippers' Accounts from the individual Receipt Point.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Presubscription Agreement" means an agreement entered into by Transporter and a Shipper prior to an Open Season, wherein the Shipper and Transporter commit to enter into one or more Service Agreements upon the fulfillment of specified conditions, consistent with the Commission's Regulations.

"Point Thomson Transmission Receipt Point" has the meaning ascribed to such term in Exhibit A to the Tariff.

"Prudhoe Bay Transmission Receipt Point" has the meaning ascribed to such term in Exhibit A to the Tariff.

"Psia" or "psia" means pounds per square inch absolute.

"Psig" or "psig" means pounds per square inch gauge.

"Quantity" means the applicable amount of Gas calculated in Btu or Dth.

"Rate Schedule" means Transporter's Rate Schedule FT, Rate Schedule IT, Rate Schedule FGT, Rate Schedule IGT, Rate Schedule FC, Rate Schedule IC, Rate Schedule FTR, or Rate Schedule ITR, which defines the conditions of Service provided thereunder.

"Receipt Point" means a point on Transporter's system listed on Exhibit A of this Tariff, at which Shipper may, in accordance with a Service Agreement, tender or cause to be tendered, Gas for Service.

"Released Capacity" means Capacity released by a Releasing Shipper to a Replacement Shipper pursuant to Article 23 (Capacity Release) of these General Terms and Conditions.

"Releasing Shipper" means a Shipper under Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR, who releases Capacity pursuant to Article 23 (Capacity Release) of these General Terms and Conditions.

"Replacement Shipper" means a Person acquiring Released Capacity pursuant to Article 23 (Capacity Release) of these General Terms and Conditions.

"Reservation Charge" means the applicable charge specified in Subsection 4.3(a) of Rate Schedule FT, Subsections 3.3(a) and 3.3(b) of Rate Schedule FGT, Subsection 3.3(a) of Rate Schedule FC, or Subsection 4.3(a) of Rate Schedule FTR.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Right of First Refusal" has the meaning ascribed to such term in Section 22.2 of Article 22 (Pre-Granted Abandonment) of these General Terms and Conditions.

"Service" means Transmission Service, Gas Treating Service, Compression Service, and/or Transportation Service, as applicable.

"Service Agreement" means a Transportation Agreement, a Gas Treating Agreement, a Compression Agreement, a Transmission Agreement, or a Master Capacity Release Agreement between Transporter and Shipper.

"Shipper" means a Person who enters into a Firm Service Agreement with Transporter, or who has acquired Firm Service rights pursuant to the provisions of Article 23 (Capacity Release) of these General Terms and Conditions hereof or, if the context so requires, a Person who has executed an Interruptible Service Agreement with Transporter.

"Shipper's Account" means Shipper's Gas account under the applicable Service Agreement with Transporter.

"Tariff" means Transporter's FERC Gas Tariff, as amended by Transporter and approved by the Commission from time to time.

"Temporary Release" means a release of Capacity for a period of time less than the remaining term of the applicable Service Agreement.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Timely Nomination Cycle" has the meaning ascribed to such term in Subsection 13.6(a) of Article 13 (Nominations) of these General Terms and Conditions.

"Title Transfer(s)" means the transfer by a Shipper of Quantities of Gas from the account of Shipper to the account of another Shipper.

"Transmission" means the receipt of Gas for Shipper's Account at the Receipt Point that is available to Shipper pursuant to Shipper's Firm Transmission Agreement or Interruptible Transmission Agreement, and the delivery of Equivalent Quantities for Shipper's Account at the applicable Delivery Point.

"Transmission Agreement" means an agreement for Service under Rate Schedule FTR or Rate Schedule ITR, pursuant to which Transporter is obligated to provide Transmission Service to a Shipper.

"Transmission Fuel Requirement" means the Fuel Requirement associated with providing Transmission Service under Rate Schedule FTR or Rate Schedule ITR and allocated to Shipper based on the Quantity of Gas nominated by Shipper for such Transmission Service.

"Transmission Service" means the Transmission of Shipper's Gas under Rate Schedule FTR pursuant to a Firm Transmission Agreement or under Rate Schedule ITR pursuant to an Interruptible Transmission Agreement.

"Transportation" means the receipt of Gas for Shipper's Account at the Receipt Point that is available to Shipper pursuant to Shipper's Firm Transportation Agreement or Interruptible Transportation Agreement, and the delivery of Equivalent Quantities for Shipper's Account at the Delivery Point(s).

"Transportation Agreement" means a Firm Transportation or an Interruptible Transportation Agreement between Transporter and Shipper.

"Transportation Service" means the Transportation of Shipper's Gas under Rate Schedule FT pursuant to a Firm Transportation Agreement or under Rate Schedule IT pursuant to an Interruptible Transportation Agreement.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 1 DEFINITIONS (Contd.)

"Transporter" means Denali – The Alaska Gas Pipeline LLC.

"Transporter's Facilities" means the natural gas transportation system and related facilities (including treatment, transmission, and compression facilities) owned and operated by Transporter that carries Gas produced in Alaska to a point or points within Alaska or to a point of interconnection with the Canada Mainline.

"Usage Charge" means the applicable charge specified in Subsection 4.3(b) of Rate Schedule FT, Subsection 3.3(b) of Rate Schedule FGT, Subsection 3.3(b) of Rate Schedule FC, or Subsection 4.3(b) of Rate Schedule FTR.

"Volume" means the applicable amount of Gas calculated in Cubic Feet or Mcf.

"Year" means a period of 365 consecutive days, provided, however, that any such year which contains a date of February 29 shall consist of 366 consecutive days.

Sheet Nos. 204-220 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 2 REQUESTS FOR SERVICE

2.1 To request Service under any Rate Schedule, a potential Shipper shall submit a written request to Transporter by mail or through Transporter's EDM. Transporter will time and date stamp each valid request on the date Transporter receives it and shall evaluate and respond to such requests as soon as is reasonably possible, after receipt of such request. Requests for Service by mail shall be directed to:

Denali – The Alaska Gas Pipeline, LLC
188 W. Northern Lights Blvd., Suite 1300
P. O. Box 241747
Anchorage, Alaska 99524-1747
Attention: Manager Transportation Services

2.2 A valid request for Service under any Rate Schedule must include all information described below, in a form reasonably satisfactory to Transporter:

(a) a completed Service Request Form in the form located on Transporter's EDM in downloadable format;

(b) Shipper's legal name;

(c) Shipper's business address for notices and billing;

(d) Shipper's telephone number, including a telephone number at which Shipper can be contacted 24 hours per day;

(e) character of Service requested (Service under Rate Schedule FT, Rate Schedule IT, Rate Schedule FGT, Rate Schedule IGT, Rate Schedule FC, Rate Schedule IC, Rate Schedule FTR, or Rate Schedule ITR);

(f) requested MDQ for Firm Service or Maximum Daily Service Quantity for Interruptible Service, stated in Dth per Day;

(g) requested date of commencement of Service;

(h) requested term of Service;

(i) documentation providing evidence that Shipper meets Transporter's creditworthiness criteria as described in Article 9 (Creditworthiness) of these General Terms and Conditions;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 2 REQUESTS FOR SERVICE (Contd.)
2.2 (Contd.)

(j) a certification by Shipper that Shipper has title or a current contractual right to acquire title to the Gas to be delivered to Transporter;

(k) if Shipper requests Service on behalf of another Person, Shipper shall submit a copy of an executed agreement between Shipper and the third party, which authorizes Shipper to act on behalf of the third party to secure the Service requested. Shipper shall provide the name, address, telephone number, and status (e.g., local distribution company, producer, etc.) of that Person;

(l) for Transportation Service, a certification by Shipper that Shipper has, or will, enter into arrangements for downstream transportation of comparable Quantities on the applicable downstream pipeline and that these arrangements will be in place prior to commencement of Transportation Service; and

(m) affiliation with Transporter, either as Shipper, supplier, or as the party for whom Service is provided and, if so, the extent of that affiliation.

2.3 A valid request for Firm Service must include the additional information described below:

(a) requested Receipt Point from the Receipt Points listed on Exhibit A of Transporter's Tariff and portion of the MDQ requested at each Receipt Point;

(b) requested Delivery Point(s) from the Delivery Point(s) listed on Exhibit B of Transporter's Tariff and portion of the MDQ requested at each Delivery Point; and

(c) a prepayment to Transporter in an amount equal to the total Reservation Charge applicable to the requested Service for a three-Month period, with a maximum prepayment of [$_______] per Shipper. In the event Transporter is unable to provide the requested Service, or Transporter and Shipper are unable to reach agreement on terms of a final Service Agreement, the prepayment shall be refunded without interest. If a Service Agreement is completed, the prepayments plus any accrued interest thereon calculated at Month-end at the LIBOR (one Month) rate shall be credited to Shipper in the first Monthly billing for the requested Service and each Month thereafter until the credit is used.

Sheet Nos. 223-230 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 3 CONDITIONS GOVERNING SERVICE REQUESTS

3.1 All valid requests for Firm Service received by Transporter after the in-service date of Transporter’s Facilities shall be awarded on a first-come, first-served basis according to the order in which Transporter receives requests.

3.2 Notwithstanding the above, Transporter is not obligated to award capacity for Firm Service to any Shipper that is not willing to pay the Maximum Rates for such Service unless agreed to otherwise by Transporter.

3.3 Subject to Section 3.2 above, Transporter shall be obligated to accept any request for Firm Service provided adequate capacity is available without the construction of additional facilities by Transporter. To the extent Firm capacity becomes available (excluding capacity resulting from a system expansion), Transporter shall, as soon as practicable, post the capacity on Transporter’s EDM for a period of not less than 15 Days and accept bids for such capacity accordingly. Subject to 15 U.S.C. § 720a(h), capacity subject to bidding hereunder shall be awarded first to the contracts generating the highest NPV.

3.4 Within 15 Days, or as otherwise agreed by the parties, after its receipt of a valid request for Service, Transporter shall prepare and tender in writing to Shipper for execution a Service Agreement under the applicable Rate Schedule and in the form attached to this Tariff. Shipper shall execute the Service Agreement as soon as possible thereafter. If Shipper fails to execute and return to Transporter the Service Agreement within 20 Days of the date tendered, Shipper’s request for Service shall be deemed invalid.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 3 CONDITIONS GOVERNING SERVICE REQUESTS (Contd.)

3.5 Transporter shall not be required to perform Service under any Service Agreement for any Shipper who is or has become insolvent, or who fails to demonstrate creditworthiness pursuant to Article 9 (Creditworthiness) of these General Terms and Conditions, or who fails to make payments pursuant to Article 18 (Billing and Payments) of these General Terms and Conditions except if Shipper has disputed a bill and made provision for such payment in accordance with Section 18.8 of Article 18 (Billing and Payments) of these General Terms and Conditions.

3.6 For requests for Firm Service made pursuant to the initial Open Season or to a subsequent Open Season, Transporter will provide information regarding timing and other requirements for participation by potential Shippers. All valid requests for Firm Service received as part of an Open Season will be deemed as received simultaneously at the beginning of such Open Season for Capacity allocation purposes.

Sheet Nos. 233-240 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 4 GAS QUALITY

4.1 Gas delivered by Shipper, or for Shipper’s Account, at the applicable Receipt Point shall conform to the following Gas Quality Standards:

(a) Gas tendered for delivery for Transmission Service at the Point Thomson Transmission Receipt Point shall conform to the following Gas Quality Standards, any of which may be waived by Transporter in its discretion on a not unduly discriminatory basis. Such Gas shall:

(i) be commercially free from dust, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the pipeline, regulators, meters, or other equipment;

(ii) contain no more than 90 parts per million by volume of hydrogen sulfide;

(iii) contain no more than 12 parts per million by volume of other sulfur compounds (including no more than 0.22 grains of methyl mercaptan per 100 Cubic Feet), with composition adjusted to 2.0 mole % carbon dioxide;

(iv) have an oxygen content of 0.1 mole % or less;

(v) contain 13.0 mole % or less of carbon dioxide; provided, however, Gas with a carbon dioxide content in excess of 13.0 mole % will be accepted at the Point Thomson Transmission Receipt Point by Transporter in a not unduly discriminatory manner to the extent GTP treating capacity is available without pro-rating shippers who meet the carbon dioxide inlet specifications;

(vi) contain total inert substances (other than carbon dioxide) of no more than 2.0 mole %;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (contd.)
4.1 (Contd.)
(a) (Contd.)

(vii) contain water vapor of 0.3 pounds or less per million Cubic Feet;

(viii) contain 0.05 mole % or less of C6+ hydrocarbon components;

(ix) have a cricondenbar of 1200 psia or lower;

(x) have a temperature between 90 degrees Fahrenheit and 100 degrees Fahrenheit, inclusive;

(xi) have a Gross Heating Value of not less than 967 Btu per Cubic Foot, with composition adjusted to 2.0 mole % carbon dioxide; and

(xii) not contain any component or mix of components that may cause the presence of any liquid anywhere in Transporter’s facilities under normal operating conditions.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)
4.1 (Contd.)

(b) Gas tendered for delivery for Transmission Service at the Prudhoe Bay Transmission Receipt Point shall conform to the following Gas Quality Standards, any of which may be waived by Transporter in its discretion on a not unduly discriminatory basis. Such Gas shall:

(i) be commercially free from dust, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the Transmission pipeline, regulators, meters, or other equipment;

(ii) contain no more than 90 parts per million by volume of hydrogen sulfide;

(iii) contain no more than 12 parts per million by volume of other sulfur compounds (including no more than 0.22 grains of methyl mercaptan sulfur per 100 Cubic Feet), with composition adjusted to 2.0 mole % carbon dioxide;

(iv) have an oxygen content of 0.1 mole % or less;

(v) contain 13.0 mole % or less of carbon dioxide; provided, however, Gas with a carbon dioxide content in excess of 13.0 mole % will be accepted at the Prudhoe Bay Transmission Receipt Point by Transporter in a not unduly discriminatory manner to the extent GTP treating capacity is available without pro-rating shippers who meet the carbon dioxide inlet specifications;

(vi) contain total inert substances (other than carbon dioxide) of no more than 2.0 mole %;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)
4.1 (Contd.)
(b) (Contd.)

(vii) contain water vapor of 0.3 pounds or less per million Cubic Feet;

(viii) contain 0.05 mole % or less of C6+ hydrocarbon components;

(ix) have a cricondenbar of 1200 psia or lower;

(x) have a temperature between 45 degrees Fahrenheit and 80 degrees Fahrenheit, inclusive;

(xi) have a Gross Heating Value of not less than 967 Btu per Cubic Foot, with composition adjusted to 2.0 mole % carbon dioxide; and

(xii) not contain any component or mix of components that may cause the presence of any liquid anywhere in Transporter’s facilities under normal operating conditions.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)
4.1 (Contd.)

(c) Gas tendered for delivery for Gas Treating Service shall conform to the following Gas Quality Standards, any of which may be waived by Transporter in its discretion on a not unduly discriminatory basis. Such Gas shall:

(i) be commercially free from dust, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the Gas Treatment Plant, regulators, meters, or other equipment;

(ii) contain no more than 90 parts per million by volume of hydrogen sulfide;

(iii) contain no more than 12 parts per million by volume of other sulfur compounds (including no more than 0.22 grains of methyl mercaptan sulfur per 100 Cubic Feet), with composition adjusted to 2.0 mole % carbon dioxide;

(iv) have an oxygen content of 0.1 mole % or less;

(v) contain 13.0 mole % or less of carbon dioxide; provided, however, Gas with a carbon dioxide content in excess of 13.0 mole % will be accepted at the GTP by Transporter in a not unduly discriminatory manner to the extent GTP treating capacity is available without pro-rating shippers who meet the carbon dioxide inlet specifications;

(vi) contain total inert substances (other than carbon dioxide) of no more than 2.0 mole %;

(vii) contain 0.05 mole % or less of C6+ hydrocarbon components;

(viii) have a cricondenbar of 1200 psia or lower;

(ix) have a temperature between 45 degrees Fahrenheit and 80 degrees Fahrenheit, inclusive; and

(x) have a Gross Heating Value of not less than 967 Btu per Cubic Foot, with composition adjusted to 2.0 mole % carbon dioxide.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)
4.1 (Contd.)

(d) Gas tendered for delivery by Shipper for Compression Service or Transportation Service shall conform to the following Gas Quality Standards, or any more stringent quality specifications of a downstream pipeline, any of which may be waived by Transporter in its discretion on a not unduly discriminatory basis. Such Gas shall:

(i) be commercially free from dust, gums, gum-forming constituents, dirt, impurities, or other solid or liquid matter that might cause injury to or interference with proper operation of the compressors, pipeline, regulators, meters, or other equipment;

(ii) contain no more than 4 parts per million by volume of hydrogen sulfide;

(iii) contain no more than 0.22 grains of methyl mercaptan sulfur per 100 Cubic Feet and no more than 16 parts per million by volume of total sulfur (including the sulfur in any hydrogen sulfide and methyl mercaptan sulfur);

(iv) have an oxygen content of 0.4 mole % or below;

(v) have a carbon dioxide content of 2.0 mole % or below;

(vi) contain total inert substances (carbon dioxide, nitrogen, helium, oxygen, or any other diluents compound) of no more than 4.0 mole %;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)
4.1 (Contd.)
(d) Contd.)

(vii) contain water vapor of 0.8 pounds or less per million Cubic Feet;

(viii) contain 0.05 mole % or less of C6+ hydrocarbon components;

(ix) have a cricondenbar of 1200 psia or lower;

(x) have a temperature between 20 degrees Fahrenheit and 30 degrees Fahrenheit, inclusive;

(xi) have a Gross Heating Value of not less than 967 Btu per Cubic Foot; and

(xii) not contain any component or mix of components that may cause the presence of any liquid anywhere in Transporter’s facilities under normal operating conditions.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)

4.2 If the Gas tendered for delivery by Shipper fails at any time to meet the above Gas Quality Standards, Transporter may refuse to accept the Gas, in which case Transporter will, as soon as possible, inform Shipper of such failure to allow Shipper to promptly remedy any deficiency in quality. Any such refusal to accept Gas shall not relieve Shipper from any obligation to pay any rate, charge, or other amount payable to Transporter.

4.3 Transporter reserves the right to waive any or all such Gas Quality Standards, in a not unduly discriminatory manner, if it is determined by Transporter that such waiver can be granted without, in any way, jeopardizing the integrity of its system or violating any requirements of downstream systems.

4.4 No waiver by Transporter of any failure by Shipper to meet any of the above quality specifications shall constitute a continuing waiver of such specification or constitute a waiver of any subsequent failure whether of a like or different character.

4.5 If any Gas tendered for delivery by Shipper causes the composite Gas stream in Transporter’s facilities to fail the Gas quality specifications of a downstream pipeline, Transporter may take whatever action is necessary on its own accord or by use of a another Person, as solely determined by Transporter, to treat and/or process the Gas stream at Shipper’s sole cost and expense such that the Gas stream can be made acceptable to the applicable downstream pipelines. Until remedial action is taken to make Gas acceptable to downstream pipelines, Transporter may refuse to accept receipt of any Gas that, in Transporter’s sole discretion, prevents Transporter from making deliveries into downstream pipelines.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 4 GAS QUALITY (Contd.)

4.6 Transporter shall deliver Equivalent Quantities of Gas for the account of Shipper.

4.7 Gas Processors Association or American Society of Testing and Materials adopted and approved test methods shall be used in verifying compliance with the requirements of this Article.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 5 MEASUREMENT

5.1 The unit of measurement shall be one Cubic Foot of Gas. The readings and recordings of the measuring equipment provided for herein and determinations of Gross Heating Value shall be computed in terms of such measurement.

5.2 The unit of energy for purposes of measurement shall be one Dth. This will also be the unit of energy for all Gas received and delivered by Transporter. The number of Dth delivered shall be determined by multiplying the number of Cubic Feet of Gas received or delivered, measured on the measurement bases herein specified, by the Gross Heating Value of such Gas, in Btu's per Cubic Foot, and dividing the product by one million.

5.3 The average absolute atmospheric (barometric) pressure shall be assumed to be 14.73 psia, irrespective of actual elevation or location of the points of measurement above sea level or variations in actual barometric pressure from time to time.

5.4 The temperature of the Gas shall be determined at each point of measurement by means of a properly installed recording thermometer or temperature transmitter of standard manufacture.

5.5 The specific gravity of the Gas shall be determined at each point of measurement by continuous sampler and Gas chromatograph or, in the absence of such equipment, other methods mutually agreed upon by Transporter and Shipper.

5.6 The supercompressibility of the Gas (deviation from the laws for ideal gases) shall be determined by use of the tables or formulas published in the applicable American Gas Association Report referred to in Section 5.8 of this Article 5 (Measurement).

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 5 MEASUREMENT (Contd.)

5.7 The Gross Heating Value of the Gas received at each Receipt Point, and the Gross Heating Value of the Gas delivered at each Delivery Point shall be determined, at least Monthly, by use of a continuous sampler and Gas chromatograph or, in the absence of such equipment, other methods mutually agreed upon by Transporter and Shipper. For the purposes of scheduling receipts and deliveries, the Gross Heating Value of the Gas so determined at each such point of measurement shall be deemed to remain constant for such point until the next determination.

5.8 To determine the Volume and Quantity of Gas received and delivered by Transporter, calculations shall be made that incorporate use of required factors such as pressure, temperature, specific gravity, and supercompressibility in accordance with the American Gas Association Report Number 3 and any modifications and amendments thereof, or in the event ultrasonic meters are used, in accordance with American Gas Association Report Number 9 and any modifications and amendments thereof, and applied in a practical manner. Any determination for a given Month shall make use of samples taken during that Month and factors developed for that Month.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 6 MEASUREMENT EQUIPMENT

6.1 All meters and measuring equipment for the determination of Volume, Gross Heating Value, and specific gravity shall be approved pursuant to, and installed and maintained in accordance with the currently published standards of the American Gas Association, or as mutually agreed upon by Transporter and Shipper.

6.2 Notwithstanding the foregoing, all installation of equipment applying to or affecting deliveries of Gas shall be made in such manner as to permit an accurate determination of the Volume and Quantity of Gas delivered and ready verification of the accuracy of measurement. Both Shipper and Transporter shall exercise care in the installation, maintenance, and operation of pressure regulating equipment so as to prevent any inaccuracy in the determination of the Volume or Quantity of Gas delivered under the Service Agreement(s).

6.3 The accuracy of measuring equipment shall be verified by Transporter once each Month or at such longer intervals as agreed to by the parties, and if requested, the verification shall take place in the presence of representatives of Shipper. Transporter will verify the accuracy of measurement equipment whenever requested by Shipper, provided requests do not require verification more than once each Month. In the event either Transporter or Shipper notify the other that it desires a special test of any measuring equipment the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment is found to be in error by not more than the limits set out as follows:

(a) 1.5% for measuring equipment utilized to measure Volume, or

(b) 1.0% for any instrument utilized to determine specific gravity or Gross Heating Value.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 6 MEASUREMENT EQUIPMENT (Contd.)

6.4 If upon test, any measuring equipment is found to be in error by not more than the limits specified above, the previous readings of such equipment shall be considered accurate in computing deliveries or receipts of Gas but such equipment will be adjusted at once to register accurately.

6.5 If upon test, any measuring equipment is found to be in error by an amount exceeding the limits specified above, then the previous readings of measurement equipment and/or instruments utilized to determine the Volume, specific gravity, or Gross Heating Value, as the case may be, shall be corrected to zero for any period known definitely or that can be agreed upon, but if the period is not known definitely or cannot be agreed upon, such corrections shall be for a period covering the last half of the time elapsed since the date of the last test.

6.6 The cutoff for the closing of measurement is five Business Days after the Month of flow. If an error is discovered in the measured Volumes or Quantities, claims therefor shall be made within six Months of the Month of flow in which the claimed error occurred. The time for dispute or resolution of the claim shall be three Months from the date the claim is made. If there is an agreement as to the amount of an error, any adjustment shall be made within 30 Days of the determination thereof. Such time limits shall not apply in the case of deliberate omission or misrepresentation, or mutual mistake of fact.

6.7 Transporter will install, maintain, and operate, or will cause to be installed, maintained, and operated, at or near each Receipt Point a measuring station equipped with a meter or meters and other necessary equipment for accurate measurement of the Gas received or delivered.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 6 MEASUREMENT EQUIPMENT (Contd.)

6.8 Shipper may install, maintain, and operate, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Transporter's measuring equipment.

6.9 Each party shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in conjunction with the other's equipment used in measuring receipts and deliveries hereunder. The records from such measurement equipment shall remain the property of their owner, but, upon request, each party will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within 30 Days after receipt thereof. Each party shall preserve for a period of at least two Years all test data, charts, and other similar records or for such longer period as may be required by FERC.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 7 RECEIPT AND DELIVERY POINT(S)

7.1 The Receipt Points hereunder shall be the points where Gas is received into Transporter's facilities. Transporter will make all Receipt Points available to all Shippers as defined in Sections 7.2 and 7.3 of this Article 7 (Receipt and Delivery Point(s)). A current list of all Receipt Points is shown on Exhibit A.

7.2 Shipper's Receipt Point(s) will be set forth on Exhibit A of Shipper's Service Agreement.

7.3 The Delivery Point(s) hereunder shall be the points of connection between Transporter's facilities and the facilities of Shipper or a third party, as specified in Exhibit B and the applicable Service Agreement, or other points that may be added from time to time. A current list of all Delivery Points is shown on Exhibit B.

7.4 Shipper's Delivery Point(s) will be set forth on Exhibit A of Shipper's Service Agreement.

Sheet Nos. 282-290 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 8 PRESSURE

8.1 All Gas delivered by Shipper or on behalf of Shipper to Shipper’s Account at a Receipt Point shall be delivered at Transporter’s prevailing line pressure; provided, however:

(a) all Gas delivered by Shipper or on behalf of Shipper to Shipper’s Account at the Prudhoe Bay Transmission Receipt Point under a Transmission Service Agreement shall be delivered at a pressure not in excess of 650 psig or less than 550 psig;

(b) all Gas delivered by Shipper or on behalf of Shipper to Shipper’s Account at the Point Thomson Transmission Receipt Point under a Transmission Service Agreement shall be delivered at a pressure not in excess of 1,000 psig;

(c) all Gas delivered by Shipper or on behalf of Shipper to Shipper’s Account at a Receipt Point into the GTP or the First Stage Compression Facility shall be delivered at a pressure not in excess of 650 psig or less than 550 psig; and

(d) in no instance shall Shipper be required to deliver, or Transporter be obligated to receive, Gas downstream of the First Stage Compression Facilities at a receipt pressure in excess of 2,500 psig.

8.2 All Gas delivered by Transporter for Shipper’s Account shall be made at the prevailing pressure of the downstream transporter, not to exceed Transporter’s normal operating pressure immediately upstream of such Delivery Point, or as agreed to by Transporter and the downstream transporter.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 9 CREDITWORTHINESS

9.1 Shipper shall at all times comply with one of the following creditworthiness requirements:

(a) Shipper has an investment grade rating for its long-term senior unsecured debt, unsubordinated and without third-party enhancement, from a recognized rating agency. The minimum acceptable rating from each of the indicated rating agencies is: (i) Moody's – Baa2 or better; and (ii) Standard & Poors – BBB or better. In the event Shipper is rated by multiple agencies, the lowest rating shall be used.

(i) Other equivalent ratings from recognized rating agencies will be acceptable, as determined by Transporter in its reasonable opinion.

(ii) A Shipper who qualifies under this category initially as of the date the applicable Service Agreement is executed, but is later downgraded (or whose guarantor is downgraded, as applicable) below the ratings specified in Section 9.1(a) will be required to qualify under another category below.

(b) A Shipper who does not have an acceptable rating as outlined above will be accepted as creditworthy at the time of the Shipper's request for Service or at any future time that, in Transporter's reasonable judgment, Shipper no longer meets the creditworthiness requirements of this Article 9 (Creditworthiness), if Transporter and its Lenders determine that, notwithstanding the absence of an acceptable rating, the financial position of Shipper is acceptable to Transporter and its Lenders. In making the determination of whether the financial position of Shipper is acceptable to Transporter and its Lenders, Transporter may consider the following information:

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

(ii) the pro forma effect on Shipper's debt rating of execution by Shipper of any Service Agreement;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 9 CREDITWORTHINESS (Contd.)
9.1 (Contd.)
(b) (Contd.)

(iii) financial statements and reports;

(iv) 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;

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

(vi) 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;

(vii) 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); and

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

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 9 CREDITWORTHINESS (Contd.)
9.1 (Contd.)

(c) A Shipper who, at the time of execution and delivery of a Service Agreement, or at any time thereafter while Shipper is bound thereby, becomes ineligible under Subsection 9.1(a) or (b) above, must, within 15 Business Days of receiving Notice from Transporter, provide sufficient information requested to establish Shipper's eligibility under Subsection 9.1(a) or (b) above, or provide security for its obligations by:

(i) posting a letter of credit or pledging a cash deposit, in an amount equal to the amount of the letter of credit, as set forth below; provided, however, for cash deposits, the first Month of estimated Reservation Charges must be deposited with Transporter within 15 Business Days of Shipper's receipt of the Notice and the remainder of the cash deposit must be deposited with Transporter within 30 Days after Shipper's receipt of the Notice;

(ii) providing an unconditional and irrevocable written guarantee, on Transporter's usual form, from a Person who meets the criteria set forth in Subsection 9.1(a) above guaranteeing the obligations of Shipper; or

(iii) providing other security acceptable to Transporter and, to the extent deemed necessary, its Lenders.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 9 CREDITWORTHINESS (Contd.)
9.1 (Contd.)

(d) A letter of credit or pre-paid cash deposit under Subsection 9.1(c) above shall be in the following amounts:

(i) With respect to a Shipper under an agreement for Firm Service or a Master Capacity Release Agreement, an amount equal to three Months of estimated Reservation Charges, such security to be adjusted annually to reflect any change in the estimated Reservation Charges for the upcoming three Months;

(ii) With respect to a Shipper under an Interruptible Service Agreement, such security shall be equal to the Maximum Daily Service Quantity in Shipper’s Interruptible Service Agreement, multiplied by the Maximum Rate specified in the applicable Rate Schedule, multiplied by 30, and shall be adjusted from time to time to reflect changes to Shipper’s Maximum Daily Service Quantity or to the Maximum Rate in the applicable Rate Schedule.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 9 CREDITWORTHINESS (Contd.)

9.2 Transporter shall maintain on its EDM an Approved Bidders List containing the names of the parties eligible to bid for Released Capacity under Article 23 (Capacity Release) hereof. A prospective Replacement Shipper is not eligible to submit a valid bid for Service unless its name appears on the Approved Bidders List.

(a) In order to be listed on the Approved Bidders List, a prospective Replacement Shipper must meet the creditworthiness requirements of Subsection 9.1(a) or (b) of this Article 9.1 (Creditworthiness), or post a letter of credit or other security acceptable to Transporter and, to the extent deemed necessary, its Lenders, pursuant to Subsection 9.1(c) of this Article 9.1 (Creditworthiness).

(b) If a prospective Replacement Shipper satisfies the requirements of this Article 9 (Creditworthiness) by satisfying the criteria of Subsection 9.1(a), by a determination by Transporter and, to the extent necessary its Lenders, pursuant to Subsection 9.1(b), or by posting a letter of credit or other security acceptable to Transporter and, to the extent necessary, its Lenders, pursuant to Subsection 9.1(c), such prospective Replacement Shipper shall be eligible to bid for released Capacity for a rate and term such that the maximum financial obligation under such bid (excluding amounts bid for AOS service) shall not exceed an amount determined by Transporter. Such amount shall be the prospective Replacement Shipper’s “Bid Limit”, which may change from time to time.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 9 CREDITWORTHINESS (Contd.)
9.2 (Contd.)

(c) Prospective Replacement Shippers Bid Limits shall be adjusted downward from time to time in an amount equivalent to the maximum financial obligation (excluding amounts bid for AOS service) under any bid that is accepted and results in the acquisition of Released Capacity, and shall be readjusted upward upon the expiration of such Released Capacity. Such adjusted Bid Limits shall be posted on Transporter’s Approved Bidders List.

(d) On any Day, a prospective Replacement Shipper may make multiple, simultaneous bids for Capacity offered (provided that each individual bid is in compliance with the prospective Replacement Shipper’s Bid Limit) which, if accepted in the aggregate, would exceed the prospective Replacement Shipper’s Bid Limit. If multiple awards of such Capacity are made in such circumstances that, in the aggregate, exceed the applicable Bid Limit: (i) such Replacement Shipper’s Bid Limit shall be reduced to $0.00, and (ii) Transporter shall notify the Replacement Shipper that it must post a letter of credit or cash deposit within seven Days in an amount equal to or greater than the difference between the Bid Limit that was in effect prior to the awards of Capacity and the additional maximum financial obligation under the awards of such Capacity. If the Replacement Shipper fails to post such letter of credit or cash deposit within the seven Days, the award of such Capacity shall be invalidated as of the next Day following such seven-Day period and the Capacity shall revert to the Releasing Shipper.

(e) A prospective Replacement Shipper may be removed from the Approved Bidders List if Transporter determines that such prospective Replacement Shipper is no longer creditworthy under the criteria of this Article 9 (Creditworthiness), or that such prospective Replacement Shipper has failed to comply with Transporter’s General Terms and Conditions, any applicable Rate Schedule, or any Service Agreement.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 10 LIABILITY OF SHIPPER AND TRANSPORTER

10.1 For the purpose of determining the liability of Transporter and Shipper, respectively, Shipper shall be deemed to be in exclusive control and possession of the Gas for which any Service is provided by Transporter (a) until such Gas has been actually received by Transporter at a Receipt Point, and (b) after the Gas has been delivered to or for the Shipper's Account hereunder by Transporter at a Delivery Point. Transporter shall be deemed to be in exclusive control and possession of the Gas for which any Service is provided by Transporter (a) after it is received by Transporter at the applicable Receipt Point, and (b) until it is delivered to Shipper of for Shipper's Account at the applicable Delivery Point.

10.2 The party deemed to be in control and possession of the Gas as described in Section 10.1 above shall:

(a) be liable to the other party and each of its directors, officers, contractors, agents, and employees (each, an "Indemnified Person") for any losses, claims, liabilities, damages, and expenses, including court costs and reasonable attorneys' fees (except punitive, incidental, consequential, or special damages), which any of them may sustain, pay, or incur; and

(b) indemnify and save harmless each Indemnified Person from all actions, proceedings, claims, and demands brought against any of them

arising therefrom, except to the extent such losses, claims, liabilities, and expenses arise from any Indemnified Person's sole, joint, or concurrent negligence, or gross negligence, or intentional or willful misconduct.

10.3 Except as set out in Section 17.5 of Article 17 (Curtailment) of these General Terms and Conditions, Transporter shall have no liability to Shipper, nor obligation to indemnify and save harmless Shipper, with respect to Transporter's failure for any reason whatsoever to accept receipt of, or deliver Gas pursuant to any Service Agreement between Transporter and Shipper.

Sheet Nos. 322-330 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 11 WARRANTY OF TITLE AND INDEMNIFICATION

11.1 Shipper warrants to Transporter that it will at the time Shipper tenders, or causes to be tendered, Gas for Service hereunder have title to or good right to tender Gas to Transporter, free and clear of liens and encumbrances and adverse claims of every kind. Shipper further warrants to Transporter that it will at any time Shipper tenders, or causes to be tendered, Gas for Service, have all governmental, regulatory, and other authorizations required to permit such Gas to be treated, compressed, and/or transported hereunder, including but not limited to, U.S. export authorizations.

11.2 Shipper further warrants to Transporter that all Gas tendered, or caused to be tendered, by Shipper under a Service Agreement shall be free from adverse claims of any Person with respect to such Gas, including any claims for taxes, licenses, fees, royalties, or charges.

11.3 Transporter warrants to Shipper that at the time of delivery of Gas to Shipper such Gas will be free and clear of all liens and encumbrances arising as part of Transporter’s activities. Title to the Gas received by Transporter at the Receipt Point(s) shall not pass to Transporter except as specified in Section 16.9 of Article 16 (Resolution of Imbalances and Adjustment) and Section 30.5 of Article 30 (Fuel Retention Adjustment) of these General Terms and Conditions.

11.4 Transporter and Shipper will each:

(a) be liable to each Indemnified Person for any losses, claims, liabilities, damages, and expenses, including court costs and reasonable attorneys’ fees (except punitive, incidental, consequential, or special damages), which any of them may sustain, pay, or incur; and

(b) indemnify and save harmless each Indemnified Person from all actions, proceedings, claims, and demands brought against any of them

arising out of a breach of such party’s warranty set forth in Section 11.1, 11.2, or 11.3 above, except to the extent such losses, claims, liabilities, and expenses arise from any Indemnified Person’s sole, joint, or concurrent negligence, or gross negligence, or intentional or willful misconduct.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 12 FORCE MAJEURE

12.1 Force Majeure means any acts of God; war; civil insurrection, disturbance, or disobedience; acts of public enemy; strikes, lockouts, or other industrial disturbances; accidents; blockades; riots; epidemics; landslides; lightning; earthquakes; avalanches; explosions; fires; storms; floods and washouts; arrests and restraints of government and people, either federal or state, civil or military; breakage or accidents to machinery or lines of pipe; freezing of machinery or lines of pipe; emergency shutdowns for purposes of necessary repairs, relocation, or construction of facilities; the necessity for testing wells, production facilities, pipelines or other facilities (as required by government authority or as deemed necessary by the testing party for safe operation thereof); failure of wells, surface equipment, or pipelines; inability to obtain materials, supplies, permits, or labor; inability of a downstream pipeline to receive Gas for any of the foregoing reasons; or other cause whether of the kind enumerated or otherwise, which is beyond the control of any applicable party and which by the exercise of due diligence such party is unable to prevent or overcome. The following shall not be events of Force Majeure: (a) insufficiency of Shipper's Gas supplies; (b) inadequate or uneconomic markets for Shipper's Gas; or (c) Shipper's lack of funds.

12.2 If either Transporter or Shipper fails to perform any obligations under the Tariff or any Service Agreement due to an event of Force Majeure or any other event beyond its reasonable control, then, subject to the provisions of the Tariff (including, but not limited to, Subsection 12.4(c) of this Article 12 (Force Majeure)) and such Service Agreement, such failure shall be deemed not to be a breach of such obligations and that party shall be relieved of its obligation to perform for a number of Days equal to the number of Days during which the relevant event existed.

12.3 A party that fails to perform any obligation under the Tariff or Service Agreement where such failure is caused by an event of Force Majeure, shall (a) give written Notice to the other party specifying full particulars of such Force Majeure as soon as reasonably possible, with a reasonable estimated date of when the Force Majeure will be remedied; (b) as far as possible remedy such Force Majeure as soon as reasonably possible (but the settlement of strikes, lockouts, or other labor disputes shall be entirely within the discretion of the party having the difficulty); and (c) give written Notice to the other party as soon as reasonably possible after such Force Majeure has been remedied.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 12 FORCE MAJEURE (Contd.)

12.4 Notwithstanding the provisions of this Article 12 (Force Majeure), no event referred to herein shall:

(a) relieve any party from any obligation or obligations pursuant to the Tariff or Service Agreement unless such party gives Notice with reasonable promptness of such event to the other party;

(b) relieve any party from any obligation or obligations pursuant to the Tariff or Service Agreement after the expiration of a reasonable period of time within which, by the use of due diligence, such party could have remedied or overcome the consequences of such event;

(c) relieve either party from its obligations to make payments of amounts as provided in the applicable Rate Schedule; or

(d) relieve any party from any obligation or obligations pursuant to the Tariff or Service Agreement in the event of its contributory negligence or misconduct.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 13 NOMINATIONS

13.1 For Service under each Service Agreement, Shipper shall provide Transporter with a "Nomination" reflecting Shipper's contract numbers, the applicable Rate Schedule, the Quantities of Gas that Shipper desires to be delivered from the specified Receipt Point to specified Delivery Point(s) on Transporter's system, and such other information as Transporter reasonably determines to be necessary.

13.2 Transporter shall support a seven-days-a-week, twenty-four-hours-a-day Nomination process.

13.3 Whenever Shipper desires Service, Shipper shall furnish to Transporter a separate Nomination for each nominated Receipt and Delivery Point with a beginning and end date, or beginning hour if applicable, for flow which can be for any duration within the term of the applicable Service Agreement; provided, however, any such Nomination shall not be binding to the extent Shipper submits subsequent Nominations. All Nominations should be considered original Nominations and must be replaced in order to be deemed changed. When a Nomination for a date range is received, each Day within the 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 prospective effect only.

13.4 Nominations are to be provided to Transporter under the timeline set forth under Section 13.6 of this Article 13 (Nominations) via Transporter's EDM. All such postings for Nomination purposes shall comply with all format and protocol requirements specified by Transporter.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)

13.5 In addition to the Receipt Points listed on Exhibit A, Shippers may, as part of a Nomination, request Title Transfers to and from the receipt accounts of other Shippers. Shippers may also nominate for Title Transfers from Shipper's Delivery Point(s) to the delivery accounts of other Shippers. If both Shippers confirm such Title Transfers through matching and equal Nominations, all remaining Nominations, scheduling, and curtailment procedures will be implemented based on the parties' aggregate Nominations, net of such Title Transfers.

13.6 Transporter supports the following standard Nomination cycles:

(a) The Timely Nomination Cycle: 11:30 a.m. for Nominations leaving control of the Nominating Party; 11:45 a.m. for receipt of nominations by Transporter (including from Title Transfer Tracking Service Providers (TTTSP's)); noon to send Quick Response; 3:30 p.m. for receipt of completed confirmations by Transporter from upstream and downstream connected parties; 4:30 p.m. for receipt of scheduled Volumes and Quantities by Shipper and point operator; the cycle being know as the "Timely Nomination Cycle." (All times shown are Central Clock Time on the Day prior to flow).

(b) The Evening Nomination Cycle: 6:00 p.m. for Nominations leaving control of the Nominating Party; 6:15 p.m. for receipt of Nominations by Transporter (including from TTTSP's); 6:30 p.m. to send Quick Response; 9:00 p.m. for receipt of completed confirmations by Transporter from upstream and downstream connected parties; 10:00 p.m. for Transporter to provide scheduled Volumes and Quantities to affected Shippers and point operators, and to provide scheduled Volumes and Quantities to bumped parties (notice to bumped parties); the cycle being known as the "Evening Nomination Cycle". (All times shown are Central Clock Time on the Day prior to flow). Scheduled Volumes and Quantities resulting from an Evening Nomination that do not cause another Service requester to receive notice that it is being bumped should be effective at 9:00 a.m. Central Clock Time on the Gas Day; and when an Evening Nomination causes another Service requester on Transporter to receive notice that it is being bumped, the scheduled Quantities should be effective at 9:00 a.m. on the Gas Day.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)
13.6 (Contd.)

(c) The Intraday 1 Nomination Cycle: 10:00 a.m. for Nominations leaving control of the Nominating Party; 10:15 a.m. for receipt of Nominations by Transporter (including from TTTSP's); 10:30 a.m. to send Quick Response; 1:00 p.m. for receipt of completed confirmations by Transporter from upstream and downstream connected parties; 2:00 p.m. for Transporter to provide scheduled Volumes and Quantities to affected Shippers and point operators, and to provide scheduled Volumes and Quantities to bumped parties (notice to bumped parties); the cycle being known as the "Intraday 1 Nomination Cycle". (All times shown are Central Clock Time on the Gas Day). Scheduled Volumes and Quantities resulting from Intraday 1 Nominations should be effective at 5:00 p.m. Central Clock Time on the Gas Day.

(d) The Intraday 2 Nomination Cycle: 5:00 p.m. for Nominations leaving control of the Nominating party; 5:15 p.m. for receipt of Nominations by Transporter (including from TTTSP's); 5:30 p.m. to send Quick Response; 8:00 p.m. for receipt of completed confirmations by Transporter from upstream and downstream connected parties; 9:00 p.m. for Transporter to provide scheduled Volumes and Quantities to affected Shippers and point operators; the cycle being known as the "Intraday 2 Nomination Cycle". (All times shown are Central Clock Time on the Gas Day). Scheduled Volumes and Quantities resulting from Intraday 2 Nominations should be effective at 9:00 p.m. on the Gas Day. Bumping is not allowed during the Intraday 2 Nomination Cycle.

(e) For purposes of the Evening, Intraday 1, and Intraday 2 Nomination Cycles, "provide" shall mean, for transmittals pursuant to NAESB Standard 1.8, receipt at the designated site, and for purposes of other forms of transmittal, it shall mean send or post.

(f) With the exception of otherwise stated NAESB Nomination deadlines, when Transporter receives a Nomination from a Shipper by the conclusion of a given quarter hour period, Transporter will send to the Shipper's designated site a corresponding Quick Response document by the conclusion of the subsequent quarter hour period.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)
13.6 (Contd.)

(g) The quarter hour periods will be defined to begin on the hour and at 15, 30, and 45 minutes past the hour. A given quarter hour will contain all transactions whose receipt time is less than the beginning of the subsequent quarter hour.

(h) Transporter’s nightly processing and routine maintenance occurring outside of normal business hours are apt to interrupt the normal schedule for Nominations/Quick Response turnaround stated above. Such delays should be kept to a minimum. The normal schedule should be resumed at the earliest opportunity and no later than the start of normal working hours the following Day, seven Days per week.

(i) The Timely Nomination Cycle and Evening Nomination Cycle pertain to Transportation for the upcoming Gas Day. The Intraday 1 Nomination Cycle and Intraday 2 Nomination Cycle pertain to the current Gas Day. Transporter will process Nominations in addition to the four supported Nomination cycles subject to the additional Intraday Nomination subsections herein, and accordingly Transporter is not required to hold capacity for Nominations until a standard Nomination cycle.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)

13.7 The following additional requirements apply to Intraday Nominations.

(a) An Intraday Nomination is a Nomination submitted after the Nomination deadline for the Timely Nomination Cycle, as outlined in Subsection 13.6(a) of this Article 13 (Nominations), whose effective time is no earlier than the beginning of the Gas Day and runs through the end of that Gas Day. The Evening, Intraday 1, and Intraday 2 Nomination Cycles constitute Transporter's standard Intraday Nomination opportunities. All Nominations, including Intraday Nominations, should be based on a Daily Volume and Quantity; thus, an intraday nominator need not submit an hourly Nomination. Intraday Nominations must include an effective date and time. The interconnected parties should agree on the hourly flows of the Intraday Nomination, if not otherwise addressed in Transporter's agreement or Tariff. Intraday nominations do not rollover (i.e., Intraday Nominations span one Day only). Intraday nominations do not replace the remainder of a standing Nomination. There is no need to re-nominate if an Intraday Nomination modifies an existing Nomination.

(b) There is no limitation as to the number of Intraday Nominations a Shipper may submit at any one standard Nomination cycle or in total across all standard Nomination cycles.

(c) Firm Intraday Nominations are entitled to bump scheduled interruptible Service only during the Evening Nomination Cycle and Intraday 1 Nomination Cycle. Transporter will provide Notice of the applicability and types of penalties to be effective the following Gas Day for any bumped Volumes on its EDM by 3:00 p.m. prior to the Gas Day. During most periods, Daily penalties will be waived for bumped Volumes on the date of the bump. Penalties related to the bumped Volume will be waived if notice has not been provided.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)
13.7 (Contd.)

(d) At its option, Transporter may accept Nominations submitted and received outside the timelines applicable to timely or standard Intraday Nominations, but Transporter shall not be required to comply with the NAESB Nominations-related standards with respect to such Nominations. Nominations received after the Nomination deadlines specified in Section 13.6 of this Article 13 (Nominations) will be scheduled after the Nominations received before the Nomination deadlines.

13.8 Transporter shall directly notify any Shipper who is bumped pursuant to Section 13.6 or 13.7 of this Article 13 (Nominations) at their primary telephone or facsimile number, as designated by Shipper, as well as through Internet e-mail. Transporter shall endeavor, but shall not be obligated, to notify Shipper at alternate numbers.

13.9 Nominations shall be confirmed as follows:

(a) Shippers shall cause the operator of each Delivery Point designated in any Nomination to confirm all such Nominations prior to implementation by Transporter.

The receiver of the Nomination initiates the confirmation process. The party that would receive a request for confirmation or an unsolicited confirmation response may waive the obligation of the sender to send.

The operator(s) of the Receipt and Delivery Point(s) shall confirm the Quantities of Gas being Nominated by Shipper under the timelines set forth in Section 13.6 of this Article 13 (Nominations). At the end of each Gas Day, Transporter should provide the final scheduled Quantities for the just completed Gas Day.

(b) 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 should 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 should be the new confirmed Quantity.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)
13.9 (Contd.)

(c) With respect to the processing of requests for increases during the Intraday Nomination/confirmation process, in the absence of agreement to the contrary, the lesser of the confirmation Quantities should be the new confirmed Quantity. If there is no response to a request for confirmation or an unsolicited confirmation response, the previously scheduled Volume and Quantity should be the new confirmed Volume and Quantity.

(d) With respect to the processing of requests for decreases during the Intraday Nomination/confirmation process, in the absence of agreement to the contrary, the lesser of the confirmation Quantities should be the new confirmed Quantity, but in any event no less than 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 should be the new confirmed Quantity.

(e) With respect to Subsections 13.9(d), (e), and (f) of this Article 13 (Nominations), if there is no response to a request for confirmation or an unsolicited confirmation response, Transporter shall provide the Shipper 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; and/or

(v) the downstream service requester did not have the market or submit the Nomination.

This information should be imparted to the Shipper on the scheduled Quantity document.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 13 NOMINATIONS (Contd.)
13.9 (Contd.)

(f) The explicit confirmation process requires that the confirming party respond to a request for confirmation or initiate an unsolicited confirmation response. Absent mutual agreement to the contrary, explicit confirmation is the default methodology.

13.10 A Shipper may delegate to a third party responsibility for submitting and receiving Nominations under any Service Agreement (a "Nominating Party"), subject to the following conditions:

(a) Any designation of such a Nominating Party, and any change in such designation, must be in writing and must be submitted at least two Business Days prior to the requested effective date.

(b) The written designation shall specify any limits on the authority of the Nominating Party, including any time limit on the designation; provided, however, that Transporter may reject any such limited designation if the limitations specified in the designation would result in an undue administrative burden.

(c) Transporter may rely on communications from the designated Nominating Party for all purposes except to the extent the designation is explicitly limited as specified in Subsection 13.10(b) of this Article 13 (Nominations). Communications by Transporter to such designated Nominating Party shall be deemed Notice to Shipper except to the extent the Nominating Party's authority is explicitly limited with respect to the receipt of Notice under the procedure set forth in Subsection 13.10(b) of this Article 13 (Nominations).

(d) Any third party may nominate under multiple Service Agreements as the designated Nominating Party for one or more Shippers.

13.11 All Nominations are subject to adjustment by Transporter in accordance with Article 16 (Resolution of Imbalances and Adjustment) of these General Terms and Conditions.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 14 SCHEDULING

14.1 Transporter shall schedule all Firm Service Quantities prior to the scheduling of any Make-Up Quantities, AOS Quantities, or Interruptible Service Quantities. Gas Quantities nominated and confirmed in accordance with Article 13 (Nominations) of these General Terms and Conditions shall be deemed to be received and shall be scheduled in accordance with the following order of declining priority:

(a) With respect to Transportation Service:

(i) Firm Service Quantities within Shippers' MDQ under Rate Schedule FT, pro rata based on each Shipper's MDQ.

(ii) Make-Up Quantities under Rate Schedule FT, pro rata based on each Shipper's MDQ.

(iii) AOS Quantities under Rate Schedule FT and Interruptible Service Quantities under Rate Schedule IT, allocated on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IT.

(b) With respect to Gas Treating Service:

(i) Firm Service Quantities within Shippers' MDQ under Rate Schedule FGT, pro rata based on each Shipper's MDQ.

(ii) Make-Up Quantities under Rate Schedule FGT, pro rata based on each Shipper's MDQ.

(iii) AOS Quantities under Rate Schedule FGT and Interruptible Service Quantities under Rate Schedule IGT, allocated on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IGT.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)
14.1 (Contd.)

(c) With respect to Compression Service:

(i) Firm Service Quantities within Shippers' MDQ under Rate Schedule FC, pro rata based on each Shipper's MDQ.

(ii) Make-Up Quantities under Rate Schedule FC, pro rata based on each Shipper's MDQ.

(iii) AOS Quantities under Rate Schedule FC and Interruptible Service Quantities under Rate Schedule IC, allocated on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IC.

(d) With respect to Transmission Service:

(i) Firm Service Quantities within Shippers' MDQ under Rate Schedule FTR, pro rata based on each Shipper's MDQ.

(ii) Make-Up Quantities under Rate Schedule FTR, pro rata based on each Shipper's MDQ.

(iii) AOS Quantities under Rate Schedule FTR and Interruptible Service Quantities under Rate Schedule ITR, allocated on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule ITR.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)

14.2 Scheduling for Service at specific Receipt Points shall be in accordance with the following order of declining priority:

(a) With respect to Transportation Service:

(i) Firm Service Quantities under Rate Schedule FT, prorated on the basis of Shipper's MDQ at the Receipt Point, and limited by Shipper's Nomination.

(ii) Make-Up Quantities under Rate Schedule FT, prorated on the basis of Shipper's MDQ at the Receipt Point, and limited by Shipper's Nomination.

(iii) AOS Quantities under Rate Schedule FT in excess of Shipper's MDQ for such Receipt Point and all Interruptible Service Quantities under Rate Schedule IT on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IT.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)
14.2 (Contd.)

(b) With respect to Gas Treating Service:

(i) Firm Service Quantities under Rate Schedule FGT, prorated on the basis of Shipper's MDQ, and limited by Shipper's Nomination.

(ii) Make-Up Quantities under Rate Schedule FGT, prorated on the basis of Shipper's MDQ, and limited by Shipper's Nomination.

(iii) AOS Quantities under Rate Schedule FGT and all Interruptible Service Quantities under Rate Schedule IGT, on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IGT.

(c) With respect to Compression Service:

(i) Firm Service Quantities under Rate Schedule FC, prorated on the basis of Shipper's MDQ, and limited by Shipper's Nomination.

(ii) Make-Up Quantities under Rate Schedule FC, prorated on the basis of Shipper's MDQ, and limited by Shipper's Nomination.

(iii) AOS Quantities under Rate Schedule FC and all Interruptible Service Quantities under Rate Schedule IC, on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IC.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)
14.2 (Contd.)

(d) With respect to Transmission Service:

(i) Firm Transmission Service Quantities under Rate Schedule FTR to the extent of Shipper’s MDQ, prorated on the basis of Shipper’s MDQ, and limited by Shipper’s Nomination.

(ii) Make-Up Quantities under Rate Schedule FTR to the extent of Shipper’s MDQ, prorated on the basis of Shipper’s MDQ, and limited by Shipper’s Nomination.

(iii) AOS Quantities under Rate Schedule FTR in excess of Shipper’s MDQ and all Interruptible Transmission Service Quantities under Rate Schedule ITR on the basis of rate paid, from highest to lowest, with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule ITR.

14.3 Available AOS, as posted on Transporter’s EDM from time to time, will be allocated by Service as follows:

(a) Each Shipper with an agreement for Firm Service will be allocated AOS, equal to the lesser of:

(i) a pro rata portion of available AOS for the applicable Firm Service (i.e., Firm Transportation Service under Rate Schedule FT, Firm Service under Rate Schedule FGT, Firm Service under Rate Schedule FC, or Firm Service under Rate Schedule FTR) according to the ratio of Shipper’s MDQ and total MDQ under all Agreements for Firm Service for the applicable Service; and

(ii) Shipper’s Nomination under the applicable agreement for Firm Service in excess of its MDQ.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)
14.3 (Contd.)

(b) Each Shipper with an agreement for Firm Service not already being allocated sufficient AOS to satisfy such Shipper's Nomination in excess of its MDQ will be additionally allocated a portion of any available unallocated AOS equal to the lesser of:

(i) a pro rata portion of available unallocated AOS according to the ratio of the Shipper's total MDQ and the total MDQ of all Shippers not already being allocated sufficient AOS to satisfy such Shipper's Nominations in excess of its MDQ; and

(ii) the deficiency between the Shipper's Nomination in excess of its MDQ and the AOS previously allocated to the Shipper under Subsection 14.3(a) of this Article 14 (Scheduling).

(c) In the event additional unallocated AOS remains following the allocation procedure described in Subsection 14.3(b) of this Article 14 (Scheduling), the remaining unallocated AOS will be allocated among Shippers not already being allocated sufficient AOS to satisfy such Shippers' Nominations in excess of their MDQ (if any), through a replication of the allocation procedure described in Subsection 14.3(b) of this Article 14 (Scheduling). If all Nominations in excess of all MDQs have been satisfied through the allocation process, remaining unallocated AOS would be made available under Rate Schedule IT, Rate Schedule IGT, Rate Schedule IC, or Rate Schedule ITR, as applicable.

14.4 Until Transporter has informed Shipper that its Nomination, whether Monthly, Daily or Intraday, is confirmed pursuant to Article 13 (Nominations) of these General Terms and Conditions, such Quantities will not be deemed as scheduled.

14.5 Any allocation of Capacity on the basis of rate paid shall be subject to the limitations of Article 38 (Negotiated Rates) of these General Terms and Conditions.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)

14.6 Scheduling for Service at specific Delivery Point(s) shall be in accordance with the following order of declining priority:

(a) With respect to Transportation Service:

(i) Firm Transportation Service Quantities under Rate Schedule FT, prorated on the basis of Shipper’s MDQ, and limited by Shipper’s Nomination.

(ii) Make-Up Quantities under Rate Schedule FT, prorated on the basis of Shipper’s MDQ, and limited by Shipper’s Nomination.

(iii) AOS Quantities under Rate Schedule FT and all Interruptible Service Quantities under Rate Schedule IT on the basis of rate paid, from highest to lowest; with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IT.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)
14.6 (Contd.)

(b) With respect to Gas Treating Service:

(i) All Firm Service Quantities under Rate Schedule FGT, prorated on the basis of Shipper's MDQ, and limited by Shipper's Nomination.

(ii) Make-Up Quantities under Rate Schedule FGT, prorated on the basis of Shipper's MDQ, and limited by Shipper's Nomination.

(iii) All AOS Quantities under Rate Schedule FGT and all Interruptible Service Quantities under Rate Schedule IGT, on the basis of rate paid, from highest to lowest; with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IGT.

(c) With respect to Compression Service:

(i) All Firm Service Quantities under Rate Schedule FC, prorated on the basis of Shipper's MDQ at the Delivery Point, and limited by Shipper's Nomination.

(ii) Make-Up Quantities under Rate Schedule FC, prorated on the basis of Shipper's MDQ at the Delivery Point, and limited by Shipper's Nomination.

(iii) All AOS Quantities under Rate Schedule FC and all Interruptible Service Quantities under Rate Schedule IC, on the basis of rate paid, from highest to lowest; with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule IC.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 14 SCHEDULING (Contd.)
14.6 (Contd.)

(d) With respect to Transmission Service:

(i) All Firm Transmission Service Quantities under Rate Schedule FTR provided at the Delivery Point to the extent of Shipper’s MDQ, prorated on the basis of Shipper’s MDQ, and limited by Shipper’s Nomination.

(ii) Make-Up Quantities under Rate Schedule FTR provided at the Delivery Point, prorated on the basis of Shipper’s MDQ, and limited by Shipper’s Nomination.

(iii) All AOS Quantities under Rate Schedule FTR and all Interruptible Transmission Service Quantities under Rate Schedule ITR on the basis of rate paid, from highest to lowest; with pro rata allocation when the rate paid is equal, including the Maximum Rate applicable to Service under Rate Schedule ITR.

14.7 In the event of a conflict between the priorities for scheduling at specific Receipt Points and those for scheduling at specific Delivery Points, the Receipt Point priorities as provided in Section 14.2 of this Article 14 (Scheduling) shall govern.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 15 ALLOCATIONS

15.1 Allocation of actual Quantities at Receipt Points:

(a) In the event Gas from multiple Shippers is measured at any Receipt Point, a Designated Allocator shall provide, or cause to be provided, to Transporter a PDA for the purpose of determining the Quantity of Gas expressed in Dth actually received by Transporter for each Shipper’s Account for each Gas Day, and in the aggregate for the Month. The Designated Allocator should submit the PDA to Transporter during or after confirmation and before start of the Gas Day.

(b) Except as provided in Subsection 15.1(e) of this Article 15 (Allocations), the PDA provided for a Receipt Point on Transporter’s system shall include:

(i) An allocation by the Designated Allocator of the actual Quantities of Gas in Dth to be received by Transporter of each working interest owner’s Gas from the production source field(s) on each Day following a Gas Day based on one and only one of the following allocation methodology types; ranked, pro rata, percentage, swing and operator provided value; as described in Subsection 15.1(b)(iii) of this Article 15 (Allocations). In the event the Gas received by Transporter at a Receipt Point is from more than one production source field, the Designated Allocator of the facilities immediately upstream of the Receipt Point shall provide Transporter an allocation of the Gas delivered to the Receipt Point from each production source pursuant to one of the methods listed above.

(ii) An allocation of each working interest owner’s Gas to the various Service Agreements on which said working interest owner intends to ship Gas on a Gas Day expressed in Dth and based on one and only one of the following allocation methodology types; ranked, pro rata, percentage, swing and operator provided value; as described in Subsection 15.1(b)(iii) of this Article 15 (Allocations). PDA statements shall include the contract number assigned by Transporter to each Service Agreement and the name of the Shipper thereunder.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 15 ALLOCATIONS (Contd.)
15.1 (Contd.)
(b) (Contd.)

(iii) Ranking methodologies referred to in Subsections 15.1(b)(i), 15.1(b)(ii), and 15.2(a) of this Article 15 (Allocations) are further described as: "ranked" by the order in which the Service Agreements are to be allocated to the extent Gas is available; "pro rata" based on the Shipper's confirmed Nominations; "percentage" of the Gas received by Transporter; "designation of a swing contract" for receipt Volume imbalances; or "an operator provided value."

(c) The PDA for Receipt Point(s) interconnecting with third-party pipelines shall be provided by the third-party pipeline and shall rank the various Service Agreements to be supplied at the Receipt Point in accordance with one of the methodologies described in Subsection 15.1(b)(iii) of this Article 15 (Allocations). In the event there is a conflict between the foregoing methodologies and the third-party pipeline's provision in its tariff governing the allocations of deliveries, the owner of such third-party pipeline and Transporter shall mutually agree on the PDA to be used. The ranking shall include the contract number assigned by Transporter to each Service Agreement and the name of the Shipper thereunder.

(d) Transporter must receive each PDA, and revision thereto, by 9:00 a.m. the next Business Day following the Day of Gas flow. If there are no changes in Nominations by a Shipper at a Receipt Point that require a revised PDA, the current PDA will stay in effect as submitted until it is changed pursuant to the foregoing procedures.

(e) In the event Transporter does not receive a PDA, or revised PDA, for a Receipt Point in a timely manner, each Shipper agrees that Transporter shall be authorized to allocate Gas supplies at that Receipt Point on a pro-rata basis based on all scheduled Quantities at such Receipt Point.

(f) Shipper hereby agrees that Transporter shall have the right to rely conclusively on the PDA for the purposes of determining the Daily Quantities of Gas received by Transporter for the account of Shipper at each Receipt Point.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 15 ALLOCATIONS (Contd.)

15.2 Allocation of actual Quantities at Delivery Point(s):

(a) The downstream party providing the point confirmation should submit the PDA to Transporter after or during confirmation and before start of a Gas Day. The PDA shall allocate the actual Quantities of Gas in Dth delivered each Day, and in the aggregate for the Month, for the Shippers' Accounts at all of its various Delivery Point(s). The allocation methodology types agreed upon are as follows; ranked, pro rata, percentage, swing and operator provided value; as described in Subsection 15.1(b)(iii) of this Article 15 (Allocations).

(b) If there is an insufficient Quantity of Gas to match the total scheduled Quantities within a particular priority category of Service as set forth below and an operational balancing agreement between Transporter and the downstream party is not in place, then the available Quantity of Gas shall be allocated pro rata within that priority category based on scheduled Quantities; and if there is a Quantity of Gas in excess of the Quantity needed to match the total scheduled Quantities within the last priority category below, then the excess Quantity of Gas shall be allocated pro rata within that priority category based on scheduled Quantities. The priority categories below are shown in descending order.

(i) The scheduled Quantity of Gas expressed in Dth for Firm Transportation Service under Rate Schedule FT at Delivery Point(s) up to Shipper's MDQ.

(ii) The scheduled Quantity of Gas expressed in Dth for Make-Up Quantities under Rate Schedule FT at Delivery Point(s).

(iii) All other scheduled Quantities of Gas expressed in Dth including Interruptible Service Agreements under Rate Schedule IT and Firm Service Agreements under Rate Schedule FT at the Delivery Point(s) in excess of Shipper's MDQ.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 15 ALLOCATIONS (Contd.)

15.3 Any allocation data or corrections received by Transporter after it has closed the previous Month of flow shall be handled as a prior period adjustment. Transporter shall process prior period adjustments as soon as practicable but no later than six Months after the applicable Month of flow in question with a three-Month rebuttal period. These deadlines do not apply in the case of deliberate omission or misrepresentation by a party (or its representative) or mutual mistake of fact. The parties' other statutory or contractual rights shall not be diminished by this provision. The correction shall be made to the Month of flow with a restated line item and a new total Quantity of Gas for the specific Day(s) and the respective Month.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 16 RESOLUTION OF IMBALANCES AND ADJUSTMENT

16.1 Shipper shall use reasonable efforts to minimize variances between scheduled Quantities and the Quantities of Gas actually tendered, or caused to be tendered, to Transporter by Shipper under each Service Agreement. Transporter shall use reasonable efforts to tolerate Shipper variances due to temporary limitations of the physical capability of Transporter's system, giving due consideration to flexibility available to Transporter by fluctuating line pack levels and the use of any operational balancing agreements with interconnecting pipeline facilities. Under no circumstances shall Transporter tolerate Shipper imbalances that have a deleterious and discriminatory effect upon the capacity available to Shippers under Firm Transportation Agreements.

16.2 Shipper shall use reasonable efforts to maintain a Daily balance at all times, between:

(a) total Gas scheduled for receipt to Shipper's Account from each Receipt Point and actual Gas received to Shipper's Account from each Receipt Point; and

(b) aggregate Gas tendered to Shipper's Account at all Receipt Points and aggregate Gas (less the applicable Fuel Requirement) delivered by Transporter from Shipper's Account at the Delivery Point(s). To the extent Transporter has entered into operational balancing agreements with downstream pipelines, no imbalance will arise at the Delivery Point and only Subsection 16.2(a) above will apply.

16.3 All imbalances and variances described in Section 16.2 (collectively "Imbalances") shall be held in the Shipper's Account. Transporter shall make available in advance of the Timely Nomination Cycle each Day the best available estimate of the various Imbalances to Shipper's Account.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 16 RESOLUTION OF IMBALANCES AND ADJUSTMENT (Contd.)

16.4 Other than as specified in Section 16.9 of this Article 16 (Resolution of Imbalances and Adjustment), Shipper shall not be subject to any penalty for prevailing Imbalances, provided that at all times:

(a) Shipper’s Account is within acceptable tolerance levels, as specified by Transporter from time to time, based on the best-available information; and

(b) Shipper makes reasonable efforts to eliminate any Imbalances, as required by the provisions of this Article 16 (Resolution of Imbalances and Adjustment), including complying with all reasonable directions of Transporter to address prevailing Imbalances, with Transporter giving due consideration to avoiding potential impacts on other Shippers in identifying reasonable courses of action in specific circumstances.

16.5 Transporter shall communicate to all Shippers, as part of the Nomination procedures, the current acceptable level of tolerance for Imbalances. Transporter shall use reasonable efforts to operate its system so as to permit tolerance of periodic Imbalances by each Shipper, subject to compliance with the requirements of this Article 16 (Resolution of Imbalances and Adjustment), up to 5% of the Quantity scheduled by Transporter. However, Transporter reserves the right to impose more stringent Imbalance tolerance levels, based on the need to maximize throughput or to protect the integrity of Transporter’s facilities. Transporter shall assess penalties only to the extent necessary to prevent impairment of reliable Service.

16.6 Daily allocations by Designated Allocators of interconnecting facilities upstream of the applicable Receipt Point shall only give rise to Imbalance penalties if Shipper fails to reduce any identified Imbalances to within tolerance levels specified by Transporter at that time. In the event such actions are not taken, Transporter may adjust new or standing Nominations so as to bring Shipper’s Account within specified tolerance levels.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 16 RESOLUTION OF IMBALANCES AND ADJUSTMENT (Contd.)

16.7 Any month-end allocation adjustments by Designated Allocators shall not give rise to Imbalance penalties, except to the extent the Month-end allocations confirm Imbalances indicated by the corresponding Daily allocations. For the purposes of establishing final Imbalances and imposing associated penalties, if any, differences between the Month-end allocation and the aggregate of the individual Daily allocations shall be prorated across each Day in the Month based upon the daily allocations confirmed by the Designated Allocators.

16.8 Any cumulative Imbalance confirmed at the end of a Month, including Month-end allocation adjustments by Designated Allocators, may be minimized or eliminated by trading Imbalances between Shippers within five Days after the Notice of the confirmed Imbalance is received by each Shipper. This is accomplished by implementing Title Transfers to or from Shippers' Accounts, as Nominated by the affected Shippers.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 16 RESOLUTION OF IMBALANCES AND ADJUSTMENT (Contd.)

16.9 Any Imbalance remaining after the end of any applicable Title Transfer period referenced in Section 16.8 of this Article 16 (Resolution of Imbalances and Adjustments) will be cashed out on a tiered basis in accordance with the following schedule:

Imbalance Level	Overage (Transporter Pays Shipper)	Underage (Shipper Pays Transporter)
Greater than 0% and up to 5%	100% of AMIP	100% of AMIP
Greater than 5% and up to 10%	90% of AMIP	110% of AMIP
Greater than 10% and up to 15%	80% of AMIP	120% of AMIP
Greater than 15% and up to 20%	70% of AMIP	130% of AMIP
Greater than 20%	60% of AMIP	140% of AMIP

To accomplish any cash out for any overage Imbalance, title to the Quantity of overage Imbalance shall transfer to Transporter at the end of the applicable Title Transfer period.

(a) A Shipper's remaining Imbalance will be cashed out based on the percentage of that Imbalance compared to the total deliveries for that Shipper during the Month. For example, if the total deliveries under the applicable Service Agreement were 1,000 Dth and the remaining underage Imbalance were 100 Dth, the total Imbalance Level would be 10%. The first 5% (50 Dth) would be cashed out at 100% of the AMIP and the remaining 50 Dth would be cashed out at 110% of the AMIP.

(b) The Average Monthly Index Price (AMIP) is the arithmetic average of:

(i) the arithmetic average of the weekly index prices (WIP) for the applicable Month reported in "Gas Price Report" issued by "Natural Gas Week" in the "Canadian Price Report" for "AECO-Hub Dlvd (pipe)", and

(ii) the index price for the applicable Month reported in "Canadian Gas Price Reporter", published by Canadian Enerdata Ltd, in the table "NGX AB-NIT Same Day Index" which is found in the "Canadian domestic gas price report" section, in the Column "Avg. Price US$/MMBtu", for the row "1. Tot./Wtd Avg."

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 16 RESOLUTION OF IMBALANCES AND ADJUSTMENT (Contd.)
16.9 (Contd.)

(c) In calculating the AMIP, Transporter will utilize the applicable index prices reported in the issues of “Natural Gas Week” and “Canadian Gas Price Reporter” dated on or after Transporter’s Nomination deadline for first of the Month Service for that Month, and the subsequent issues, if any, dated prior to Transporter’s Nomination deadline for the following Month’s first of the Month Service.

(d) Shippers with remaining Imbalances shall pay Transporter, or will be credited with the appropriate cashout amounts, and in either event the Imbalance will be adjusted to zero after such payment or credit, as applicable.

16.10 In the event “Natural Gas Week” or “Canadian Gas Price Reporter” cease to publish entirely or fail to publish either of the index prices listed in Subsection 16.9(b) of this Article 16 (Resolution of Imbalances and Adjustments), the following procedures shall apply in determining a Month’s AMIP:

(a) Should “Natural Gas Week” fail to publish, in any given week, the index price listed in Subsection 16.9(b)(i), then no WIP for that week will used in determining the Month’s AMIP.

(b) Should “Natural Gas Week” fail to publish any WIP during the applicable Month, or should “Canadian Gas Price Reporter” fail to publish the index price specified in Subsection 16.9(b)(ii) during the applicable Month, then the AMIP for such Month shall be calculated using only the remaining indexes published for such Month.

(c) Should “Natural Gas Week” and “Canadian Gas Price Reporter” fail to publish the index prices for the entire Month in question, the parties will in good faith mutually agree upon a replacement index or indexes that approximates the un-published indexes. If the parties do not agree upon a replacement index or indexes within 10 Business Days after the end of the applicable Month, then the issue shall be submitted to the dispute resolution provisions of Article 27 (Dispute Resolution) of these General Terms and Conditions.

Sheet Nos. 406-410 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 17 CURTAILMENT

17.1 Transporter shall have the right to curtail or discontinue Service, in whole or in part, on all or a portion of its system, including at any specific Receipt Point or Delivery Point, at any time for reasons of Force Majeure or when, in Transporter's judgment, capacity or operating conditions so require, or it is necessary or desirable to maintain or make modifications, repairs, or operating changes to its system. Transporter shall provide Shipper such Notice of the curtailment as is reasonable under the circumstances.

17.2 Transporter shall have the unqualified right to interrupt Interruptible Service, AOS Quantities, and Make-Up Quantities at any time to the extent necessary to provide Firm Service.

17.3 In the event of curtailment or interruption pursuant to Section 17.1 or 17.2 of this Article 17 (Curtailment), Service shall be curtailed or interrupted in the following order:

(a) With respect to Transportation Service:

(i) All AOS Quantities under Rate Schedule FT and all Interruptible Service under Rate Schedule IT will be curtailed, on the basis of rate paid, from lowest to highest, with pro-rata curtailment when the rate paid is equal, including Service at Maximum Rates.

(ii) Make-Up Quantities under Rate Schedule FT will be curtailed next, among all Shippers receiving this Service, provided a Shipper's entitlement to Service shall not exceed its Nomination.

(iii) Firm Service within Shippers' MDQ under Rate Schedule FT will be curtailed next, among all Shippers receiving this Service, provided a Shipper's entitlement to Service shall not exceed its Nomination.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 17 CURTAILMENT (Contd.)
17.3 (Contd.)

(b) With respect to Gas Treating Service:

(i) All AOS Quantities under Rate Schedule FGT and all Interruptible Service under Rate Schedule IGT will be curtailed, on the basis of rate paid, from lowest to highest, with pro-rata curtailment when the rate paid is equal, including Service at Maximum Rates.

(ii) Make-Up Quantities under Rate Schedule FGT will be curtailed next, among all Shippers receiving this Service, provided a Shipper’s entitlement to Service shall not exceed its Nomination.

(iii) Firm Service within Shippers’ MDQ under Rate Schedule FGT will be curtailed next, among all Shippers receiving this Service, provided a Shipper’s entitlement to Service shall not exceed its Nomination.

(c) With respect to Compression Service:

(i) All AOS Quantities under Rate Schedule FC and all Interruptible Service under Rate Schedule IC will be curtailed, on the basis of rate paid, from lowest to highest, with pro-rata curtailment when the rate paid is equal, including Service at Maximum Rates.

(ii) Make-Up Quantities under Rate Schedule FC will be curtailed next, among all Shippers receiving this Service, provided a Shipper’s entitlement to Service shall not exceed its Nomination.

(iii) Firm Service within Shippers’ MDQ under Rate Schedule FC will be curtailed next, among all Shippers receiving this Service, provided a Shipper’s entitlement to Service shall not exceed its Nomination.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 17 CURTAILMENT (Contd.)
17.3 (Contd.)

(d) With respect to Transmission Service:

(i) All AOS Quantities under Rate Schedule FTR and all Interruptible Transmission Service under Rate Schedule ITR will be curtailed, on the basis of rate paid, from lowest to highest, with pro-rata curtailment when the rate paid is equal, including Service at Maximum Rates.

(ii) Make-Up Quantities under Rate Schedule FTR will be curtailed next, among all Shippers receiving this Service, provided a Shipper’s entitlement to Service shall not exceed its Nomination.

(iii) Firm Transmission Service within Shippers’ MDQ under Rate Schedule FTR will be curtailed next, among all Shippers receiving this Service, provided a Shipper’s entitlement to Service shall not exceed its Nomination.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 17 CURTAILMENT (Contd.)

17.4 Any curtailment on the basis of rate paid shall be subject to the limitations of Article 38 (Negotiated Rates) of these General Terms and Conditions.

17.5 If Transporter curtails, for any reason (other than Transporter's refusal to receive Gas failing to comply with Article 4 (Gas Quality) or Article 8 (Pressure) of the General Terms and Conditions), including an event of Force Majeure or issuance of an OFO, that relates solely to the physical capability of any portion of Transporter's system to provide Firm Service, to receive under one or more of Rate Schedule FTR, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FT, Gas Shipper is ready, willing, and able to deliver under the applicable Rate Schedule within Shipper's MDQ, at the applicable Receipt Point, then, subject to this Article 17 (Curtailment) the Quantity Transporter curtailed as a result thereof shall be considered "Deficient Quantities" and Transporter shall, subject to availability, allow Shipper to nominate Quantities above Shipper's MDQ during the remainder of the term of the applicable Service Agreement ("Make-Up Quantities") until such Deficient Quantities have been made up. For the avoidance of doubt, if Transporter curtails Gas Shipper is ready, willing, and able to deliver for Service on more than one portion of Transporter's Facilities, and Deficient Quantities accrue to Shipper's Account on a Day on any portion of such facilities, then the same level of Deficient Quantities will accrue to Shipper's Account for each such Service on such Day, subject to reduction to the extent that the Shipper elects to replace the curtailed Quantities from other sources in the applicable portion of Transporter's Facilities. For example, if Shipper's MDQ were 1,000 Dth per Day and Shipper was ready, willing, and able to deliver 1,000 Dth for Firm Service under Rate Schedules FTR, FGT, FC, and FT on a certain Day, but due to a Force Majeure event on the facilities used by Transporter to provide Service under Rate Schedule FTR, Shipper's Quantities were curtailed to 500 Dth during such Day, then, subject to Shipper having properly scheduled and tendered the Gas, Transporter would provide Firm Service for Shipper for 500 Dth of Gas under Rate Schedules FTR, FGT, FC, and FT, and 500 Dth of Deficient Quantities would accrue to Shipper's Account under each of such Rate Schedules. However, if Shipper replaced 300 Dth of Gas of the Deficient Quantities with non-curtailed Gas for Service under Rate Schedules FGT, FC, and FT that was properly scheduled and tendered on Transporter's Facilities, the Deficient Quantities accruing during such Day for Service under such Rate Schedules would be 200 Dth, while that under FTR would remain at 500 Dth.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 17 CURTAILMENT (Contd.)

17.6 Make-Up Quantities shall have priority as set forth in Article 14 (Scheduling) of these General Terms and Conditions.

17.7 At the end of the primary term of the applicable Service Agreement, or upon Shipper's permanent Release of the applicable Service Agreement, Deficient Quantity balances in Shipper's Account for the applicable Service shall be deemed zero and such Deferred Quantity balance shall be closed. Any balance of Deficient Quantities remaining in a Shipper's Account shall not be a basis for consideration of expansion requests to Transporter.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 18 BILLING AND PAYMENTS

18.1 On or before the 10th Day of each Month, Transporter shall render (for purposes of this Article 18 (Billing and Payments), “render” shall mean either postmarked and mailed or time stamped and electronically transmitted via the EDM to the designated site, whichever is applicable) to Shipper an invoice of the amount payable by Shipper for the preceding Month under each applicable Service Agreement. Transporter will also render a statement of any charges, penalties, or credits calculated in accordance with the applicable Service Agreement, Rate Schedule, and/or these General Terms and Conditions.

18.2 If actual Quantities are not available in time to prepare the invoice, such charges shall be based on estimated Quantities and Transporter shall provide, in the subsequent Month’s invoice, an adjustment based on any differences between actual Quantities and estimated Quantities. Any required invoice backup will accompany the invoice. When information necessary for billing purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 6th Day of the Month. At the reasonable request of Transporter, Shipper shall provide to Transporter in a timely manner any information or data required by Transporter to calculate and verify the Volume, quality, and Gross Heating Value of Shipper’s actual deliveries to Transporter.

18.3 Shipper shall pay Transporter the invoiced amount by electronic funds transfer on or before the later of the 25th Day of the Month or the 5th Business Day following receipt by Shipper of the Monthly invoice. Such payment will be to a depository designated by Transporter, in United States funds immediately payable to Transporter. If the payment due date falls on a Day the designated depository is not open in the normal course of business to receive Shipper’s payment, then Shipper’s payment shall be made on the first Business Day after the payment due date that such depository is open in the normal course of business.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 18 BILLING AND PAYMENT (Contd.)

18.4 If Shipper fails to pay all or part of a Monthly invoice in accordance with this Article 18 (Billing and Payments), Shipper shall pay a charge for late payment, which shall be included by Transporter on the next regular Monthly invoice, rendered to Shipper under this Article 18 (Billing and Payments). The charge for late payment shall be determined by multiplying (a) the unpaid portion of the invoice by (b) the ratio of the number of Days from the due date to the date of actual payment to 365 by (c) the annual interest rate as determined in accordance with 18 C.F.R. Section 154.501(d)(l) or any successor provision of the Commission's Regulations. If the failure to pay continues for ten Days after payment is due, Transporter, in addition to any other remedy it may have, may suspend further delivery of Gas without further Notice. Transporter shall report such suspension of Service to the Commission. Such suspension of Service shall not constitute a failure by Transporter to perform any of its obligations under this Tariff or any Service Agreement, and shall not give rise to any Make-Up Quantities pursuant to Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR.

18.5 In the event an error is discovered in the amount invoiced in any invoice rendered by Transporter, such error shall be adjusted within 30 Days of the determination thereof, provided that a claim is made within 60 Days of discovery of a billing error, and in any event within six Months from the date on the invoice claimed to be in error. The party harmed by any such adjustment shall have three Months to dispute such adjustment. The timing of invoice claims and adjustments referenced in this Article 18 (Billing and Payments) shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. The parties' other statutory or contractual rights shall not be diminished by this standard.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 18 BILLING AND PAYMENT (Contd.)

18.6 Invoicing errors shall be corrected as follows:

(a) Where Shipper has been overcharged and has paid the invoice, the amount of the overpayment will be refunded to Shipper with interest at the interest rate determined in accordance with 18 C.F.R. 154.501(d)(l) or any successor provision of the Commission’s Regulations from the date of the overpayment to the date of the refund. When a refund is provided to Shipper by way of credit on another Transporter invoice, the overpayment will be deemed to have been refunded on the date the credited invoice was received by the Shipper.

(b) Where Transporter has undercharged Shipper, Shipper will pay the amount of the undercharge without interest provided the undercharge is paid within 30 Days. Undercharge amounts not paid within 30 Days will be subject to interest charges from the day of receipt by Shipper at the interest rate determined in accordance with 18 C.F.R. 154.501(d)(l) or any successor provision of the Commission’s Regulations from the date of the invoice.

18.7 Shippers shall have the right, at all reasonable times, during normal business hours, upon written request and at their own expense, to review or cause to be reviewed all books, records, documents, or other data of Transporter pertaining to its performance under Shipper’s Service Agreement. This right to review, as necessary, is solely to verify the amount payable by a Shipper to Transporter under those agreements, so long as such review shall be completed within two Years following the end of the calendar year in which such amount is payable.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 18 BILLING AND PAYMENT (Contd.)

18.8 Good Faith Disputes:

(a) Transporter shall not be entitled to suspend further delivery of Gas pursuant to Section 18.4 of this Article 18 (Billing and Payment) if Shipper in good faith:

(i) disputes the amount of any such bill or part thereof;

(ii) provides Transporter with a written Notice including a full description of the reasons for the dispute, together with copies of supporting documents; and

(iii) pays to Transporter such amounts as it concedes to be correct.

(b) Shipper shall not offset any disputed amounts against the Reservation Charge portion of its invoice.

(c) In the event of a good-faith billing dispute, Transporter may demand, and Shipper, within ten Days of such demand, shall furnish a good and surety bond guaranteeing payment to Transporter of all disputed amounts for any invoices that are or will be affected by such dispute. If Shipper fails to provide such a bond to Transporter guaranteeing payment, or if Shipper defaults on the conditions of such bond, then Transporter shall have the right to suspend Service under or terminate Shipper’s Service Agreement.

(d) Except where the Commission has exclusive jurisdiction, any good-faith billing dispute shall be submitted to arbitration pursuant to Article 26 (Complaint Resolution) of these General Terms and Conditions within 30 Days of Transporter’s receipt of Shipper’s Notice.

(e) In the event Shipper does not pay the full amount due Transporter in accordance with this Article 18 (Billing and Payments), Transporter, without prejudice to any other rights or remedies it may have, shall have the right to withhold or offset payment or credit of any amounts of monies due or owing by Transporter to Shipper, whether in conjunction with Shipper’s Service Agreement, or otherwise, against any and all amounts or monies owing by Shipper to Transporter.

Sheet Nos. 425-430 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 19 REGULATORY ACCOUNTING

19.1 Income taxes for purposes of establishing Transporter's cost of service and rates for any period during which Transporter is organized as a partnership or other pass-through entity, shall be deemed to mean the amounts of income taxes which would have been paid or accrued if Transporter were organized during such period as a corporation, without limit as to negative or positive amounts of current or deferred income taxes. An allowance for federal and state income taxes, including current income taxes and provision for deferred income taxes, shall be computed in accordance with income tax accounting procedures that reflect the current and deferred tax consequences of all events that have been recognized in the financial statements or in taxable income, all as recorded in Account Nos. 409.1, before any reduction to reflect investment tax credit, 409.3 before any reduction to reflect investment tax credit, 410.1 and 411.1, including the amortization of any excess or deficient deferred income tax amounts, plus any interest received or paid on tax refunds or deficiencies, as recorded in Account Nos. 419 or 431.

19.2 As used in this Article 19 (Regulatory Accounting), "income tax accounting procedures which reflect the current and deferred tax consequences of all events that have been recognized in the financial statements or in taxable income" shall mean those procedures that require recording deferred tax liabilities and assets with a full provision for all income tax effects of all temporary differences and tax credit carryforwards.

19.3 A temporary difference is a difference between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable or deductible amounts in future years when the reported amount of the asset or liability is recovered or settled, respectively.

Sheet Nos. 432-435 Are Reserved for Future Use

ARTICLE 20 CREDITING OF REVENUE

20.1 For all Interruptible Service rendered for a Shipper each Month, a revenue credit shall be accrued in the amount received by Transporter under the applicable Rate Schedule, net of any applicable costs incurred in providing the Service.

20.2 Each Month, 100% of the net aggregate revenue credit attributable to Interruptible Service under the Rate Schedule for the applicable Interruptible Service received during the previous Month shall be credited to the Firm Shippers receiving the same type of Service (e.g., the revenue credit applicable to Service under Rate Schedule IT will be credited to those Firm Shippers receiving Service under Rate Schedule FT, the revenue credit applicable to Service under Rate Schedule IGT will be credited to those Firm Shippers receiving Service under Rate Schedule FGT, etc.) as a credit against such Shippers' invoices. Allocation of the applicable revenue credits among each Shipper will be pro rata, based on each Shipper's Reservation Charge for the Month in which the credits are accrued.

20.3 For each unit of AOS Service that is provided to a Shipper under a Firm Service Agreement including an agreement whereby Shipper has elected Negotiated Rates, a revenue credit shall be accrued in the amount received by Transporter for AOS Service pursuant to the applicable Rate Schedule, net of any applicable costs incurred by Transporter in providing the Service.

20.4 Each Month, 100% of the revenue credits accrued for each type of Firm Service under Section 20.3 of this Article 20 (Crediting of Revenue) during the prior Month shall be credited to all Firm Shippers utilizing the same type of Service. Allocation of the aggregate accrued revenue credits among such Shippers will be pro rata based on such Shippers relative Reservation Charge for the Month in which the credits accrued.

20.5 Each Month, 100% of any penalty revenues received by Transporter pursuant to Article 16 (Resolution of Imbalances and Adjustment) of these General Terms and Conditions in the previous Month shall be credited to Shippers, net of any applicable costs incurred by Transporter, under Rate Schedule FT as a credit against such Shippers' invoices. Allocation of the penalty revenues received among such Shippers shall be pro rata, based on the Rate Schedule FT Shippers' Reservation Charges for the Month in which the credits are accrued.

Sheet Nos. 437-440 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 21 NOTICES

21.1 Except as otherwise provided in this Tariff, any request, demand, statement, or invoice, or any notice (collectively a "Notice"), which either party desires to give to the other, must be in writing and shall be validly communicated by the delivery thereof to its addressee, either personally or by courier or by facsimile, and will be considered duly delivered to the party to whom it is sent at the time of its delivery if personally delivered or if sent by facsimile during normal business hours, or on the Day following transmittal thereof if sent by courier (provided that in the event normal courier service, or facsimile service shall be interrupted by a cause beyond the control of the parties hereto, then the party sending the Notice shall utilize any service that has not been so interrupted or shall personally deliver such notice) to the other party at the address set forth below. Each party shall provide Notice to the other of any change of address for the purposes thereof.

Transporter:
Denali – The Alaska Gas Pipeline, LLC
188 W. Northern Lights Blvd., Suite 1300
P.O. Box 241747
Anchorage, Alaska 99524-1747
Attention: Manager, Transportation Services

Fax: (907) 865-4304

Shipper: At the address set out in the applicable Service Agreement

Routine communications, including Monthly invoices, will be considered duly delivered when mailed either by registered, certified, or ordinary mail.

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GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 22 PRE-GRANTED ABANDONMENT

22.1 A Shipper receiving Service under an agreement for Firm Service having a term of less than 12 consecutive Months of Service and Shippers receiving Service under an Interruptible Service Agreement retain no rights to continued Service after the expiration of such agreement. Upon expiration of such an agreement, Transporter shall have all necessary abandonment authorization under the Natural Gas Act and the Alaska Natural Gas Pipeline Act as of such termination date, and shall not be required to seek case-specific authorization prior to abandoning Service.

22.2 Shippers receiving Service under agreements for Firm Service at Maximum Rates with a term of 12 or more consecutive Months of Service ("Firm Shippers") may exercise the right of first refusal ("Right of First Refusal") described in Section 22.4 of this Article 22 (Pre-Granted Abandonment). Such agreements are not subject to pre-granted abandonment provided Notice is given as described herein. Firm Shippers with an agreement having a Right of First Refusal who wish to extend their contract at Maximum Rates for a term of at least five Years, can extend such agreement without exercising the Right of First Refusal process or posting. A Firm Shipper may elect to retain a portion of its Capacity, subject to the Right of First Refusal process, and have Transporter's pre-granted abandonment authorization apply to the remainder of the Capacity.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 22 PRE-GRANTED ABANDONMENT (Contd.)

22.3 Other than as set forth in Section 22.7 of this Article 22 (Pre-Granted Abandonment), the procedure for exercising the Right of First Refusal is as follows:

(a) Transporter shall provide no more than ten Months', and no less than nine Months' advance written Notice of pending contract expirations to eligible Firm Shippers. A Firm Shipper must give written Notice to Transporter within 60 Days of the date of Transporter's notification to the Firm Shipper that it wishes Transporter to post its Capacity to begin the Right of First Refusal Process. Failure by the Firm Shipper to give Transporter the Notice specified in this Subsection 22.3(a) of Article 22 (Pre-Granted Abandonment) will result in the automatic abandonment of Service, and the Firm Shipper's right to the subject Capacity will cease, at the end of the term of the applicable Service Agreement. A Firm Shipper may also waive its right to participate in the Right of First Refusal process, which will result in automatic abandonment of Service upon the termination of the applicable Service Agreement.

(b) Subsequent to Transporter receiving Shipper's Notice described in Subsection 22.3(a) of this Article 22 (Pre-Granted Abandonment), Transporter will post the Capacity on the EDM in order to solicit bids for the Capacity.

(c) A bidder desiring to obtain the posted Capacity must submit a bid to Transporter within 30 Days of the posting to participate in the Right of First Refusal process. The bid must include all of the information required pursuant to Article 2 (Requests for Service) of these General Terms and Conditions.

(d) If Transporter receives no bids, or if Transporter receives no bids at the applicable Maximum Rate, and Transporter determines not to accept any bids below the applicable Maximum Rate, Transporter shall notify the Firm Shipper of the maximum bid received, or that no bids were received. If Transporter receives a bid at the applicable Maximum Rate, or it accepts any bid below the applicable Maximum Rate, Transporter shall, within 30 Days of the close of bidding, inform Shipper of the offer to purchase Capacity Transporter intends to accept.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 22 PRE-GRANTED ABANDONMENT (Contd.)
22.3 (Contd.)

(e) Shipper shall have 30 Days to match the offer in terms of price and duration. Shipper may elect to exercise its right to match with respect to a Quantity (but not a geographic portion) of the Firm Service. Shipper shall not be required to match a rate in excess of the applicable Maximum Rate, or a term in excess of five Years.

(f) Transporter shall post any matched offer below the applicable Maximum Rate on its EDM for an additional 30 Days, during which time bids may be submitted at a higher rate. Shipper again will be given the opportunity to match any higher bid. This process will continue until either the Firm Shipper has agreed to pay Transporter's Maximum Rate, the Firm Shipper fails to match an offer, or no higher bid is submitted. The iterative process will not extend for greater than 120 Days from the initial posting of a matched offer pursuant to this Article 22 (Pre-Granted Abandonment). At the expiration of the 120-Day period, the most-recent offer shall be accepted.

(g) If Shipper fails to match the offer presented by Transporter, Transporter shall enter into an agreement for Firm Service with the Person submitting the competing offer pursuant to the terms and conditions of the offer.

22.4 Any bid at a rate in excess of the applicable Maximum Rate shall be treated as a bid at the Maximum Rate pursuant to the applicable Rate Schedule.

22.5 Transporter shall not be required to accept any bid at less than the applicable Maximum Rate.

22.6 If any bid submitted by a bidder is subsequently withdrawn, any new bids submitted by such Shipper for the same Capacity must be at a higher rate.

22.7 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 36 months prior to termination of Shipper's Service Agreement that Shipper's capacity is subject to the right of first refusal. Shipper must notify Transporter regarding whether it will or will not exercise its Right of First Refusal within 10 Business Days from the date Transporter's notice is issued.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 22 PRE-GRANTED ABANDONMENT (Contd.)

22.8 In the event equivalent offers are submitted, the Capacity will be made available on a pro-rata basis to the equal bidders. Should any one of the equal bidders veto their pro-rata allocation of the Capacity, Transporter will then conduct a lottery to select the winning bidder, who will then be allocated its requested Capacity. The remainder of the Capacity, if any, will be available to the other equal bidder(s) on a pro-rata basis, which will again trigger the veto and lottery process.

22.9 Where there are no competing bids for the Capacity and the original Firm Shipper agrees to pay the Maximum Rate, Service may be contracted for any term the original Firm Shipper chooses. If no bids are submitted at the Maximum Rate and Transporter refuses to accept a lower bid, Transporter may abandon Service to Shipper unless Shipper agrees to pay the Maximum Rate for a period of one Year, or Transporter and Shipper negotiate the terms and conditions of an agreement for Firm Service.

Sheet Nos. 455-460 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 23 CAPACITY RELEASE

23.1 This Article 23 (Capacity Release) sets forth the terms and conditions applicable to the release by a Firm Shipper of capacity (in Dth) held under an agreement for Firm Service, together, if applicable, with the AOS rights associated with the Shipper's capacity (hereinafter referred to jointly as "Capacity").

23.2 This Article 23 (Capacity Release) is applicable to any Shipper that has executed an agreement for Firm Service under Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR. Any such Shipper shall have the right to release any portion of the Capacity it holds provided that a Replacement Shipper pursuant to the terms of this Article 23 (Capacity Release) acquires the Capacity released. Three types of Capacity Release are available: a Temporary Release, a Pre-Arranged Release, or a Permanent Release.

23.3 Any prospective Replacement Shipper bidding for Released Capacity must be listed on Transporter's Approved Bidders List, must meet all eligibility provisions provided in this Tariff, and must have executed an Electronic Delivery Mechanism agreement with Transporter.

23.4 Any such release shall result in a temporary suspension of the Releasing Shipper's right to use the Released Capacity, subject to any recall rights specified in the release.

23.5 Capacity to be released shall be made available on a not unduly discriminatory basis.

23.6 A Replacement Shipper shall be entitled to release acquired Capacity to another Replacement Shipper, subject to the requirement that the releasing Replacement Shipper satisfies, and is subject to, all of the provisions of this Article 23 (Capacity Release), and that the new Replacement Shipper meets all eligibility requirements provided in this Tariff in a timely manner.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.7 The term for any release of Capacity under this Article 23 (Capacity Release) shall be for a minimum period of one Day, and shall not exceed the balance of the period until the expiration of the primary term of the applicable agreement for Firm Service or Master Capacity Release Agreement under which the Releasing Shipper holds the Capacity to be released.

23.8 The Releasing Shipper shall submit the following information, objectively stated and applicable to all prospective Replacement Shippers on a not unduly discriminatory basis, to Transporter on the applicable form attached as Exhibit K (for Permanent Releases) or Exhibit L (for Temporary Releases):

(a) the Releasing Shipper’s legal name, contract number, and the name, phone number, and fax number of the individual who will authorize the release of Capacity for the Releasing Shipper;

(b) whether the Capacity is Biddable;

(c) the amount of Capacity the Releasing Shipper elects to release expressed in Dth per Day;

(d) the Receipt Point and Delivery Point(s) associated with the Capacity to be released;

(e) whether Replacement Shippers may change the Receipt Point and/or Delivery Point(s) associated with the Capacity to be released (if the Releasing Shipper permits the Replacement Shipper to modify the Receipt and/or Delivery Point(s) associated with the Capacity to be released, the following procedure will be followed to effect any such change: (i) the Replacement Shipper shall inform the Releasing Shipper of the desired point(s); (ii) the Releasing Shipper shall make request to Transporter to change the point(s) pursuant to the Shipper’s agreement for Firm Service; and (iii) the Releasing Shipper shall execute an amendment to the agreement for Firm Service as provided in the applicable Rate Schedule);

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.8 (Contd.)

(f) the requested effective date and term of the release;

(g) the minimum acceptable period of release and minimum acceptable Quantities (if any);

(h) rate conditions, including: (i) any Minimum Rate requirement; (ii) whether bids may be submitted on a Quantity and/or Volume basis; (iii) any minimum Volume commitment if Volume bids are allowed; (iv) the rate that must be bid for AOS Service (if any) associated with the released Capacity; and (v) whether the bids should be stated in dollars and cents, percent of the Maximum Rate, or percent of the rate derived from the terms of a Negotiated Rate Agreement (if applicable and as identified in the Releasing Shipper's notice);

(i) the legal name of the Replacement Shipper that is designated in any Pre-Arranged Release ("Pre-Arranged Replacement Shipper"), and, where applicable, identification of the Pre-Arranged Replacement Shipper as an "asset manager" (as that term is defined Section 284.8(h)(3) of the Commission's Regulations) or a "marketer participating in a state-regulated retail access program" (as that term is defined in Section 284(h)(4) of the Commission's Regulations), together with the terms of the pre-arranged deal and a statement as to whether the Pre-Arranged Replacement Shipper is an Affiliate of the Releasing Shipper;

(j) whether the Capacity is to be released on a temporary or permanent basis, and if temporary, whether the Capacity is to be released on a recallable basis, with the terms and conditions applicable to such recalls, including any prioritization of Capacity rights reductions under Section 23.10 of this Article 23 (Capacity Release) (reput methods and rights are to be specified in the Releasing Shipper's notice);

(k) whether the Capacity to be released is contingent on the release of other Capacity, or if the release of such Capacity is contingent on certain other terms and conditions and, if so, the terms and/or conditions upon which the release is contingent;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.8 (Contd.)

(l) the terms and conditions under which the Releasing Shipper will accept contingent bids, including bids that are contingent upon the Replacement Shipper acquiring transportation on a pipeline interconnected to Transporter, the method for evaluating contingent bids, what level of proof is required by the contingent bidder to demonstrate that the contingency did not occur, and for what time period the next highest bidder will be obligated to acquire the Capacity if the winning contingent bidder declines the release;

(m) any other reasonable and not unduly discriminatory terms and conditions to accommodate the release, including provisions necessary to evaluate bids and tie-breaking criteria; provided, however, that bid evaluations will be limited to highest rate, net revenue, and NPV (if the Releasing Shipper selects NPV as the bid evaluation criterion, bid evaluations shall utilize the formula set forth in Section 23.15 of this Article 23 (Capacity Release);

(n) whether the Releasing Shipper requests that Transporter actively market the Capacity to be released; and

(o) any other additional information Transporter deems necessary, from time to time, to effectuate releases hereunder, as posted on Transporter's EDM.

23.9 For Pre-Arranged Releases: (i) at the Maximum Rate (including the Maximum AOS Rate, if applicable) for a term of more than one Year; (ii) for a period of 31 Days or less; or (iii) to a Pre-Arranged Replacement Shipper that is either an "asset manager" (as that term is defined in Section 284.8(h)(3) of the Commission's Regulations) or a "marketer participating in a state-regulated retail access program" (as that term is defined in Section 284.8(h)(4) of the Commission's Regulations), a Releasing Shipper may release Capacity, without subjecting the release to bidding, by notifying Transporter via Transporter's EDM of such release. The Replacement Shipper shall adhere to the contracting requirements pursuant to Section 23.17 of this Article 23 (Capacity Release). The Replacement Shipper shall confirm electronically the Pre-Arranged release by 9:30 a.m. on the Day of the release and meet the eligibility requirements under this Article 23 (Capacity Release). Transporter will support the electronic upload of Pre-Arranged Releases.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.10 Recall/Reput Rights:

(a) The original Releasing Shipper may specify recall rights and conditions and shall be the only party that can exercise and administer such recall rights. Recall conditions cannot be expanded or in any way modified by subsequent Releasing Shippers. Releasing Shippers may, to the extent permitted as a condition to the Capacity release, recall scheduled released Capacity.

(b) Transporter shall support the following recall notification periods for all released Capacity subject to recall rights (all times shown below are Central Clock Time):

(i) Timely Recall Notification:

(A) A Releasing Shipper recalling Capacity should provide Notice of such recall to Transporter and the first Replacement Shipper no later than 8:00 a.m. on the Day Timely Nominations are due;

(B) Transporter should provide notification of such recall to all affected Replacement Shippers no later than 9:00 a.m. on the Day Timely Nominations are due;

(ii) Early Evening Recall Notification:

(A) A Releasing Shipper recalling Capacity should provide Notice of such recall to Transporter and the first Replacement Shipper no later than 3:00 p.m. on the Day Evening Nominations are due;

(B) Transporter should provide notification of such recall to all affected Replacement Shippers no later than 4:00 p.m. on the Day Evening Nominations are due;

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.10 (Contd.)
(b) (Contd.)

(iii) Evening Recall Notification:

(A) A Releasing Shipper recalling Capacity should provide notice of such recall to Transporter and the first Replacement Shipper no later than 5:00 p.m. on the Day Evening Nominations are due;

(B) Transporter should provide notification of such recall to all affected Replacement Shippers no later than 6:00 p.m. on the Day Evening Nominations are due;

(iv) Intraday 1 Recall Notification:

(A) A Releasing Shipper recalling Capacity should provide Notice of such recall to Transporter and the first Replacement Shipper no later than 7:00 a.m. on the Day Intraday 1 Nominations are due;

(B) Transporter should provide notification of such recall to all affected Replacement Shippers no later than 8:00 a.m. on the Day Intraday 1 Nominations are due; and

(v) Intraday 2 Recall Notification:

(A) A Releasing Shipper recalling Capacity should provide Notice of such recall to Transporter and the first Replacement Shipper no later than 2:30 p.m. on the Day Intraday 2 Nominations are due;

(B) Transporter should provide notification of such recall to all affected Replacement Shippers no later than 3:30 p.m. on the Day Intraday 2 Nominations are due.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.10 (Contd.)

(c) For the recall notification provided to Transporter the Quantity should be expressed in terms of total released Capacity entitlements.

(d) In the event of an Intraday Capacity recall, Transporter should determine the allocation of Capacity between the Releasing Shipper and the Replacement Shipper(s) based upon the Elapsed Pro Rata Capacity (EPC). Variations to the use of EPC may be necessary to reflect the nature of Transporter's Tariff, Services, and/or operational characteristics.

(e) Transporter should not be obligated to deliver in excess of the total Daily contract Quantity of the release as a result of NAESB WGQ Standard No. 5.3.55.

(f) The amount of Capacity allocated to the Replacement Shipper(s) should equal the original released Capacity less the recalled Capacity that is adjusted based upon the EPC or other Transporter Tariff specific variations of the EPC in accordance with NAESB WGQ Standard No. 5.3.56.

(g) Upon notification of a recall, the Capacity of the Replacement Shipper(s) shall be reduced by the Quantity of the recall. If the original Releasing Shipper recalls less than the total amount of the Released Capacity and the original Replacement Shipper has re-released less than the total amount of the Released Capacity, then, upon such recall, the Capacity of the original Replacement Shipper shall be reduced first, absent a specification to the contrary in the original Replacement Shipper's submittal under Subsection 23.8(j) of this Article 23 (Capacity Release).

(h) Any necessary Nomination changes are subject to Transporter's Nomination deadline in accordance with Section 13 (Nominations) of these General Terms and Conditions). Transporter shall be entitled to rely upon such Nomination change and not be held liable under any circumstances whatsoever in the event of any such recall.

(i) Reput rights may be specified by Releasing Shipper via Transporter's EDM at the time the release is posted.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.11 Bidding Period

(a) The Releasing Shipper may specify the date and time the Bidding Period starts and ends; provided, however, that the Bidding Period does not commence any later than the time set forth in the Capacity release timeline below.

(b) The Releasing Shipper’s offer to release Capacity shall be posted for the Bidding Period; provided, however, that the Releasing Shipper may withdraw such offer before the end of the Bidding Period where unanticipated circumstances justify the withdrawal and a notice of withdrawal of the offer is posted on the EDM prior to the receipt of any valid bids for such Capacity. Offers to release shall be binding until Transporter receives written notice or the electronic Notice of withdrawal.

23.12 Subject to a Releasing Shipper’s right to specify an earlier start to the Bidding Period pursuant to Section 23.11 of this Article 23 (Capacity Release), the following timeline is applicable to all parties involved in the Capacity release process; provided, however, the timeline is only applicable if: (i) all information provided by the parties to the transaction is valid; and (ii) the Replacement Shipper has been placed on the Approved Bidders List before its bid is tendered. All times shown below are Central Clock Time.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.12 (Contd.)

(a) For Biddable releases (less than 1 year):

(i) offers should be tendered by 12:00 p.m. on a Business Day;

(ii) Bidding Period ends no later than 1:00 p.m. on a Business day (evaluation period begins at 1:00 p.m. during which contingency is eliminated, determination of best bid is made, and ties are broken);

(iii) evaluation period ends and award posting if no match required at 2:00 p.m.;

(iv) match or award is communicated by 2:00 p.m.;

(v) match response by 2:30 p.m.;

(vi) where match required, award posting by 3:00 p.m.;

(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 (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.12 (Contd.)

(b) For Biddable releases (1 year or more):

(i) offers should be tendered by 12:00 p.m. four Business Days before award;

(ii) Bidding Period ends no later than 1:00 p.m. on the Business Day before timely Nominations are due (Bidding Period is three Business Days);

(iii) evaluation period begins at 1:00 p.m. during which contingency is eliminated, determination of best bid is made, and ties are broken;

(iv) evaluation period ends and award posting if no match required at 2:00 p.m.;

(v) match or award is communicated by 2:00 p.m.;

(vi) match response by 2:30 p.m.;

(vii) where match required, award posting by 3:00 p.m.;

(viii) 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 (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.12 (Contd.)

(c) For non-Biddable releases:

(i) Timely Nomination Cycle

(A) posting of prearranged deals not subject to bid are due by 10:30 a.m. on a Day;

(B) 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.

(ii) Evening Nomination Cycle

(A) posting of prearranged deals not subject to bid are due by 5:00 p.m. on a Day;

(B) 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.

(iii) Intraday 1 Nomination Cycle

(A) posting of prearranged deals not subject to bid are due by 9:00 a.m. on a Day;

(B) 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 (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.12 (Contd.)
(c) (Contd.)

(iv) Intraday 2 Nomination Cycle

(A) posting of prearranged deals not subject to bid are due by 4:00 p.m. on a Day;

(B) 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.

23.13 Open Bidding Process:

(a) A prospective Replacement Shipper wishing to acquire Capacity available for release ("Bidding Shipper") shall place a bid on Transporter's EDM for the available Capacity during the Posting Period. All complete bids will be posted upon receipt. To be complete, a bid shall contain the following information:

(i) the Bidding Shipper's legal name and the name, title, address, and phone number of the individual who will authorize the acquisition of the available Capacity;

(ii) the amount of Capacity the Bidding Shipper requests and the minimum Quantity it will accept;

(iii) the requested effective date and term of the acquisition; and

(iv) the Bidding Shipper's bid, addressing all criteria required by the Releasing Shipper.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.13 (Contd.)

(b) Bids not expressly labeled as contingent shall be binding until Transporter receives written or electronic notice of withdrawal. The Bidding Shipper cannot withdraw its bid after the Bidding Period ends. If the Bidding Shipper withdraws its bid, it may not submit a lower bid. If the Bidding Shipper submits a higher bid, lower bids previously submitted by the Bidding Shipper will be automatically eliminated. A Bidding Shipper may submit multiple bids where the term or Quantity involved in each bid is different. Transporter shall post all information provided by Bidding Shippers, except the information provided in Subsection 23.13(a)(i) of this Article 23 (Capacity Release).

(c) For releases for a term of one Year or greater, no bid shall exceed the applicable Maximum Rates, including the Maximum Rate for AOS service, if applicable, in addition to any and all applicable fees and surcharges, as specified in the Tariff. Neither the requested term nor the requested Quantity contained in such bids shall exceed the maximum term or Quantity specified by the Releasing Shipper.

23.14 In the case of a Pre-Arranged Release that is subject to bidding, the Pre-Arranged Replacement Shipper shall have the right of first refusal for one hour following the time the Pre-Arranged Replacement Shipper has been notified of the winning bid ("Matching Period"). In the event a bid is received offering a higher rate or more closely meeting the criteria specified by the Releasing Shipper, Transporter shall provide the Pre-Arranged Replacement Shipper an opportunity during the Matching Period to match or exceed the bid offering a higher rate or more closely meeting the criteria specified by the Releasing Shipper. No later than 3:15 p.m. of the Day prior to the Day Nominations are due, the Pre-Arranged Replacement Shipper shall receive notification on Transporter's EDM of the terms and conditions of the prevailing bid, and shall have the Matching Period to respond via EDM. Absent a response, the Capacity shall be awarded to the prevailing Bidding Shipper no later than 5:00 p.m. of the Day prior to the Day Nominations are due.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.15 Capacity will be awarded no later than 5:00 p.m. of the Business Day prior to the Day Nominations are due. The Capacity available for release shall be awarded to the Bidding Shipper with the highest bid matching all terms and conditions specified by the Releasing Shipper. In the case of multiple bid winners, the highest ranking bid will receive the entire maximum amount of Capacity bid. The next highest bidder will receive the remainder of the offered Capacity up to the maximum of Capacity amount bid for, provided that the amount remaining is above the minimum acceptable Quantity specified by the bidder. Any remaining Capacity will be given to the next highest bidder under the same provisions as above. This process will repeat until either all of the offered Capacity is awarded or the remaining Capacity falls below either the Releasing Shipper’s minimum Quantity or all the remaining bidder’s acceptable Quantities.

(a) If bids are received that do not match all the terms and conditions provided by the Releasing Shipper, bids will be evaluated by the criteria provided by the Releasing Shipper. If no criteria are provided by the Releasing Shipper, the Bidding Shipper bidding the greatest NPV shall be awarded the Capacity. NPV shall be calculated pursuant to the following formula:

$$R * \{[1 - (+ i)^{(-n)}]/i\} * Q = NPV$$

Where:

i = annual interest rate, i.e., Transporter’s return on equity in its currently effective recourse rates, divided by 365;

n = term of the release in days;

R = the Reservation Rate(s) bid in $/Dth per Month; and

Q = Daily Quantity stated in Dth

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.15 (Contd.)
(a) (Contd.)

Such NPV evaluation in the absence of criteria specified by the Releasing Shipper shall not take into account amounts bid for AOS Service associated with the released Capacity. If more than one such bid has an equal NPV, then the Capacity shall be awarded on a first-come, first-served basis. The ultimate awarding of Capacity will be posted on Transporter's EDM by 5:00 p.m. on the Business Day prior to the Day Nominations are due. Unless the bidder was a contingent bidder and the contingency did not occur, Transporter will tender a numbered Master Capacity Release Agreement (unless Shipper has previously executed a Master Capacity Release Agreement) and a numbered Capacity Release Schedule to the winning bidder by 10:00 a.m. of the Day Nominations are due and the winning bidder shall execute such Agreement and Schedule.

23.16 In the event a Releasing Shipper does not release all of its Capacity, the Releasing Shipper is entitled to utilize the remaining Capacity.

23.17 The Replacement Shipper shall promptly enter into a Master Capacity Release Agreement once Released Capacity has been acquired. Such agreement may be executed electronically. All Replacement Shippers shall accept by an award of Capacity all rights and obligations of the Releasing Shipper with respect to the Capacity released, including Nominations in accordance with Article 13 (Nominations) of these General Terms and Conditions. The Releasing Shipper shall remain fully liable to Transporter for all Reservation Charges payable under the Releasing Shipper's agreement for Firm Service, unless Replacement Shipper has agreed to accept all obligations of the Releasing Shipper for the remaining term of such Releasing Shipper's agreement for Firm Service, and a Permanent Release has been effected in accordance with Section 23.23 or Section 23.24(b) of this Article 23 (Capacity Release).

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.18 Transporter shall invoice each Replacement Shipper for all Reservation Charges contained within its bid and all applicable Usage Charges, AOS charges, penalties, and late charges that are incurred by the Replacement Shipper. In the event a Replacement Shipper fails to pay any Reservation Charges in the time required by Article 18 (Billings and Payments), such unpaid Reservation Charges shall be invoiced to Releasing Shipper in the following Month. By invoicing such unpaid amounts to Releasing Shipper, Transporter does not relinquish its rights to seek recovery of such amounts, plus applicable late payment charges, from Replacement Shipper.

23.19 Each Month, Releasing Shipper's statement rendered pursuant to Article 18 (Billing and Payments) shall reflect a credit against the Monthly Reservation Charges applicable to the preceding Delivery Month. Such credit shall be equal to the sum of (a) the amount of any Reservation Charges billed by Transporter to the Replacement Shipper for Service utilizing the Released Capacity during the previous Delivery Month, plus (b) the amount of any AOS Charges invoiced by Transporter to the Replacement Shipper for Service utilizing the Released Capacity during the preceding Delivery Month. In the event Transporter makes refunds to a Replacement Shipper pursuant to Section 23.20 of this Article 23 (Capacity Release), any credit otherwise available to Releasing Shipper for the Month subsequent to the disbursement of such refunds shall be reduced by the amount of such refunds.

23.20 In the event the Commission orders refunds of any such rates charged by Transporter on a subject-to-refund basis, Transporter shall make appropriate refunds of amounts paid by Releasing Shippers and Replacement Shippers in excess of Transporter's ultimately determined just and reasonable, applicable Maximum Rates.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.21 Transporter shall allow a prospective Replacement Shipper to post on Transporter's EDM for at least 30 Days its offers to acquire released Capacity. The offer must contain the following information:

(a) the prospective Replacement Shipper's legal name and, where applicable, identification of the Replacement Shipper as an "asset manager" (as that term is defined Section 284.8(h)(3) of the Commission's Regulations) or a "marketer participating in a state-regulated retail access program" (as that term is defined in Section 284.8(h)(4) of the Commission's Regulations), and the name, fax, and phone number of the individual who will authorize the acquisition of the available Capacity.

(b) the daily Quantities of Capacity the prospective Replacement Shipper requests; and

(c) the Receipt Point and/or Delivery Points where Capacity is requested, as applicable.

23.22 The Releasing Shipper may request that Transporter actively market the Capacity available for release. In such instances, Transporter and Releasing Shipper will negotiate the terms and conditions upon which Transporter will market the Releasing Shipper's Capacity.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.23 Permanent Releases of Capacity under Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR:

(a) A Shipper holding an executed agreement for Firm Service under Rate Schedule FT, Rate Schedule FGT, Rate Schedule FC, or Rate Schedule FTR may release its Capacity to a third party ("Permanent Replacement Shipper") for the remaining term of the agreement prospectively from the effective date of such release, provided that the following conditions are satisfied:

(i) the Permanent Replacement Shipper executes an assignment and novation agreement and, if determined to be necessary, a new agreement for Firm Service under the applicable Rate Schedule pursuant to Part 284 of the Commission's Regulations that is subject to pre-granted abandonment;

(ii) the Permanent Replacement Shipper agrees to pay the applicable rates for Service under the Releasing Shipper's agreement for Firm Service (unless otherwise agreed to by Transporter pursuant to Subsection 23.23(b) of this Section 23.23) and accepts all obligations of the Releasing Shipper;

(iii) the Commission provides any necessary abandonment authorizations for the Service subject to such Permanent Release on or before the effective date thereof;

(iv) the Permanent Replacement Shipper meets all of the creditworthiness requirements contained in Article 9 (Creditworthiness) of these General Terms and Conditions and appears on Transporter's Approved Bidders List; and

(v) the Permanent Replacement Shipper receives the approval of Transporter and, to the extent deemed necessary, its Lenders, which shall not be unreasonably withheld.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)
23.23 (Contd.)

(b) Transporter is not required to but may choose to accept a bid at less than the rate provided for in Releasing Shipper's Service Agreement provided that (i) the Releasing Shipper remits to Transporter as an exit fee, a lump-sum payment for the positive difference between the rate provided for in the Releasing Shipper's Service Agreement and the bid rate for the full term of the Capacity release, and (ii) when the Releasing Shipper's contract is at maximum tariff rates, Transporter and the Permanent Replacement Shipper reach agreement on a mechanism permitting the periodic adjustment to the bid rate to reflect subsequent rate adjustments filed for and approved by the FERC.

(c) If the Releasing Shipper permanently releases Capacity hereunder, Transporter will relieve said Releasing Shipper from its obligations under its Service Agreement, if (i) the release is at or above the rates provided for under (and for the remaining term of) Releasing Shipper's Service Agreement or (ii) the release is at less than the rates provided for in Releasing Shipper's Service Agreement and Transporter has accepted the bid in accordance with Subsection 23.23(b) of this Section 23.23, and:

(i) the applicable requirements of Subsection 23.23(a) of this Section 23.23 have been met;

(ii) the Permanent Replacement Shipper accepts all obligations of the Releasing Shipper; and

(iii) Transporter is otherwise financially indifferent with respect to the released Capacity.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 23 CAPACITY RELEASE (Contd.)

23.24 Immediately after Capacity has been awarded pursuant to this Article 23 (Capacity Release), Transporter shall electronically post on its EDM a Notice of completed transaction containing the following information:

(a) term of release;

(b) price bid;

(c) Receipt Point and Delivery Point(s);

(d) Quantity released;

(e) whether the Capacity is recallable; and

(f) the name of the Replacement Shipper or Permanent Replacement Shipper, and whether such Shipper is an Affiliate of the Releasing Shipper.

23.25 Transporter may elect to terminate any Capacity release transaction, upon 30 Days' written notice to the Replacement Shipper, under the following conditions:

(a) The Releasing Shipper has failed to maintain credit in accordance with Article 9 (Creditworthiness) of these General Terms and Conditions; and

(b) The effective rate for the Replacement Shipper is less than the Maximum Rate for the applicable Service; and

(c) The Replacement Shipper has not, prior to the expiration of the 30-Day notice period, agreed in writing to pay, beginning the first Day after the end of the 30-Day notice period and for the remainder of the term of the applicable Capacity release transaction, the lesser of (1) the Releasing Shipper's contract rate, or (2) the Maximum Rate under the applicable Rate Schedule.

Sheet Nos. 481-490 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 24 TRANSPORTER’S FACILITIES OPERATION AND MAINTENANCE

24.1 Transporter and Shipper shall notify each other from time to time, as necessary, of expected changes in the rates of delivery or receipt of Gas, or in the pressures or other operating conditions, and the reason for such expected changes, with the objective that the other party may be prepared to meet them when they occur.

24.2 Transporter shall have the right to designate a Person to function as Operator of its facilities, with respect to, but not limited to, the operation and management of facilities, receipt and disposition of Nominations, scheduling of receipts and deliveries, administration of the Service Agreements, and accounting. If Transporter designates an Operator, references to Transporter in this Tariff shall be read to include such Operator acting on behalf of Transporter, to the extent appropriate.

24.3 When there is a need for Transporter to engage in routine and normal maintenance of Transporter’s system, including the GTP, to undertake repairs and replacements of lines of pipe, meter stations, treating facilities, or other equipment, to schedule regulatory compliance activities, to install taps, to make pig runs, to test equipment, or to engage in other similar actions affecting the capacity of any portions of Transporter’s system, Transporter shall inform all Shippers by posting on Transporter’s EDM a description of activities that will affect the capacity of any portions of Transporter’s system affected and the estimated time period for such activities.

24.4 Transporter may reduce the flow under an agreement for Firm Service to perform maintenance on Transporter’s system and during such time period(s) all Shipper’s with an agreement for Firm Service shall continue to be subject to all applicable Reservation Charges under such Service Agreements.

24.5 Transporter shall provide Shippers at least six Months’ written notice prior to the commencement of any planned pipeline maintenance and Gas Treatment Plant turnarounds.

24.6 Transporter and Shippers will meet to discuss Transporter’s program of planned pipeline maintenance and Gas Treatment Plant turnarounds. The purpose of such meeting will be to attempt to coordinate maintenance and turnaround schedules. Such meeting will take place not less than 30 Days following the notice provided in Section 24.5.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 24 TRANSPORTER’S FACILITIES OPERATION AND MAINTENANCE

24.7 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.

24.8 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.

24.9 Notices given under this Article 24 (Transporter’s Facilities Operation and Maintenance) 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 treating capacity by Receipt Point and Delivery Points on each included Day.

Sheet Nos. 493-500 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 25 GOVERNMENT REGULATIONS

25.1 These General Terms and Conditions, the Rate Schedules contained in this Tariff, and each Service Agreement entered into between Transporter and a Shipper are subject to all valid laws, orders, rules, and regulations of duly constituted authorities having jurisdiction.

Sheet Nos. 502-510 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 26 MARKETING AFFILIATES

26.1 At this time, Transporter transacts no business with any Affiliate who engages in "marketing functions" as defined in Section 358.3 of the Commission's Regulations, and shares no operating personnel, if any, with any such Person. In the event Transporter commences in the future to transact any business with any Affiliate who engages in "marketing functions," Transporter shall post on its EDM the information required by Part 358 of the Commission's Regulations.

Sheet Nos. 512-520 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 27 DISPUTE RESOLUTION

27.1 Except where the Commission has exclusive jurisdiction, any disputes arising pursuant to Section 16.10 of Article 16 (Resolution of Imbalances and Adjustment) or Article 18 (Billing and Payments) of these General Terms and Conditions shall be submitted to arbitration in accordance with this Article 27 (Dispute Resolution) and Shipper and Transporter agree to be bound by the results of such arbitration.

27.2 All such disputes shall be submitted to final and binding arbitration in Anchorage, Alaska in accordance with the Rules of Commercial Arbitration of the AAA then in effect.

27.3 The dispute shall be decided by a panel of three neutral arbitrators, qualified by education, training, and experience to hear the dispute, and chosen as follows. The party initiating the arbitration proceeding shall name one arbitrator at the time it notifies the other party of its intention to arbitrate the dispute, and the responding party shall name an arbitrator within 15 Days of receiving the above notification. Within 20 Days of the appointment of the second arbitrator, the two arbitrators shall select a third arbitrator to act as chairman of the tribunal. If either party fails to appoint an arbitrator within the allotted time or the two party-appointed arbitrators fail to appoint a third arbitrator as provided above, the AAA shall appoint these arbitrators. Any vacancies will be filled in accordance with AAA procedures.

27.4 The parties expressly agree to the consolidation of separate arbitral proceedings for the resolution in a single proceeding of all disputes arising from the same factual situation, and the parties further expressly agree that either party may apply to a court of competent jurisdiction, pending arbitration, for injunctive relief to preserve the status quo, to preserve assets, or to protect documents or facilities from loss or destruction, and such application will not be deemed inconsistent with or operate as a waiver of the party’s right to arbitration. A judgment of the court shall be entered upon the award made pursuant to the arbitration in any court of competent jurisdiction. The arbitrators shall apply as the substantive law to the dispute the laws of the state of Delaware.

Sheet Nos. 522-530 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 28 ELECTRONIC DELIVERY MECHANISM

28.1 Transporter shall maintain an interactive bulletin board and information publication system on its website, referred to as the EDM, for the purpose of providing its Shippers and third parties equal and timely access to Transporter's Affiliate transportation log, standards of conduct and information relevant to the availability of capacity on Transporter's system, whether the capacity is available from Transporter or a Releasing Shipper under the provisions of Article 23 (Capacity Release) hereof. Transporter shall also provide each Shipper access through its EDM to information related to activity under its agreements with Transporter, such as Nominations, estimated imbalances, and allocated Volumes and/or Quantities. Furthermore, Transporter shall administer each Shipper's release of firm capacity, as more particularly described in Article 23 (Capacity Release) hereof, exclusively through its EDM and shall provide to Shipper other interactive capabilities such as the ability to request Service, amendments or discounts, submit Nominations, confirmations and PDAs, view information on agents that administer or perform appointed functions for Shipper under its Service Agreement(s), and execute Service Agreement(s) and amendments thereto. It is understood and agreed that Transporter, through its EDM, shall make available to Shippers or working interest owners sufficient details to support the Volumes and/or Quantities allocated to that party under the PDA method at each point.

28.2 Unless specifically provided otherwise in this Tariff, the generic provisions of this Tariff requiring that Notices, requests, and other communications be in writing may be satisfied by Shipper through submission of such communications over Transporter's EDM. All forms set forth or referenced in the Tariff will also be maintained on Transporter's EDM for Shipper's use. Service Agreement-specific Notices requiring communications to be in writing remain unchanged unless agreed to otherwise by the parties. Submission of information, communications, and execution of documents through Transporter's EDM shall be legally binding on Shipper. Transporter will also require, for its records, written execution by Shipper of all Service Agreements and any other agreements between Shipper and Transporter.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 28 ELECTRONIC DELIVERY MECHANISM (Contd.)

28.3 Transporter's EDM site will display current information, have on-line help, a menu of available information for ease of reference, and search functions. Any party will be able to download information provided on Transporter's EDM. Transporter shall maintain and retain daily back-up records of the information displayed on Transporter's EDM for a period of three Years for purposes of restoring such information to on-line availability if there is a computer malfunction or loss. Completed transactions and posted information will remain on Transporter's EDM for at least 30 Days and then will be archived. Archived information will be available from Transporter upon 15 Days' prior written Notice. Copies of archived information will be made available at $0.10 per page if a paper copy is requested or $20.00 per CD-Rom, plus shipping costs.

Sheet Nos. 533-540 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 29 ANNUAL CHARGE ADJUSTMENT

29.1 This Article 29 (Annual Charge Adjustment) establishes a surcharge (the "ACA Surcharge") as permitted by Section 154.402 of the Commission's Regulations, which allows a natural gas pipeline company to adjust its rates annually to recover from its Shippers annual charges assessed against it by the Commission under Part 382 of the Commission's Regulations.

29.2 The ACA Surcharge shall be applicable to the Quantities treated, compressed, and/or transported under Transporter's Service Agreements. Transporter shall not recover the annual charges assessed by the Commission in a NGA Section 4 rate case for any time period during which this ACA Surcharge is assessed.

29.3 The currently effective ACA Surcharge shall be reflected in each applicable Rate Sheet containing Currently Effective Rates.

29.4 The ACA Surcharge shall be an annual charge unit rate, adjusted to Transporter's pressure base and heating value, as appropriate, which shall be authorized by the Commission each fiscal Year. Changes to the ACA Surcharge shall be filed annually to reflect the annual charge unit rate authorized by the Commission for such fiscal Year.

29.5 Transporter shall file the revised ACA unit charge at least 30 Days prior to the effective date of such rate adjustment unless, for good cause shown, a different effective date is allowed by valid Commission order.

Sheet Nos. 542-550 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 30 FUEL RETENTION ADJUSTMENT

30.1 Shipper's Receipt Point Nomination for each Service shall include: (a) a Quantity of Gas equal to Transporter's reasonable estimate of Fuel for such Service, (b) a Quantity of Gas equal to Canadian Transporter's reasonable estimate of fuel for service on the Canada Mainline ("Canada Fuel"), if applicable, and (c) a Quantity of Gas equal to Transporter's reasonable estimate of Lost or Unaccounted for Gas attributable to such Service (collectively, the "Fuel Requirement").

30.2 Transporter shall be entitled to retain the portion of the Fuel Requirement necessary to operate its system and, consequently, Shipper's Nomination at each Delivery Point should be reduced accordingly. Shippers shall not be required to pay Transporter any fee or rate for Transportation of the Fuel Requirement (including the portion of the Fuel Requirement, if any, attributable to Canada Fuel).

30.3 Transporter will advise Shipper of the applicable Fuel Requirement via the EDM at least five Days in advance of the first of each Month, or in the absence of such notification, Shipper shall use the last Monthly Fuel Requirement provided by Transporter.

30.4 The Fuel Requirement will be calculated on a percentage basis and expressed as a percentage of the Quantity of Gas nominated at the applicable Receipt Point.

30.5 Title to the Gas constituting the Fuel Requirement (other than the Canada Fuel) shall pass to Transporter at the applicable Receipt Point.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 30 FUEL RETENTION ADJUSTMENT (Contd.)

30.6 After each three-Month period beginning with the first Day of the Month after Transporter has operated for three Months, Transporter shall re-determine the Fuel Requirement applicable to its Rate Schedules in accordance with the following procedures. Transporter shall calculate the total actual Fuel Requirement for each Service based on data for the preceding three-Month period. This shall be the Fuel Requirement basis for the subsequent three-Month period for the applicable Service. Transporter shall file revised tariff sheets with the Commission containing the re-determined Fuel Requirement at least ten Days prior to the effective date requested by Transporter, which effective date shall be no later than three Months after the end of the preceding three-Month period; provided, however, that Transporter may choose not to file to revise the Fuel Requirement for any Service if the re-determined Fuel Requirement for such Service, expressed as a percentage, does not vary by more than 0.1 from the Fuel Requirement, expressed as a percentage, in effect for such Service at that time. Transporter shall notify its Shippers within the above filing period if it chooses to exercise the option not to revise the applicable Fuel Requirement.

30.7 If the adjustment referenced in Section 30.6 of this Article 30 (Fuel Retention Adjustment) shows Transporter has over-collected the Fuel Requirement for the previous three-Month period, Transporter shall, at its option, either (a) issue a credit to each Shipper for the value of the over-collection, or (b) reduce its Fuel Requirement for the subsequent three-Month period to account for the over-collection. If the adjustment referenced in Section 30.6 of this Article 30 (Fuel Retention Adjustment) shows Transporter has under-collected the Fuel Requirement for the previous three-Month period, Transporter may increase the Fuel Requirement for the subsequent three-Month period to account for the under-collection.

30.8 Transporter shall post on its EDM a revised estimated Fuel Requirement applicable to its Rate Schedules five Days in advance of the first of each Month to be effective during the Month. Transporter shall have the right to adjust the estimated Fuel Requirement to reflect the actual Quantities of Gas used by Transporter so as not to create an imbalance on its system. The estimate will include three components attributable to each Rate Schedule: (1) Lost or Unaccounted for Gas Quantities; (2) Fuel, and (3) prior variance adjustments, which include unamortized or over-amortized Quantities at December 31.

Sheet Nos. 553-560 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 31 OPERATIONAL FLOW ORDERS

31.1 Transporter shall have the right to issue orders to Shippers (each, an "Operational Flow Order" or "OFO") as specified in this Article 31 (Operational Flow Orders), which require actions by the Shippers in order to alleviate conditions threatening the integrity of Transporter's facilities, to maintain operations at the pressures required to provide an efficient and reliable Service to all Shippers, and to maintain Transporter's system in balance for the foregoing purposes. Before issuing an OFO, Transporter will attempt to identify specific Shippers causing a problem and attempt to remedy those problems with those Shippers. If Transporter issues an OFO pursuant to this Article 31 (Operational Flow Orders), Transporter shall not be required to limit or suspend Service to a Shipper whose current use of Transporter's system does not aggravate the operating conditions on which the OFO is based regardless of the class of Service utilized by that Shipper. Shipper's response to any specified Gas Quantity provision contained in an OFO shall be subject to the penalty provisions of Section 31.2 of this Article 31 (Operational Flow Orders) to the extent the actual Quantities of Gas tendered to Transporter and/or received by Shipper in response to the OFO are greater or less than the tolerances specified in the OFO. Within a reasonable period following the end of the OFO, Transporter will post on its EDM a report detailing the conditions that required the issuance and termination of the OFO.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 31 OPERATIONAL FLOW ORDERS (Contd.)

31.2 Penalty

(a) All Quantities tendered to Transporter and/or received by Shipper on a Daily basis in violation of Transporter’s OFO shall constitute unauthorized receipts or deliveries for which a charge of $25.00 per Dth shall be assessed and paid by Shipper(s) in violation.

(b) Net penalties shall be credited back to all Shippers who complied with the OFO (compliant Shippers). Transporter’s out-of-pocket expenses incurred or revenues foregone as a direct result of the OFO violation(s) shall reduce any penalties collected to determine the net penalty amount to be credited. The net penalty amount shall be credited to the second Month’s invoice from the Month of collection and shall be credited based on the pro-rata share of each compliant Shipper’s Gas throughput by the total compliant Shippers’ throughput for the Month of the OFO violation. If direct expenses or foregone revenues are greater than the penalty collected, no credit shall occur. To the extent Transporter has collected penalties subject to Subsection 31.2(a) of this Article 31 (Operational Flow Orders), Transporter will file a report July 1 of each Year detailing the penalty revenues received under Subsection 31.2(a) of this Article 31 (Operational Flow Orders), Transporter’s out-of-pocket expenses incurred or revenues foregone, and net penalty amounts credited back to the compliant Shippers.

31.3 Shippers will be exempt from penalties on imbalances pursuant to Article 16 (Resolution of Imbalances and Adjustments) of these General Terms and Conditions that result from complying with an OFO. Shippers will be allowed to correct OFO-created imbalances until the end of the Month following the Month in which any such imbalance occurs, based on the then-current operations of Transporter’s system. Upon an OFO becoming effective as specified in the OFO or as provided in this Section 31.3, Shipper or the operator of the facilities connecting with Transporter’s facilities shall be permitted up to the time stated in the OFO to make adjustments in compliance with the OFO. If Shipper complies with the provisions of the OFO within such notice period, then no penalty pursuant to Section 31.2 of this Article 31 (Operational Flow Orders) shall be assessed.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 31 OPERATIONAL FLOW ORDERS (Contd.)

31.4 Transporter will post to its EDM its intention to place an OFO into effect and notify the affected Shipper(s) at least 24 hours prior to the implementation of the OFO; provided, however, that a shorter notice period may be given where action must be taken to protect the integrity of Transporter's system. Such Notice and posting shall identify (a) the parties subject to the OFO, (b) the time the OFO will become effective, and (c) the estimated duration of the OFO (or, if unknown, that the OFO is indefinite). Where an OFO is made effective on less than 24 hours' Notice, Transporter will also provide affected Shippers with an explanation with all relevant information specific to the individual situation to justify issuance of that particular OFO. Whenever an OFO requires action in less than 72 hours, Transporter will provide prompt Notice to the affected Shippers via e-mail or direct notification to the Shippers' pre-designated phone and facsimile numbers, as well as by posting on Transporter's EDM.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 31 OPERATIONAL FLOW ORDERS (Contd.)

31.5 Conditions

(a) If in Transporter’s judgment, impending operating conditions will cause the operating pressure at one or more Receipt Point or Delivery Point to exceed the maximum allowable operating pressure or a firm contract pressure, or the operating pressure of one or more Delivery Points to decrease below the firm contract pressure, Transporter may issue an OFO pursuant to this Subsection 30.5(a) requiring that all Shippers adjust the Gas Volumes and/or Quantities or adjust the Nominations at the Receipt Point and Delivery Point(s) under all Service Agreements to be in balance (considering Shipper’s pro-rata share of Fuel and Lost or Unaccounted for Gas) effective the earliest opportunity Shippers have in their control to effect Gas Volumes and/or Quantities at either the Receipt Point or Delivery Point(s). Transporter shall use all available opportunities in its control to effect Gas Volumes and/or Quantities at either the Receipt Point or Delivery Point(s) in support of Shipper’s actions pursuant to the OFO and to mitigate the adverse effects on Transporter’s system.

(b) Transporter may issue, on a not unduly discriminatory basis, such other reasonable OFOs as may be required for the purposes set forth in Section 31.1 of this Article 31 (Operational Flow Orders).

(c) Compliance with the OFOs and the other terms and conditions of Transporter’s Tariff is essential to Transporter’s ability to provide Services under all Rate Schedules. A failure by one or more Shippers to comply with an OFO may affect Transporter’s ability to provide such Services. In such event and in addition to the other provisions hereof and not in lieu of any other remedies available at law or in equity, Transporter will, except to the extent Transporter’s inability to provide Service arose from Transporter’s gross negligence, undue discrimination, or intentional misconduct, have no liability or responsibility for its inability to provide Service as a result of an OFO condition or Shipper’s failure to comply with an OFO, and Shipper(s) shall indemnify and hold Transporter harmless from any claims brought by a third party against Transporter arising from such failure except that Shippers shall not be responsible for any incidental, consequential, punitive, or special damages, including lost profits resulting therefrom.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 31 OPERATIONAL FLOW ORDERS (Contd.)

31.6 In recognition of the fact that this Article 31 (Operational Flow Orders) is intended to promote conscientious operations by Shippers such that Service to other Shippers is not impaired in any way, Transporter may waive any penalty charges incurred by a Shipper if Transporter determines, in its reasonable judgment, that Shipper was conducting its operations in a responsible manner at the time the penalty charges were incurred and that Shipper's conduct did not impair Service to another Shipper. Transporter must grant waivers under this section on a not unduly discriminatory basis, but the waiver of any penalty charges shall not constitute an automatic waiver of any future penalty charges. Transporter shall maintain a record of all waivers granted under this Section 31.6 and shall make such record available upon written request to the Commission and to any Shipper.

Sheet Nos. 566-570 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 32 WAIVER

32.1 Transporter may waive any of its rights under this Tariff, or any obligations of Shipper under any Service Agreement, on a not unduly discriminatory basis.

32.2 No waiver by Transporter or Shipper of any one or more defaults by the other in the performance of any provisions of a Service Agreement, nor any election not to terminate such an agreement, shall operate or be construed as a waiver of any continuing or future default or defaults, whether of a like or different character.

Sheet Nos. 572-580 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 33 CONSTRUCTION OF FACILITIES

33.1 Transporter shall not deny a request for new interconnection facilities without adequate operational, environmental, or legal justification. Transporter shall grant requests to construct, or permit the construction of, such facilities if:

(a) the party seeking the construction of the facilities is willing to bear the cost of construction if Transporter performs the construction, or such party constructs the facilities itself in compliance with Transporter's technical requirements;

(b) the proposed construction and operation of the facilities does not adversely affect Transporter's operations;

(c) the proposed construction and any resulting Service does not diminish Service to Transporter's existing customers;

(d) the proposed construction does not cause Transporter to be in violation of any applicable laws or regulations with respect to the facilities required to establish an interconnection with Transporter's existing facilities; and

(e) the proposed construction does not cause Transporter to be in violation of its right-of-way agreements or any other contractual obligations with respect to the proposed facilities.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 33 CONSTRUCTION OF FACILITIES (Contd.)

33.2 Requests for new interconnection facilities must be made in writing to Transporter, and shall include the following information:

(a) the legal name and principal place of business of the Person requesting the interconnection;

(b) a description of the facilities to be interconnected with Transporter’s facilities;

(c) the capacity of the proposed facilities to be interconnected at the proposed point of interconnection;

(d) the specific location of the proposed facilities;

(e) the economic justification for the proposed facilities; and

(f) additional data concerning such facilities as may reasonably be required by Transporter, including pressures, anticipated hourly, Daily, Monthly, and Yearly throughput levels of the Service that support the new facilities, estimated composition of Gas, and such other data reasonably required to enable Transporter to asses the operational, environmental, or legal consequences of the construction and operation of the proposed facilities.

33.3 Any Person owning and/or requesting the construction of interconnection facilities shall execute an interconnection agreement with Transporter. If the requesting Person is not the owner of the proposed facilities, the requesting Person shall demonstrate that the owner of the facilities is capable and willing to construct, or permit the construction of, any required facilities. Execution of an interconnection agreement by Transporter shall not affect the terms and conditions of Service on Transporter’s system, nor will it guarantee priority access to Transporter’s system.

33.4 New interconnection facilities shall not impose any minimum pressure requirements or other operating parameters that could require alteration of the operation of Transporter’s system, unless Transporter agrees otherwise, which agreement shall not be unreasonably withheld.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 33 CONSTRUCTION OF FACILITIES (Contd.)

33.5 Transporter shall have the option to design, construct, operate, and own the proposed interconnection facilities at its own expense. Facilities constructed on Transporter's system will be designed according to the specifications of Transporter, to be determined by Transporter in consultation with the requesting Person.

33.6 The requesting Person's agreement to reimburse Transporter for all costs related to the new facilities shall include, but not be limited to, permitting, engineering, land or land rights, buildings, materials, contractor fees, taxes (including income taxes), associated overhead, and any carrying costs.

33.7 Transporter shall not be responsible for any upstream or downstream Person's facilities or the operation or maintenance of such facilities. Nor shall Transporter be obligated to accept Gas from or effect deliveries of Gas to such facilities except in accordance with the terms of this Tariff.

33.8 In the event Transporter determines a potential need exists to expand the capacity of its facilities, or is advised by FERC or another governmental authority with jurisdiction of the need to consider an expansion, Transporter will work diligently to evaluate the system modifications and the economic justification for such an expansion.

Sheet Nos. 584-590 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 34 AGENCY

34.1 Shipper may engage a third party to act as Shipper's agent under any Rate Schedule and to perform acts, including but not limited to the receipt and payment of invoices, the giving of Notices, the designation of Delivery Point(s) and the Receipt Point, making Nominations for Service and the receipt of proceeds from, or the payment of amounts due for, the Monthly resolution of imbalances under Article 16 (Resolution of Imbalances and Adjustment) of these General Terms and Conditions in connection with any Service so arranged. In this event, Shipper shall provide Transporter with a written request that Transporter accept the specified third party as agent for Shipper. The request shall (a) state specifically the scope and term of the agency, (b) state that Transporter is authorized to accept the actions of the agent within the scope of its authority to the same extent as it would accept the actions of Shipper, (c) provide that Shipper shall indemnify Transporter and hold it harmless for any loss or damage occasioned by the agent's actions or Transporter's reliance thereon, and (d) be accompanied by an affidavit verifying the information contained in the request. If the request conforms to the provisions of this Article 34 (Agency), then Transporter shall accept such agency and notify Shipper in writing of its acceptance of the request.

Sheet Nos. 592-600 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 35 ASSIGNMENT

35.1 A Shipper may assign its Service Agreement, in whole or in part, subject to the provisions of Article 9 (Creditworthiness) of these General Terms and Conditions and so long as Transporter is financially indifferent, to:

(a) any Person acquiring all, or substantially all, of the Gas business of said Shipper;

(b) a trustee or trustees, individual or corporate, as security for bonds or other obligations or securities; or

(c) any Person who succeeds by purchase, merger, consolidation, sale or assignment to the interest, in whole or in part, in properties that produce or will produce Gas for which Service is provided under the applicable Service Agreement.

35.2 Upon assignment under Section 35.1, and appropriate notification to Transporter and Transporter's acceptance of that Notice, the assignee shall be entitled to the rights, including the related rights to pipeline capacity under the applicable Rate Schedule, and subject to the obligations of Shipper's Service Agreement.

35.3 If a Shipper wishes to assign a portion or its entire firm capacity under a Service Agreement to a party not described above, it must do so using the Capacity release provisions of this Tariff.

Sheet Nos. 602-610 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 36 NAESB STANDARDS

36.1 Transporter hereby incorporates into this Tariff by reference the following NAESB WGQ Version __ business standards, which have been adopted by the Commission in the Commission's Regulations.

[NAESB standards required to be incorporated by reference at the time of filing will be included in the Tariff.]

Sheet Nos. 612-620 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 37 DISCOUNTED RATES

37.1 Transporter reserves the right to provide, by contract with any Shipper, Service at rates below the Maximum Rates applicable to such Service, as stated in the Tariff, but no less than the Minimum Rates as applicable to such Service, as stated in the Tariff. All discounts for Firm Service will be applied to the applicable Reservation Charge.

37.2 Nothing herein shall require Transporter to agree to any discount below the applicable Maximum Rates.

Sheet Nos. 622-630 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 38 NEGOTIATED RATES

38.1 Notwithstanding anything to the contrary contained in this Tariff, including the provisions of the Rate Schedules contained herein, Transporter and Shipper may mutually agree to a Negotiated Rate under any agreement for Firm Service; provided that Shipper has not acquired the Capacity on a temporary basis under the provisions of Article 23 (Capacity Release) of these General Terms and Conditions. If a portion of the Capacity under an existing agreement for Firm Service is priced at a higher Negotiated Rate, the existing maximum or discounted rates will continue to apply to the Capacity not subject to the Negotiated Rates.

38.2 A Negotiated Rate may be less than, equal to, or greater than the maximum otherwise applicable rate, but shall not be less than the applicable Minimum Rate. A Negotiated Rate may be based on a rate design other than straight-fixed variable, and may include a minimum Volume or Quantity.

38.3 Transporter and Shipper may agree to a Negotiated Rate for the entire term of an agreement for Firm Service, or may agree to a Negotiated Rate for some portion of the term of an agreement for Firm Service. Transporter and Shipper may agree to apply the Negotiated Rate to all or a portion of Shipper's Capacity under an agreement for Firm Service. An agreement for Firm Service incorporating a Negotiated Rate shall be referred to herein as a "Negotiated Rate Agreement".

38.4 This Article 38 (Negotiated Rates) does not authorize Transporter to negotiate terms and conditions of Service other than the rate charged.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 38 NEGOTIATED RATES (Contd.)

38.5 During the period a Negotiated Rate is in place, the Negotiated Rate shall govern and apply to Shipper's Service under the agreement for Firm Service and the otherwise applicable rate, rate component, charge, or credit shall not apply or be available to the Shipper. Only those rates, rate components, charges, or credits identified by Transporter and Shipper in writing as being superseded by a Negotiated Rate shall be ineffective during the period the Negotiated Rate is effective; all other rates, rate components, charges, or credits prescribed, required, established, or imposed by this Tariff shall remain in effect. At the end of the period during which the Negotiated Rate is in effect, the otherwise applicable Maximum Rates or charges shall govern any Service provided to Shipper.

38.6 Transporter shall submit to the Commission a Tariff sheet stating the exact legal name of the Shipper and the Negotiated Rate. The applicable Rate Schedule, Receipt Point and Delivery Point(s), and the contract Volumes shall be posted on Transporter's EDM. Such Tariff sheet will be filed as soon as practicable, but in no event later than the time Transporter intends the rate to go into effect. The filing will contain a statement that the Negotiated Rate Agreement does not deviate in any material respect from the Form of Agreement in Transporter's Tariff for the applicable Rate Schedule. If, however, the Negotiated Rate Agreement does deviate in any material respect, Transporter shall file the Non-Conforming Service Agreement in accordance with FERC policy regarding Non-Conforming Agreements then in effect.

38.7 Transporter shall have the right to seek in future general rate proceedings discount-type adjustments in the design of its rates related to Negotiated Rate Agreements that were converted from pre-existing discount agreements to Negotiated Rate Agreements. In those situations, Transporter may seek a discount-type adjustment based upon the greater of: (a) the Negotiated Rate revenue received, or (b) the discounted Tariff rate revenues that otherwise would have been received.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 38 NEGOTIATED RATES (Contd.)

38.8 Transporter shall maintain separate records for all revenues associated with Negotiated Rate transactions. Transactions related to Negotiated Rate Agreements that originated as pre-existing discounted transactions and were subsequently converted shall be recorded separately from those originating as Negotiated Rate Agreements. Transporter shall record the Volumes and/or Quantities, as applicable, for which Service is provided, billing determinants, rate component, surcharge, and the revenue associated with its Negotiated Rates so that this information can be separately identified in the format of Statement G, I, and J in Transporter’s general rate change applications.

38.9 Negotiated Rates do not apply as the price cap for capacity release transactions. All applicable capacity release bids must conform to Transporter’s applicable Maximum Rates. Unless otherwise agreed, the Negotiated Rate Shipper shall be required to pay any difference by which the Negotiated Rate exceeds the rate paid by the Replacement Shipper. Transporter and Shipper may negotiate Shipper’s payment obligations, or crediting mechanisms, which would apply when Capacity subject to a Negotiated Rate is released, so long as the terms and conditions of Service are not modified.

38.10 For purposes of exercising rights to continue Service pursuant to Article 22 (Pre-Granted Abandonment) of these General Terms and Conditions, the highest rate a Shipper must match if it desires to retain all or a portion of its Capacity is the Maximum Rate applicable, including surcharges. The NPV of revenues to be received from a Shipper bidding a Negotiated Rate shall be calculated using the proposed Reservation Charge revenues and any proposed Usage Charge revenues guaranteed by a minimum Quantity commitment or otherwise. Where a Negotiated Rate is based on a formula, the future value of which cannot be determined at the time of bidding, Transporter shall estimate the future revenues to be received under the Negotiated Rate formula using currently available data.

38.11 Any Negotiated Rate Agreement entered into between Transporter and Shipper shall state that the agreement represents a Negotiated Rate Agreement and not a discounted rate.

Sheet Nos. 634-640 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 39 FLOW CONTROL EQUIPMENT

Transporter has the right to install and/or use remote or manual flow control equipment ("Flow Control") to preserve the operational safety and reliability of its system. Transporter's use of Flow Control is subject to the following provisions.

39.1 Pursuant to the provisions set forth in this Section 39.1, Transporter may exercise, using reasonable judgment and in a not unduly discriminatory manner, Flow Control to restrict or temporarily suspend the flow of Gas into or out of its system.

(a) The use of Flow Control shall be on a specific location basis.

(b) Except as otherwise provided in Subsection 39.1(d) below, prior to invoking Flow Control, Transporter shall provide at least eight hours' advance notice to the affected operator(s) of the interconnecting facilities by phone and email.

(c) Except as otherwise provided in Subsection 38.1(d) below, Flow Control will be exercised consistent with Transporter's service obligations under its rate schedules and will not be used at the following locations:

(i) a location included in a pre-determined allocation methodology elected by an operator of any interconnecting facilities; or

(ii) a location that is being operated within the parameters of an executed operational balancing agreement.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 39 FLOW CONTROL EQUIPMENT (Contd.)
39.1 (Contd.)

(d) Transporter may exercise Flow Control under the following circumstances, notwithstanding anything in this Article 39 (Flow Control Equipment) but shall provide as much advance notice as reasonably possible):

(i) when immediate shut-in of Gas that fails to conform to the Gas Quality Standards is necessary to preserve the safety or the integrity of the location, segment, lateral, or overall system;

(ii) in an emergency situation where safety or the integrity of the location, segment, lateral, or overall system is at immediate risk and necessitates immediate shut-in of facilities; or

(iii) when Transporter and the applicable operator of the interconnecting facilities mutually agree to the use of Flow Control.

39.2 In the event remote-controlled Flow Control has not been installed by Transporter at a certain point and Transporter has issued notice to the operator of the interconnecting facilities on more than one occasion of Transporter’s intent to use Flow Control manually at such point, Transporter may install, using reasonable judgment in a not-unduly discriminatory manner, at the applicable operator’s expense remote-controlled Flow Control at such point to promote safety and reliability. Such payment requirement shall reflect Transporter’s reasonable judgment.

39.3 Transporter will not be held liable for any damages to any operator or Shipper resulting from Transporter’s use of Flow Control that meets the requirements of this Article 39 (Flow Control Equipment) except to the extent of the negligence of Transporter (but in no event shall Transporter be liable for punitive, incidental, consequential, or special damages unless it is determined that Transporter was grossly negligent or acted with willful misconduct or in bad faith).

Sheet Nos. 643-650 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 40 OPERATIONAL PURCHASES AND SALES OF GAS

40.1 Transporter may purchase and/or sell Gas to the extent necessary to: (i) balance Transporter Fuel and Lost and Unaccounted for Gas pursuant to Article 16 (Resolution of Imbalances and Adjustment) 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; or (v) otherwise protect the operational integrity of Transporter’s system. Any sales shall be made on an unbundled basis. The sale or purchase of Gas shall occur at any Receipt Point or Delivery Point on Transporter’s 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 not unduly discriminatory basis.

40.2 Transporter shall post for bid its operational purchases and/or sales on Transporter’s EDM. Such posting shall include the following information:

(a) the level of daily Quantities and whether such purchase and/or sale Quantities shall be made on a firm or interruptible basis;

(b) the requested effective date and term of the purchase and/or sale;

(c) the names of the applicable Receipt Point(s) or Delivery Point(s);

(d) the method for determining the best bid(s);

(e) the time period for accepting and awarding bid(s); and

(f) any additional information as may be required by Transporter.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 40 OPERATIONAL PURCHASES AND SALES OF GAS (Contd.)

40.3 Transporter shall ask prospective bidders to place a bid on Transporter's EDM or via fax or electronic mail with such bid(s) containing the following information:

(a) Bidder's legal name and the name, title, address, and phone number of each individual authorized to purchase or sell natural gas;

(b) Bidder's price;

(c) information addressing all criteria requested by Transporter in its posting;

(d) any conditions on the prospective bidder's offer to purchase and/or sell Gas.

40.4 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 the 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 Section 40.5 below.

40.5 In the event Transporter purchases or sells Gas in a calendar year pursuant to this Article 40 (Operational Purchases and Sales of Gas), Transporter shall file a report with 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, the 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. 653-660 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 41 RESERVATION OF CAPACITY FOR EXPANSION PROJECTS

41.1 Notwithstanding the other provisions of this Tariff, Transporter may elect to reserve capacity required for an expansion project out of:

(a) unsubscribed capacity;

(b) capacity under expiring Service Agreement(s) where such Service Agreement(s) do not have a Right of First Refusal;

(c) capacity under expiring Service Agreement(s) where Shipper elects not to exercise its Right of First Refusal; or

(d) turnback capacity Transporter has agreed to accept in response to a direct solicitation from Transporter to serve an expansion project.

41.2 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 Transporter posts such capacity as being reserved. Capacity may be reserved for expansion projects for only a 12-month period prior to Transporter filing for FERC certificate approval for construction of the proposed expansion facilities and thereafter until all expansion facilities related to the certificate filing are placed into service.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 41 RESERVATION OF CAPACITY FOR EXPANSION PROJECTS (Contd.)

41.3 If Transporter reserves capacity for an expansion project, it will notify Shippers of its intent via a posting on Transporter's EDM. 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.

41.4 If any available expansion capacity posted for bid remains unsubscribed after the close of any Open Season with respect to such expansion capacity, 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, Transporter shall post a solicitation for expansion project related turnback capacity specifying the minimum terms for a response to the solicitation.

41.5 Any capacity reserved under this Article 41 (Reservation of Capacity for Expansion Projects) will be made available for 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 22.2 of Article 22 (Pre-Granted Abandonment) of these General Terms and Conditions, commensurate with the proposed in-service date of any expansion project.

GENERAL TERMS AND CONDITIONS (Contd.)
ARTICLE 41 RESERVATION OF CAPACITY FOR EXPANSION PROJECTS (Contd.)

41.6 Any capacity reserved for a project that does not go forward for any reason shall be reposted as generally available within 30 Days of the date the capacity becomes available. The previously reserved capacity will become available when Transporter posts the capacity on Transporter's EDM.

Sheet Nos. 664-670 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 42 OFF-SYSTEM SERVICES

42.1 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.

42.2 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 Article 42 (Off-System Services), the "Shipper must have title" requirement shall not be applicable to the acquired off-system services.

42.3 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 not unduly 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.

42.4 Any off-system services acquired by Transporter for the benefit of a specific Shipper, which are not being utilized shall be offered on a not unduly discriminatory basis to Transporter's other Shippers on an 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 (which will be charged to Shipper at Transporter's actual cost) 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 Article 42 (Off-System Services) be offered beyond the term during which Transporter has contracted to obtain such off-system service from a third party.

Sheet Nos. 672-680 Are Reserved for Future Use

GENERAL TERMS AND CONDITIONS (Contd.)

ARTICLE 43 MISCELLANEOUS PROVISIONS

43.1 The headings used in these General Terms and Conditions, Rate Schedules, and Service Agreements are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and provisions of any paragraph nor to be deemed in any way to qualify, modify, or explain the effects of any such terms or provisions.

43.2 In the interpretation of these General Terms and Conditions, Rate Schedules, and any Service Agreement, words in the singular shall be read and construed in the plural and words in the plural shall be read and construed in the singular where the context so requires.

Sheet Nos. 682-700 Are Reserved for Future Use

EXHIBIT A

RECEIPT POINTS

Transmission Service

Inlet to Transmission Line from Prudhoe Bay Unit to Gas Treatment Plant (the "Prudhoe Bay Transmission Receipt Point")

Inlet to Transmission Line from the Point Thomson area to Gas Treatment Plant (the "Point Thomson Transmission Receipt Point")

Gas Treating Service

Outlet of Transmission Line from Prudhoe Bay Unit to Gas Treatment Plant

Outlet of Transmission Line from the Point Thomson area to Gas Treatment Plant

Compression Service

Outlet of Gas Treating Service

Transportation Service

Outlet of Compression Service

EXHIBIT B

DELIVERY POINTS

Transmission Service

Outlet of Transmission Line from Prudhoe Bay Unit to Gas Treatment Plant

Outlet of Transmission Line from the Point Thomson area to Gas Treatment Plant

Gas Treating Service

Outlet of Gas Treating Service

Treated Gas Return Point

Compression Service

Outlet of Compression Service

Transportation Service

Outlet of Transporter’s system at Livengood

Outlet of Transporter’s system at the Parks Highway Spur

Outlet of Transporter’s system at Fairbanks

Outlet of Transporter’s system at Delta Junction

Outlet of Transporter’s system at Tok

Interconnection with the Canada Mainline

EXHIBIT C

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE FT
FIRM TRANSPORTATION SERVICE

Service Agreement No. ______

FIRM TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT

THIS FIRM TRANSPORTATION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Transportation on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FT, as such rates and charges and Rate Schedule FT may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FT. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of the commitment reflected in this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________	By: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________

ATTACHMENT 1 TO
FIRM TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT

Receipt Point(s), Delivery Point(s), and MDQ

Receipt Point	Delivery Point	MDQ (Dth/Day)

**ATTACHMENT 2 TO
FIRM TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT**

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter’s FERC Gas Tariff.

EXHIBIT D

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE IT
INTERRUPTIBLE TRANSPORTATION SERVICE

Service Agreement No. ______

**INTERRUPTIBLE TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE IT**

THIS INTERRUPTIBLE TRANSPORTATION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Transportation on an interruptible basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Service Quantity, plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the Maximum Daily Service Quantity, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule IT, as such rates and charges and Rate Schedule IT may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.3 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachment 1 to this Agreement is incorporated herein. The parties may amend Attachment 1 by mutual agreement, which amendment shall be reflected in a revised Attachment 1 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ___________________________	Title: ___________________________

ATTACHMENT 1 TO
INTERRUPTIBLE TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE IT

Receipt Point(s), Delivery Point(s), and Maximum Daily Service Quantity

Receipt Point	Delivery Point	Maximum Daily Service Quantity (Dth/Day)

EXHIBIT E

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE FGT
FIRM GAS TREATING SERVICE

Service Agreement No. ______

FIRM GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE FGT

THIS FIRM GAS TREATING SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Gas Treating Service on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FGT, as such rates and charges and Rate Schedule FGT may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FGT. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of the commitment reflected in this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ___________________________	Title: ___________________________

ATTACHMENT 1 TO
FIRM GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE FGT

Receipt Point(s), Delivery Point(s), and MDQ

	Receipt Point	Delivery Point	MDQ (Dth/Day)

ATTACHMENT 2 TO
FIRM GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE FGT

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter's FERC Gas Tariff.

EXHIBIT F

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE IGT
INTERRUPTIBLE GAS TREATING SERVICE

Service Agreement No. ______

INTERRUPTIBLE GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE IGT

THIS INTERRUPTIBLE GAS TREATING SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Gas Treating Service on an interruptible basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Service Quantity, plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the Maximum Daily Service Quantity, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter’s line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter’s line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER’S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter’s Rate Schedule IGT, as such rates and charges and Rate Schedule IGT may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 This Agreement in all respects is subject to the provisions of Transporter’s FERC Gas Tariff, which is by reference made a part hereof.

4.3 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachment 1 to this Agreement is incorporated herein. The parties may amend Attachment 1 by mutual agreement, which amendment shall be reflected in a revised Attachment 1 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ___________________________	Title: ___________________________

ATTACHMENT 1 TO
INTERRUPTIBLE GAS TREATING SERVICE AGREEMENT
UNDER RATE SCHEDULE IGT

Receipt Point(s), Delivery Point(s), and Maximum Daily Service Quantity

Receipt Point	**Delivery Point**	**Maximum Daily Service Quantity (Dth/Day)**

EXHIBIT G

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE FC
FIRM COMPRESSION SERVICE

Service Agreement No. ______

FIRM COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FC

THIS FIRM COMPRESSION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Compression Service on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FC, as such rates and charges and Rate Schedule FC may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FC. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of the commitment reflected in this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ___________________________	Title: ___________________________

ATTACHMENT 1 TO
FIRM COMPRESSION AGREEMENT
UNDER RATE SCHEDULE FC

Receipt Point(s), Delivery Point(s), and MDQ

Receipt Point	Delivery Point	MDQ (Dth/Day)

ATTACHMENT 2 TO
FIRM COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FC

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter's FERC Gas Tariff.

EXHIBIT H

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE IC
INTERRUPTIBLE COMPRESSION SERVICE

Service Agreement No. ______

INTERRUPTIBLE COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE IC

THIS INTERRUPTIBLE COMPRESSION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Compression Service on an interruptible basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Service Quantity, plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the Maximum Daily Service Quantity, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter’s line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter’s line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER’S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter’s Rate Schedule IC, as such rates and charges and Rate Schedule IC may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 This Agreement in all respects is subject to the provisions of Transporter’s FERC Gas Tariff, which is by reference made a part hereof.

4.3 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachment 1 to this Agreement is incorporated herein. The parties may amend Attachment 1 by mutual agreement, which amendment shall be reflected in a revised Attachment 1 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________________	By: ______________________________
Name: ____________________________	Name: ____________________________
Title: ___________________________	Title: ___________________________

ATTACHMENT 1 TO
INTERRUPTIBLE COMPRESSION SERVICE AGREEMENT
UNDER RATE SCHEDULE IC

Receipt Point(s), Delivery Point(s), and Maximum Daily Service Quantity

Receipt Point	Delivery Point	Maximum Daily Service Quantity (Dth/Day)

EXHIBIT I

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE FTR
FIRM TRANSMISSION SERVICE

Service Agreement No. ______

FIRM TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FTR

THIS FIRM TRANSMISSION SERVICE AGREEMENT (the “Agreement”) is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as “Transporter,” and ________________, a ________________, hereinafter referred to as “Shipper.”

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter’s FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter’s FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Transmission on a firm basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Quantity (MDQ), plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter’s FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the MDQ, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter's line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER'S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter's Rate Schedule FTR, as such rates and charges and Rate Schedule FTR may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 Notwithstanding the provisions of Section 4.1 above, in accordance with Transporter's FERC Gas Tariff, Shipper and Transporter may agree to negotiate different rates than those set forth in Rate Schedule FTR. If Transporter and Shipper negotiate such rates, the Negotiated Rates shall be set forth in Attachment 2 to this Agreement.

4.3 This Agreement in all respects is subject to the provisions of Transporter's FERC Gas Tariff, which is by reference made a part hereof.

4.4 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachments 1 and 2 attached to this Agreement are incorporated herein. The parties may amend Attachment 1 and/or Attachment 2 by mutual agreement, which amendments shall be reflected in a revised Attachment 1 and/or Attachment 2 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights. Notwithstanding the aforementioned items, Shipper shall in all cases be liable for payment to Transporter of the commitment reflected in this Agreement; Shipper is obligated to pay reservation charges during a period of interruption of Firm Service.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________	By: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________

ATTACHMENT 1 TO
FIRM TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FTR

Receipt Point(s), Delivery Point(s), and MDQ

Receipt Point	Delivery Point	MDQ (Dth/Day)

ATTACHMENT 2 TO
FIRM TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE FTR

Negotiated Rates

If applicable, the Negotiated Rates shall be specified below and this Agreement shall be deemed to be a Negotiated Rate Agreement pursuant to the provisions of Transporter’s FERC Gas Tariff.

EXHIBIT J

FORM OF SERVICE AGREEMENT UNDER RATE SCHEDULE ITR
INTERRUPTIBLE TRANSMISSION SERVICE

Service Agreement No. ______

INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE ITR

THIS INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT (the "Agreement") is made and entered into this ___ day of ________, 20__ by and between DENALI – THE ALASKA GAS PIPELINE LLC, a Delaware limited liability company, hereinafter referred to as "Transporter," and ________________, a ________________, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements in this Agreement, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 Capitalized terms used in this Agreement shall have the meanings given to such terms in Transporter's FERC Gas Tariff.

ARTICLE II
SERVICE OBLIGATIONS

2.1 Subject to the provisions of this Agreement and of Transporter's FERC Gas Tariff, Transporter agrees to receive such Quantities of Gas as Shipper may cause to be scheduled with and tendered to Transporter at the Receipt Point(s) designated on Attachment 1 for Transmission on an interruptible basis; provided, however, that in no event shall Transporter be obligated to receive on any Day in excess of the Maximum Daily Service Quantity, plus the applicable Fuel Requirement, for each Receipt Point as set forth on Attachment 1.

2.2 Subject to the provisions of this Agreement and Transporter's FERC Gas Tariff, Transporter agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Delivery Point(s) designated on Attachment 1 Equivalent Quantities of Gas; provided, however, that Transporter shall not be obligated to deliver on any Day in excess of the Maximum Daily Service Quantity, less applicable Fuel and Lost or Unaccounted for Gas, for each Delivery Point as set forth on Attachment 1.

2.3 Shipper warrants to Transporter that it will, at the time of delivery under this Agreement, have title to or good right to deliver Gas tendered, or caused to be tendered, to Transporter hereunder, free and clear of liens and encumbrances and adverse claims of every kind.

ARTICLE III
RECEIPT AND DELIVERY POINT(S) AND PRESSURES

3.1 Natural gas to be received hereunder by Transporter from or on behalf of Shipper shall be received at the inlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Receipt Point(s) designated on Attachment 1 at Transporter’s line pressure existing at such Receipt Point(s).

3.2 Natural gas to be delivered hereunder by Transporter to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) (or a similar point designated by Transporter) at or near the Delivery Point(s) designated on Attachment 1 at Transporter’s line pressure existing at such Delivery Point(s).

ARTICLE IV
RATES; TRANSPORTER’S FERC GAS TARIFF

4.1 Shipper shall pay Transporter each Month for all Service rendered hereunder the then-effective, applicable rates and charges under Transporter’s Rate Schedule ITR, as such rates and charges and Rate Schedule ITR may hereafter be modified, supplemented, superseded, or replaced generally or as to the Service hereunder in accordance with the Tariff. Shipper agrees that Transporter shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to Service hereunder, (b) the rate schedule(s) pursuant to which Service hereunder is rendered, or (c) any provision of the Tariff incorporated by reference in such rate schedule(s) or as otherwise applicable to Service provided to Shipper; provided, however, Shipper shall have the right to protest any such changes.

4.2 This Agreement in all respects is subject to the provisions of Transporter’s FERC Gas Tariff, which is by reference made a part hereof.

4.3 Except as expressly stated in this Agreement, termination of this Agreement shall not relieve either 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.

ARTICLE V
TERM

5.1 This Agreement shall become effective on the date first set forth above and shall continue in full force and effect for ____ Months thereafter. This agreement may continue past the initial term, subject to the exercise of applicable Right of First Refusal rights specified in Transporter's FERC Gas Tariff.

ARTICLE VI
NOTICES

6.1 All notices required by this Agreement shall be sent to the following addresses:

To Transporter:

Payments: as directed on the applicable invoice

Notices: as specified in Transporter's FERC Gas Tariff

To Shipper:

Invoices and Notices:

[Shipper name]
[Shipper address]
[Shipper address]
[City, State Zip Code]
Attention: [Shipper Designee]
Fax: (___) ___ - ____

ARTICLE VII
REGULATORY AUTHORIZATIONS AND APPROVALS

7.1 Transporter's obligation to provide Service is conditioned upon receipt and acceptance of the necessary regulatory authorizations to provide Service to Shipper in accordance with the terms of this Agreement, all applicable agreements for Service, and Transporter's FERC Gas Tariff. Shipper agrees to reimburse Transporter for all reporting and/or filing fees incurred by Transporter in providing Service under this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 The interpretation, performance, and enforcement of this Agreement shall be construed in accordance with the laws of the State of Delaware.

8.2 Attachment 1 to this Agreement is incorporated herein. The parties may amend Attachment 1 by mutual agreement, which amendment shall be reflected in a revised Attachment 1 and shall be incorporated by reference as part of this Agreement.

8.3 Due to competitive concerns of Transporter and Shipper, each party and its respective agents, employees, Affiliates, officers, directors, attorneys, auditors, consultants, partners, and other representatives shall keep and maintain this Agreement, the individual provisions hereof, and the information contained herein in strict confidence, and shall not transmit, reveal, disclose, or otherwise communicate any of the foregoing to any person without first obtaining the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided, however, that such consent shall not be required to the extent that either party determines in its reasonable judgment that any such disclosure is expressly contemplated or required by law, regulation, or order of any governmental authority of competent jurisdiction, including but not limited to FERC.

8.4 This Agreement is for the sole benefit of the parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person or entity whomsoever or whatsoever, it being the intention of the parties that no third Person shall be deemed a third-party beneficiary of this Agreement.

8.5 Shipper acknowledges that it is responsible for risk of transportation upstream and downstream of Transporter’s Facilities, export and/or import licenses, market fluctuations, provision of Gas, tax and royalty systems, and leaseholder rights.

8.6 OTHER THAN AS SET FORTH HEREIN, TRANSPORTER MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

IN WITNESS WHEREOF, authorized representatives of the parties hereto have executed this Agreement effective as of the day and year first above written.

Denali – The Alaska Gas Pipeline LLC	**[SHIPPER]**
By: ______________________	By: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________

ATTACHMENT 1 TO
INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT
UNDER RATE SCHEDULE ITR

Receipt Point(s), Delivery Point(s), and Maximum Daily Service Quantity

Receipt Point	Delivery Point	Maximum Daily Service Quantity (Dth/Day)

EXHIBIT K

Offer No. ______

OFFER TO RELEASE – PERMANENT

RATE SCHEDULE (SELECT AS APPLICABLE)

☐ FT ☐ FGT ☐ FC ☐ FTR

Name of Shipper: ____

Offering Capacity from Service Agreement No: ______________________________

Name of Individual Authorizing Release: ________________________________

Title: ____

Address: ____

Phone No: _______________________ Fax No: _____________________

Shipper agrees to release _______ [Dth/day] or any increment of Quantity up to _______ [Dth/day] pursuant to Article 23 (Capacity Release) of the General Terms and Conditions of Transporter's FERC Gas Tariff, upon the following terms and conditions:

Requested Effective Date of Release: _______________________________________

*Primary Point(s) of Receipt and Quantity to be Released at Point(s):

____

____

*Primary Point(s) of Delivery and Quantity to be Released at Point(s):

____

*If bids for less than the full path can be accepted, describe any conditions.

EXHIBIT L

Offer No.

OFFER TO RELEASE - TEMPORARY
RATE SCHEDULE (SELECT AS APPLICABLE)

☐ FT ☐ FGT ☐ FC ☐ FTR

Name of Shipper: ______________________________

Offering Capacity from Service Agreement No: ______________________________

Name of Individual Authorizing Release: ______________________________

Title: ______________________________

Shipper agrees to release _______ [Dth/day] or any increment of Quantity up to _______ [Dth/day] pursuant to Article 23 (Capacity Release) of the General Terms and Conditions of Transporter's FERC Gas Tariff, upon the following terms and conditions:

Release to: Designated Replacement Shipper _________ or _________
Offer/Bid Procedures __________

Requested Effective Date of Release: ______________________________

Term of Release: ______________________________

Minimum Acceptable Period of Release (if any): ______________________________

Rate Requirement:

Max. Rate Yes ______ Min. Rate _____

Other (i.e. demand/commodity) specify: ______________________________

*Primary Point(s) of Receipt and Quantity to be Released at Point(s):
____
____

*Primary Point(s) of Delivery and Quantity to be Released at Point(s):
____
____

*Can bids for less than the full path be accepted, describe any conditions.

EXHIBIT L

OFFER TO RELEASE – TEMPORARY (CONTD.)

Does Shipper retain right to recall capacity? Yes __________ No___________

If so, state terms of recall ____

____

____

____

Is this offered capacity subject to other Shipper's right of recall?

Yes ______ No ______

If so,. terms of that recall: ____

____

____

____

____

____

Other Conditions to Offer: ____

____

____

____

EXHIBIT L

OFFER TO RELEASE – TEMPORARY (CONTD.)

Describe and Provide Example of Bid Evaluation Method: ______________________

____

____

____

____

Name of Designated Replacement Shipper (if any): ___________________________

____

Contact for Designated Replacement Shipper:

Name: ____

Title: ____

Address: ____

Phone No: __________________________ Fax No: ___________________

Effective Date of this Offer to Release is ___________________________

ATTEST:

By:

By ___________________________ By______________________________
Title: ___________________________

ATTEST: [NAME OF SHIPPER]

By ___________________________ By______________________________
Title: ___________________________

Sheet Nos. 759-999 Are Reserved for Future Use

Estimated Cost of Service - Recourse Rates

All data in $MM except as noted

	25 Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Transmission Line - Prudhoe Bay																			
Operations & Maintenance Expenses	28	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Administrative & General Expenses	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Expenses	52	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
AFUDC Equity Amortization	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC Debt Amortization	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxes Other Than Income	18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Income Taxes	17	1	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
Equity Return Allowance	20	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	0	0
Debt Return Allowance	22	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	0
Deferred Cost of Service	(0)	(4)	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Prudhoe Bay Transmission Line Cost of Service	**167**	**4**	**10**	**13**	**9**	**8**	**8**	**8**	**7**	**7**	**7**	**7**	**7**	**7**	**6**	**6**	**6**	**6**	**6**
Dismantlement, Restoration & Removal Collections	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Line - Point Thomson																			
Operations & Maintenance Expenses	246	5	7	8	8	8	8	8	9	9	9	9	10	10	10	10	11	11	11
Administrative & General Expenses	94	2	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4
Depreciation Expenses	940	29	37	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
AFUDC Equity Amortization	64	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
AFUDC Debt Amortization	47	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Taxes Other Than Income	315	16	20	20	19	19	18	18	17	17	16	16	15	14	13	12	11	11	9
Income Taxes	283	22	25	23	20	18	17	15	14	13	12	11	11	10	10	9	8	8	7
Equity Return Allowance	342	29	34	30	26	24	21	19	17	16	15	14	13	12	11	10	9	8	7
Debt Return Allowance	374	31	37	33	29	26	23	21	19	17	16	15	14	13	12	11	10	9	8
Deferred Cost of Service	0	(76)	11	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Point Thomson Transmission Line Cost of Service	**2,705**	**62**	**179**	**223**	**147**	**140**	**133**	**127**	**121**	**117**	**114**	**111**	**108**	**105**	**102**	**99**	**96**	**93**	**90**
Dismantlement, Restoration & Removal Collections	19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
GTP Acid Gas Removal																			
Operations & Maintenance Expenses	4,519	100	123	140	144	148	151	155	159	163	167	171	175	180	184	189	194	198	203
Administrative & General Expenses	900	19	24	28	29	29	30	31	32	32	33	34	35	36	37	38	39	40	41
Depreciation Expenses	10,716	235	363	437	440	440	440	440	440	440	440	440	440	440	440	440	440	440	440
AFUDC Equity Amortization	1,268	30	44	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
AFUDC Debt Amortization	949	22	33	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Taxes Other Than Income	3,701	136	205	241	237	231	225	219	212	205	197	188	179	170	160	149	138	126	113
Income Taxes	3,721	194	276	298	268	244	224	205	188	174	164	156	148	139	131	123	115	107	99
Equity Return Allowance	4,062	248	352	376	333	298	269	242	217	198	184	171	160	148	136	125	113	101	90
Debt Return Allowance	4,439	271	384	410	364	326	294	264	238	216	201	187	174	162	149	136	123	111	98
Deferred Cost of Service	(0)	(551)	146	406	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total GTP Acid Gas Removal Cost of Service	**34,273**	**704**	**1,950**	**2,427**	**1,905**	**1,808**	**1,725**	**1,647**	**1,576**	**1,520**	**1,476**	**1,438**	**1,402**	**1,365**	**1,328**	**1,290**	**1,252**	**1,214**	**1,174**
Dismantlement, Restoration & Removal Collections	1,443	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GTP Compression																			
Operations & Maintenance Expenses	1,398	31	38	43	45	46	47	48	49	50	52	53	54	56	57	58	60	61	63
Administrative & General Expenses	339	7	9	11	11	11	11	12	12	12	13	13	13	14	14	14	15	15	15
Depreciation Expenses	3,472	83	108	142	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
AFUDC Equity Amortization	420	11	14	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
AFUDC Debt Amortization	313	8	10	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Taxes Other Than Income	1,194	48	61	78	77	75	73	71	69	66	64	61	58	55	52	48	44	40	36
Income Taxes	1,209	69	82	97	88	80	73	67	61	57	54	51	48	45	43	40	37	35	32
Equity Return Allowance	1,312	88	104	122	108	97	87	79	71	64	60	55	52	48	44	40	36	33	29
Debt Return Allowance	1,434	96	114	133	118	106	96	86	77	70	65	61	56	52	48	44	40	36	31
Deferred Cost of Service	0	(210)	108	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total GTP Compression Cost of Service	**11,092**	**231**	**649**	**759**	**619**	**587**	**560**	**534**	**512**	**493**	**479**	**466**	**454**	**442**	**430**	**418**	**405**	**393**	**380**
Dismantlement, Restoration & Removal Collections	171	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
AK Mainline																			
Operations & Maintenance Expenses	3,154	70	86	98	100	103	106	108	111	114	117	119	122	125	129	132	135	138	142
Administrative & General Expenses	1,183	28	33	37	38	39	40	41	42	43	44	45	46	47	48	49	51	52	53
Depreciation Expenses	12,570	384	463	508	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
AFUDC Equity Amortization	1,369	46	52	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
AFUDC Debt Amortization	1,006	33	38	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Taxes Other Than Income	4,401	221	260	279	274	267	260	253	245	237	228	218	208	197	186	174	161	147	133
Income Taxes	4,347	315	348	337	301	275	252	231	212	198	187	178	168	159	150	141	131	122	113
Equity Return Allowance	4,858	406	447	427	376	339	306	275	248	228	213	199	186	173	159	146	133	119	106
Debt Return Allowance	5,309	443	488	467	411	370	335	301	271	249	233	218	203	189	174	160	145	131	116
Deferred Cost of Service	(0)	(1,056)	328	727	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total AK Mainline Cost of Service	**38,195**	**890**	**2,543**	**2,975**	**2,105**	**1,998**	**1,905**	**1,815**	**1,734**	**1,673**	**1,626**	**1,583**	**1,539**	**1,496**	**1,452**	**1,407**	**1,361**	**1,315**	**1,269**
Dismantlement, Restoration & Removal Collections	255	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Estimated Cost of Service - Recourse Rates

All data in $MM except as noted

	25 Years	2038	2039	2040	2041	2042	2043	2044
Transmission Line - Prudhoe Bay								
Operations & Maintenance Expenses	28	1	1	1	1	1	1	1
Administrative & General Expenses	4	0	0	0	0	0	0	0
Depreciation Expenses	52	2	2	2	2	2	2	2
AFUDC Equity Amortization	5	0	0	0	0	0	0	0
AFUDC Debt Amortization	3	0	0	0	0	0	0	0
Taxes Other Than Income	18	0	0	0	0	0	0	0
Income Taxes	17	0	0	0	0	0	0	0
Equity Return Allowance	20	0	0	0	0	0	0	0
Debt Return Allowance	22	0	0	0	0	0	0	0
Deferred Cost of Service	(0)	0	0	0	0	0	0	0
Total Prudhoe Bay Transmission Line Cost of Service	**167**	**6**	**5**	**5**	**5**	**5**	**5**	**4**
Dismantlement, Restoration & Removal Collections	1	0	0	0	0	0	0	0
Transmission Line - Point Thomson								
Operations & Maintenance Expenses	246	11	12	12	12	13	13	13
Administrative & General Expenses	94	4	4	5	5	5	5	5
Depreciation Expenses	940	38	38	38	38	38	38	38
AFUDC Equity Amortization	64	3	3	3	3	3	3	3
AFUDC Debt Amortization	47	2	2	2	2	2	2	2
Taxes Other Than Income	315	8	7	6	5	4	2	1
Income Taxes	283	6	6	5	4	4	3	3
Equity Return Allowance	342	7	6	5	4	3	2	1
Debt Return Allowance	374	7	6	5	4	3	2	1
Deferred Cost of Service	0	0	0	0	0	0	0	0
Total Point Thomson Transmission Line Cost of Service	**2,705**	**87**	**83**	**80**	**77**	**73**	**70**	**66**
Dismantlement, Restoration & Removal Collections	19	1	1	1	1	1	1	1
GTP Acid Gas Removal								
Operations & Maintenance Expenses	4,519	208	214	219	225	230	236	242
Administrative & General Expenses	900	42	43	44	45	46	47	48
Depreciation Expenses	10,716	440	440	440	440	440	440	440
AFUDC Equity Amortization	1,268	52	52	52	52	52	52	52
AFUDC Debt Amortization	949	39	39	39	39	39	39	39
Taxes Other Than Income	3,701	100	85	70	55	38	21	3
Income Taxes	3,721	91	83	74	66	58	50	42
Equity Return Allowance	4,062	78	66	55	43	32	20	8
Debt Return Allowance	4,439	85	73	60	47	34	22	9
Deferred Cost of Service	(0)	0	0	0	0	0	0	0
Total GTP Acid Gas Removal Cost of Service	**34,273**	**1,134**	**1,094**	**1,053**	**1,011**	**969**	**926**	**883**
Dismantlement, Restoration & Removal Collections	1,443	58	58	58	58	58	58	58
GTP Compression								
Operations & Maintenance Expenses	1,398	65	66	68	69	71	73	75
Administrative & General Expenses	339	16	16	16	17	17	18	18
Depreciation Expenses	3,472	143	143	143	143	143	143	143
AFUDC Equity Amortization	420	17	17	17	17	17	17	17
AFUDC Debt Amortization	313	13	13	13	13	13	13	13
Taxes Other Than Income	1,194	32	27	22	17	12	6	0
Income Taxes	1,209	29	27	24	21	19	16	14
Equity Return Allowance	1,312	25	21	17	14	10	6	2
Debt Return Allowance	1,434	27	23	19	15	11	7	2
Deferred Cost of Service	0	0	0	0	0	0	0	0
Total GTP Compression Cost of Service	**11,092**	**367**	**353**	**340**	**326**	**312**	**298**	**284**
Dismantlement, Restoration & Removal Collections	171	7	7	7	7	7	7	7
AK Mainline								
Operations & Maintenance Expenses	3,154	145	149	153	157	161	165	169
Administrative & General Expenses	1,183	54	56	57	59	60	62	63
Depreciation Expenses	12,570	510	510	510	510	510	510	510
AFUDC Equity Amortization	1,369	55	55	55	55	55	55	55
AFUDC Debt Amortization	1,006	41	41	41	41	41	41	41
Taxes Other Than Income	4,401	117	101	84	66	48	28	7
Income Taxes	4,347	103	94	85	76	66	57	48
Equity Return Allowance	4,858	93	80	66	53	40	27	13
Debt Return Allowance	5,309	102	87	73	58	44	29	15
Deferred Cost of Service	(0)	0	0	0	0	0	0	0
Total AK Mainline Cost of Service	**38,195**	**1,221**	**1,173**	**1,124**	**1,074**	**1,024**	**973**	**920**
Dismantlement, Restoration & Removal Collections	255	10	10	10	10	10	10	10

DENALI - The Alaska Gas Pipeline

Estimated Capitalization, Return and Cost of Debt - Recourse Rates

Capital Structure During Construction	
Equity Weight	30.0%
Debt Weight	70.0%
Total	100.0%
Capital Structure For Return	
Equity Weight	25.0%
Debt Weight	75.0%
Total	100.0%
Equity Cost	14.00%
Debt Cost	5.10%
Weighted Cost of Capital During Construction	
Weighted Cost of Equity	4.20%
Weighted Cost of Debt	3.57%
Total	**7.77%**
Weighted Cost of Capital For Return	
Weighted Cost of Equity	3.50%
Weighted Cost of Debt	3.83%
Total	**7.33%**

Estimated Rate Design Volumes - Recourse Rates

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Transmission Line - Prudhoe Bay (Dth/d)																
Prudhoe Bay	1,177,422	3,392,446	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419
Transmission Line - Point Thomson (Dth/d)																
Point Thomson	306,578	883,329	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303
GTP By Service (Dth/d)																
Acid Gas Removal	1,484,000	4,275,775	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722
Compression	1,484,000	4,275,775	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822
AK Mainline by Delivery Point (Dth/d)																
Livengood	2,972	8,563	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017
Parks Highway Spur (Note 1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fairbanks	18,162	52,329	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215
Delta Junction	89,819	258,792	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736
Tok	330	951	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Canadian Border	1,372,716	3,955,139	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741
Total AK Mainline	1,484,000	4,275,775	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822

Note 1:
Spur line volumes to Southcentral region of Alaska assumed delivered at Delta Junction. The location of the spur line interconnection will determine where these volumes will be delivered.

Estimated Rate Design Volumes - Recourse Rates

	2036	2037	2038	2039	2040	2041	2042	2043	2044
Transmission Line - Prudhoe Bay (Dth/d)									
Prudhoe Bay	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419
Transmission Line - Point Thomson (Dth/d)									
Point Thomson	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303
GTP By Service (Dth/d)									
Acid Gas Removal	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722
Compression	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822
AK Mainline by Delivery Point (Dth/d)									
Livengood	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017
Parks Highway Spur (Note 1)	0	0	0	0	0	0	0	0	0
Fairbanks	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215
Delta Junction	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736
Tok	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Canadian Border	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741
Total AK Mainline	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822

Note 1:
Spur line volumes to Southcentral region of Alaska assumed delivered at Delta Junction. The location of the spur line interconnection will determine where these volumes will be delivered.

Estimated Cost of Service - Negotiated Rates

All data in $MM except as noted

	20 Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Transmission Line - Prudhoe Bay																			
Operations & Maintenance Expenses	21	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Administrative & General Expenses	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Expenses (Note 1)	41	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
AFUDC Equity Amortization (Note 1)	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC Debt Amortization (Note 1)	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxes Other Than Income	17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Income Taxes	15	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
Equity Return Allowance	19	1	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
Debt Return Allowance	24	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1
Deferred Cost of Service	(0)	(5)	(4)	(2)	(1)	(1)	(1)	(0)	(0)	0	0	0	1	1	1	1	1	2	2
Total Prudhoe Bay Transmission Line Cost of Service	**146**	**2**	**6**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**
Dismantlement, Restoration & Removal Collections	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Line - Point Thomson																			
Operations & Maintenance Expenses	184	5	7	8	8	8	8	8	9	9	9	9	10	10	10	10	11	11	11
Administrative & General Expenses	70	2	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4
Depreciation Expenses (Note 1)	750	29	37	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
AFUDC Equity Amortization (Note 1)	42	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
AFUDC Debt Amortization (Note 1)	38	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Taxes Other Than Income	297	16	20	20	19	19	18	18	17	17	16	16	15	14	13	12	11	11	9
Income Taxes	264	18	22	21	19	18	17	16	15	14	13	13	12	11	10	10	9	8	7
Equity Return Allowance	336	24	30	28	26	24	22	20	19	18	17	16	15	14	13	12	11	9	8
Debt Return Allowance	429	31	38	35	33	30	28	26	24	22	21	20	19	18	16	15	14	12	10
Deferred Cost of Service	(0)	(94)	(59)	(30)	(23)	(18)	(13)	(7)	(2)	1	4	7	10	14	17	21	25	30	34
Total Point Thomson Transmission Line Cost of Service	**2,410**	**35**	**101**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**
Dismantlement, Restoration & Removal Collections	15	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
GTP Acid Gas Removal																			
Operations & Maintenance Expenses	3,367	100	123	140	144	148	151	155	159	163	167	171	175	180	184	189	194	198	203
Administrative & General Expenses	670	19	24	28	29	29	30	31	32	32	33	34	35	36	37	38	39	40	41
Depreciation Expenses (Note 1)	8,516	235	363	437	440	440	440	440	440	440	440	440	440	440	440	440	440	440	440
AFUDC Equity Amortization (Note 1)	831	25	36	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
AFUDC Debt Amortization (Note 1)	754	22	33	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Taxes Other Than Income	3,514	136	205	241	237	231	225	219	212	205	197	188	179	170	160	149	138	126	113
Income Taxes	3,299	164	238	265	247	230	216	202	188	178	169	162	154	146	137	128	118	107	96
Equity Return Allowance	3,895	210	304	337	311	287	266	246	227	212	200	189	178	166	153	140	126	111	95
Debt Return Allowance	4,966	268	388	429	396	365	339	314	289	270	254	241	226	212	196	179	161	142	121
Deferred Cost of Service	0	(720)	(471)	(414)	(337)	(263)	(199)	(135)	(75)	(25)	16	54	93	134	178	225	274	328	384
Total GTP Acid Gas Removal Cost of Service	**29,810**	**459**	**1,243**	**1,545**	**1,547**	**1,549**	**1,550**	**1,552**	**1,554**	**1,556**	**1,558**	**1,560**	**1,562**	**1,564**	**1,566**	**1,568**	**1,571**	**1,573**	**1,575**
Dismantlement, Restoration & Removal Collections	1,154	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GTP Compression																			
Operations & Maintenance Expenses	1,042	31	38	43	45	46	47	48	49	50	52	53	54	56	57	58	60	61	63
Administrative & General Expenses	253	7	9	11	11	11	11	12	12	12	13	13	13	14	14	14	15	15	15
Depreciation Expenses (Note 1)	2,759	83	108	142	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
AFUDC Equity Amortization (Note 1)	275	9	11	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
AFUDC Debt Amortization (Note 1)	249	8	10	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Taxes Other Than Income	1,136	48	61	78	77	75	73	71	69	66	64	61	58	55	52	48	44	40	36
Income Taxes	1,066	58	71	86	80	74	70	65	61	57	55	52	50	47	44	41	38	35	31
Equity Return Allowance	1,252	74	90	109	100	93	86	79	73	68	64	61	57	53	49	45	40	36	30
Debt Return Allowance	1,596	95	115	139	128	118	109	101	93	87	82	77	73	68	63	57	51	45	39
Deferred Cost of Service	0	(260)	(87)	(135)	(111)	(87)	(65)	(45)	(26)	(10)	4	16	28	41	55	70	86	103	121
Total GTP Compression Cost of Service	**9,627**	**154**	**427**	**499**	**499**	**500**	**500**	**501**	**501**	**501**	**502**	**502**	**503**	**503**	**504**	**504**	**504**	**505**	**505**
Dismantlement, Restoration & Removal Collections	137	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
AK Mainline																			
Operations & Maintenance Expenses	2,350	70	86	98	100	103	106	108	111	114	117	119	122	125	129	132	135	138	142
Administrative & General Expenses	882	28	33	37	38	39	40	41	42	43	44	45	46	47	48	49	51	52	53
Depreciation Expenses (Note 1)	10,021	384	463	508	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
AFUDC Equity Amortization (Note 1)	899	38	43	45	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
AFUDC Debt Amortization (Note 1)	803	33	38	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Taxes Other Than Income	4,167	221	260	279	274	267	260	253	245	237	228	218	208	197	186	174	161	147	133
Income Taxes	3,917	266	301	304	283	265	249	233	217	206	197	188	179	169	159	148	137	124	111
Equity Return Allowance	4,711	344	389	390	360	334	311	288	266	250	237	224	211	197	182	167	150	132	114
Debt Return Allowance	6,007	438	496	498	459	426	397	367	339	318	302	286	269	251	233	213	191	169	145
Deferred Cost of Service	(0)	(1,293)	(605)	(442)	(352)	(271)	(198)	(124)	(56)	(2)	43	86	131	180	231	286	344	407	473
Total AK Mainline Cost of Service	**33,757**	**529**	**1,504**	**1,758**	**1,759**	**1,759**	**1,760**	**1,760**	**1,761**	**1,761**	**1,762**	**1,762**	**1,763**	**1,763**	**1,764**	**1,764**	**1,765**	**1,765**	**1,766**
Dismantlement, Restoration & Removal Collections	204	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Note 1:
80% of Depreciation Expenses, AFUDC Equity Amortization and AFUDC
Debt Amortization will be recovered over the twenty year contract term.

Estimated Cost of Service - Negotiated Rates

All data in $MM except as noted

	20 Years	2038	2039
Transmission Line - Prudhoe Bay			
Operations & Maintenance Expenses	21	1	1
Administrative & General Expenses	3	0	0
Depreciation Expenses (Note 1)	41	2	2
AFUDC Equity Amortization (Note 1)	3	0	0
AFUDC Debt Amortization (Note 1)	3	0	0
Taxes Other Than Income	17	0	0
Income Taxes	15	0	0
Equity Return Allowance	19	0	0
Debt Return Allowance	24	0	0
Deferred Cost of Service	(0)	2	2
Total Prudhoe Bay Transmission Line Cost of Service	**146**	**8**	**8**
Dismantlement, Restoration & Removal Collections	1	0	0
Transmission Line - Point Thomson			
Operations & Maintenance Expenses	184	11	12
Administrative & General Expenses	70	4	4
Depreciation Expenses (Note 1)	750	38	38
AFUDC Equity Amortization (Note 1)	42	2	2
AFUDC Debt Amortization (Note 1)	38	2	2
Taxes Other Than Income	297	8	7
Income Taxes	264	6	5
Equity Return Allowance	336	7	5
Debt Return Allowance	429	8	7
Deferred Cost of Service	(0)	39	44
Total Point Thomson Transmission Line Cost of Service	**2,410**	**126**	**126**
Dismantlement, Restoration & Removal Collections	15	1	1
GTP Acid Gas Removal			
Operations & Maintenance Expenses	3,367	208	214
Administrative & General Expenses	670	42	43
Depreciation Expenses (Note 1)	8,516	440	440
AFUDC Equity Amortization (Note 1)	831	43	43
AFUDC Debt Amortization (Note 1)	754	39	39
Taxes Other Than Income	3,514	100	85
Income Taxes	3,299	84	72
Equity Return Allowance	3,895	78	60
Debt Return Allowance	4,966	100	76
Deferred Cost of Service	0	445	509
Total GTP Acid Gas Removal Cost of Service	**29,810**	**1,578**	**1,580**
Dismantlement, Restoration & Removal Collections	1,154	58	58
GTP Compression			
Operations & Maintenance Expenses	1,042	65	66
Administrative & General Expenses	253	16	16
Depreciation Expenses (Note 1)	2,759	143	143
AFUDC Equity Amortization (Note 1)	275	14	14
AFUDC Debt Amortization (Note 1)	249	13	13
Taxes Other Than Income	1,136	32	27
Income Taxes	1,066	27	23
Equity Return Allowance	1,252	25	19
Debt Return Allowance	1,596	32	24
Deferred Cost of Service	0	140	161
Total GTP Compression Cost of Service	**9,627**	**506**	**507**
Dismantlement, Restoration & Removal Collections	137	7	7
AK Mainline			
Operations & Maintenance Expenses	2,350	145	149
Administrative & General Expenses	882	54	56
Depreciation Expenses (Note 1)	10,021	510	510
AFUDC Equity Amortization (Note 1)	899	46	46
AFUDC Debt Amortization (Note 1)	803	41	41
Taxes Other Than Income	4,167	117	101
Income Taxes	3,917	97	82
Equity Return Allowance	4,711	94	72
Debt Return Allowance	6,007	119	92
Deferred Cost of Service	(0)	543	619
Total AK Mainline Cost of Service	**33,757**	**1,767**	**1,767**
Dismantlement, Restoration & Removal Collections	204	10	10

Note 1:
80% of Depreciation Expenses, AFUDC Equity Amortization and AFUDC Debt Amortization will be recovered over the twenty year contract term.

Estimated Capitalization, Return and Cost of Debt - Negotiated Rates

Capital Structure During Construction	
Equity Weight	30.0%
Debt Weight	70.0%
Total	100.0%
Capital Structure For Return	
Equity Weight	25.0%
Debt Weight	75.0%
Total	100.0%
Equity Cost	12.00%
Debt Cost	5.10%
Weighted Cost of Capital During Construction	
Weighted Cost of Equity	3.60%
Weighted Cost of Debt	3.57%
Total	**7.17%**
Weighted Cost of Capital For Return	
Weighted Cost of Equity	3.00%
Weighted Cost of Debt	3.83%
Total	**6.83%**

Estimated Rate Design Volumes - Negotiated Rates

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Transmission Line - Prudhoe Bay (Dth/d)													
Prudhoe Bay	1,177,422	3,392,446	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419
Transmission Line - Point Thomson (Dth/d)													
Point Thomson	306,578	883,329	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303
GTP By Service (Dth/d)													
Acid Gas Removal	1,484,000	4,275,775	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722
Compression	1,484,000	4,275,775	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822
AK Mainline by Delivery Point (Dth/d)													
Livengood	2,972	8,563	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017	10,017
Parks Highway Spur (Note 1)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fairbanks	18,162	52,329	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215	61,215
Delta Junction	89,819	258,792	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736	302,736
Tok	330	951	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Canadian Border	1,372,716	3,955,139	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741
Total AK Mainline	1,484,000	4,275,775	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822

Note 1:
Spur line volumes to Southcentral region of Alaska assumed to be delivered at Delta Junction. The location of the spur line interconnection will determine where these volumes will be delivered.

Estimated Rate Design Volumes - Negotiated Rates

	2033	2034	2035	2036	2037	2038	2039
Transmission Line - Prudhoe Bay (Dth/d)							
Prudhoe Bay	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419	4,233,419
Transmission Line - Point Thomson (Dth/d)							
Point Thomson	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303	1,102,303
GTP By Service (Dth/d)							
Acid Gas Removal	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722	5,335,722
Compression	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822
AK Mainline by Delivery Point (Dth/d)							
Livengood	10,017	10,017	10,017	10,017	10,017	10,017	10,017
Parks Highway Spur (Note 1)	0	0	0	0	0	0	0
Fairbanks	61,215	61,215	61,215	61,215	61,215	61,215	61,215
Delta Junction	302,736	302,736	302,736	302,736	302,736	302,736	302,736
Tok	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Canadian Border	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741	4,626,741
Total AK Mainline	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822	5,001,822

Note 1:
Spur line volumes to Southcentral region of Alaska assumed to be delivered at Delta Junction. The location of the spur line interconnection will determine where these volumes will be delivered.

Estimated Negotiated Rates

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Line - Prudhoe Bay															
Monthly Reservation Charge ($/Dth/d)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Usage Charge ($/Dth)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost to Ship Full FT Commitment ($/Dth)	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049
Dismantlement, Restoration & Removal Collection ($/Dth)	0.00010	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003
Fuel Retention	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Transmission Line - Point Thomson															
Monthly Reservation Charge ($/Dth/d)	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54
Usage Charge ($/Dth)	0.0008	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Cost to Ship Full FT Commitment ($/Dth)	0.3144	0.3139	0.3139	0.3139	0.3139	0.3139	0.3139	0.3139	0.3139	0.3139	0.3139	0.3139	0.3140	0.3140	0.3140
Dismantlement, Restoration & Removal Collection ($/Dth)	0.0069	0.0024	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019
Fuel Retention	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GTP Acid Gas Removal															
Monthly Reservation Charge ($/Dth/d)	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09	23.09
Usage Charge ($/Dth)	0.0878	0.0375	0.0342	0.0351	0.0359	0.0368	0.0377	0.0387	0.0397	0.0407	0.0417	0.0427	0.0438	0.0449	0.0460
Cost to Ship Full FT Commitment ($/Dth)	0.8471	0.7968	0.7935	0.7943	0.7952	0.7961	0.7970	0.7980	0.7989	0.7999	0.8009	0.8020	0.8031	0.8042	0.8053
Dismantlement, Restoration & Removal Collection ($/Dth)	0.1066	0.0370	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296	0.0296
Fuel Retention	3.6529%	2.7786%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%	2.5662%
GTP Compression															
Monthly Reservation Charge ($/Dth/d)	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08
Usage Charge ($/Dth)	0.0188	0.0080	0.0078	0.0080	0.0082	0.0084	0.0086	0.0089	0.0091	0.0093	0.0095	0.0098	0.0100	0.0103	0.0105
Cost to Ship Full FT Commitment ($/Dth)	0.2844	0.2736	0.2734	0.2736	0.2738	0.2740	0.2742	0.2744	0.2746	0.2748	0.2751	0.2753	0.2756	0.2758	0.2761
Dismantlement, Restoration & Removal Collection ($/Dth)	0.0127	0.0044	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038
Fuel Retention	2.1195%	1.6061%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%	1.5794%
AK Mainline by Delivery Point															
Monthly Reservation Charge ($/Dth/d)															
Livengood	17.05	16.50	16.48	16.49	16.50	16.51	16.52	16.53	16.54	16.55	16.56	16.57	16.58	16.59	16.61
Parks Highway Spur	18.87	18.40	18.38	18.39	18.39	18.40	18.41	18.42	18.43	18.44	18.45	18.46	18.47	18.48	18.49
Fairbanks	19.00	18.53	18.52	18.52	18.53	18.54	18.55	18.56	18.57	18.57	18.58	18.59	18.60	18.61	18.62
Delta Junction	22.32	22.00	21.99	21.99	22.00	22.00	22.01	22.01	22.02	22.03	22.03	22.04	22.05	22.05	22.06
Tok	26.33	26.18	26.18	26.18	26.18	26.19	26.19	26.19	26.19	26.20	26.20	26.20	26.21	26.21	26.21
Canadian Border	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66
Usage Charge ($/Dth)															
Livengood	0.0117	0.0050	0.0049	0.0050	0.0051	0.0052	0.0054	0.0055	0.0056	0.0058	0.0059	0.0061	0.0062	0.0064	0.0065
Parks Highway Spur	0.0131	0.0056	0.0055	0.0056	0.0057	0.0059	0.0060	0.0062	0.0063	0.0065	0.0066	0.0068	0.0070	0.0072	0.0073
Fairbanks	0.0132	0.0056	0.0055	0.0056	0.0058	0.0059	0.0061	0.0062	0.0064	0.0065	0.0067	0.0069	0.0070	0.0072	0.0074
Delta Junction	0.0158	0.0068	0.0066	0.0067	0.0069	0.0071	0.0073	0.0074	0.0076	0.0078	0.0080	0.0082	0.0084	0.0086	0.0088
Tok	0.0190	0.0081	0.0079	0.0081	0.0083	0.0085	0.0087	0.0089	0.0091	0.0094	0.0096	0.0099	0.0101	0.0104	0.0106
Canadian Border	0.0216	0.0092	0.0090	0.0092	0.0094	0.0097	0.0099	0.0102	0.0104	0.0107	0.0109	0.0112	0.0115	0.0118	0.0121
Cost to Ship Full FT Commitment ($/MMBtu)															
Livengood	0.5724	0.5474	0.5466	0.5470	0.5474	0.5479	0.5484	0.5488	0.5493	0.5498	0.5503	0.5508	0.5514	0.5519	0.5525
Parks Highway Spur	0.6335	0.6104	0.6097	0.6100	0.6105	0.6109	0.6113	0.6117	0.6122	0.6126	0.6131	0.6136	0.6141	0.6146	0.6151
Fairbanks	0.6380	0.6150	0.6142	0.6146	0.6150	0.6154	0.6159	0.6163	0.6167	0.6172	0.6177	0.6181	0.6186	0.6191	0.6197
Delta Junction	0.7496	0.7300	0.7294	0.7297	0.7301	0.7304	0.7308	0.7312	0.7315	0.7319	0.7324	0.7328	0.7332	0.7336	0.7341
Tok	0.8846	0.8689	0.8685	0.8688	0.8691	0.8694	0.8697	0.8700	0.8703	0.8706	0.8710	0.8713	0.8717	0.8720	0.8724
Canadian Border	0.9966	0.9842	0.9840	0.9842	0.9844	0.9846	0.9849	0.9851	0.9854	0.9857	0.9859	0.9862	0.9865	0.9868	0.9871
Dismantlement, Restoration & Removal Collection ($/Dth)															
Livengood	0.0104	0.0036	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031
Parks Highway Spur	0.0117	0.0041	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035
Fairbanks	0.0118	0.0041	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035
Delta Junction	0.0141	0.0049	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042
Tok	0.0170	0.0059	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050
Canadian Border	0.0193	0.0067	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057
Fuel Retention															
Livengood	0.4338%	0.6724%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%
Parks Highway Spur	0.4866%	0.7539%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%
Fairbanks	0.4904%	0.7599%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%
Delta Junction	0.5866%	0.9084%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%
Tok	0.7027%	1.0874%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%
Canadian Border	0.7987%	1.2353%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%

Estimated Negotiated Rates

		2035	2036	2037	2038	2039
Transmission Line - Prudhoe Bay						
Monthly Reservation Charge ($/Dth/d)		0.15	0.15	0.15	0.15	0.15
Usage Charge ($/Dth)		0.0000	0.0000	0.0000	0.0000	0.0000
Cost to Ship Full FT Commitment ($/Dth)		0.0049	0.0049	0.0049	0.0049	0.0049
Dismantlement, Restoration & Removal Collection ($/Dth)		0.00003	0.00003	0.00003	0.00003	0.00003
Fuel Retention		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Transmission Line - Point Thomson						
Monthly Reservation Charge ($/Dth/d)		9.54	9.54	9.54	9.54	9.54
Usage Charge ($/Dth)		0.0004	0.0004	0.0005	0.0005	0.0005
Cost to Ship Full FT Commitment ($/Dth)		0.3140	0.3140	0.3140	0.3140	0.3140
Dismantlement, Restoration & Removal Collection ($/Dth)		0.0019	0.0019	0.0019	0.0019	0.0019
Fuel Retention		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GTP Acid Gas Removal						
Monthly Reservation Charge ($/Dth/d)		23.09	23.09	23.09	23.09	23.09
Usage Charge ($/Dth)		0.0471	0.0483	0.0495	0.0508	0.0520
Cost to Ship Full FT Commitment ($/Dth)		0.8064	0.8076	0.8088	0.8100	0.8113
Dismantlement, Restoration & Removal Collection ($/Dth)		0.0296	0.0296	0.0296	0.0296	0.0296
Fuel Retention		2.5662%	2.5662%	2.5662%	2.5662%	2.5662%
GTP Compression						
Monthly Reservation Charge ($/Dth/d)		8.08	8.08	8.08	8.08	8.08
Usage Charge ($/Dth)		0.0108	0.0111	0.0113	0.0116	0.0119
Cost to Ship Full FT Commitment ($/Dth)		0.2763	0.2766	0.2769	0.2772	0.2775
Dismantlement, Restoration & Removal Collection ($/Dth)		0.0038	0.0038	0.0038	0.0038	0.0038
Fuel Retention		1.5794%	1.5794%	1.5794%	1.5794%	1.5794%
AK Mainline by Delivery Point						
Monthly Reservation Charge ($/Dth/d)						
	Livengood	16.62	16.63	16.64	16.66	16.67
	Parks Highway Spur	18.50	18.51	18.52	18.53	18.54
	Fairbanks	18.63	18.64	18.66	18.67	18.68
	Delta Junction	22.07	22.07	22.08	22.09	22.10
	Tok	26.22	26.22	26.22	26.23	26.23
	Canadian Border	29.66	29.66	29.66	29.66	29.66
Usage Charge ($/Dth)						
	Livengood	0.0067	0.0069	0.0070	0.0072	0.0074
	Parks Highway Spur	0.0075	0.0077	0.0079	0.0081	0.0083
	Fairbanks	0.0076	0.0078	0.0080	0.0082	0.0084
	Delta Junction	0.0091	0.0093	0.0095	0.0098	0.0100
	Tok	0.0109	0.0111	0.0114	0.0117	0.0120
	Canadian Border	0.0124	0.0127	0.0130	0.0133	0.0137
Cost to Ship Full FT Commitment ($/MMBtu)						
	Livengood	0.5530	0.5536	0.5542	0.5548	0.5555
	Parks Highway Spur	0.6156	0.6162	0.6168	0.6173	0.6179
	Fairbanks	0.6202	0.6207	0.6213	0.6219	0.6224
	Delta Junction	0.7345	0.7350	0.7355	0.7360	0.7365
	Tok	0.8727	0.8731	0.8735	0.8739	0.8743
	Canadian Border	0.9874	0.9877	0.9880	0.9883	0.9886
Dismantlement, Restoration & Removal Collection ($/Dth)						
	Livengood	0.0031	0.0031	0.0031	0.0031	0.0031
	Parks Highway Spur	0.0035	0.0035	0.0035	0.0035	0.0035
	Fairbanks	0.0035	0.0035	0.0035	0.0035	0.0035
	Delta Junction	0.0042	0.0042	0.0042	0.0042	0.0042
	Tok	0.0050	0.0050	0.0050	0.0050	0.0050
	Canadian Border	0.0057	0.0057	0.0057	0.0057	0.0057
Fuel Retention						
	Livengood	0.8424%	0.8424%	0.8424%	0.8424%	0.8424%
	Parks Highway Spur	0.9444%	0.9444%	0.9444%	0.9444%	0.9444%
	Fairbanks	0.9518%	0.9518%	0.9518%	0.9518%	0.9518%
	Delta Junction	1.1374%	1.1374%	1.1374%	1.1374%	1.1374%
	Tok	1.3609%	1.3609%	1.3609%	1.3609%	1.3609%
	Canadian Border	1.5454%	1.5454%	1.5454%	1.5454%	1.5454%