THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Robert M. Pickett, Chairman Stephen McAlpine Rebecca L. Pauli Norman Rokeberg Janis W. Wilson

In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-16-066

Date: 6/2/17 Exh # T-18
Regulatory Commission of Alaska
By: Lyk
Northern Lights Realtime & Reporting, Inc.
(907) 337-2221 U-16066

PREFILED TESTIMONY OF RONALD CLIFF

Q1: Please identify yourself for the record, including your relationship with Titan Alaska LNG, LLC ("Titan").

A1: My name is Ronald Cliff. I am the President of Highcliff Energy Services Ltd. of Vancouver, B.C. I have over 30 years of experience in the energy and utility industry, and provide consulting services to utilities and large energy users in the areas of pipeline regulation, cost of service studies, rate design, financial structuring, mergers and acquisitions, gas supply, and marketing. My resume is attached as Exhibit RLC-1. I have provided advisory services to Titan, its predecessors, and its affiliate company, Fairbanks Natural Gas, LLC ("FNG"), since February 2000.

Q2: Have you previously prepared testimony for Titan or its predecessors?

A2: Yes. In 2003 I was engaged by Northern Eclipse, LLC (NE), then FNG's parent company, to review a rate design application filed by ENSTAR (Docket U-00-88). In 2009, I was engaged by FNG to do the same review of ENSTAR's application at that time (U-09-70). Finally, I again participated in ENSTAR's 2014 rate case (U-14-111).

Q3: What is the scope and purpose of your testimony in the present docket?

A3: To review the appropriateness of the allocations by ENSTAR to Titan's cost of service, to comment on the proposed rate being proposed for Titan, and to suggest a more reasonable cost allocation and a commensurate rate for Titan based on that allocation.

Q4: Please comment generally about ENSTAR's rate structure.

A4: The fully allocated cost of service (FACOS) filed with the ENSTAR application can be best described as an appropriate method for allocating costs among customers at a standard gas "distribution" utility. As such, it fails to reflect that ENSTAR is in fact a hybrid utility with a distinct "transmission" function. While ENSTAR's methodology may yield appropriate rates for gas distribution customers, I believe it is an inappropriate method for setting transmission rates for "transmission only" customers such as Titan.

Description of Titan

Q5: How would you characterize Titan's use of the ENSTAR system?

A5: Titan is a transmission only customer. Titan sources its own gas supply. The gas is delivered to ENSTAR at the start (mile 0) or within several miles of the start of

ENSTAR's Beluga-Anchorage Pipeline (BAP). ENSTAR transports that gas to Titan's Point MacKenzie Liquefied Natural Gas (LNG) facility at mile 39 of the BAP. Titan produces LNG, which is then transported by truck to its customers, the largest of which is FNG and its utility customers in Fairbanks, Alaska.

Q6: Which of Enstar's Rate Classes includes Titan?

A6: In previous ENSTAR proceedings, Titan was the only customer in its own customer class. In the current filing, Enstar included Titan in the Medium Sized Firm Transportation ("MSFT") customer class. That tariff applies to two customers: Titan and Homer Electric Association ("HEA"). ENSTAR proposes separate rates applicable for the MSFT Class, as reflected in Section 2145 of its tariff.

Overview

Q7: What is ENSTAR's actual cost of providing service to Titan? How does that compare with the costs ENSTAR proposes to allocate to Titan?

A7: My estimate of the appropriate allocation of Enstar's costs to Titan is $124,456, and my analysis is described in more detail below. At current rates, Titan's costs are expected to be $308,436[1]. This compares to the application by ENSTAR that allocates costs of $351,776[2] to Titan's service, which would be an increase of 14.5% [BHF-2].

[1] $308,456 is derived from 12 monthly fixed charges ($14,300) plus 838,806 MCF at the previous variable rate ($0.1631/MCF)

[2] $351,776 is derived from 12 monthly fixed charges ($14,300) plus 838,806 MCF at the proposed variable rate ($0.2148/MCF) [Titan-Enstar-2-31, RLC-3]

I will not directly comment on the appropriateness of the MSFT rate for HEA, and in my analysis I have not identified the appropriate costs allocations for HEA. I do note that HEA has similar annual volumes to Titan and it is a transmission only customer.

Q8: Please discuss the major differences that cause the two very different estimates of Titan's cost of service?

A8: In general, ENSTAR assigns to Titan costs that are not related to the facilities and operations that are required to serve Titan, specifically those costs required to move Titan's gas supply for 39 miles through the BAP transmission line to Point McKenzie. The differences are the result of three categories of inappropriate allocations by ENSTAR:

(i) Titan is allocated shares of transmission related plant that is not used, or even reasonably able to be used, by Titan;

(ii) There are multiple ENSTAR functions that are allocated to Titan that are not used, and cannot be used, by Titan; and finally,

(iii) These inappropriate allocations then drive the allocation process for other related costs such as overheads, general plant, earned return, and income taxes.

These changes are shown in the Tables in RLC-2: "Titan - Alternative Allocation Model" for each of the major asset and O&M categories, consistent with the presentation in ENSTAR's application at BHF-2.

Transmission Allocation

Q9: Please explain how you would allocate transmission plant differently than ENSTAR.

A9: First, the approach taken in the ENSTAR Application is to assume that all transmission plant and operating costs are common to all customers. In the case of a short haul, point-to-point transmission customer like Titan, the correct approach is to consider only the transmission plant that is used by Titan, specifically the Beluga-Anchorage Pipeline (BAP). This plant has a gross plant value of $70.8 Million [Titan-Enstar-2-20(d), RLC-3] which is considerably less than $217.6 Million estimated for ENSTAR's entire transmission gross plant [BHF-2].[3] Titan is using a pipeline that consists of 32.5% of ENSTAR's total transmission plant.

Second, only the section of the BAP that is used by Titan should be included in Titan's rate calculation. Titan utilizes the first 39 miles of the BAP [Titan-ENSTAR-2-20(f), RLC-3] out of a total distance of 103.2 miles [Titan-ENSTAR-2-20(b), RLC-3]. This results in Titan using only 37.8% of the BAP distance.[4]

Third, ENSTAR allocated transmission costs on the basis of 50% average day demand, or annual throughput, [Factor "V"; BHF-1] and 50% 3-Day Average Peak Demand, or 3CP [Factor "D"; BHF-1]. The correct allocation is the 3CP of the applicable asset, the BAP.

[3] The correct allocation would use Net Plant. The revenue requirement for ENSTAR is based on rate base or net plant in service. Unfortunately, ENSTAR was not willing to provide an estimate of the Net Plant of the BAP [Titan-ENSTAR-2-20(e), RLC-3]. We do know that the BAP was placed in service in 1984 [Titan-ENSTAR-2-20 (a), RLC-3] but cannot ascertain the relative value of the BAP's net plant as a proportion of the transmission asset class.

[4] As ENSTAR was unable to provide a segmentation of costs within the 103.2 miles of the BAP, I assumed the cost of the 6 inch and 8 inch laterals were zero as these were not provided so that all of the costs were included in the 20 inch main transmission line. Further, I assumed that costs per unit distance are constant throughout the BAP [Titan-ENSTAR-2-20 (b), RLC-3].

Titan's 3CP is 3,401 Mcf [BHF-2], and the 3CP for the BAP is 115,850 Mcf[5]. The result is that Titan's uses 2.936% of the first 39 miles of the BAP on a peak demand basis. This is a proportionately higher utilization factor for the BAP than the 1.929% applied by ENSTAR for overall transmission utilization [BHF-2, page 19, Factor 'S'].

I believe that only 18.71% of the Transmission Net Plant that ENSTAR allocates to Titan should be allocated.[6] It is not possible to breakdown these assets into more detail, as a greater level of detail cannot be provided by ENSTAR. [Titan-ENSTAR-2-20(e), RLC-3].

Furthermore, as ENSTAR does not track transmission expenses to the BAP or to any sub-portion of the BAP [Titan-ENSTAR-2-21(b) and 2-22, RLC-3], this percentage is as close as one can estimate a fair allocation of transmission expenses (Accts 850-866) and transmission depreciation expenses (Accts 365-370).

Q10: Why is Peak Demand (3CP) the appropriate allocator?

A10: The key driver for the cost of the transmission system is the capacity to which it is designed. These costs are essentially "fixed" due to nature of the carrying costs (i.e., rate base) and operating costs. In my view, the only significant cost item that would be variable with throughput would be compressor fuel and odorant. Neither of these cost elements is present in the first 39 miles of the BAP.

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[5] The total throughput for the 3 peak days for the BAP was 347,547 Mcf [Titan-ENSTAR-2-20(h), RLC-3]; this is an average of 115,850 Mcf per day.

[6] Calculation:

$$\frac{\$70.8}{\$217.6} \times \frac{39.0}{103.2} \times \frac{2.936}{1.929} = 0.1871$$

The BAP has a current capacity of 200,000 Mcf per day [Titan-ENSTAR-2-20(c), RLC-3]. The average of the 3CP was 115,850 Mcf per day, or 57.9%. This line does not have compression, only land for future compression [Titan-ENSTAR-2-18 and Titan-ENSTAR-2-20(i), RLC-3]. Odorant is not injected until downstream of Titan at Mile 39 [Titan-ENSTAR-2-20(f), RLC-3]. As such, the Demand Allocator [BHF-2, Factor 'D'] is the best representation of costs for this facility.

Q11: Under the methodology used by ENSTAR to allocate costs to Titan, what would have been the effect on the Titan rate if the Titan facility had been placed in a different location on the ENSTAR transmission system?

A11: The "postage stamp" rate methodology used by ENSTAR does not reflect the actual location of a customer. Had Titan located 10 feet from the inlet of the BAP line or adjacent the point at which the BAP line terminates in Anchorage (Mile 103.2), ENSTAR would have proposed the same transmission component in Titan's. This unfairly allocates costs to Titan and offers no incentive to place demand on a system that minimizes cost.

Q12: Does the fact that ENSTAR has excess capacity on the BAP line imply that the postage stamp method is appropriate?

A12: As discussed earlier, the BAP line operated at 58% capacity in the test year. The fact that ENSTAR has a low utilization rate on the BAP, or any other transmission line, does not imply that the customers should simply be charged the "average" of all transmission asset costs. At some point, growth may trigger an expansion on the system. Titan's predecessor located where it did, in part, to minimize its impact on the ENSTAR system, and it should receive a rate that reflects that choice. If Titan had located elsewhere on the ENSTAR system it may have triggered additional capital and operating costs.

Q13: Are there any other aspects of Titan's situation on the ENSTAR system that warrant further consideration of Titan as a unique type of customer?

A13: There are two facts that should be considered. Both apply to Titan and HEA. The first is that the Tariff for Titan states that Titan is "located along the Company's Beluga to Anchorage Pipeline" [Section 2145 a (1)(a), RLC-4]. This clearly implies Titan is not using the full length of this pipeline and that service is specific to the location of "LNG Plant #1". In other words, Titan is not entitled to service at any location, only at the LNG plant.

The second factor is that the actual Beluga to Anchorage Pipeline is owned by Alaska Pipeline Company ("APC") and not by ENSTAR itself [Titan-ENSTAR-2-23, RLC-3]. Titan is a customer of ENSTAR only because ENSTAR and APC are consolidated. While perhaps this consolidation offers efficiency, it does not imply that Titan requires, and therefore should be allocated, the costs related to ENSTAR's assets. If APC and Enstar were regulated separately, there would be no claim that Enstar's expenses could be allocated to Titan. Titan would simply be an APC transmission customer using a portion of one of APC's pipelines. The corporate management decision does not change the use of the facilities, and should not alter the rate design.

Functions Not Used by Titan

Q14: What services or functions included in the ENSTAR application are not used by Titan?

A14: I will list several items and state why they are not relevant to Titan:

(1) ***Production and Gathering Expenses*** – These are not used by Titan as Titan simply receives its gas supply at the meter at or near the interconnection with an upstream pipeline. Titan's suppliers are responsible for the costs associated with delivery to the point of custody transfer. To the extent that ENSTAR operates facilities or incurs costs upstream of this location, ENSTAR is obliged to recover those costs from the entities that are using these facilities or services. Titan has not contracted for these services and therefore should not pay for them.

(2) ***Compression Related Expenses*** – These facilities do not exist on the BAP either upstream or downstream of Titan's Point McKenzie facility [Titan-ENSTAR-2-18, RLC-3]. As such, there is no basis for collection of these costs from Titan.

(3) ***Odorant*** – ENSTAR admits that odorant is injected at Mile 39 on the BAP which is downstream of Titan's facility. Therefore, none of the plant, its maintenance or the consumption of odorant should be included in Titan's costs. Odorant expenses are included in Acct 807. [Titan-ENSTAR-2-19 and 2-20(1), RLC-3].

(4) ***Pressure Reduction*** – As Titan's gas is delivered directly to its facility at Mile 39 on the BAP at line pressure, there is no justification to charge Titan for pressure reduction [Titan-ENSTAR-2-17, RLC-3].

(5) ***Distribution Plant*** There are no distribution facilities between Beluga and the Titan LNG plant [Titan-ENSTAR-2-25, RLC-3]. ENSTAR's downstream distribution costs are not relevant to Titan's service.

In summary, there is no reasonable basis for ENSTAR to collect these costs from Titan.

Q15: In its attempts to justify its rate design, ENSTAR frequently refers to comingling of gas. Do you agree with this statement, and does it justify charging Titan a share of all ENSTAR's costs?

A15: The fact that ENSTAR comingles gas is simply because it is a common carrier for the transmission of natural gas for multiple entities. This is a good thing; it allows for the most overall efficient movement of a valuable energy source.

However, it is not a justification to spread the costs of particular assets or services used by many customers to another customer that does not use those assets or services. For instance, the fact that Titan's natural gas is physically placed in the same transmission line with gas for ENSTAR's distribution customers (residential and commercial users) for the first 39 miles of the BAP does not imply that Titan should pay for a share of downstream distribution costs. Nor should Titan pay for other transmission assets that it does not use.

Q16: ENSTAR refers frequently to prior Dockets (U-83-38 and U-87-2] in its discovery responses. In particular, it re-iterates that the "ENSTAR system is functionally designed and operated as an integrated delivery network". Is this still relevant to ENSTAR's situation today?

A16: It should be noted that there have been many changes in the Anchorage area in the past 30 plus years. The population of greater Anchorage has grown substantially over that time. The simple assumption that all plant assets serve all customers should be reviewed.

In particular, Titan did not exist until 1997, well after these Dockets were reviewed. A medium size transmission only customer like Titan, that required only a simple point to point service on a single transmission pipeline, was likely not contemplated in the 1980's decisions. It is my understanding that Enstar had no transmission customers until at least 1989 when its first special contract for transmission was approved by the RCA's predecessor. Furthermore, HEA is a similar point-to-point transmission customer, albeit on a different transmission pipeline.

The assumptions and implications embedded in these 30-year-old decisions regarding Anchorage-area power companies who purchased gas from Enstar were never intended to apply to customers like Titan and HEA who are transmission only customers, and who do not take gas at power plants in Anchorage.

ENSTAR Affiliate – Pacific Northern Gas

Q17: Are you aware of similar transmission/distribution natural gas utilities with transmission-only customers that have established transmission rates reflecting the distance customer gas is transported?

A17: Pacific Northern Gas Ltd.("PNG") is a similar company. PNG's West Division is a hybrid transmission and distribution utility that serves Northern British Columbia from just west of Prince George, BC, to the Pacific Coast. It has over 400 miles of transmission pipeline and serves over 20,000 customers including residential, commercial and industrials.

PNG is an affiliate of ENSTAR through its common ownership by Altagas[7]. Its last Fully Allocated Cost of Service ("FACOS") review was filed in 2003. A copy of the 2003 FACOS study is attached as RLC-6.

Q18: In its FACOS study, did PNG West use transmission demand and distance as weighting factors in determining cost allocation?

A18: Yes. At page 10 of its FACOS (RLC-6), PNG states that "Costs were allocated on the basis of the distance weighted non-coincidental peak day demand projected for 2003."

This statement confirms that transmission distance was an allocator for this Enstar-affiliate company. This is confirmed on Appendix 4, page 1 (RLC-6), which clearly shows how rates were calculated for each customer class, and that each large industrial transmission customer's distance of transport was reflected.

It also confirms that peak day demand was used as an allocator and not annual transportation volume.

Q19: How did PNG West treat the allocation of distribution capacity to transmission only customers?

[7] Reference: MLP-Enstar-3-14 (RLC-5)

A19: No distribution costs were attributed to transmission only customers. At page 10 (RLC-6), PNG states "Deliveries to the large industrial customers are made directly from the transmission pipeline system and therefore do not attract any distribution capacity costs."

This is confirmed on Appendix 4, page 2 (RLC-6), which clearly shows that zero distribution capacity costs were allocated to the large industrial customers.

Allocation of General Plant

Q20: Does the amount of General Plant need to be adjusted as a result of the above recommended changes to allocations?

A20: Yes. As General Plant is allocated based on the sum of Production & Gathering, Transmission and Distribution assets (Allocation Factor "H"), General Plant needs to be adjusted accordingly to reflect the reduction in the allocation of these assets. In my analysis, Titan is only using 18.50% [RLC-2, page 1, line 37] of the assets attributed to it in ENSTAR's filing. Hence, General Plant is reduced commensurately.

Allocation of Administrative & General

Q21: Does the amount of Administration & General Expenses (A&G) need to be adjusted as a result of the above recommended changes to allocations?

A21: Yes. As A&G is allocated based on the sum of O&M Expense and Ad Valorem Taxes excluding Purchased Gas and A&G (Allocation Factor "M"), A&G needs to be adjusted accordingly to reflect the reduction in the allocation of these assets. In my analysis, Titan is only using 17.78% [RLC-2, page 2, line 34] of the expenses attributed. Hence, A&G is reduced commensurately.

<u>**Allocation of Earned Return, Income Tax & Other Revenue**</u>

Q22: How should the amount of Earned Return, Income Taxes and Other Revenues be adjusted as a result of the above recommended changes to allocations?

A22: Return and Income Tax are allocated based on proportion of rate base (Allocation Factor "P"). As Titan should only be allocated 20.33% of the rate base that was originally allocated, these two items need to be reduced.

Other Revenues are allocated on the basis of Revenue Requirements (Allocation Factor "O") and this factor should be reduced to 19.42% [RLC-2, page 2, line 38]. Since Other Revenues is a credit to the cost of service, this adjustment increases Titan's cost of service.

<u>**Other Adjustments**</u>

Q23: What if the Revenue Requirement is altered during the regulatory process?

A23: To the extent that Return, Income Taxes and overall O&M levels are changed as part of the regulatory process, those changes are not included in the estimates provided above and in RLC-2. The identified excess allocated to Titan assumes that the cost of service remains constant. For instance, if the RCA decreases ENSTAR's proposed rate of return, that lower return will cause its entire cost of service to fall. This would also be true of Dr. Fairchild's analysis in BHF-2. My proposed allocation to Titan in RLC-2 would also be lower than indicated.

Summary & Conclusion

Q24: Could you summarize the net change in Revenue Requirement allocated to Titan as a result of the above changes?

A24: A reasonable cost allocation to Titan is $124,456. ENSTAR is recovering $308,436 in rates from Titan at current levels. In its application, ENSTAR is asking to charge approximately $351,766.

Titan (and indirectly Titan's downstream customers FNG and Fairbanks area ratepayers) should not be allocated substantial costs for facilities and services Titan does not use. I believe that Titan's rates should be based on a cost allocation of not more than $124,456.

Q25: Based on this allocation, what would you propose for Titan's rates?

A25: Historically, Titan's tariff has roughly split its allocation of costs evenly between fixed and variable charges.

Consistent with that split, the proposed rates are found on RLC-2, page 3, line 22, as follows:

Fixed Monthly Charge:	$5,000 per month
Variable Charge:	$0.0768 per MCF

Q26: Does this complete your testimony?

A26: Yes.

Ronald L. Cliff, *P. Eng, M.B.A.*

2920 Highbury Street
Vancouver, B.C., Canada
V6R 3T8
Tel: (604) 222-4461
E-mail: ron@highcliff.ca

Professional Experience:

August 1998 to Present **Highcliff Energy Services Ltd.**
President

- Provision of consulting services in the areas of market analysis, rate and tariff design, regulatory applications, cost of service studies, negotiations with suppliers and service providers for natural gas, electricity and thermal energy.
- Participation in Regulatory Hearings, Alternate Dispute Resolution processes, and contract negotiations on behalf of clients
- Clients include utilities and clients intervening on utility applications
- Merger and Acquisition analysis and negotiation
- Project Development advisory services
- Strategic Analysis in Energy and Regulatory Policy
- Serving multiple clients in British Columbia, Alberta, Yukon and the United States who are typically energy utilities, large users of natural gas or energy project developers.
- Have participated in projects involving water distribution, waste-water collection and treatment, telecom infrastructure, municipal agreements and land remediation.
- **A list of Recent Projects is included below at page 3.**

January 1997 to August 1998 **BC Gas Utility Ltd.**
Project Manager, Southern Crossing Pipeline

- Reporting to the Senior Vice President, Gas Supply, project managed a 312 kilometer, $400 million natural gas transmission pipeline
- Responsible for leading or coordinating feasibility, regulatory filings, rate design, project design, project construction, public consultation and implementation.
- Testified before the British Columbia Utilities Commission.

June 1991 to December 1996 **BC Gas Inc.**
Project Development Officer

- Corporate Development activities including a regulatory restructuring to separate utility and non-utility enterprises including liaison work with Stone & Webster.
- Mergers, Divestitures & Acquisitions
- Responsible for liaison with oil and gas subsidiary and corporate investment in technology development fund
- Feasibility analysis of several large energy projects
- Liaison with Provincial Government with respect to Economic Development agreements relating to the purchase of BC Gas.

January 1989 to July 1989 **Inland Natural Gas/BC Gas**
Rates Engineer

- Prepared tariffs for large industrial customers for the use of natural gas, performed rate design analysis and analyzed sales industrial sales forecasts
- Undertook marketing and sales of natural gas and transportation services
- During this period, seconded to prepare the bid documents for the Williams Lake Electrical Generation Project, which was a 55 MW wood residue generator selling its output to BC Hydro.

June 1985 to December 1988 **Inland Natural Gas Co. Ltd.**
Staff Engineer

- Responsible for Transmission and Distribution system analysis and planning to ensure adequate winter capacity for design conditions
- Provided capacity and design criteria for new pipelines and compressors
- Provided and analyzed data for use in rate design and cost of service reviews
- Met with Industrial Customers to assess their annual and peak winter demand for natural gas.
- Assisted in the preparation and analysis of the successful acquisition the Lower Mainland Gas Division of BC Hydro.

June 1984 to February 1985 **Burrard Yarrows Inc.**
Operations Engineer
Victoria, B.C.

- Assisted the Manager of Operations on facility related projects to assist in the ongoing viability of a ship construction and repair operation.
- Worked on the project bid team for the Polar 8 Icebreaker with specific responsibility on construction facilities and logistics.

Professional Memberships:

- Association of Professional Engineers and Geoscientists of British Columbia (1987) – P. Eng
- Canadian Institute of Energy, Vancouver Branch (1990-2008)

Education:

- Bachelor of Applied Science in Civil Engineering (UBC 1984)
- Canadian Securities Course - Honours (1987)
- Masters of Business Administration (UBC 1991)

HESL - Recent Projects

➢ *Utility Regulatory Applications*

On behalf of Utility clients have filed regulatory applications for the following purposes before the BC Utilities Commission, primarily for natural gas, propane and electricity distribution:

- Certificates of Public Convenience and Necessity (CPCN)
- Applications for Interim and Permanent Rates
- Gas Cost Recovery Applications
- Unaccounted for Gas Reporting and Analysis
- Approval of Ownership Transfer of Regulated Utility Assets
- Developed General Terms and Conditions for Tariffs
- Developed and filed expert evidence on behalf of clients.

➢ *District and Thermal Energy Systems*

- Have served as a member on the City of Vancouver, Expert Rate Review Panel, for its Southeast False Creek Neighbourhood Energy Utility (NEU) from its inception (2010-present); the Panel annually reviews the NEU's rates, rate structure, comparison to other energy sources (including business as usual) in order to balance the needs of the NEU and its ratepayers. Consideration has been given to financial risk, risk mitigation, greenhouse gas emissions and conservation based rates.
- In addition, have provided assistance and guidance to the City of Vancouver engineering department on other District Energy initiatives being proposed.
- Provided regulatory guidance to several contractors and associations with respect to the regulation of Thermal Energy Services in B.C. under the BCUC Proceeding to develop its TES Regulatory Guidelines.
- Provided regulatory guidance and support services to the Energy Services Association of Canada (ESAC) in its intervention into the FortisBC Energy Utilities AES Inquiry (2011-12) as well ESAC's intervention in the FortisBC Energy Inc. 2012-2013 Revenue Requirements Application.

➢ *Intervener on Regulatory Proceedings*

- Acted as an expert witness on numerous occasions on behalf of a gas distribution utility with the Regulatory Commission of Alaska to support reduced transportation tolls on a regulated pipeline. Filed testimony and participated in negotiated settlement amongst multiple parties.

- Developed a Cost of Service Study and Testimony on behalf of Fairbanks Natural Gas, LLC that was filed as evidence with the Regulatory Commission of Alaska in June 2014.
- Represented a small utility company in a major electric rate design hearing. Tasks included filing interrogatories, reviewing evidence and submitting argument on behalf of the client.
- Acted on behalf of large industrial users in several regulatory proceedings before the BCUC, which included a Revenue Requirement Applications, Rate Design and related matters.
- Assisted in the development of cross-examination, evidence preparation and witness aids. Responsible for developing strategies for argument and assisting client counsel in this regard.

➤ *Renewable Landfill Gas Projects*

- Advisor to an owner of a landfill as to how to structure a long term sale of Renewable Natural Gas to a third party. Issues examined included pricing strategy, general contractual terms and potential regulatory impacts of the deal structure.
- Advisor to a land developer who was considering the conversion of a landfill site redevelopment on the possible alternatives for the residual methane on the site, including potential utility regulatory issues.

➤ *Electric Tariff Negotiation*

- Representing a small electric utility, Corix Multi-Utility Services Inc., a re-seller who negotiated a unique tariff with BC Hydro for its electricity supply to Corix's utility operations in the interior of BC. The tariff was a result of a negotiated settlement process (NSP) and was approved by the BCUC

➤ *Expert Witness in Sewer Pipeline Dispute*

- Engaged by a Municipality to provide Expert Testimony in a civil trial where a land-owner is in dispute over the cost allocation and recovery of a privately constructed sewer line that was later integrated into the municipal sewer network.
- Required to develop a model to fairly allocate the costs of construction amongst the various parties including the land-owner and adjacent property owners and provide written testimony.

➢ *Energy Advisor*

- Reviewed the energy use of a large natural gas user in B.C. including longer-term price risk management and capital investment decisions.
- Advised on matters relating to alternative fuels and potential regulatory implications related to natural gas transportation tolls.
- Negotiate directly with pipelines and utilities for transportation services on behalf of utilities and large natural gas users.
- Acted for clients as liaison with Government and regulatory agencies to pursue policy and communication initiatives.

➢ *Negotiation of Municipal Franchise Agreements*

- Assisting a distribution utility in re-negotiating existing agreements with various towns requiring innovative financing, tax and regulatory strategies.
- Undertaken valuation of utility assets, assisted in drafting various legal agreements, and prepared draft applications for submission to the BCUC for the approval of various transactions.
- Completed the first "Lease-In-Lease-Out" structure of gas utility distribution assets in Canada.

➢ *Midstream Project Development:*

- Assisting a mid-stream project developer with the economic and political analysis to support the construction of a pipeline gathering system with a tie in to existing gas processing infrastructure. Work focused on competitive analysis with other projects including the relative impact of royalty collection to the crown.

➢ *Gas Extension Project to a Major Ski Resort*

- Assisted a large ski resort in the Interior of B.C. to obtain a Certificate of Public Convenience and Necessity from the BCUC for the right to distribute natural gas to customers at the resort community.
- Prepared the natural gas tariff and interim rate schedules, reviewed utility's Annual Financial Statements and assisted in drafting the Annual Report for submission to the BCUC.
- Preparing an application to the BCUC for justification of permanent rates.

➢ *Participation in a Utility ADR Process*

- Have acted on behalf of industrial gas users in an Alternate Dispute Resolution (ADR) processes with respect to utility revenue requirement. In these cases, the client successfully resolved issues and avoided expense of participation in Regulatory Hearings as a result.

➢ *Prepared Business Analysis of small LDCs*

- Undertook a business analysis of a small gas distribution utility in Fairbanks, Alaska. Assisted the majority owner in assessing options and strategies for advancing a small, LNG supplied grid system in the early stages of its market development.
- Reviewed the prospects of a natural gas or propane grid distribution system for a community in northern Canada on behalf of a prospective owner-operator.

➢ *Southern Crossing Pipeline Approval*

- Provided justification and regulatory support during the 1998-99 Hearing before the B.C. Utilities Commission, which resulted in the approval of this project's application.
- Work included preparing for open season as well as negotiations and drafting of agreements with prospective shippers on the pipeline.

➢ *Real Estate – Owner's Representative*

- Managing commercial, industrial and retail properties on behalf of a family owned real estate holding company.
- Performed acquisition and development analysis for new and existing properties. Focus is on Industrial, Commercial and Retail properties.
- Negotiating and monitor commercial leasing agreements
- Develop and maintain corporate budgets
- Negotiating and obtaining mortgage financing
- Responsible for monitoring and ensuring that all tenants comply with prudent operating practice with respect to environmental damage and site contamination
- Liaise with Property Management firm, as required

➢ *Miscellaneous Projects*

- **Land Remediation Project:** Acted as a landowner's agent with respect to the remediation of real estate project. Responsibility included developing a strategy for remediation and sale of the real estate, coordination of the legal, environmental and other advisors, as well as project implementation.

- **Strategic Analysis of IPP Opportunities:** On behalf of a client, provided advice with respect to location attributes of various independent power projects, including hydro and natural gas fired plants in various regions in B.C.

- **Market Analysis of Maritime LDC Opportunity:** Assisted a potential proponent on the merits of pursuing an investment in a natural gas distribution franchise in Atlantic Canada.

- **Water Services Company Acquisition Business Case:** Developed a business case for a successful acquisition of a water equipment supply and service company which included strategic and business issues.

- **Utility Acquisition Analysis:**
  - Examined the potential acquisition of a small natural gas distribution utility in a remote location for technical, market and competitive issues.
  - Examined the potential acquisition of an interest in a small, multi-utility company by a larger utility for strategic and valuation issues.

- **Financing Strategy for a Wastewater Treatment Plant:** Assisted a ski resort in assessing various off-balance sheet methods and risk sharing strategies related to the financing a Wastewater treatment plant that was required for permit reasons.

Additional Activities

- **Highcliff Investments Ltd.**: President & Founder (1992 – present)
- **Heathcliff Properties Ltd.**: President (2002 – present)
- **Jacklin Road Properties Ltd.**: President (2004 – present)
- **Esquimalt Building Ltd.**: President (2006 – present)
- **B.C. Hockey – Carded Referee** (2010 – present)
- **Speech Technology Empowering People Society (STEPS)**: Director (2007-2011). Charitable organization that seeks to provide voice activated computer alternatives for those who are physically challenged.
- **University of Guelph:** Member of the Parents Excellence in Education Committee (2007-2010)
- **York House School**: Governor (1999-2008); Board Chair (2002-2005); Vice Chair (2001-2002); Chair Advancement Committee (1999-2002); Annual Giving Volunteer (1997-2008).
- **St. George's School**: Director (1990-92); Alumni Director (1980-1994), Alumni President (1990-1992).
- **Heathcliff Foundation:** Trustee

Titan - Allocation Model

Gas Plant in Service (MSFT)

	Accts	Allocation Factor	Net Plant per BHF-2	Adjustments %	Adjustments Estimate	Comments/References
Production & Gathering	301-334					
Gross		D	24,011			
Depreciated		D	(12,451)	0.00%	-	- no basis for commodity purchases being attributed to Titan
			11,560			Ref: RLC testimony, Resp. 14
Transmission	365-370					- allocate only Beluga at 39 of 103.2 miles
Gross		S	4,196,949			- adjusted for Titan relative use of Beluga (2.936% of peak days)
Depreciated		S	(2,018,383)	18.71%	407,675	this is relative to Demand allocation factor "D" (1.929%)
			2,178,566			- Beluga is $70.8 of $217.62 mln Total Transmission assets (before depreciation)
						Ref: RLC testimony, Resp. 9
Distribution	374-387					
Gross		(multiple)	37,974			
Depreciated		(multiple)	(25,007)	0.00%	-	- no basis for distribution activities being attributed to Titan
			12,967			Ref: RLC testimony, Resp. 14
General Plant						
Gross		H	270,478			- Adjust for reduced Gathring, Transmission & Distribution
Depreciated		H	(181,195)	18.50%	16,522	- See note (A) below.
			89,283			Ref: RLC testimony, Resp. 20
Total Net Plant			$ 2,292,376		$ 424,196	18.50%
Working Capital (+ unamortized software)		H	64,647	18.50%	11,963	- per Allocation H, adjusted in Note (A), below
Deferred Income Taxes		N	(211,988)	18.50%	(39,228)	- per Allocation N, adjusted in Note (B), below
TOTAL MSFT RATE BASE			$ 2,145,035		$ 436,159	20.33%

Notes:

(A) *Gath, Trans + Dist*	*$ 2,203,093*	*$ 407,675*	*18.50%*	- per Allocation Factor H adjustment
(B) *Total Net Plant*	*$ 2,292,376*	*$ 424,196*	*18.50%*	- per Allocation Factor N adjustment

Titan - Allocation Model

MSFT Allocation - Cost of Service

	Accts	Allocation Factor	Rev. Req't per BHF-2	Adjustments %	Adjustments Estimate	Comments/Reference
O&M Expense:						
Purchased Gas	807	E.1, E	6,070	0.00%	-	- no basis for commodity purchases being attributed to Titan Ref: RLC testimony, Resp. 14
Transmission Expense	850-866	T, S	75,692	18.71%	14,164	- Point to Point allocation of BAP line as per Plant Allocation Ref: RLC testimony, Resp. 9
Distribution Expense	870-893	(multiple)	5,341	0.00%	-	- no basis for distribution activities being attributed to Titan Ref: RLC testimony, Resp. 14
Customer Accounting Expense	901-904	C	9,873	50.00%	4,937	- This takes into account that MSFT includes costs for both HEA and Titan Ref: RLC testimony, Resp. xx
Sales Expenese	911-912	C	240	100.00%	240	- no change
Admin. & General Expense	920-931	M	104,617	17.78%	18,603	- Allocation adjusted to account for lower share of O&M per Note (C), below Ref: RLC testimony, Resp. 21
Depreciation						
Production & Gathering	301-334	D	112	0.00%	-	]
Transmission	365-370	S	82,434	18.71%	15,426	] Same Allocations as Net Plant Allocation
Distribution	374-387	(multiple)	935	0.00%	-	]
General Plant		H	34,079	18.50%	6,306	]
			117,560		21,732	
Taxes (other than Income)		N, M	33,902	18.50%	6,273	] proportional to Total Net Plant Note (A), above
Earned Return		P	191,265	20.33%	38,891	] proportional to Rate Base Note (D), below Ref: RLC testimony, Resp. 22
Income Taxes		P	97,122	20.33%	19,748	] proportional to Rate Base Note (D), below Ref: RLC testimony, Resp. 22
Other Revenues		O	(682)	19.42%	(132)	] proportional to Revenue Requirement Note (E), below Ref: RLC testimony, Resp. 22
TOTAL MSFT REVENUE REQUIREMENT			$ 641,000		$ 124,456	19.42%

Notes:

(C) *O&M Expense, & Ad Val.*	*$ 114,935*	*$ 20,438*	*17.78%*	- per Allocation Factor M
(D) *Total Rate Base*	*$ 2,145,035*	*$ 436,159*	*20.33%*	- per Allocation Factor P
(E) *Revenue Requirements*	*$ 641,682*	*$ 124,588*	*19.42%*	- per Allocation Factor O

Titan - Allocation Model

Summary of Proposed Adjustments

Allocated Costs	Volume (MCF)	Per Application	Proposed Adjustment	Proposal/ Application
TITAN	838,806	$ 351,776	$ 124,456	35.4%
HEA	547,461	$ 289,195		
TOTAL MSFT	1,386,267	$ 640,971		

Tariff Schedule		MSFT Class Per Application	Proposed TITAN Tariff
	Fixed Monthly Charge	$ 14,300	$ 5,000
	Variable Charge (per MCF)	$ 0.2148 (F)	$ 0.0768 (G)
	Fixed Component	48.8%	48.2%
	Variable Component	51.2%	51.8%

Notes:

(F) $0.2148 is th corrected volume charge ($/MCF) for BHF-2, page 26 [Titan-Enstar-2-31]

(G) *Proposed allocation $ 124,456 less 12 monthly fixed charges of $ 5,000 = $64,456*

- $64,456 divided by the Annual Volume for Titan 838,806 MCF = $ 0.0768 per MCF

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Robert M. Pickett, Chairman Stephen McAlpine Rebecca L. Pauli Norman Rokeberg Janis W. Wilson

In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	U-16-066

ENSTAR NATURAL GAS COMPANY'S RESPONSE TO TITAN ALASKA LNG'S SECOND DISCOVERY REQUESTS

Pursuant to 3 AAC 48.155 and 3 AAC 48.141-145, ENSTAR Natural Gas Company ("ENSTAR"), by and through its counsel, responds to the Second Discovery Requests from Titan Alaska LNG, LLC ("Titan") as follows:

PRELIMINARY STATEMENT

Discovery in this docket is not complete. As discovery proceeds, facts, information, evidence, documents, and other matters may be discovered which are not set forth in these responses, but which may be responsive to these discovery requests. The following responses are complete based on ENSTAR's current knowledge, information, and belief. Furthermore, these responses were prepared based on as receipt points, as well as the CIGGS/KNPL interconnection on the Kenai Peninsula as a receipt point, which has been used by Titan's predecessor company. As explained in the ENSTAR's responses to Titan-2-4 and Titan-2-7 above, gas received by ENSTAR from producers and other suppliers, regardless of whether it is resold by ENSTAR or transported by ENSTAR on behalf of others, is comingled in the ENSTAR system. ENSTAR then delivers to both sales and transport customers gas from the ENSTAR system when and in the quantities required by sales and transport customers (including Titan). Account 334 includes costs associated with a Beluga River Unit receipt point and the Beluga Pipe Line Company receipt point. Consistent with Docket Nos. U-83-38 and U-87-2, which found the ENSTAR system is functionally designed and operated as an integrated delivery network, Titan was allocated $771 in net plant ($2,969 in gross plant less $2,198 in accumulated depreciation) related to Account 334 as shown in the revised Exhibit BHF-2.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-17: Please admit that no pressure reduction facilities are required for service to TITAN's Point MacKenzie LNG plant, and that TITAN takes the natural gas at the transmission line pressure.

Response: ENSTAR admits that Titan's Point MacKenzie LNG plant currently takes gas from the ENSTAR system at transmission line pressure.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-18: Does ENSTAR own and operate its own compressors or compressor stations on its transmission pipelines? If so please identify each compressor station, and specify its location.

Response: ENSTAR currently has two compressor stations located on its Kenai to Anchorage transmission line. One is near the origin of the line at the Kenai Gas Field, and the other is near Sterling, Alaska. ENSTAR has valves, related facilities, and land for a compressor station on its Beluga to Anchorage transmission line near Mile Post 39, but no compressor has been installed there to date.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-19: In which accounts reflected in BHF-2 are costs of odorization reflected? For each account indicate the portion of that account related to odorization. Please admit that Titan ships unodorized gas.

Response: The costs of odorization are reflected in Account 807. ENSTAR admits that, generally, the gas that is received for and delivered to Titan is unodorized. Please also see ENSTAR's response to TITAN-2-5(b), and the general ledger lines referenced therein. Expenses for odorant are identified in Column I (Explanation Alpha Name) and/or Column J (Explanation-Remark).

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

<u>TITAN-ENSTAR 2-20</u>: Please answer each of the following questions relating to the Beluga-Anchorage pipeline:

(a) When was this pipeline constructed?

(b) What is the total length (miles) and diameter of this pipeline?

(c) What is the design capacity of this pipeline?

(d) What was the original cost of this pipeline?

(e) What is the net plant in service of this pipeline in the current application?

(f) At what distance from the start of this pipeline does TITAN connect?

(g) What was the total throughput on the line during the test year? How was this throughput allocated among the various customer classes utilized in the Cost of Service Study (ie. G1, G2, G3, G4/T4, VLFT/APFT, MSFT, and IIT/ITS).

(h) What was the throughput of the pipeline for each day of the three-day period November 16-18, 2015, allocated among the same customer classes?

(i) Are there any compressor stations currently on this pipeline or contemplated for future installation? If so, where are the compressors located relative to the TITAN LNG plant (upstream or downstream)?

(j) At what pressure does ENSTAR typically receive natural gas from TITAN at the start of the Beluga Pipeline?

(k) At what pressure does ENSTAR typically deliver natural gas to TITAN at the LNG plant?

(l) Does ENSTAR add odorant to the natural gas in the pipeline at any point? If so, where does it inject the odorant? Confirm whether it is upstream or downstream of the TITAN LNG plant location.

Response:

(a) The initial pipeline construction occurred in 1983 and 1984. It was placed in service in October 1984.

(b) The Beluga to Anchorage pipeline system totals 120.1 miles. There are 102.4 miles of 20-inch transmission main that were included in the original construction and were put into service in 1984. An additional 0.8 miles of 20-inch main were added for a river crossing rerouting in 2004. The remaining mileage is an assortment of 4 and 6-inch mains used for laterals.

(c) Approximately 200 MMcf/day.

(d) ENSTAR does not maintain a separate plant account or subaccount for the Beluga to Anchorage pipeline. Asset descriptions from ENSTAR's records indicate that the original cost of assets currently in service associated with the Beluga to Anchorage pipeline in accounts 365, 366, 367, 368, 369, and 370 total $70.8 million. That includes assets that have been added since the original construction in 1983-1984.

(e) The information requested is not available. As noted in ENSTAR's response to Titan-2-16, ENSTAR does not maintain a separate plant account or subaccount for the Beluga to Anchorage pipeline. Further, ENSTAR utilizes the group life depreciation method. Under that method, depreciation is not calculated on an individual asset basis.

(f) The interconnection to Titan's Point MacKenzie facility is approximately 39 miles from the origin of the Beluga to Anchorage pipeline.

(g) Receipt point meters on ENSTAR's Beluga to Anchorage pipeline recorded 26.45 Bcf as being received into the ENSTAR system during the test year. Because of the comingling of gas on the ENSTAR system, and consistent with Docket Nos. U-83-38 and U-87-2, which found the ENSTAR system is functionally designed and operated as an integrated delivery network, all gas moved on ENSTAR system, including throughput on the Beluga pipeline, was combined and allocated between customer classes in proportion to total adjusted volumes during the test year as shown in as Allocation Factor E on Exhibit BHF-1, the cost-of-service study (*i.e.*, G1-33.64%; G2-3.71%; G3-7.41%; G4-13.18%; VLFT/APFT-36.75%; MSFT-2.58%, and ITT/ITS-2.74%).

(h) Receipt meters on ENSTAR's Beluga to Anchorage pipeline recorded 347,547 Mcf as being received into the ENSTAR system for the three-day period November 16-18, 2015. Because of the comingling of gas on the ENSTAR system, and consistent with Docket Nos. U-83-38 and U-87-2, which found the ENSTAR system is functionally designed and operated as an integrated delivery network, the throughput on the Beluga pipeline for the three-day period November 16-18, 2015, was not separately allocated between customer classes. Total adjusted volumes on the ENSTAR system for the three-day period November 16-18, 2015, were as shown in Allocation Factor D, in Exhibit BHF-1, the Cost-of-Service Study.

(i) Please see ENSTAR's response to Titan-ENSTAR-2-18.

(j) In addition to its General Objections, ENSTAR objects to this request as seeking information that does not exist. As noted ENSTAR's response to Titan-ENSTAR-2-14 above, gas delivered on behalf of Titan is comingled with other gas ENSTAR receives at the common receipt points and cannot be segregated. ENSTAR does not calculate a "typical" pressure for its receipt points.

Subject to and without waiving this objection, a review of ENSTAR's records for the past year indicates that the pressure at the Beluga River Unit connection and Beluga Pipe Line Company interconnection generally ranges between 820 psig to 710 psig.

(k) In addition to its General Objections, ENSTAR objects to this request as seeking information that does not exist. ENSTAR does not calculate a "typical" pressure for its delivery points. ENSTAR also objects to providing information that is already in the possession of Titan, as Titan measures the pressure at its plant itself.

Subject to and without waiving these objections, a review of ENSTAR's records for the past year indicates that the pressure generally ranges between 820 psig and 750 psig in the summer and 760 psig and 660 psig in the winter.

(l) Yes, at approximately mile 39, just downstream of the connection to Titan.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-21: For the total amount in each of the plant Accounts 365-370 listed at Exhibit BHF-2, page 10, please provide:

(a) The portion of the account associated with the Beluga-Anchorage pipeline.

(b) The portion of the account associated with the first 39 miles of the Beluga-Anchorage pipeline.

Response:

(a) Please see ENSTAR's response to Titan-ENSTAR-2-20(d).

(b) In addition to its General Objections, ENSTAR objects to this request as seeking information that does not exist. That level of detail is not available for all of the assets associated with the Beluga to Anchorage pipeline. The original transmission main constructed in 1983-1984 was recorded as a single asset.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-22: For the total amount in each of the expense Accounts 850-866 listed at BHF-2, page 8, please provide:

(a) The portion of the account associated with the Beluga-Anchorage pipeline.

(b) The portion of the account associated with the first 39 miles of the Beluga-Anchorage pipeline.

Response:

(a) In addition to its General Objections, ENSTAR objects to this request as seeking information that does not exist. ENSTAR does not track the expense information at this level of detail. Please also see ENSTAR's response to Titan-ENSTAR-2-21.

(b) In addition to its General Objections, ENSTAR objects to this request as seeking information that does not exist. ENSTAR does not track the expense information at this level of detail. Please also see ENSTAR's response to Titan-ENSTAR-2-21.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-23: Please confirm which legal entity owns the Beluga-Anchorage Pipeline.

Response: Alaska Pipeline Company.

Person(s) Supplying Information: Daniel Dieckgraeff.

TITAN-ENSTAR 2-24: Please confirm that during the test year, and since the test year to date, TITAN received service via the same section of the Beluga-Anchorage Pipeline. Please confirm that Titan's gas was received by ENSTAR at Mile 0 of the pipeline and delivered to the Titan facility at Point MacKenzie.

Response: ENSTAR confirms that during the test year, and since the test year to date, TITAN has received service from ENSTAR's entire fully integrated natural gas delivery system, which includes the Beluga-Anchorage pipeline segment. The Commission found in Docket U-83-38 that "the plant used for the delivery of gas to all customers is so thoroughly interdependent that efforts to isolate specific portions of the system which serve particular customers is not only impractical, but attempts to do so will produce inappropriate distortions in a COS study," that "a customer need not be directly or physically connected to a unit of plant in order to benefit from its existence," and "all classes of customers have benefitted from ENSTAR's integrated design approach and, therefore, must share in the costs." In U-87-2, the Commission further stated that "ENSTAR's system is designed and operated to meet the needs of the system as a whole." ENSTAR does confirm that during the test year and since the test year to date, the gas receipts for the account of Titan has been provided to the receipt points on the Beluga-Anchorage pipeline segment, and that gas deliveries to Titan have been to Titan's delivery point which is on the Beluga-Anchorage pipeline segment.

Person(s) Supplying Information: Daniel Dieckgraeff.

TITAN-ENSTAR 2-25: Please admit that Enstar has no distribution facilities between Beluga and the TITAN LNG plant.

Response: Admit.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild

TITAN-ENSTAR 2-26: Please admit that natural gas flowing from Beluga to TITAN's LNG plant is never physically in contact with any distribution plant owned or operated by Enstar. Please admit that the natural gas delivered does not need to travel through distribution plant to arrive at the TITAN LNG Plant.

Response: Denied. Because of the comingling of gas explained in ENSTAR's responses to TITAN-2-13, 2-14, 2-16 and 2-20, it is not possible to track the "natural gas flowing from Beluga to Titan's LNG plant." Moreover, the notion of whether that gas was "physically in contact with any distribution plant owned or operated by ENSTAR" is at odds with the findings in Docket No. U-83-38 that "for COS and rate design purposes [ENSTAR is a] a fully integrated natural gas delivery system." The Commission also found that "the plant used for the delivery of gas to fall customers is so thoroughly interdependent that efforts to isolate specific portions of the system which serve particular customers is not only impractical, but attempts to do so will produce inappropriate distortions in a COS study," that "a customer need not be directly or physically connected to a unit of plant in order to benefit from its existence," and "all classes of customers have benefitted from ENSTAR's integrated design approach and, therefore, must share in the costs." Please also see ENSTAR's responses to Titan-2-25 and Titan-2-27.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-27: Please identify and provide the location for the Enstar distribution facilities closest to the TITAN LNG plant.

Response: There is an odorant injection facility and a regulation station located downstream of the FNG facility interconnection with the Beluga to Anchorage pipeline. Both facilities are within 200 feet of the interconnection.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

TITAN-ENSTAR 2-28: Please admit that none of the distribution plant in Enstar's Accounts 374-387 is used to provide service to TITAN.

Response: Denied. The Commission found in U-87-2 that $4,595,424 in Account 376 (Distribution Mains) was used to provide service to large customers similarly situated to FNG/Titan (i.e., connected directly to ENSTAR's transmission pipelines). Because of the manner in which Account 376 affects the allocation of other distribution plant, the Commission's finding resulted in amounts in Accounts 374, 375, 377, 378, 379, 385, and 387 also being used to provide service to large customers similarly situated to Titan.

Person(s) Supplying Information: Daniel Dieckgraeff and Dr. Bruce Fairchild.

<u>TITAN-ENSTAR 2-29</u>: Please admit that none of the expenses reflected in Accounts 870-893 are related to the transportation of natural gas between Beluga and the TITAN LNG plant.

<u>Response:</u> Denied. Because of the manner in which distribution operating and maintenance expenses are allocated, the Commission's finding in U-87-2 that $4,595,424 in Account 376 (Distribution Mains) was used to provide service to large customers similarly situated to FNG/Titan (*i.e.*, connected directly to ENSTAR's transmission pipelines) resulted in a portion of the expenses reflected in Accounts 870-893 also being related to providing service to large customers similarly situated to Titan.

<u>Person(s) Supplying Information:</u> Daniel Dieckgraeff and Dr. Bruce Fairchild.

<u>TITAN-ENSTAR 2-30</u>: Since TITAN does not use any of the distribution plant, please explain Enstar's rationale for allocating any distribution costs to TITAN in the rate design process. (Accounts 870-893, 374-387)

<u>Response:</u> Please see ENSTAR's responses to Titan-ENSTAR-2-28 and Titan-ENSTAR-2-29.

<u>Person(s) Supplying Information:</u> Daniel Dieckgraeff and Dr. Bruce Fairchild.

<u>TITAN-ENSTAR 2-31</u>: On page 32 of his testimony and again on page 26 of BHF-2, Dr. Fairchild states that the MSFT test year volumes are 1,471,718 Mcf. On page 23 of BHF-2 and in TA285-4, Attachment B, page 8, the MSFT test year volume is shown as 1,386,267 Mcf. Please clarify and confirm the correct volume for the MSFT class, and provide a corrected BHF-2.

Response: The 1,471,718 Mcf volume figure cited on page 32 of Dr. Fairchild's testimony and shown on page 26 of Exhibit BHF-2 is incorrect—it should be 1,386,267 Mcf. The only change to Exhibit BHF-2 is on page 26, where the volume charge at cost-of-service increases from $0.2023 per Mcf to $0.2148 per Mcf, and the volume charge adjusted for gradualism increases from $0.2098 per Mcf to $0.2227 per Mcf.

Person(s) Supplying Information: Dr. Bruce Fairchild.

DATED this 30th day of January, 2017, at Dallas, Texas.

By: ______________________

Moira K. Smith
Vice President and General Counsel
Alaska Bar No. 0805032
P.O. Box 190288
Anchorage, AK 99519-0288
Phone: (907) 334-7662
Fax: (907) 334-7657
moira.smith@enstarnaturalgas.com

Matthew C. Henry
Texas Bar No. 00790870
Myles F. Reynolds
Texas Bar No. 24033002
VINSON & ELKINS LLP
2001 Ross Avenue, Suite 3700
Dallas, Texas 75201
Phone: (214) 220-7873
Fax: (214) 999-7873
mhenry@velaw.com
mreynolds@velaw.com

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STATE OF ALASKA
REGULATORY COMMISSION OF ALASKA

ENSTAR Natural Gas Company

§2145 **Schedule MSFT – Mid-Sized Firm Transportation Service**

§2145a **Application**

~~*§2145a(1)* This rate schedule applies to firm transportation service to:~~

§2145a(1)(a) Titan Alaska LNG, LLC (formerly Fairbanks Natural Gas Company (FNG)) LNG Plant #1 located along the Company's Beluga to Anchorage Pipeline.

§2145a(1)(b) Alaska Electric and Energy Cooperative, Inc. Soldotna Combustion Turbine power plant located along the Company's Kenai to Anchorage Pipeline.

§2145a(2) This service shall be supplied under Sections 1605 and 1640, and

§2145a(3) The Firm Transportation Service Agreement between the Customer and the Company.

§2145b **Monthly Rate**

Service Charge (Base)-Volumetric Rate:

$0.1831 per thousand cubic feet (Mcf) I

Customer charge:

$14,300 per Month I

§2145c **Rate Adjustments**

Rates for service under this Schedule are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

U-16-066
Exhibit RLC-4
Page 1 of 1

PACIFIC NORTHERN GAS LTD.

2003 FULLY ALLOCATED COST OF SERVICE STUDY

1 INTRODUCTION

On July 31, 2002 the B.C. Utilities Commission (the "Commission") released its decision on the 2002 Revenue Requirements Applications filed by Pacific Northern Gas ("PNG") and PNG (N.E.) on November 30, 2001 and subsequently amended on February 25, 2002. The Commission approved the cost allocation methodology as applied for by PNG and accepted the suggestion by PNG that it defer further rate rebalancing until it can review the allocation of costs among its rate classes. The Commission directed PNG to include a Fully Allocated Cost of Service ("FACOS") study with its 2003 Revenue Requirements Application. The following describes the 2003 FACOS which is referred to as the "2003 Study".

In November 1997, PNG filed with the Commission a Cost of Service Allocation/Rate Design Study based on the projected volumes and revenue requirement for 1998 (the "1998 Study"). The Commission reviewed the 1998 Study in a public hearing held in March 1998 and issued its decision in June 1998. Except for some minor changes described herein, the 2003 Study uses the same methodology to allocate costs to each of the rate classes as was used in the 1998 Study. As in the 1998 Study, gas supply costs are excluded from the analysis and therefore the resulting revenue to cost ratios are a comparison of fixed and variable transportation and distribution revenues and costs.

The 1998 Study estimated gas supply administrative costs based on a review of wages, benefits and expenses associated with the administration of PNG's gas supply portfolio and allocated these costs directly to the core market. All gas supply administrative costs are now allocated to the cost of gas supply and therefore do not appear in the gross delivery margin. This reflects the fact that PNG now outsources all of its gas supply functions to a third party.

The 2003 Study follows the standard three-part methodology in which costs are: (i) functionalized, or categorized according to which function (i.e. transmission, distribution, or customer metering and administration) causes the costs to be incurred; (ii) classified according to whether the costs are demand (capacity), customer service or commodity related and (iii) allocated to each customer rate class according to its share of each of the classified costs. Specifically, the 2003 Study classifies each rate base and cost of service component into one or more of the following:

<u>Transmission Capacity</u>

The facilities and costs of providing transportation capacity and compression for moving gas from the interconnect with the Duke Energy T-South mainline at Summit Lake to delivery points off of the PNG high pressure transmission system.

<u>Distribution Capacity</u>

The facilities and related costs associated with providing more than the minimum distribution and metering capacity to larger customers utilizing the distribution system. The minimum capacity is defined as that required to service a residential customer.

<u>Customer Service</u>

The facilities and related costs associated with meeting the minimum distribution capacity and metering requirements as well as for the provision of customer service.

<u>Commodity</u>

The variable costs associated with moving a unit of gas through the pipeline system.

The capacity and metering requirement of a single residential customer was used as a basis for classifying the cost of service and rate base components of the distribution system into capacity and customer related components. Cost and rate base components associated with distribution mains were functionalized according to a minimum size criterion into capacity and customer related components. The minimum size of distribution main required to serve a customer was assumed to be 0.5 inches in diameter. The equivalent 0.5 inch capacity (0.5 times length) of all distribution mains was calculated and compared to the actual diameter times length. The excess was associated with providing extra capacity for certain customers and was therefore classified as a capacity component. Similarly, the average unit cost of a minimum meter type (AL-225TC) was used to functionalize meter costs into distribution capacity and customer related components. The minimum meter requirement for a customer was assumed to be the AL-225TC. The cost of providing minimum metering to all customers was compared to the actual meter costs. The excess was associated with providing extra capacity for certain customers and was therefore classified as a capacity component.

The ratio of capacity to customer was determined in the 1998 Study to be 73.4% to 26.6% for costs related to distribution mains and 44.20% and 55.80% for costs related to metering. None of the changes to the PNG system since 1998 have warranted revising this study or changing these classification coefficients and consequently, these same factors were used in the current study.

Sections 2 to 4 describe the cost of service allocation principles as applied in the 2003 Study. Section 5 presents the Study's recommendations and conclusions. Tables supporting the study are provided in the appendices.

2 FUNCTIONALIZATION AND CLASSIFICATION OF THE RATE BASE

2.1 Introduction

The rate base was calculated using the forecast average balances of the plant in-service, depreciation and deferred charges. Estimated normal levels of conversion loans, construction work in progress and working capital were included as well. The forecast average balances of contributions in aid of construction and construction advances as well as an adjustment for expenditure timing and the balance of deferred taxes were deducted from the rate base. The classified projected average 2003 balances of the rate base components are presented in Appendix 2.

The classification of each of the major rate base components is discussed in the following sub-sections.

2.2 Transmission Plant

The transmission plant in service has been classified as being related to the provision of transmission pipeline capacity.

2.3 Distribution Plant

The components of the distribution plant in service are classified in accordance with the following table. All service related costs are classified as providing customer service.

Rate Base Item: Distribution Plant	Distribution Function	Classified as: Distribution Capacity	Customer Service
- Structures - Mains - Regulating Equipment	Mains	73.4%	26.6%
Meters	Metering	44.2%	55.8%
- Services - House Installations	Services	-	100%
Other capacity related	Capacity	100%	-

2.4 General Plant

The general plant was classified pro rata on the sum of the transmission and distribution net-plant-in-service classifications.

2.5 Deferred Charges

The average balances of line break costs, stress corrosion cracking costs, extraordinary plant losses, preliminary engineering studies and deferred revenues from industrial customer deliveries in 2002 were classified as being related to the provision of transmission pipeline capacity. Customer conversion costs and systems development costs associated with the CIS and FIS systems were classified as providing basic customer service. Rate design costs and property tax variances were classified into transmission and distribution capacity and customer service pro rata on the basis of the net-plant-in-service.

2.6 Other Rate Base Items

The average balance of contributions in aid of construction, construction advances, and construction work in progress as well as the adjustment for expenditure timing were classified to transmission and distribution capacity and customer service pro rata on the basis of the net-plant-in-service. Conversion loans and cash working capital were deemed to be rate base items related to the provision of customer service. The line pack and inventory components of 'other working capital' were classified as transmission capacity and pro rata on the net-plant-in-service classifications, respectively.

Deferred income taxes were classified pro rata on the basis of net-plant-in-service.

3 FUNCTIONALIZATION AND CLASSIFICATION OF THE COST OF SERVICE

3.1 Introduction

The 2003 Study uses the forecast 2003 test year cost of service including the projected 2003 revenue deficiency as presented in PNG's 2003 Revenue Requirements application. The cost of service net of gas supply costs (ie. the gross margin) is used in the allocation study. The following subsections describe classification of each of the major components of PNG's gross margin as presented in Appendix 3.

3.2 Cost of Gas Used in Operations

The cost of gas used in operations, which includes pipeline and regulating gas as well as compressor fuel, is a function of pipeline throughput and was therefore classified as a commodity cost.

3.3 Operating and Maintenance Expenses

Transmission operating and maintenance expenses were classified as providing transmission capacity.

Distribution operating and maintenance expenses net of costs recovered from the provision of shared services to the PNG (NE) division were classified in accordance with the following table. Expenses related to specific plant facilities were classified on the same basis as the related rate base item. All service related costs were classified as providing customer service. The operating expense associated with 'mains and services' was classified into distribution capacity and customer service using the average of the mains (73.4%/26.6%) and service (0%/100%) classifying coefficients.

Operating and Maintenance Item	Distribution Function	Classified as: Distribution Capacity	Classified as: Customer Service
Regulating Stations	Distribution Mains	73.4%	26.6%
- Supervision - Removing and resetting meters	Metering	44.2%	55.8%
- Service on customer premises - Sales promotion - Customer accounting	Services	-	100%
Mains and Services	Mains and Services	36.7%	63.3%

General operating expenses net of costs recovered from shared services were classified pro rata on the basis of the sum of the transmission and distribution operating expenses net of the cost of gas used in operations. Similarly, general maintenance expenses were classified pro rata on the basis of the sum of the transmission and distribution maintenance expenses.

3.4 Administrative and General Expenses

Administrative costs, including employee benefits and net of recoveries from shared services, were classified pro rata on the basis of the sum of the operating and maintenance costs. Costs incurred for special services, insurance premiums and general corporate expenses were deemed to be a function of the size of the organization and were therefore classified pro rata on the total rate base.

3.5 Depreciation and Amortization Expenses

Depreciation and amortization was classified on the same basis as the utility plant or deferred charge to which it relates. The amortization of non rate base interest bearing deferrals was classified pro rata on total rate base.

3.6 Taxes Other Than Income Taxes

Regular property taxes were classified pro rata on the basis of net-plant-in-service.

The one percent in lieu tax related to residential and commercial customers was classified into distribution capacity and customer related costs on the basis of the mains classifying coefficient. The industrial portion of this tax was classified as providing transmission capacity.

3.7 Other Income and Miscellaneous Revenue

Other income and miscellaneous revenues were classified on the same basis as the total rate base.

3.8 Income Tax and Earned Return

The earned return was classified on the same basis as the total rate base.

Income taxes are a function of the equity component of the earned return and were therefore classified on the same basis as the total rate base.

4 ALLOCATION OF THE COST OF SERVICE TO THE RATE CLASSES

Each rate class is allocated a share of one or more of the classified components of the gross margin. The core market is comprised of the residential, commercial firm, commercial transportation, commercial interruptible, small industrial sales, seasonal off-peak sales and natural gas vehicle ("NGV") customer rate classes. The Granisle propane customers have been broken out of the residential class and treated as a separate rate class for the purposes of this study.

The large and small industrial firm and interruptible transportation customers make up the non-core market. The large industrial customers have been separately identified as Methanex, Skeena, Eurocan, Alcan and BC Hydro.

The 2003 Study implements several minor changes to the allocation of costs as compared to the 1998 Study. The allocation of customer related costs to the commercial interruptible sales customers and the BC Hydro interruptible transportation service was discontinued in the 2003 Study. All interruptible services are now allocated a share of the commodity costs only. In addition, seasonal off-peak customers are now allocated a portion of the transmission capacity costs, on the basis of a 50% load factor, in addition to customer and commodity costs.

Costs have been allocated to all other customer classes in the same manner as in the 1998 Study.

The costs associated with each of the classified cost components were allocated across rate classes in the manner described in the subsections below. The results are presented in Appendix 4.

Transmission Capacity

The costs associated with the provision of transmission capacity were allocated to all firm customer classes with the exception of the customers on the Granisle propane system who do not use the transmission system.

Costs were allocated on the basis of the distance weighted non-coincidental peak day demand projected for 2003. Peak demand for the large and small industrial transportation customers was deemed to be a customer's firm daily contracted demand converted to GJ's using the heat content at Summit Lake forecast by Duke Energy for the 2003 gas year.

The distance factor for each rate class was determined by calculating the distance-weighted average of the annual projected volumes for each delivery point where the distance is measured along the mainline from Summit Lake. Projections on a per delivery point basis for the residential, commercial sales and small industrial sales customers were not available and, consequently, actual volumes delivered in 2001 at each location were used.

Distribution Capacity

The costs associated with the provision of distribution capacity were allocated to all firm service customers with the exception of the residential sales and large industrial transportation customers. Residential customers represent the minimum level of gas service within the distribution system and, consequently, these volumes do not use the additional distribution capacity required for the other customers. Deliveries to the large industrial customers are made directly from the transmission pipeline system and therefore do not attract any distribution capacity costs. Costs were allocated on the basis of the forecast non-coincidental peak day demand.

<u>Customer Service</u>

Customer costs were allocated to all firm service customers on the basis of the deemed number of meters installed for each customer. Each small industrial customer and large industrial firm customer was deemed to be equivalent to 10 and 220 installed residential meters, respectively.

<u>Commodity</u>

The variable costs associated with transporting and delivering a unit volume are limited to the cost of company use gas and were allocated on the basis of projected annual volume to all customers except Methanex. Under the terms of the new firm transportation service agreement between PNG and Methanex (the "Methanex Agreement"), Methanex supplies its own company use gas and, consequently, these costs have been excluded from PNG's projected gross margin.

5 2003 STUDY RECOMMENDATIONS AND CONCLUSIONS

5.1 General

The purpose of a cost allocation study is to test the reasonableness of rates currently in effect. This is done by calculating revenue to cost ratios which compare the projected revenues to the projected allocated costs for each customer class. The projected revenues to be recovered from each customer class were calculated by multiplying forecast 2003 deliveries by the approved 2002 rates and allocating a portion of the projected revenue deficiency to each rate class in accordance with the established methodology of allocating pro rata on the net margin of each rate class. Pursuant to the Methanex Agreement, Methanex deliveries are not allocated a portion of the deficiency.

A revenue to cost ratio of 1:1 means that a customer class is paying exactly its allocated cost of service. In practice, cost allocation studies and rate designs are not precise enough to generate the ideal ratio of 1:1. The Commission has confirmed on several occasions that, on general terms, ratios between 0.9 and 1.1 result in rates that are just and reasonable. The circumstances of each utility are different and this rule of thumb will not always be strictly applied by the Commission.

Appendix 1 presents the projected revenue to cost ratios for 2003 and compares them to the 1998 study. This table presents a set of revenue to cost ratios based on annualized revenues from, and costs allocated to, Skeena Cellulose which is expected to return to full capacity on July 1st, 2003 and generate six months of revenue from firm and interruptible deliveries. The commodity costs allocated to the annualized Skeena deliveries were pro rated to one full year based on the actual projected deliveries for 2003. The revenues associated with Skeena were pro rated to one full year based on the projected revenues for six months of deliveries in 2003. Finally, the revenue deficiency projected for 2003 less the incremental revenue from the annualized Skeena deliveries were reallocated to all customer classes except Methanex.

In its decision on the 1998 Cost of Service Allocation/Rate Design Study, the Commission invited PNG to apply for further inter-class shifts in revenue for 1999 and 2000 in line with the direction indicated in the 1998 Study. The results of the 2003 Study reflect the actions that PNG has taken to trend the revenue to cost ratios towards unity for all customer classes. However, the Methanex Agreement overshadows the effects that the inter-class shifts have had since 1998 and, as a result, the revenue to cost ratios for the remaining large industrial transportation customers have increased with respect to those presented in the 1998 Study. However, since the recovery of the gross margin from Methanex is higher than the commodity costs associated with their deliveries, the Methanex volumes are recovering a significant portion of the gross margin that would otherwise be allocated to the remaining customers. Therefore PNG is recommending that no rate shifts be implemented at this time. Given the fact that the residential customers' revenue to cost ratio is under 1.0, there may be an opportunity in the future to shift margin to them and decrease the Skeena, Eurocan and Alcan margin requirements. Gas supply prices are still too high to permit rate shifting at this time.

Pacific Northern Gas Ltd.

APPENDIX 1

Revenue to Cost Ratios

2003 Forecast with Skeena Deliveries Annualized

Customer Class	2003 Deliveries (GJ)	Allocated Cost of Service ($000)	Allocated Cost of Service (%)	Gross Margin using 2002 Rates ($000)	2003 Revenue Deficiency ($000)	Gross Margin Including 2003 Revenue Deficiency ($000)	Gross Margin Including 2003 Revenue Deficiency (%)	Rev/Cost 2003	Rev/Cost 1998
Residential Sales ex Granisle (RS 1)	1,836,834	$ 11,925	28.3%	$ 9,876	$ 1,320	$ 11,196	26.6%	0.94	0.73
Granisle (RS 1)	18,797	$ 63	0.2%	$ 55	$ 7	$ 63	0.1%	0.99	0.73
Commercial Classes (RS 2, 3, 4)									
Small & Large Commercial Firm (RS 2)	1,238,410	$ 6,683	15.9%	$ 5,833	$ 779	$ 6,612	15.7%	0.99	0.65
Commercial Transport (RS 3)	64,081	$ 247	0.6%	$ 172	$ 23	$ 195	0.5%	0.79	1.08
Commercial Interruptible (RS 4)	43,996	$ 10	0.0%	$ 108	$ 14	$ 122	0.3%	11.74	12.65
Small Industrial Classes (RS 5)									
Sales	564,908	$ 994	2.4%	$ 946	$ 126	$ 1,073	2.6%	1.08	0.83
Transport	966,306	$ 1,424	3.4%	$ 1,261	$ 168	$ 1,430	3.4%	1.00	0.96
Interruptible Transport	0	$ -	0.0%	$ -	$ -	$ -	0.0%	na	0.00
Seasonal Off-Peak Sales (RS 6)	30,935	$ 46	0.1%	$ 135	$ 18	$ 153	0.4%	3.30	12.85
NGV (RS 7)	33,651	$ 48	0.1%	$ 52	$ 7	$ 59	0.1%	1.22	0.82
Large Industrial									
Methanex - Firm	21,355,335	$ 15,144	36.0%	$ 11,280	$ -	$ 11,280	26.8%	0.74	1.22
- Interruptible	3,289,366	$ -	0.0%	$ 1,049	$ -	$ 1,049	2.5%	na	2.74
Skeena - Firm	2,190,730	$ 2,315	5.5%	$ 2,956	$ 395	$ 3,351	8.0%	1.45	1.21
- Interruptible	189,705	$ 45	0.1%	$ 269	$ 36	$ 305	0.7%	6.80	10.12
Eurocan - Firm	2,687,326	$ 2,509	6.0%	$ 3,180	$ 425	$ 3,605	8.6%	1.44	1.19
- Interruptible	0	$ -	0.0%	$ -	$ -	$ -	0.0%	na	11.40
Alcan - Firm	431,799	$ 477	1.1%	$ 561	$ 75	$ 636	1.5%	1.33	1.08
- Interruptible	558,201	$ 132	0.3%	$ 791	$ 106	$ 897	2.1%	6.80	11.85
B.C. Hydro	10,000	$ 2	0.0%	$ 36	$ 5	$ 41	0.1%	17.34	5.86
Total	35,510,380	$ 42,066	100%	$ 38,561	$ 3,505	$ 42,066			

Adjusted Revenue Deficiency:

As Filed:	$	4,825
Increase in Skeena Gross Margin	$	(1,599)
less Increase in Skeena commodity costs	$	279
Adjusted Revenue Deficiency:	$	3,505

12/4/2002

Pacific Northern Gas Ltd.

APPENDIX 2

Functionalization and Classification of the Rate Base

2003 Forecast ($ 000's)

Line	Description	Total	Capacity Trans.	Capacity Dist.	Customer	Commodity
1	**Net Plant In Service**					
2	Transmission	103,842	103,842	-	-	-
3	Distribution					
4	Structures	279	-	205	74	-
5	Services	15,026	-	-	15,026	-
6	House installations	2,271	-	-	2,271	-
7	Mains	19,182	-	14,079	5,102	-
8	Regulating equipment	172	-	127	46	-
9	Meters	2,655	-	1,174	1,481	-
10	Other capacity related	460	-	460	-	-
11	Subtotal Processing, Trans and Dist	143,886	103,842	16,044	24,001	-
12	General	8,227	5,938	917	1,372	-
13	Total Net Plant In-service	152,115	109,780	16,962	25,374	-
14	**Deferred Charges**					
15	Transmission	700	700	-	-	-
16	Distribution	245	-	-	245	-
17	General	(27)	(19)	(3)	(4)	-
18	Total Deferred Charges	918	681	(3)	240	-
19	**Other Items**					
20	Adjustment for expenditure timing	(41)	(30)	(5)	(7)	-
21	Contributions In Aid Of Construction	(5,955)	(4,298)	(664)	(993)	-
22	Construction Advances	(245)	(177)	(27)	(41)	-
23	Deferred Income Taxes	(14,462)	(10,437)	(1,613)	(2,412)	-
24	Construction Work In Progress	100	72	11	17	-
25	Conversion Loans	7	-	-	7	-
26	Cash Working Capital	4,814	-	-	4,814	-
27	Other Working Capital - Linepack	600	600	-	-	-
28	Other Working Capital - Inventory	984	710	110	164	-
29	Total Other Rate Base Items	(14,198)	(13,559)	(2,188)	1,548	-
30	**Total Rate Base**	138,835	96,902	14,771	27,162	-
31	Percentage of Rate Base	100.00%	69.80%	10.64%	19.56%	0.00%

Pacific Northern Gas Ltd.

APPENDIX 3

Functionalization and Classification of the Cost of Service

2003 Forecast ($ 000's)

Description	Total	Capacity: Trans.	Capacity: Dist.	Customer	Commodity
Operating Costs					
Transmission	1,969	1,969	-	-	-
Distribution					
Supervision	273	-	121	152	-
Removing & resetting meters	162	-	71	93	-
Service on customer premises	45	-	-	45	-
Mains and services	366	-	134	231	-
Regulating stations	3	-	2	1	-
Sales promotion	40	-	-	40	-
Customer Accounting	1,442	-	-	1,442	-
Total Transmission and Distribution	4,283	1,969	328	2,002	-
General System Operations	1,495	685	114	696	-
Total Operating	5,794	2,653	443	2,698	-
Maintenance Costs					
Transmission	907	907	-	-	-
Distribution					
Structures	8	-	4	1	-
Mains and services	66	-	32	55	-
Regulating equipment	-	-	-	-	-
Meters	96	-	42	53	-
Total Transmission and Distribution	1,094	907	78	109	-
General	79	66	6	8	-
Total Maintenance	1,173	972	84	117	-
Total Operating and Maintenance	6,967	3,626	526	2,815	-
Administrative and General Costs					
Administration	1,833				
Employee benefits	932				
Transfers to capital	(517)				
Subtotal	2,249	1,170	170	909	-
Special Services	340	237	36	67	-
Insurance	1,530	1,068	163	299	-
General Expense	537	376	57	105	-
Total Administrative and General	4,656	2,851	426	1,380	-
Depreciation					
Transmission	4,710	4,710	-	-	-
Distribution					
Structures	12	-	9	3	-
Services	737	-	-	737	-
House installations	99	-	-	99	-
Mains	635	-	466	169	-
Regulating equipment	10	-	7	3	-
Meters	107	-	47	60	-
Other capacity related	54	-	54	-	-
Subtotal Depreciation Expense	6,354	4,710	584	1,070	-
General	677	501	62	114	-
Amortization of Contributions In Aid of Cons	(245)	(177)	(27)	(41)	-
Depreciation Capitalized	(127)	(94)	(12)	(21)	-
Total Depreciation Expense	6,659	4,940	607	1,122	-
Amortization					
Line break costs	50	50	-	-	-
Stress Corrosion Cracking	83	83	-	-	-
Conversion Costs	6	-	-	6	-
Systems development costs - FIS	59	-	-	59	-
Extraordinary Plant Loss	3	3	-	-	-
Systems development costs - CIS	36	-	-	36	-
Hearing Costs	127	92	14	21	-
Rate design	6	4	1	1	-
Property taxes	(66)	(48)	(7)	(11)	-
Industrial Customers 02 Deliveries	151	151	-	-	-
Interest Bearing Deferral	87	61	9	17	-
Total Amortization Expense	542	396	17	129	-

Pacific Northern Gas Ltd.

APPENDIX 4

Derivation of Allocators

2003 Forecast

	(1)	(2)	(3)	(4)	(5) = (1) x (4)	(6)	(7)	
		Customer Count (July 1, 2003)		Peak day	Volume Distance Factors			
Customer	km-Post	Raw	Deemed	(GJ/D)	GJ/D - km	%	Annual	
Residential Sales (RS 1) (less Granisle)	398.29	19,901	19,901	18,793	7,455,310	14.00%	1,836,834	
Granisle (RS 1)	158.49	160	160	84	0	0.00%	18,797	
Commercial Classes (RS 2, 3, 4)								
Small & Large Commercial Firm (RS 2)	407.09	2,828	2,828	13,072	5,321,665	9.95%	1,238,410	
Commercial Transport (RS 3)	294.38	8	8	657	193,319	0.36%	64,081	
Commercial Interruptible (RS 4)	663.03	4	4		0	0.00%	43,996	
Small Industrial Classes (RS 5)								
Sales	263.88	19	19	2,556	674,508	1.26%	554,908	
Transport	247.09	6	60	3,598	859,039	1.66%	966,306	
Interruptible Transport	247.09							
Seasonal Off-Peak Sales (RS 6)	455.22	4	4	170	77,162	0.14%	30,935	
NGV (RS 7)	439.86	4	4	92	40,651	0.08%	33,651	
Large Industrial								
Methanex - Firm	499.70	1	220	62,001	30,981,903	57.96%	21,355,335	
- Interruptible	499.70				0	0.00%	3,289,366	
Skeena - Firm	586.70	1	220	6,002	3,521,373	6.59%	2,190,730	Note 1
- Interruptible	586.70				0	0.00%	189,705	Note 1
Eurocan - Firm	497.89	1	220	7,388	3,678,411	6.88%	2,887,326	
- Interruptible	497.89				0	0.00%	0	
Alcan - Firm	502.17	1	220	1,183	594,067	1.11%	431,799	
- Interruptible	502.17				0	0.00%	558,201	
B.C. Hydro	591.84	1	10		0	0.00%	10,000	
Total		22,940	23,878	115,597	53,457,306	100.00%	35,510,330	

Note 1: The volumes projected to be delivered to Skeena have been annualized in order to provide a more representative set of revenue to cost ratios

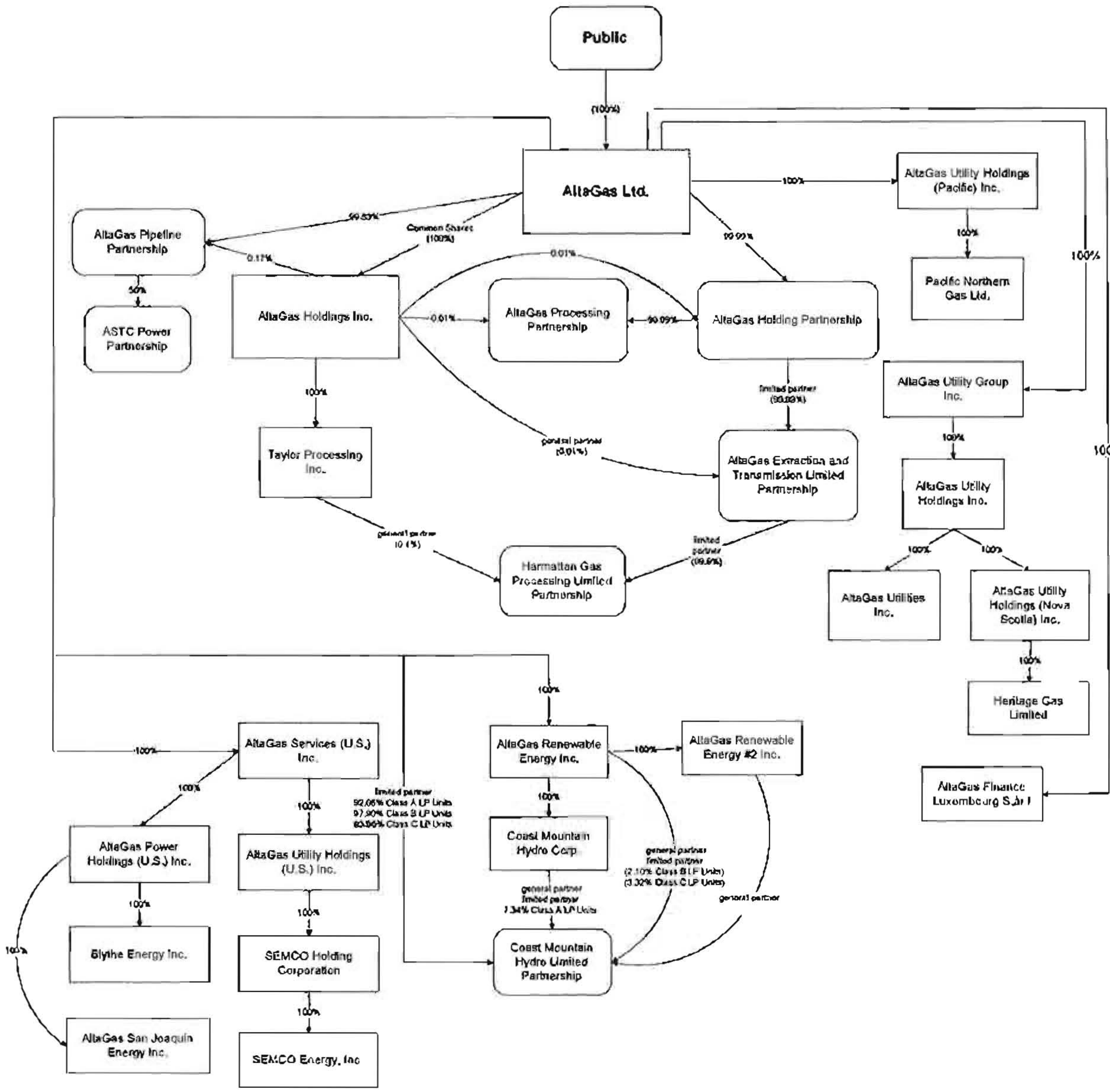
Pacific Northern Gas Ltd.

APPENDIX 4

Allocation of Cost of Service to Customer Classes

2003 Forecast

Customer Class	Transmission Capacity GJ/D-km	Transmission Capacity %	Transmission Capacity ($000)	Distribution Capacity GJ/D	Distribution Capacity %	Distribution Capacity ($000)	Customer Service Deemed	Customer Service %	Customer Service ($000)	Commodity GJ	Commodity %	Commodity ($000)	Total %	Total ($000)
Residential Sales ex Granisle (RS 1)	7,485,310	14.00%	$ 3,638	0	0.00%	$ -	19,801	83.39%	$ 7,653	1,836,834	19.00%	$ 434	28.54%	$ 11,925
Granisle (RS 1)	0	0.00%	$ -	0	0.00%	$ -	160	0.67%	$ 63	0	0.00%	$ -	0.15%	$ 63
Commercial Classes (RS 2, 3, 4)														
Small & Large Commercial Firm (RS 2)	5,321,665	9.95%	$ 2,566	13,072	65.44%	$ 2,688	2,828	11.65%	$ 1,116	1,238,410	12.81%	$ 292	15.99%	$ 6,683
Commercial Transport (RS 3)	183,319	0.36%	$ 94	657	3.29%	$ 135	8	0.03%	$ 3	64,091	0.66%	$ 15	0.59%	$ 247
Commercial Interruptible (RS 4)	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	43,996	0.46%	$ 10	0.02%	$ 10
Small Industrial Classes (RS 5)														
Sales	674,509	1.26%	$ 328	2,556	12.80%	$ 526	19	0.08%	$ 7	564,908	5.84%	$ 133	2.38%	$ 994
Transport	889,039	1.66%	$ 432	3,598	18.01%	$ 740	60	0.25%	$ 24	966,306	10.00%	$ 228	3.41%	$ 1,424
Interruptible Transport	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	0.00%	$ -
Seasonal Off-Peak Sales (RS 6)	77,162	0.14%	$ 38	0	0.00%	$ -	4	0.02%	$ 2	30,835	0.32%	$ 7	0.11%	$ 46
NGV (RS 7)	40,551	0.08%	$ 20	92	0.46%	$ 19	4	0.02%	$ 2	33,651	0.35%	$ 8	0.12%	$ 48
Large Industrial														
Methanex - Firm	30,99[illegible]	57.96%	$ 15,057	0	0.00%	$ -	220	0.92%	$ 87	0	0.00%	$ -	36.24%	$ 15,144
- Interruptible	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	0.00%	$ -
Skeena - Firm	3,521,373	6.59%	$ 1,711	0	0.00%	$ -	220	0.92%	$ 87	1,104,368	11.42%	$ 261	4.93%	$ 2,059
- Interruptible	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	95,632	0.99%	$ 23	0.05%	$ 23
Eurocan - Firm	3,678,411	6.88%	$ 1,788	0	0.00%	$ -	220	0.92%	$ 87	2,687,326	27.80%	$ 635	6.00%	$ 2,509
- Interruptible	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	0.00%	$ -
Alcan - Firm	594,057	1.11%	$ 289	0	0.00%	$ -	220	0.92%	$ 87	431,799	4.47%	$ 102	1.14%	$ 477
- Interruptible	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	558,201	5.77%	$ 132	0.32%	$ 132
B.C. Hydro	0	0.00%	$ -	0	0.00%	$ -	0	0.00%	$ -	10,000	0.10%	$ 2	0.01%	$ 2
Total	53,457,306	100.0%	$ 25,980	19,975	100.0%	$ 4,107	23,886	100.0%	$ 9,417	9,665,447	100.0%	$ 2,283	100.0%	$ 41,787



Note:

(1) Each corporation listed above (other than Taylor Processing Inc., AltaGas Renewable Energy Inc., AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., AltaGas Power Holdings (U.S.) Inc., Blythe Energy Inc., Coast Mountain Hydro Corp, AltaGas Utility Holdings (Nova Scotia) Inc., Pacific Northern Gas Ltd., SEMCO Holding Corporation, SEMCO Energy, Inc., AltaGas San Joaquin Energy Inc., AltaGas Renewable Energy #2 Inc., and AltaGas Finance Luxembourg S.àr.l) is a corporation incorporated or formed by amalgamation or continuance under the CBCA. Each of Taylor Processing Inc. and AltaGas Utility Holdings (Nova Scotia) Inc. is a corporation incorporated under the *Business Corporations Act* (Alberta), each of AltaGas Renewable Energy Inc., AltaGas Renewable Energy #2 Inc., Coast Mountain Hydro Corp., and Pacific Northern Gas Ltd. is a corporation incorporated under the *Business Corporations Act* (British Columbia), each of AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., AltaGas Power Holdings (U.S.) Inc., Blythe Energy Inc., SEMCO Holding Corporation and AltaGas San Joaquin Energy Inc. is a corporation formed under the laws of Delaware and SEMCO Energy, Inc. is a corporation formed under the laws of Michigan. AltaGas Finance Luxembourg S.àr.l is a private limited liability company formed under the laws of Grand Duchy of Luxembourg. Each partnership listed above (other than AltaGas Holding Partnership and Coast Mountain Hydro Limited Partnership) was established under the laws of Alberta. AltaGas Holding Partnership was established under the laws of Ontario and Coast Mountain Hydro Limited Partnership was established under the laws of British Columbia.