Liquefied & Compressed Natural Gas (LCNG) as a Bridge to Reducing Energy Costs in Rural Alaska

Phase 1 Application for Emerging Energy Technology Grant to Alaska Energy Authority

AEA-12-047

Submitted by: City of Bethel

2 March 2012

El Paso's Sun Metro LCNG fueling station, completed 2002 (compliments of North Star).

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Title Page

PROJECT TITLE:

Liquefied & Compressed Natural Gas (LCNG) as a Bridge Solution to Reducing Energy Costs in Rural Alaska

FUND GRANTEE:

City of Bethel, Alaska

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PDC Harris Group LLC

TRL ANALYST

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PROJECT COST INFORMATION:

Requested Amount: $ 718,120

Matched Amount: $204,977

PREVIOUS APPLICATION TO AEA OR DENALI COMMISSION

An earlier version of this project application was submitted in 2008 under AEA-09-004, for the Renewable Energy Grant Program. At that time, PDC Harris Group and Orutsararmuit Native Council were the applicants. As that application involved natural gas in Bethel, it was eliminated due to the presence of renewable resources in Bethel (wind). Additionally, an earlier version of this abstract was submitted under the first round solicitation of the Emerging Energy Technology Grant Fund, RFA AEA-11-027.

1.0 PROJECT SUMMARY

1.1 Introduction & Project Description

❖ *"Provide a summary description of the project"*

Our proposed project addresses the largest contributor to sky-rocketing fuel costs in remote Alaskan communities – petroleum derived diesel fuel and fuel oil – by substituting lower priced and more environmentally acceptable natural gas. As stated in the project title, we envision this fuel substitution concept as a bridge to longer-term renewable solutions for remote Alaska communities. Renewable energy projects in Alaska's villages have the potential for reducing a crucial reliance on petroleum distillates, but not eliminating it. Our team proposes to conduct concept design and feasibility level analysis in Bethel to demonstrate the economic feasibility of transporting Liquefied Natural Gas (LNG) to a remote community, dispensing the fuel as either Compressed Natural Gas (CNG) in commercially available pressure vessels on-site, or distributing the gas for use in nearby furnaces, boilers and diesel engine-electric generators via low pressure piping, much like that used within in lower 48 communities and Anchorage. Since LCNG2 storage, delivery and dispensing technology is commercially available, Phase 1 of the project involves developing a firm understanding of the supply chain economics for this initiative, confirming the cost savings to fuel users and developing Commercialization/Financial Plans and a Permitting Strategy.

1.2 Project Eligibility

The City of Bethel qualifies as a local government entity. PDC Harris Group has a current Alaska business license.

1.3 Innovation & Technical Concept

❖ *"Describe how the project will increase performance, reliability, decrease capital or operating cost, increase lifespan etc., in Alaska…"*

1.3.1 Benefit to Project Community

The primary benefit of substituting LNG/CNG (i.e. natural gas) for space heating and power generation fuel is substantial operating cost savings. The potential of the fuel cost savings in Bethel was estimated by PDC Harris Group in 2011 to be in the range of 25% to 65%, relative to that for diesel/fuel oil. Over a project lifespan of 30 years, the range of Net Present Value cost savings for this conversion ranges between $102 million to $397 million, when 100% of the space heating and power generation fuel is assumed to be displaced in Bethel, and surrounding villages. Refer to Appendix A for more detail regarding the development of these cost estimates.

The LCNG technology described here is commercially-proven, robust and expanding at a rapid pace outside of Alaska. It requires low developmental risk to bring it to Alaska's remote communities for use in space heating and power generation. Likewise, CNG technology is commercially viable and used extensively in many parts of the world for taxi cabs, short-haul trucks, buses and even locomotives. CNG is dispensed in over 30 states in the US[3]. While not proposed as part of this project, CNG as a motor fuel for rural Alaska may be significant game-change, in terms of cost savings, and emissions reductions.

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[2] Defined as the integrated use of liquefied natural gas (LNG) & compressed natural gas (CNG).

[3] Current CNG pricing in gasoline gallon equivalents is available here: http://www.cngprices.com/index.php Refer specifically to CA, & UT.

1.3.2 Benefit to Alaska

Displacement of fuel/diesel oil with LCNG on a larger regional basis or state-wide is scale-able. If the economics are favorable for one, or a combination of remote villages, economies of scale will benefit more users, with enhanced savings. It is also safe to assume that wider use of LCNG will result in the conversion of tug or barge drive systems from diesel to LNG/natural gas, yielding additional public health and climate change benefits. Elimination of diesel/fuel oil spills are also a benefit to local residents, as the quality of ground water and surface water are protected.

The potential for rapid implementation relative to renewable alternatives makes the LCNG concept attractive. Enhanced reliability of burner and engine components, following conversion to natural gas is also an economic benefit. Public health will benefit from the applications of LCNG technology, based on a reduction in primary air pollutants SO_2, hydrocarbons, metals (e.g. mercury, lead), and particulates. Reductions in CO_2 emissions will assist in meeting future climate change goals, and may also result in valuable emissions credits as future revenues.

LNG is a commodity traded world-wide, in a vibrant high-growth market. There is currently a surplus of natural gas in the U.S., and it is likely that future export of LNG to the world market may become a reality, both for the lower 48 and Alaska. Taking advantage of a commodity with significantly lower pricing pressure than petroleum-based fuels represents the primary innovation of this initiative. Hardware components that are commercially available for this 'Pilot Scale' Bethel system, are applicable for a 'Semi-Commercial' scale for the surrounding regional communities, and then to 'Full-Scale' service to remote villages throughout Alaska.

1.4 Prioritization of Project

❖ *Describe how the proposed project addresses the priority considerations established by AS 42.45.375(d) and this RFA (sec 4.3)*

1.4.1 Residency of Applicant

The grantee (City of Bethel) and consultant (PDC Harris Group) are based in Alaska.

1.4.2 Partnership with Alaskan Post-Secondary Institution

Our team includes faculty from the University of Alaska for the first phase and ACEP for the second.

1.4.3 Matching Funding

This project provides 22.2% of the total proposed budget as matching funds in the form of an in-kind donation of labor costs.

1.4.4 Wide-Spread State Deployment

The economic and technical findings from this project are scale-able, as is the technology proposed. LCNG systems are directly applicable to larger or smaller rural applications where there is a dependency on petroleum-based fuels, i.e. the communities primarily addressed by the EETGF's enabling legislation. Bringing this technology to Alaska is a logical extension of the present system of barging liquid fuels to dozens of remote villages. Additionally, LCNG displacement of diesel/fuel oil within the developed Railbelt is likely to be economically feasible, albeit at reduced savings relative to rural communities.

2.0 TECHNOLOGY VALIDATION & RESEARCH METHODOLOGY

2.1 Objectives

❖ *Explain the project information objectives and how they will be achieved.*

The project will be developed in three (3) phases, as described in the following paragraphs. Funding for the first phase is the subject of this application. The first phase involves preliminary

engineering, assessing the technical readiness level (TRL) of diesel engine dual fuel conversion[4], and economic feasibility assessment of integrated LNG/CNG/ natural gas technology.

2.1.1 Phase 1 – Concept Design & Supply Chain Economic Model

This phase entails developing concept level design components for the demonstration scale system described in Phase 2. The design will be developed to the extent necessary to solicit vendor quotations for major equipment services, and develop a parametric (factored) capital cost estimate. This estimate, along with estimated operating costs will be used as the basis for developing a pro forma economic model. A Commercialization Plan will be developed to encompass the findings from the Phase 1 activities, and address the path forward for Phase 2.

Additional activities for this phase will include the assessment of available systems for conversion of existing diesel engines to operate on blend of natural gas and diesel oil, developing a TRL Test Plan (these two tasks are the responsibility of UAF sub-consultant Rorik Peterson) , preliminary negotiation of an LNG purchase agreement, site assessment for LNG depot facilities and storage facilities in Bethel, initiating long lead permit applications, and developing a Financing Plan for Phase 2.

2.1.2 Phase 2 – Proof of Concept Demonstration & Confirmation of Economics

LCNG hardware components (to be installed in Bethel) will include a) LNG storage depot , b) CNG storage vessels, c) LNG regasification, pressure letdown and low/medium pressure distribution piping, and d) space heating furnaces or boilers converted to gas-firing. A suitably-sized LNG supply barge, capable of serving communities that receive diesel/fuel oil by barge, will also be designed and procured. Appropriate metering in Bethel will also be installed for the purposes of commercial sale of these commodities. ACEP will test a diesel engine-generator converted to handle a gas/diesel blend, and report technical readiness, in addition to confirming diesel fuel savings.

The Phase 1 cost estimates and economic model will be revised with actual costs as LNG is purchased and shipped, larger volume agreements are negotiated, and commercial-scale equipment is installed and operated in Bethel. Based on revised economic modeling for larger scale development, the Commercialization and Financing Plans will be updated as they apply to Phase 3, for enhanced scale development. A report will be generated following a suitable operational monitoring period (approx. 40 weeks), providing validation detail.

2.1.3 Phase 3 – Large Scale Development

As with the prior phase, if the economics for further development prove feasible, and sufficient funding is acquired, the next phase will be undertaken. Phase 3 will involve further build-out in Bethel both to additional gas users, and to advance CNG distribution to surrounding villages, to demonstrate a hub-to-satellite distribution model.

2.2 Project Methodology

- *Explain how these project performances will be monitored, reported, documented, and analyzed. Include both technical and economic aspects and a discussion of project location and testing environment.*

2.2.1 Monitoring & Reporting

[4] Based on our assessment, the technology intended for all aspects of this project is commercially proven. The technology to convert an existing diesel engine to operate on blends of natural gas and diesel may not have been demonstrated in a Cold Regions setting, and may not be aligned to the operating philosophies of small rural utilities.

Prior to undertaking any formal project tasks, the team Project Manager will compile a Project Procedures Manual (PPM) based on coordination with our AEA counterpart, and routine project execution by the various stakeholders. The manual will summarize scope of work, deliverables, communication protocol, status/progress reporting, project controls (including change trending) and other project specifics. The PPM will be issued to all project participants, and will remain a living document during the project's duration. A sub-section of the PPM, entitled Progress and Cost Reporting System is included in Appendix C.

Phase 1 of the project involves the Work Breakdown Structure (WBS) listed in the Preliminary Schedule in Appendix B[5]. Each of the entries under 'Phase 1 – Pre-Deployment' which is preceded by an asterisk (*****) is considered a project deliverable, and subject to AEA review and comment. Project progress will be monitored against this WBS, using the stated deliverables as metrics for Earned Value Progress Reporting[6].

Additionally, biweekly meetings will be held in Anchorage (and conferenced telephonically) between the project participants to discuss progress, status, data needs and a sequential period look-ahead. AEA is invited to participate in these status reviews. Meeting minutes from each session will be published to all project stakeholders, including the AEA Project Manager. A secure project website will also be established for the purpose of collaboration and communication of remotely located stakeholders. Finally, the project will submit status/progress reports directly to AEA, at a minimum of monthly, summarizing milestone progress, data needs, expenditures and scope/schedule trends.

2.2.2 Location

Bethel will be the basis for the three (3) phases of the project, although the last phase may entail wider expansion to other communities. Phase 1 will consist primarily of engineering, permit applications and economic modeling and will be executed in Anchorage. Phase 2 piloting will occur in Bethel, with the exception of TRL validation on ACEP's diesel test platform. Phase 3 will involve expansion from Bethel as a hub to surrounding village users, as well as possible other communities, depending on the success of deploying the technology. Bethel is an ideal location for demonstrating the LCNG concepts described, since a) it is remote and barge accessible, b) is dependent on petroleum-based fuels for which pricing history is well known, c) the city council has indicated their commitment to participation, and willingness to donate land for storage, and d) satellite villages in the surrounding area can serve as a platform for demonstrating hub-satellite economics for LCNG deployment.

3.0 SCHEDULE & BUDGET

❖ *Provide a summary project schedule and a summary project budget of the estimated project costs. Be sure to include all funding sources and match components of the project as outlined in sec. 4.5 of this RFA.*

3.1 Preliminary Project Schedule

The preliminary project schedule[7] is provided in Appendix B. Kickoff for Phase 1 concept design and modeling is assumed to be September 2012, and Phase 1 is completed, including reporting

[5] Only those activities shown under Phase 1 – Pre-Deployment apply to this application.
[6] ANSI/EIA-748-A-1998 (reaffirmed 2002): "The value of completed work expressed in terms of the budget assigned to that work". PDC Harris prescribes to the following definition: "The earned value concept represents actual accomplishments (earned man-hours) measured against a predetermined standard (budget man-hours), and it is independent of actual man-hours expended."
[7] As noted, the Phase 1 Work Breakdown Structure is delineated under Phase 1 – Pre-Deployment activities.

by August 2013, i.e. approximately 11 months. Phase 2, which encompasses detailed design, procurement, and construction of the demonstration system, will be completed by approximately February 2015. Assuming a 40 week monitoring period for the demo system, commercial deployment may be considered complete by approximately 4Q 2015/1Q 2016.

3.2 Project Budget

The Budget Form is provided in Appendix F. As stated earlier, this grant application applies only to Phase 1 of the LCNG project. The project team will provide matching funds of $204,977 during Phase 1 of the project. Additionally, the project participants will seek federal or other 3rd party financing upon award of an AEA grant to offset these in-kind donations.

Assuming Phase 1 economic modeling indicates economic feasibility for various negotiated ranges of LNG cost, and also gives a clear indication of reduced consumer energy costs, Phase 2 of the project will be financed with a combination of state grants, federal grants, and private debt and equity markets. Depending on the condition of the municipal bond market at the time, the feasibility of issuing bonds for the demonstration project, or the formation of a city-owned utility may be investigated at that time. Additionally state and federal incentives in the form of tax credits or reduced rates will be sought. It is hypothesized that funding for Phase 3, assuming it is also shown to be feasible, will be financed from a combination of bond, private equity or debt markets.

3.3 Project Match

Matching funds commitments are presented in Appendix F and Appendix G.

4.0 TEAM QUALIFICATIONS

❖ *Briefly outline the project team and their respective responsibilities, and relate the qualifications of the project team.*

4.1 Organization

The project team for Phase 1 is comprised of project managers, engineers, designers, cost estimators, permitting specialists, and a UAF technical readiness specialist. Refer to Appendix E for the preliminary project organizational structure. The City of Bethel will provide one part-time project manager to support the project, and represent city interests. PDC Harris Group (www.pdcharrisgroup.com) will provide the engineering project management, design expertise, cost estimating, and the economic model developer. Steigers Corporation (www.steigers.com) will be responsible for project permit strategy and acquisition. Rorik Petersen, UAF Mechanical Engineering professor will assess available technologies, and design the test plan for validating the dual-fuel retrofit technology for diesel engine-generators. We will also contract with Messrs. Jeff Lowenfels and Wayne Lewis as special consultants for permit acquisition and LNG purchase negotiations. Both Wayne and Jeff were instrumental in developing and permitting Yukon Pacific's planned LNG liquefaction and export terminal in Valdez. Appendix E also provides key staff resumes.

4.2 Qualifications

Refer to Appendix E for summary-level resumes for the team identified in the organizational chart. Additional information regarding experience is available at www.pdcharrisgroup.com and www.steigers.com.

5.0 COMMERCIALIZING THE CONCEPT

❖ *Provide a description of how the proposed project will advance the commercialization of the energy technology within the next five years, and the market for purchasing energy generated by the proposed project.*

5.1 Commercialization Strategy & Market

The study undertaken for Alaska Gasline Port Authority in 2011 (refer to Appendix A) provided a preliminary indication that the economics for substituting LCNG in Bethel are favorable. The study allowed the project developers to bring the initiative through the 1st decision gate, representing pre-concept design feasibility. Further work is required to confirm the viability of the concept. These elements comprise Phase 1 of the project described herein, representing the level of investigation required to bring the project to the 2nd decision gate; wherein capital appropriation for hardware can be approved, and commercialization will begin.

The pricing advantage of LNG versus diesel fuel can be very significant (refer to comparative pricing in Appendix A), but such comparisons are based on data specific to bulk volumes of LNG delivered to locations that do not adequately represent the supply chain for rural Alaska. The initial phase of project development therefore focuses on identifying the capital and operating costs of this chain, and translating these estimates to a realistic business perspective – return on investment (ROI). An appropriate ROI is the key to attracting investment capital and creating a sustainable business. Phase 1 of the project is aimed at characterizing ROI for demonstration-scale development in Bethel, as well as the magnitude of fuel cost savings. The overall sequence for demonstrating a commercially viable initiative is described in Sections 2.1.1 and 2.1.2, above.

The Alaska market for LCNG exists: displacement of higher cost diesel/fuel oil currently used in rural Alaskan communities for space heating and electrical generation.

5.2 Commercialization Schedule

We intend to follow the WBS put forth in the Preliminary Project Schedule (Appendix B) to bring LCNG technology to commercial readiness in the first two (2) project phases. As noted earlier this equates to 4Q 2015 or 1Q 2016, including a 40 week monitoring period for the storage, distribution and space heating systems in Bethel, as well as a test bed program using ACEP facilities to validate the dual-fuel diesel engine technology. Assuming project kickoff in September 2012, this will result in demonstrating commercial viability in approximately 40 months, at which point additional systems may be deployed through-out rural Alaska. This commercialization schedule will likely coincide favorably with the development of a world-scale LNG export facility in Alaska, guaranteeing a long term supply of competitively priced LNG.

6.0 APPENDICES

Appendix A – PDC Harris Group Study, 'Potential Benefits to Alaskans from a State-Owned Gasline/LNG Project'

Appendix B - Preliminary Project Schedule

Appendix C –Project Progress & Cost Reporting System

Appendix D - City of Bethel Resolution & Action Memorandum

Appendix E – Organization Chart & Key Resumes

Appendix F – Budget Form

Appendix G – Certification of Matching Funds

Appendix H – University of Alaska Budget Form

Appendix A

'Potential Benefits to Alaskans from a State-Owned Gasline/LNG Project'

Snovit LNG plant, Norway – Compliments of Statoil

Potential Benefits to Alaskans from a State-Owned Gasline/LNG Project

30 November 2011

Prepared by:

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William M. Walker
Alaska Gasline Port Authority
731 N Street
Anchorage, AK 99501

30 November 2011

Subject: Transmittal of LCNG Economic Benefits Study
Transmitted via Email

Dear Mr. Walker:

Attached is Revision 4 of the subject study. If you have any questions or comments, please contact me at (907) 743-3263 or email mikemoora@pdceng.com .

Best Regards,

Michael W. Moora
General Manager
PDC Harris Group LLC

Attachments: 1. "Potential Benefits to Rural Alaskans From AGPA's Gasline & LNG Project" Rev 4, 30 November 2011.

C: W Ward
S Theno
AGPA-11.01.01

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1. EXECUTIVE SUMMARY

This preliminary study was conducted to provide an order-of-magnitude assessment of the benefits to Alaska communities of switching their primary fuel for space heating and electric generation from petroleum-derived diesel fuel to natural gas. For the study, natural gas was assumed to be delivered from a future liquefaction plant in Valdez aboard barges as LNG[1].

Bethel was selected as a representative community for developing cost models predicting the future retail cost of LNG-derived gas. This community is currently dependent on barge deliveries of diesel fuel. Bethel has historically experienced relatively high-cost retail fuels, based upon its remote location, and seasonal accessibility.

In addition to the work conducted on Bethel, the city gate wholesale cost of natural gas was estimated for Fairbanks, as an indicator of the approximate savings available when compared with wholesale diesel/fuel FOB[2] refinery loading rack.

Five case studies were conducted for Bethel to test the sensitivity of forecasted LNG and diesel pricing to the following parameters:

- ✓ Wholesale LNG cost, FOB Valdez
- ✓ Method of estimating LNG transport cost & retail markup
- ✓ Future wholesale diesel pricing, moderate vs. high perspective vs. worst case[3] future crude oil price @ $75/barrel

The Bethel costing model forecasts that conversion to an integrated LNG-CNG fuel, hereafter designated LCNG, will save approximately 25% to 65% over diesel for cases where a) LNG wholesale cost is equal to that defined by a recent Wood Mackenzie study[4] and b) the wholesale cost of diesel fuel remains within the 'medium' to 'high' ranges, as predicted by Alaskan economists[5]. The savings range from $229 million to $886 million over the period 2021 through 2051, when assuming 100% displacement of petroleum distillates used for space heating and power generation. The Net Present Value (NPV) of these cost savings range from $102 million to $397 million accrued over the same period.

One of the Bethel modeling scenarios, aimed at identifying sensitivity to crude oil pricing, examined retail diesel fuel costs equivalent to crude priced at $75 per

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[1] For Fairbanks delivery, natural gas will be supplied by a regional off-take.
[2] Freight On Board, indicating buyer is responsible for transport costs.
[3] A worst case from the perspective of the lowest crude price studied by Wood Mackenzie, and therefore resulting in lower-priced diesel.
[4] Wood Mackenzie, "Alaskan LNG Exports Competitiveness Study" 27 July 2011.
[5] Fay, Saylor & Foster, "Alaska Fuel Price Projections 2011-2030" Institute of Social and Economic Research, Univ. of Alaska, 2010.

barrel (in 2021) resulted in a retail cost advantage for LCNG, between 21% to nearly 42% below predicted retail diesel fuel cost.

Another scenario was modeled where LNG wholesale cost in Valdez is determined in a similar manner to Wood Mackenzie's built-up model, but with an additional well-head gas value of $1.00 per million BTU added to the FOB Valdez cost. In this case, the savings remain significant, with a predicted nominal value of approximately $335 million (NPV = $146 million).

A wholesale natural gas cost at a city gate take-off for Fairbanks was estimated @ $5.29 per million BTU, as compared to a predicted diesel fuel cost of $27.23 per million BTU in 2021, representing a savings of approximately 80%. Based on the number of oil-fired furnaces and boilers identified in the city by a 2010 survey, and the average fuel usage per year noted in the same study, and assuming that 100% of these furnaces/boilers are converted to natural gas, the predicted total value of the fuel savings from 2021 through 2051 is estimated at over $2.4 billion (NPV of $1.1 billion).

In addition to cost savings, significant reductions in air emissions will result from converting from diesel/fuel-oil (or wood fuels in the case of Fairbanks) to LNG-derived natural gas. On a per fired BTU basis, natural gas is estimated to reduce emission rates approximately 99% for SO_2[6], 29% for NO_x, 99% for PM_{10}[7], and 24% for CO_2, when comparing EPA published emission factors for natural gas versus fuel oil.

The modeling assumptions for LNG wholesale costs, which duplicate those of the referenced Wood Mackenzie study for the majority of the case studies, result in widening cost advantages for LNG over diesel/fuel oil in later years. The model assumes that the more significant cost components of the built-up LNG cost do not escalate, resulting in a relatively stable LNG cost over the life of the study duration. The diesel fuel cost forecasts assume escalation. Thus the model predicts the difference between forecasted future retail diesel prices and LNG increase from initiation in 2021 to completion in 2051.

2. INTRODUCTION

2.1 Rural Alaska's Energy Challenge

From the lean days of 2002, when a barrel of oil averaged approximately $22, to the maximum of nearly $145 per barrel observed during the summer of 2008, fuel pricing in remote Alaskan communities increased as dramatically, causing fear, anger and frustration. During 2008, the summer's fuel barge deliveries to interior

[6] Based upon a fuel oil sulfur content of 500 ppm.
[7] Defined as particulate matter with aerodynamic diameter less than 10 microns.

Alaskan villages brought unheard of prices, up $3 to $4 per gallon since the last year's delivery, to $7.50 to $8.00 per gallon[8].

The result - astounding increases in home heating and electrical costs to rural villagers – is tied not only to increased wholesale pricing of petroleum-based distillate, but also the fuel-burning transport ships or air tankers that haul it. Single family fuel costs, for space heating and cooking range from $300 to $900 per month, representing an average of 40% of a typical family's income[5]. Low per capita village income, coupled with increased fuel prices of the last several years have reached the tipping point for some; out-migrating residents from their life-time home to urban settings in Anchorage, Fairbanks and other less rural communities, in a struggle to reach economic balance.

2.2 The State Gas Line & LNG Project

The Alaska Gasline Port Authority (AGPA) has encouraged a state-owned project for transporting and liquefying 2.7 BCFD of North Slope (NS) gas to serve Alaskans and the Asian liquefied natural gas (LNG) markets. The integrated project includes a gas conditioning plant on the North Slope, a large bore gas transmission pipeline system between the North Slope (NS) and Valdez, a liquefaction and export facility in Valdez, upstream gas off-take points to serve multiple Alaska communities, military bases, as well as a lateral pipeline to augment the supply of natural gas to South Central AK.

2.2.1 Wood Mackenzie Competitiveness Study

A recent study conducted by Wood Mackenzie[9] indicates a favorable ANS gas to LNG cost structure relative to competing projects to supply the Asian market, either planned or underway in Australia, western Canada and the Lower 48. The following summarizes findings that signal an attractive pipeline to Valdez for export of LNG.

- ✓ *"Proposed LNG exports have a substantial cost advantage relative to possible competing LNG supply Projects."*
- ✓ *"Alaskan LNG exports have a delivered cost structure below $10/MMBtu….Alaskan LNG could be priced DES between $18.00 - $46.00/MMBtu through 2050."*
- ✓ *"The Pacific Basin market is short of proximate LNG and a number of projects will compete for long term supply requirements (including Alaska LNG)."*

[8] Anchorage Daily News, June 4, 2008.
[9] Wood Mackenzie, "Alaskan LNG Exports Competitiveness Study" 27 July 2011.

- ✓ *"Royalties (12.5%) and state taxes (starting at 25% post royalties) could yield $2.4 to $24 billion per year."*

2.2.2 Project Schedule

The Wood Mackenzie study assumes project startup in 2021, which may provide ample time to align the stakeholders, bring together the myriad of technical and financial components required to reach an investment decision, and then design and build this world-class project.

The challenges for LNG developers include many considerations, and "bringing these elements together to enable the investments and contractual commitments along the chain to be sanctioned simultaneously demands dedicated resources over long periods and unity of purpose by the proponents"[10]. Wood-Mackenzie recognizes these challenges in the statement: "Economics are important, but commercial issues such as the scale of value chain requirements (pipes, storage, etc.), buyer risk tolerance, financing arrangements, etc. are critical".

PDC Harris Group offers no opinion on Wood Mackenzie's ten year window, and whether it is sufficient to bring this large-scale project on-stream. It is nonetheless evident that to do so will take a fully-aligned and focused team of stakeholders; an initiative which requires numerous enabling steps in order to facilitate this complex process. It may be possible to pre-build the gas treatment plant (GTP) and gas pipeline, with the intention of supplying Alaska take-off points with natural gas, prior to startup of the liquefaction plant in Valdez. However this operational scenario will require additional engineering analysis, to determine GTP turndown capacity and alternatively the line pack volume available for Alaska users, prior to ramp-up of LNG exports.

2.3 In-State Benefits of the Alaska LNG Project

Besides the attractive Wood Mackenzie forecasts for Alaska, including substantial netbacks to NS producers, the development of a large-scale pipeline/LNG project in Alaska offers another benefit:

- ✓ *A cost competitive supply of Alaska liquefied natural gas, produced at tidewater offers fuel cost savings to rural communities accessible by barge, currently contending with high diesel/fuel oil pricing.*

The referenced fuel savings have heretofore been inferred based on significant differences in the wholesale price of a BTU of LNG relative to diesel or fuel oil[11].

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[10] Gas Strategies, "Potential LNG Production From North Slope Gas, May 2008.
[11] Petroleum News, "Could LCNG Cut Cost of Rural Energy?" 28 February 2010.

Subsequent sections of this report quantify expected savings. Other benefits to Alaska communities include:

- ✓ *Reduction of diesel/fuel oil tank farm inventories, and therefore a corresponding reduction in spill and contamination risks*
- ✓ *For each displaced volume of diesel/fuel oil, significant reductions in combustion emissions result (SO_2, NOx, unburned hydrocarbons, fine particulate matter, and CO_2)*
- ✓ *For hybrid (integrated) wind-diesel electric generation projects, switching the backup generation fuel from diesel to LNG-derived gas yields additional savings relative to diesel fuel firing[12],[13].*
- ✓ *Conversion of users from fuel oil to gas requires minor capital expense; replacement of boilers and generator drives is generally not required[14].*

The wholesale price difference between diesel/fuel oil lifted from Alaska refineries, and Cook Inlet LNG are attractive[15], but without an LNG supply infrastructure specific to small-volume, remote Alaskan users, the real cost structure remains unknown, and hence these savings have been characterized as potential. This study represents a preliminary step in defining an LNG supply chain to an Alaska community, examining wholesale gas costs for Fairbanks, and quantifying the relative incremental costs for supplying these communities with substitute fuel.

3. STUDY DESCRIPTION

3.1 LNG Implementation in Rural Alaska

The concept for supplying remote communities with LNG-derived gas involves the integration of liquefied and compressed natural gas (LCNG). The liquid form (LNG) of natural gas is approximately 600 times more dense than conventional pipeline gas distributed at low pressure to residences, and is the optimal phase for transport in its most energy-dense form over long distances. In this instance, LNG will be transported from the export docks adjoining the Valdez liquefaction plant, to various hub or larger village locations for off-loading and storage. Barges with double-walled and vacuum insulated LNG tanks will be placed in service for this leg

[12] Renewable generation capacity must be accompanied by firm generation capacity from a non-renewable source. To date this backup has generally been diesel generation in rural Alaska.
[13] Existing diesel engines can be converted to operate on a blend of approximately 90 volume % natural gas without the need for a spark ignition system.
[14] Residential forced air furnaces operating on fuel oil may need complete replacement to handle the conversion, which would not be a minor expense from the perspective of a homeowner. Conversion of higher output boilers and furnaces are likely to involve a simpler change in burner components. Refer to Schwörer & Fay, 'Economic Feasibility of North Slope Propane Productions and Distribution to Select Alaska Communities, UAA ISER, June 2010.
[15] Refer to Appendix A for a comparison of market pricing for these commodities.

of the supply chain, and hauled with tugs; which is logistically similar to the existing mid-scale line-haul barge system used for moving petroleum distillates to rural Alaska.

A disadvantage of LNG transport is its energy density relative to conventional petroleum distillates. LNG is only 60% the energy density of typical diesel fuel, thus requiring 1.67 volumes of LNG to supply the energy in 1.00 volume of diesel oil. This disadvantage must be offset by LNG's wholesale pricing advantage in order to be a feasible candidate replacing rural Alaska's primary fuel.

Once an LNG barge reaches a destination port, generally a hub community with line-haul barge accessibility, the liquid will be off-loaded via centrifugal pump to pressurized LNG storage tanks (Refer to Appendix B for a flow sheet depicting the off-load and storage alternatives). Stored LNG, contained at a pressure sufficient for distribution, will be vaporized using staged heat exchangers and gas-fired heaters to deliver low pressure gas to nearby residential, commercial or utility users.

Direct pumping and warming the LNG to the compressed natural gas (CNG) phase may also take place, to charge a shore-based CNG storage facility. Pumping the cryogenic liquid to high pressure, followed by vaporization with multi-stage heat exchangers is an efficient conversion process, and allows the charging of storage cylinders without the need for less efficient gas compressors. The on-shore pressure vessels will receive and store the CNG at pressures up to 3600 PSIG. The stored high pressure natural gas will then be available for:

- ✓ Charging of transportable gas cylinders for use beyond the immediate hub location, including bulk transport to surrounding villages.
- ✓ Refueling of CNG powered vehicles at a metered fueling station.

While the storage volume for CNG is approximately 400% of that required for the same mass of LNG[16], storage in this form requires minimal maintenance or operator attention. Storage as LNG may not be the optimum choice for relatively small volumes of gas in a rural setting. It is relatively expensive, and is more operator intensive, and may require vapor recovery refrigeration or compression to capture normal boil-off. Nonetheless, there are advantages of LNG versus CNG storage, and further study is required to determine specific LNG and CNG storage strategies, when a rural project progresses to the design phase.

For the purposes of this study, it is assumed the LNG is pumped to on-shore LNG storage as part of the off-loading process. Refer to Appendix B which depicts a line-haul barge delivery and storage facility.

[16] The density of CNG at 3600 psig is 12.1 lb/ft^3 compared with LNG at 45 to 46 lb/ft^3

3.2 Objectives

PDC Harris Group has been requested to quantify potential fuel cost savings when substituting LCNG-derived gas (or pipeline gas in the case of Fairbanks) for existing diesel/fuel in representative Alaskan communities. Our experience in this involves developing a pilot program for substituting liquefied and compressed natural gas (LCNG) in the City of Bethel[17].

Specific objectives of this study are as follows,

- ✓ Use Wood Mackenzie cost predictions as the FOB Valdez LNG cost basis.
- ✓ Develop feasibility-level cost models forecasting the retail pricing and cost savings for substitution of LCNG-derived natural gas in Bethel
- ✓ Exercise retail pricing model to assess sensitivity to various input changes such as crude oil price, FOB Valdez LNG cost and other variables.
- ✓ Estimate the wholesale cost of gas provided to Fairbanks for a representative city gate off-take. Compare these costs with those forecasted for wholesale diesel/fuel oil.

3.3 Case Study Communities

Bethel was used to establish the retail LNG pricing forecasts. It is important to note the Bethel case study is developed as a 'shared' capital project, in terms of the LNG loading or transport equipment. Facilities or equipment are assumed to be shared by three (3) additional communities, and therefore the capital and operating costs for same are borne 25% by a single community. This assumption can be considered valid for a pilot or small commercial operation involving a region, but would not adequately represent the real costs of a single community, or a start-up of a pilot facility. Greater supply chain cost benefits would of course accrue to users as an LCNG supply chain expands.

3.3.1 Bethel

Located in Western Alaska, Bethel's lengthy fuel supply chain is a common denominator for scores of other villages throughout the state; distant from supplies produced in Alaskan refineries, and subject to sea ice restrictions for much of the year. The community is a good example of a remote Western Alaska hub city which is handicapped by winter ice, and distance from fuel sources. Diesel/fuel-oil prices in the city are approximately 80% higher than the

[17] City of Bethel and PDC Harris Group LLC, "Liquefied & Compressed Natural Gas as a Bridge to Reducing Energy Prices in Rural Alaska" 17 March 2011, application for grant funding to Alaska Energy Authority RFP AEA-11-027.

wholesale refinery rack rates, attributable to delivery (20% of wholesale), sales tax (flat 6%, or 10% of wholesale), and retail markup (50% of wholesale)[18].

Bethel supports a network of 56 villages in the Yukon-Kuskokwim delta, in terms of the distribution of food, fuel, medical, and other services. Most of the surrounding villages receive barged delivery of liquid fuels at a twice per year frequency using smaller barges that are loaded from larger line-haul barges arriving from Anchorage. Fuel pricing increases with distance for the various Bethel satellite villages, and no simple pricing structure can be used to represent retail pricing in each individual village.

Bethel has approximately 1800 residences, and space heating of residences and community structures is predominately by fuel-oil fired furnaces and boilers. Electricity is provided by a private utility using diesel-fired engine generators. Tank farms for liquid fuels, owned primarily by Yukon Fuel and Crowley Marine, have approximately 15 million gallons of capacity. Significant area exists along Bethel's river wall for additional storage capacity.

3.3.2 Fairbanks

Fairbanks, like rural Alaska communities also suffers from geographic disparities in energy supplies and costs, based upon a dependency on petroleum-derived fuel for space heating and electricity production. "A sustained spike in oil prices this year has aggravated that disparity, increasing the cost of living in Interior and rural Alaska faster than in Southcentral Alaska. Fairbanks mayors have suggested the situation cripples any chance at economic development. Estimates suggest space heating represents two-thirds of the average Fairbanks businesses' or household's total energy costs, and local mayors and assembly members have lobbied for state assistance on a number of fronts"[19].

There are approximately 31,200 people, and 12,000 occupied residences in the city[20]. The Fairbanks Northstar Borough (FNSB) population is approximately 92,600. Owing to the proximity of Fairbanks to the Flint Hills Resources and PetroStar refineries in North Pole Township, fuel oil prices are low by comparison to rural, off-road Alaska communities.

4. LCNG CASE STUDY, BASIS & ASSUMPTIONS

For the Bethel LCNG case study, the following sections detail the development of the retail cost models, summarize assumptions, and describe different study cases.

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[18] Szymoniak et al, "Components of Alaska Fuel Costs: An Analysis of Market Factors and Characteristics that Influence Rural Fuel Prices", Institute of Social and Economic Research (ISER), Univ. of Alaska, February 2010

[19] Fairbanks News-Miner, May 19 2011.

[20] www.factfinder.census.gov, Source: U.S. Census Bureau, 2005-2009 American Community Survey

Refer to Section 5 for a discussion of the basis and assumptions for the case studies developed for natural gas in the Fairbanks market.

4.1 LNG Source

Description of Assumption	Case Study Variation
LNG for Alaska markets is loaded in barges @ the 2.7 BCF/day Valdez LNG export terminal	*Applicable to all cases*

To leverage the cost competitiveness of large-scale NS gas processing, transport and subsequent LNG liquefaction, this study assumes that LNG destined for Alaska users is lifted from a 2.7 BCFD liquefaction plant at the port of Valdez. Small volumes of LNG for Alaskan use will be loaded on barges[21] on an irregular basis, and would have no significant impact on the operations of the continuous multi-train LNG plant; a facility whose revenue will be tied to long term oil-indexed agreements with Asian buyers.

4.2 LNG Cost, FOB Valdez

Description of Assumption	Case Study Variation
Wholesale LNG, FOB Valdez from Wood Mackenzie 'Greenfield Alaska LNG Cost Build Up'	*Base Case*
Wholesale LNG, FOB Valdez Wood Mackenzie 'Greenfield Alaska LNG Cost Build Up' with wellhead cost set @ $1.00/million BTU	*Alternate Case*

The Base Case model was developed on the assumption that LNG loaded at Valdez is valued pursuant to the Wood Mackenzie cost buildup[22]. An alternative case was developed based on a more conservative assumption that value of LNG FOB Valdez is valued using the Wood Mackenzie cost build-up with the addition of a wellhead value of $1.00/million BTU[23].

[21] Low capacity in comparison to marine LNG tankers, carrying approximately 2-3 million gallons (5600 to 8400 metric ton).
[22] Wood Mackenzie, IBID, page 15.
[23] This value was selected based upon current gas sales from Prudhoe Bay gas conditioning facilities to Alyeska' s Pump Station No. 1.

4.3 LNG Transport Costs

Description of Assumption	*Case Study Variation*
Cost to transport and unload LNG is factored based on published data of $/gal of diesel fuel, w/ adjustment for lower LNG energy content/volume.	*Base Case*
Cost to transport and unload LNG is developed from order of magnitude capital and operating cost for new barges and Valdez loading facilities.	*Alternate Case*

Transportation costs include marine line-haul transport from the Valdez export terminal, as well as loading, unloading, working capital, administration and insurance costs. The sum of these components equals the landed wholesale price at the destination terminal, which for Bethel's current diesel/fuel oil represents approximately 70% to 75% of the total retail price.

Published data[24] specifically addressing the cost of shipping diesel/fuel oil from refinery loading terminal to the destinations' tank farm were used as the basis for estimating shipping of LNG by barge for the Base Case. In this simplified approach, the published diesel shipping costs are corrected to account for LNG energy density, i.e. the need to transport the same energy content in more gallons of LNG.

As an alternative case study, more rigorous capital and operating costs were developed for a) LNG transfer and loading equipment at Valdez, and b) two(2) line-haul barges. The capital costs were further assumed to apply 25% to the destination, i.e. the assets are shared with three other potential communities as part of a larger line-hauling route. Likewise, the operating costs for the LNG barge berth, pumps and loading arms are 25% allocated to the individual case study community. The following assumptions apply to the Bethel LNG case study:

- ✓ Capital cost two (2) LNG barges: $40 million x 25% = $10 million (2021 $)
- ✓ Capital cost Valdez loading facility (Alaska barge use only): $30 million x 25% = $7.5 million (2021 $)
- ✓ Capital recovery factor: 10%/year
- ✓ Operating cost, Valdez loading facility: $1.5 million/year x 25% = 0.38 million/year (2021)
- ✓ Operating cost, barge & tug set, $30,000/day[25] (2010)

[24] Szymoniak et al, "Components of Alaska Fuel Costs: An Analysis of Market Factors and Characteristics that Influence Rural Fuel Prices", Institute of Social and Economic Research (ISER), Univ. of Alaska, February 2010.
[25] Szymoniak et al, IBID.

4.4 Retail Markup

Description of Assumption	*Case Study Variation*
Factored from diesel/fuel oil cost data published by ISER	*Base Case*
Calculated from capital and operating cost estimates for new on-shore storage and distribution system, with contributions from overhead, working capital and profit.	*Alternative Cases.*

In Bethel, the retail markup from wholesale delivered liquid fuels currently comprises 25% to 30% of the total retail cost for these fuels. A simplified approach to estimating the retail markup for LCNG is possible by converting the diesel/fuel-oil markup reported by ISER[26] from units of $/gal to $/million BTU, and assuming the same value for LCNG, as was assumed for the base case transport cost.

A more rigorous approach to estimating retail markup involves estimating the capital and operating costs associated with the LCNG storage and distribution systems which will be installed to store sufficient inventory for the community between deliveries. For Bethel, where winter ice limits the periods when tug and barge sets can operate, a nine month inventory is necessary. In ice-free ports, such as Unalaska, only two to three months of inventory is required.

Capital (Capex) and operating costs (Opex) were developed for the following components of retail mark-up in Bethel.

4.4.1 Storage & Distribution System Capital Amortization

A new CNG storage facility is expected to have higher capital amortization charges, relative to existing diesel systems in Bethel, based on the increased volume and pressure rating required to store the equivalent energy as LCNG. This relative increase may be offset by reduced maintenance requirements associated with LCNG.

Factors from the open literature for LNG storage tank costs in $/volume were used as the initial basis of generating order of magnitude capital costs storage capacity in Bethel[27].

Resulting capital cost estimates for on-site storage are as follows. A capital recovery factor of 10%/year was used to estimate debt service.

[26] Szymoniak et al, IBID.

[27] Capital cost factor from J Powell, "LNG - Market Challenges & Opportunities for Innovation" Hydrocarbon World, 2007 states $400 per m^3. This study used 300% of this factor, to account for a small scale remote application.

- ✓ Bethel storage Capex: $26.9 million (2021 $)

Distribution system capital for low pressure piping, metering and residential tie-in were estimated as follows:

- ✓ Bethel distribution Capex: $3.9 million (2021 $)

4.4.2 Storage/Distribution System Operation & Maintenance Costs

Operating costs may be expected to be comparable between compressed natural gas storage and distribution versus the current diesel system. Maintenance costs should be considerably reduced, as less rotating equipment is required to deliver CNG-based fuel, and storage vessel maintenance and routine cleaning will be essentially absent for a gas-based system.

The following was assumed for operating and maintenance budgets for Bethel

- ✓ Operating: $1 million/year (2021)
- ✓ Maintenance: 1.5% of capital/year
- ✓ Working Capital: 50% of storage volume, interest @ 7.5%/year

4.4.3 Profit & Overhead

This category includes many of the elements common to the transport sector of the supply chain; overhead labor, regulatory compliance, insurance, and profit are examples.

- ✓ Profit assumed for both locations: 10% of Capex + Opex

4.5 Future Price of Diesel & Fuel-Oil in Rural Alaska

ISER developed estimated fuel cost rural forecasts for ~170 Alaska rural communities, for the period 2011 through 2030[28] for the Alaska Energy Authority (AEA). These forecasts were developed for three scenarios: low, medium and high ranges. This study employed the 'medium' cost data for all cases except two; one each for the two different locations used the 'high' range data.

4.7 Fuel Displacement in Representative Communities

Data published by AEA[29] and PND[30] were used to establish baseline diesel fuel use in Bethel. These data apply to space heating and electric generation, and do not include significant use for marine vessels. The baseline fuel consumption was escalated by 0.5% per year over the duration of the study period of 2021 to 2051.

[28] Fay, Saylor & Foster, "Alaska Fuel Price Projections 2011-2030" Institute of Social and Economic Research, Univ. of Alaska, 2010. Post 2030 inflation rate of 2.4%/yr. was assumed.
[29] AEA, "Statistical Report of the Power Equalization Program, Fiscal Year 2010", 22nd Edition, March 2011.
[30] PND, "Feasibility Study of Propane Distribution Throughout Coastal Alaska", August 2005.

For this study, it was assumed that 100% of these volumes were replaced by natural gas derived from LCNG. This approach is overly simplistic, since neither 100% of the diesel for heating, nor 100% of the diesel for power generation would realistically be displaced by natural gas during the early years of retrofitting. Therefore the study overstates community-wide fuel cost savings during the initial stages of conversion from diesel to LCNG/natural gas.

Another contribution attributable to displacing existing diesel/fuel oil use with LCNG is worthy of consideration. As conversion to the latter occurs in a community, and the volumes of imported diesel and fuel oil decline, it is likely that their unit costs will be driven disproportionally higher, based on the inefficiencies of transporting and dispensing the reduced volumes. This study does not address this potential cost increase for diesel/fuel-oil users in a community undergoing conversion to LCNG.

5. FAIRBANKS CASE STUDIES, BASIS & ASSUMPTIONS

5.1 Future Cost of Diesel & Fuel-Oil in Fairbanks

Energy Information Administration (EIA) predictions[31] for wholesale distillate fuel oil (diesel) pricing in the lower 48 for the years 2021 -2035 were used as the basis for developing comparable values for Fairbanks. An Alaska market surcharge was added to the forecasted lower 48 costs, based on EIA historical wholesale cost data (approximately $.23/gallon in 2021). Values for future lower 48 diesel costs for the years 2036-2051 were estimated based on an annual inflation rate of 2.4% per year.

5.2 Future Cost of Natural Gas in Fairbanks

Wholesale natural gas pricing at a city gate take-off on the 2.7 BCF/day Alaska Gas Pipeline was estimated using the built-up cost assumptions developed in the Wood Mackenzie study, with the following adjustments:

- ✓ Liquefaction, LNG losses and liquids credit contributions set to zero
- ✓ Pipeline transport cost prorated based on distance to Fairbanks, adjusted tariff ~$1.15/million BTU

[31] http://www.eia.gov/oiaf/aeo/tablebrowser/ . 2021 - 2035 EIA Petroleum Products forecast, "Reference Case" and “High Economic case values used for Transportation Fuel, Distillate Fuel Oil (Diesel Oil).

5.3 Quantity of Fuel Oil Displaced by Natural Gas

A study conducted in 2010 for the Alaska Department of Environmental Protection (ADEC)[32] surveyed residential home owners to compile data on type of heating equipment employed, and the average quantity of fuel used. The purpose of the study, from ADEC's perspective was to trend the level of wood use for residential heating. We used the data gathered on fuel-oil fired furnaces and boilers to estimate the quantity of fuel that potentially could be displaced by natural gas. The following factors were used to estimate future displaced fuel quantities.

- ✓ Residences w/ central oil furnaces or boilers in Fairbanks, total: 21,134
- ✓ Average oil consumption, gallons/year-residence: 938 gal/yr.

6. MODEL RESULTS

6.1 Bethel Case Designations

The results of the LNG pricing and energy cost savings forecasts are summarized in the following sections. Table 1 summarizes these cases in matrix format. Subsequent sub-sections provide a summary of results.

Table 1
Case Study Matrix

Case Name	LNG $ FOB Valdez	LNG Transport $	Retail Markup $	Future Diesel $/gal.
Bethel Cases				
B1 (Base)	Wood Mac build-up	Factored from diesel $/million BTU	Factored from diesel $/million BTU	AEA/ISER medium forecast
B2	Wood Mac build-up	Estimated: capex $ and opex $	Estimated: capex $ and opex $	AEA/ISER medium forecast
B3	Wood Mac build-up	Estimated: capex $ and opex $	Estimated: capex $ and opex $	AEA/ISER high forecast
B4	Wood Mac build-up	Estimated: capex $ and opex $	Estimated: capex $ and opex $	From crude @ $75/bbl and 1.18 crack ratio[33]
B5	Wood Mac build-up w/ $1/million BTU wellhead cost	Estimated: capex $ and opex $	Estimated: capex $ and opex $	AEA medium forecast

[32] Sierra Research Inc,, "Report No. SR2010-06-01, 2010 Fairbanks Home Heating Survey, June 21, 2010

[33] Crack ratio: ($ diesel/gallon) / ($/barrel crude x 42 gallons/barrel crude), here a historical average value of 1.18 was determined from cost databases supplied by EIA.

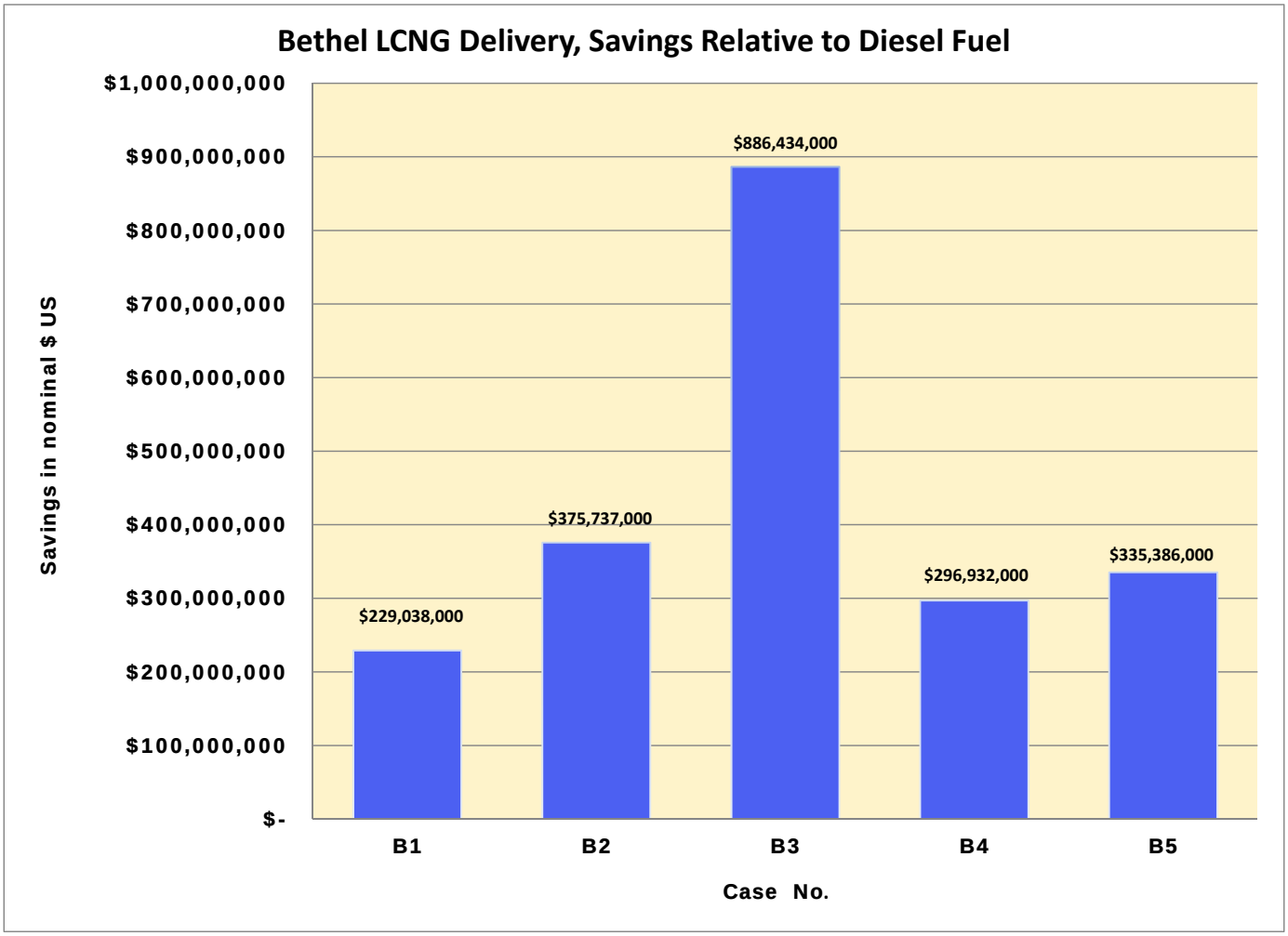
6.2 Bethel Case Studies

As detailed in Table 1, five (5) cases were developed to assess the impacts of the following variables on the predicted retail cost savings of LCNG versus diesel/fuel-oil.

- ✓ LNG Cost, FOB Valdez
- ✓ Basis for estimating LNG transport cost from Valdez to Bethel
- ✓ Basis for estimating retail mark-up
- ✓ Assumed future retail cost of diesel in Bethel

The summary results for all five cases are presented graphically in , as the total of annual fuel savings over the life of the project (years 2021 to 2051)

Figure 1



All five cases modeled predict significant fuel savings when substituting LCNG for diesel and fuel-oil in Bethel. Additional discussion of the case study results are provided in the following sections.

6.2.1 Case B1

This is considered the Base Case for the Bethel analysis. It is based on a) LNG cost FOB Valdez from the Wood Mackenzie built-up value, b) a transport cost factored from 2009-2010 ISER data for diesel/fuel oil, c) a retail markup factored from the same ISER data for diesel/fuel oil, and d) 'medium range' future diesel/fuel oil retail Bethel pricing predictions by ISER. Case B1 representative model output is provided in Figure 2.

The model predicts annual savings from switching to LCNG of 21% to 28% relative to diesel fuel.

Conversion of the predicted future retail pricing of diesel/fuel oil from a $ per gallon basis to $ per million BTU (gal/E6 BTU), using the higher heating value (HHV) of typical diesel fuel, puts the pricing on a comparable basis to that estimated for the retail price LCNG. As reported for the initial year of operation (2021) the predicted retail price for LCNG is $8.88/million BTU lower than the diesel fuel. With Bethel's forecasted consumption of Btu's for space heating and electrical generation (595,215 million BTU/yr. or approximately 4.6 million gallons diesel/yr.) in 2021, this per million BTU savings equates to annual savings of nearly $5.3 million/year. The total estimated savings over a 30 year period beginning in 2021 is approximately $229 million.

6.2.2 Case B2

Case B2 differs from B1 in the approach to estimating the transport cost from Valdez to Bethel, as well as how the retail markup is estimated.

As noted in Section 4.3, the more detailed transport cost estimate entails an estimate of capital costs (primarily transport barges and loading facilities at the liquefaction facility) and operating costs for representative supply chain elements for transporting LNG[34]. Capital recovery charges and operating costs for LNG transport are then divided by the annual BTU requirements estimated for Bethel in each future year, resulting in an estimated $/million BTU charge for transport.

In a similar manner, the retail mark-up estimate includes capital and operating estimates representing the costs accrued by a Bethel storage and distribution operation, as described in Section 4.4.

The result of the more rigorous treatment of both LCNG transport and retail markup is a) the forecasted transport cost in $/million BTU increases slightly (~7%) relative to the Base Case (B1) while b) the retail markup is reduced by about 29% of the base case[35]. The overall result is an increased savings for Case B2 over Case B1.

6.2.3 Case B3

Case B3 replicates Case B2 with one major exception; the predicted future pricing of diesel fuel has been increased to the AEA/ISER study 'high' price range for Bethel. A portion of the model output for this case is provided in Figure 4.

[34] For the purposes of this study, two barges were assumed to be shared with 3 other communities, i.e. the capital requirements are 25% assigned to Bethel's economic model.
[35] Both comparisons are for the initial operating year only.

The dramatic increase in projected retail fuel savings over the prior cases is attributable to not only the significantly higher diesel pricing, which increases annually, but an LNG price which remains relatively low, with a price that is not tied insignificantly to inflation.

6.2.4 Case B4

This case is based on replicating Case B2 with the following exception:

- ✓ Wholesale diesel fuel pricing (FOB refinery) is set based on a West Texas Intermediate (WTI) crude oil price of $75/bbl, corresponding to Wood Mackenzie's 'worst case' scenario. To develop the corresponding wholesale diesel price from the crude price, an annual average crack ratio of 1.18 was assumed.

Refer to Figure 5 for an excerpt from this case model output. According to the model, with the 2021 retail diesel price in Bethel predicted to be approximately $3.93 per gallon, and inflated annually at 2.4% thereafter, sufficient savings are still available to generate savings of approximately $297 million over the life of the project. This can be attributed to the fact that LNG wholesale cost is not affected appreciably by changes in crude oil pricing.

This same model, using the historical crude crack spread to predict retail diesel fuel pricing in Bethel, can be used to determine an approximate WTI crude price which results in retail diesel pricing which is competitive with LCNG, on a $ per million BTU basis. Using a trail and error approach, this value was found be approximately $36/bbl., for 2021 WTI crude.

6.2.5 Case B5

Case B5 examines the impact of incrementing the Valdez wholesale LNG cost by $1/million BTU, to apply a defensible wellhead gas value based on historical sales to Alyeska Pipeline. Other assumptions remain the same as Case B2. Refer to Figure 6 following, for an excerpt of the model output.

As with the other Bethel cases, B5 predicts a significant savings over the life of the project in line with cases B1, B2 and B4.

Figure 2
Excerpt of B1 (Base Case) Model

		Start-up	1	2	3	4	5		28	29	30
DIESEL		2021	2022	2023	2024	2025	2026		2049	2050	2051
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$4.74	$4.79	$4.85	$4.90	$4.96	$5.00		$8.27	$8.47	$8.67
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$34.19	$34.57	$34.99	$35.37	$35.79	$36.10		$59.70	$61.13	$62.60
LNG & CNG	(b)										
WH-Processing (invariant)		0.26	0.26	0.26	0.26	0.26	0.26		0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24		5.60	5.73	5.87
Transport (invariant)		1.70	1.70	1.70	1.70	1.70	1.70		1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57	0.58		1.01	1.03	1.06
Liquefaction (invariant)		4.00	4.00	4.00	4.00	4.00	4.00		4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96	-0.98		-1.69	-1.73	-1.77
LNG FOB Valdez, $/E6 BTU		**8.49**	**8.55**	**8.61**	**8.68**	**8.74**	**8.81**		**10.88**	**11.00**	**11.12**
LNG & CNG Price Stack											
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74	8.81		10.88	11.00	11.12
Delivery & Offload, $/E6 BTU (HHV)	(d)	4.69	4.80	4.91	5.03	5.15	5.28		9.10	9.32	9.55
Sales Tax @ 6% of FOB + Delivery		0.79	0.80	0.81	0.82	0.83	0.85		1.20	1.22	1.24
Retail Markup	(f)	11.34	11.61	11.89	12.18	12.47	12.77		22.03	22.56	23.10
Retail Price LNG/CNG, $/E6 BTU		25.31	25.77	26.23	26.71	27.20	27.70		43.21	44.10	45.01
SAVINGS											
Savings, Diesel - LNG, $/E6 BTU (HHV)		$8.88	$8.80	$8.75	$8.65	$8.59	$8.40		$16.48	$17.03	$17.59
% Savings		25.98%	25.46%	25.02%	24.47%	24.00%	23.27%		27.61%	27.86%	28.10%
Annual Savings, $/yr		$ 5,287,494	$ 5,264,385	$ 5,263,199	$ 5,229,247	$ 5,215,926	$ 5,127,705		$ 11,282,122	$ 11,714,950	$ 12,160,903
Total Savings, Project Life, $		**$ 229,038,410**									
Present Value of Savings (2021)	(g)	**$101,895,709**									
ENERGY DEMAND											
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209	610245		684422	687844	691283

Figure 3
Excerpt of Case B2 Model

		Start-up	1	2	3	4		27	28	29	30
DIESEL		2021	2022	2023	2024	2025		2048	2049	2050	2051
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$4.74	$4.79	$4.85	$4.90	$4.96		$8.07	$8.27	$8.47	$8.67
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$34.19	$34.57	$34.99	$35.37	$35.79		$58.30	$59.70	$61.13	$62.60
LNG & CNG	(b)										
WH-Processing		0.26	0.26	0.26	0.26	0.26		0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17		5.47	5.60	5.73	5.87
Transport		1.70	1.70	1.70	1.70	1.70		1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57		0.99	1.01	1.03	1.06
Liquefaction		4.00	4.00	4.00	4.00	4.00		4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96		-1.65	-1.69	-1.73	-1.77
LNG FOB Valdez, $/E6 BTU		**8.49**	**8.55**	**8.61**	**8.68**	**8.74**		**10.76**	**10.88**	**11.00**	**11.12**
LNG & CNG Price Stack											
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74		10.76	10.88	11.00	11.12
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43		11.33	11.71	12.11	12.53
Sales Tax @ 6% of FOB + Delivery		0.81	0.82	0.83	0.84	0.85		1.33	1.36	1.39	1.42
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11		8.57	8.60	8.64	8.68
Retail Price LNG/CNG, $/E6 BTU		22.41	22.58	22.75	22.94	23.13		31.99	32.55	33.13	33.74
SAVINGS											
Savings, Diesel - LNG, $/E6 BTU (HHV)		$11.78	$11.99	$12.23	$12.43	$12.66		$26.31	$27.15	$28.00	$28.86
% Savings		34.46%	34.68%	34.97%	35.15%	35.38%		45.13%	45.48%	45.80%	46.11%
Annual Savings, $/yr		$ 7,013,712	$ 7,171,338	$ 7,354,842	$ 7,509,585	$ 7,689,008		$ 17,917,587	$ 18,581,464	$ 19,259,281	$ 19,951,152
Total Savings, Project Life, $		**$ 375,737,136**									
Present Value of Savings (2011)	(g)	**$163,926,539**									
ENERGY DEMAND											
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209		681017	684422	687844	691283

Figure 4
Excerpt of Case B3 Model

		Start-up	1	2	3	4		27	28	29	30
DIESEL		2021	2022	2023	2024	2025		2048	2049	2050	2051
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$7.44	$7.53	$7.63	$7.70	$7.79		$12.57	$12.88	$13.19	$13.50
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$53.72	$54.38	$55.07	$55.56	$56.22		$90.80	$92.98	$95.21	$97.49
LNG & CNG	(b)										
WH-Processing		0.26	0.26	0.26	0.26	0.26		0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17		5.47	5.60	5.73	5.87
Transport		1.70	1.70	1.70	1.70	1.70		1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57		0.99	1.01	1.03	1.06
Liquefaction		4.00	4.00	4.00	4.00	4.00		4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96		-1.65	-1.69	-1.73	-1.77
LNG FOB Valdez, $/E6 BTU		**8.49**	**8.55**	**8.61**	**8.68**	**8.74**		**10.76**	**10.88**	**11.00**	**11.12**
LNG & CNG Price Stack											
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74		10.76	10.88	11.00	11.12
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43		11.33	11.71	12.11	12.53
Sales Tax @ 6% of FOB + Delivery		0.81	0.82	0.83	0.84	0.85		1.33	1.36	1.39	1.42
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11		8.57	8.60	8.64	8.68
Retail Price LNG/CNG, $/E6 BTU		$ 22.41	$ 22.58	$ 22.75	$ 22.94	$ 23.13		$ 31.99	$ 32.55	$ 33.13	$ 33.74
SAVINGS											
Savings, Diesel - LNG, $/E6 BTU (HHV)		$31.31	$31.80	$32.32	$32.63	$33.09		$58.81	$60.43	$62.08	$63.76
% Savings		58.28%	58.48%	58.69%	58.72%	58.86%		64.77%	64.99%	65.20%	65.40%
Annual Savings, $/yr		$ 18,633,504	$ 19,021,078	$ 19,430,465	$ 19,713,550	$ 20,093,775		$ 40,050,251	$ 41,358,632	$ 42,699,720	$ 44,074,176
Total Savings, Project Life, $		**$ 886,433,544**									
Present Value of Savings (2011)	(g)	**$397,184,212**									
ENERGY DEMAND											
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209		681017	684422	687844	691283

Figure 5
Excerpt of Case B4 Model

		Start-up	1	2	3	4		27	28	29	30
DIESEL		2021	2022	2023	2024	2025		2048	2049	2050	2051
Calculated Price, Retail Bethel, $/gal	(a)	$3.93	$4.03	$4.12	$4.22	$4.33		$7.46	$7.64	$7.83	$8.01
$/E6 BTU (HHV), Bethel Diesel Retail		$28.40	$29.08	$29.78	$30.50	$31.23		$53.88	$55.18	$56.50	$57.86
$/E6 BTU (LHV), Bethel Diesel Retail		$30.38	$31.11	$31.85	$32.62	$33.40		$57.63	$59.01	$60.43	$61.88
LNG & CNG											
Wood Mackenzie Model Duplication (HHV)											
Nominal WTI Oil Price, $/bbl	(b)	$75.00	$76.80	$78.64	$80.53	$82.46		$142.29	$145.70	$149.20	$152.78
Calculated WTI Oil, $/E6 BTU		12.50	12.80	13.11	13.42	13.74		23.71	24.28	24.87	25.46
Asia LNG $/E6 BTU, DES basis	(c)	11.73	11.82	12.10	12.39	12.69		21.90	22.42	22.96	23.51
Less infl. Shipping, $/E6 BTU		0.59	$0.60	$0.62	$0.63	$0.65		$1.12	$1.15	$1.17	$1.20
Less pipe transportation, $/E6 BTU		4.18	4.18	4.18	4.18	4.18		4.18	4.18	4.18	4.18
Less liquefaction, $/E6 BTU		4.00	4.00	4.00	4.00	4.00		4.00	4.00	4.00	4.00
Wellhead netback, $/E6 BTU		2.96	3.04	3.30	3.58	3.86		12.60	13.10	13.61	14.13
LNG & CNG Price Stack											
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74		10.76	10.88	11.00	11.12
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43		11.33	11.71	12.11	12.53
Sales Tax @ 6% of FOB + Delivery		0.81	0.82	0.83	0.84	0.85		1.33	1.36	1.39	1.42
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11		8.57	8.60	8.64	8.68
Retail Price LNG/CNG, $/E6 BTU		22.41	22.58	22.75	22.94	23.13		31.99	32.55	33.13	33.74
SAVINGS											
Savings, Diesel - LNG, $/E6 BTU (HHV)		$5.99	$6.51	$7.03	$7.56	$8.10		$21.90	$22.63	$23.37	$24.12
% Savings		21.10%	22.37%	23.60%	24.79%	25.95%		40.64%	41.01%	41.36%	41.69%
Annual Savings, $/yr		$ 3,567,490	$ 3,892,542	$ 4,226,205	$ 4,568,666	$ 4,920,114		$ 14,912,067	$ 15,488,424	$ 16,076,171	$ 16,675,350
Total Savings, Project Life, $		**$ 296,931,968**									
Present Value of Savings (2011)	(g)	**$124,303,820**									
ENERGY DEMAND											
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209		681017	684422	687844	691283

Figure 6
Excerpt of Case B5 Model

		Start-up	1	2	3	4		27	28	29	30
DIESEL		2021	2022	2023	2024	2025		2048	2049	2050	2051
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$4.74	$4.79	$4.85	$4.90	$4.96		$8.07	$8.27	$8.47	$8.67
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$34.19	$34.57	$34.99	$35.37	$35.79		$58.30	$59.70	$61.13	$62.60
LNG & CNG	(b)										
Wellhead Value (inflation adjusted)		1.30	1.33	1.36	1.39	1.43		2.46	2.52	2.58	2.64
WH-Processing		0.26	0.26	0.26	0.26	0.26		0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17		5.47	5.60	5.73	5.87
Transport		1.70	1.70	1.70	1.70	1.70		1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57		0.99	1.01	1.03	1.06
Liquefaction		4.00	4.00	4.00	4.00	4.00		4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96		-1.65	-1.69	-1.73	-1.77
LNG FOB Valdez, $/E6 BTU		**9.79**	**9.88**	**9.98**	**10.07**	**10.17**		**13.22**	**13.40**	**13.58**	**13.76**
LNG & CNG Price Stack											
LNG Price FOB Valdez, $/E6 BTU (HHV)		9.79	9.88	9.98	10.07	10.17		13.22	13.40	13.58	13.76
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43		11.33	11.71	12.11	12.53
Sales Tax @ 6% of FOB + Delivery		0.89	0.90	0.91	0.92	0.94		1.47	1.51	1.54	1.58
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11		8.57	8.60	8.64	8.68
Retail Price LNG/CNG, $/E6 BTU		23.79	23.99	24.20	24.41	24.64		34.60	35.22	35.87	36.54
SAVINGS											
Savings, Diesel - LNG, $/E6 BTU (HHV)		$10.41	$10.58	$10.79	$10.95	$11.15		$23.70	$24.48	$25.26	$26.06
% Savings		30.44%	30.61%	30.84%	30.97%	31.15%		40.65%	41.00%	41.33%	41.63%
Annual Savings, $/yr		$ 6,194,721	$ 6,328,497	$ 6,487,458	$ 6,616,942	$ 6,770,372		$ 16,139,872	$ 16,751,983	$ 17,376,525	$ 18,013,570
Total Savings, Project Life, $		**$ 335,386,438**									
Present Value of Savings (2011)	(g)	**$145,746,753**									
ENERGY DEMAND											
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209		681017	684422	687844	691283

6.3 Fairbanks Case Studies

Two case studies were run for the Fairbanks cost model, representing EIA-forecasted data for future wholesale diesel/fuel-oil pricing for a 'reference case' or baseline, and for a 'high economic growth case'. The same procedure for predicting wholesale natural gas pricing was used for both model runs; each for city-gate price corresponding to a take-off point along a large, high pressure pipeline transporting gas to liquefaction facilities at Valdez.

6.3.1 Cost Savings

To provide an approximate quantification of the savings available to the residents of Fairbanks from converting to natural gas, it was assumed that 100% of residences currently using fuel oil for space heating are converted to natural gas. This assumption is overly simplistic, since not all homeowner would be converted en masse. Nonetheless, the assumption was deemed adequate for the purpose of providing an order of magnitude annual savings which might be achieved in later years of a conversion program.

Annual savings based on the above assumption range from approximately $59 million/year to $118 million/year, depending on the assumed fuel oil pricing model, and the year from inception of the switchover to natural gas. The approximate savings in nominal $ US over the course of the project (2021 – 2051) for the two models developed are $2.41 billion, and $2.58 billion, as shown in Figure 7. Refer also to excerpts of the two models in Figure 14 and Figure 15, following.

6.3.2 Emissions Reductions

Conversion to natural gas will reduce the air emissions from home furnaces or boilers significantly for sulfur oxides (SO_2 and SO_3), oxides of nitrogen (NO and NO_2), particulate matter less 10 microns in diameter (PM-10) and carbon dioxide (CO_2). These reductions are presented graphically in the following figures[36,37].

[36] Emission factors are based on US EPA AP-42 Emission Factors, May 2010.
[37] Sulfur oxide emissions from fuel oil are based on 95% of the ADEC regulatory limitation for fuel oil of 5000 ppm.

Figure 7

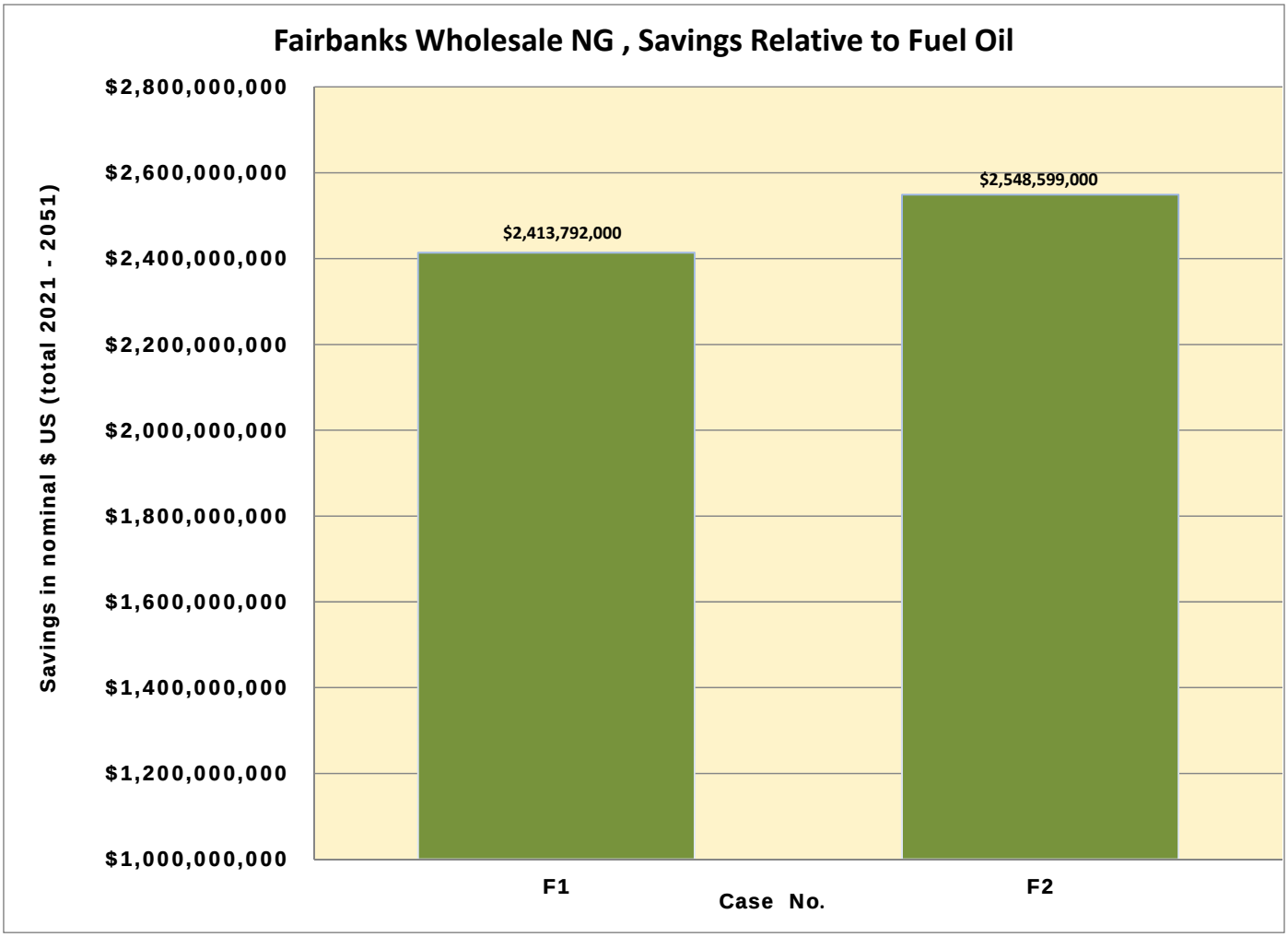

Fairbanks Wholesale NG , Savings Relative to Fuel Oil
Savings in nominal $ US (total 2021 - 2051)
$2,800,000,000
$2,600,000,000
$2,400,000,000
$2,200,000,000
$2,000,000,000
$1,800,000,000
$1,600,000,000
$1,400,000,000
$1,200,000,000
$1,000,000,000
$2,413,792,000
$2,548,599,000
F1
F2
Case No.

Figure 8
Comparison of SO_2 Emissions per BTU Fired –
Fuel Oil, Wood, and Natural Gas

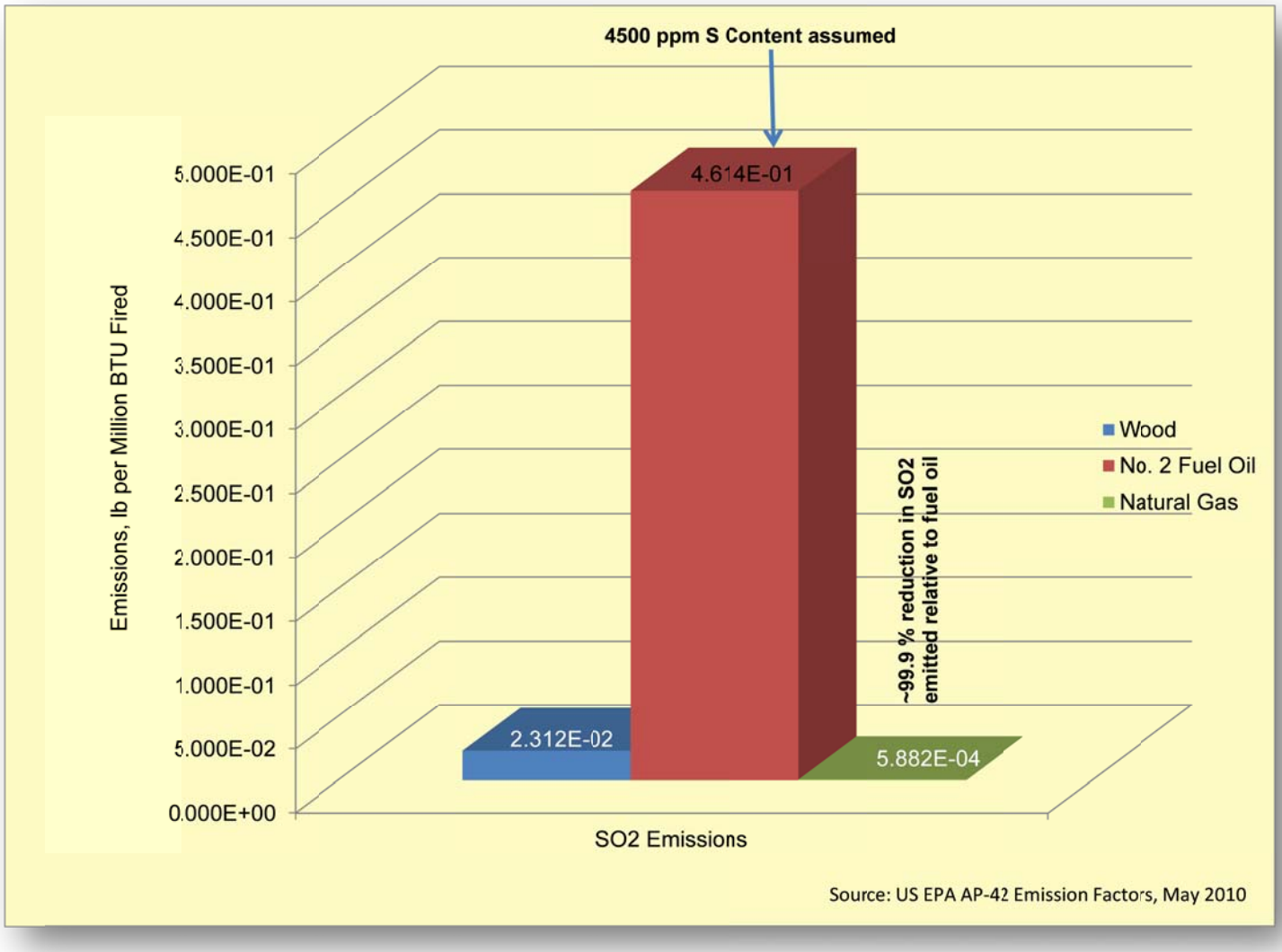


Figure 9
Comparison of NO_X Emissions per BTU
Fired - Fuel Oil, Wood, and Natural Gas

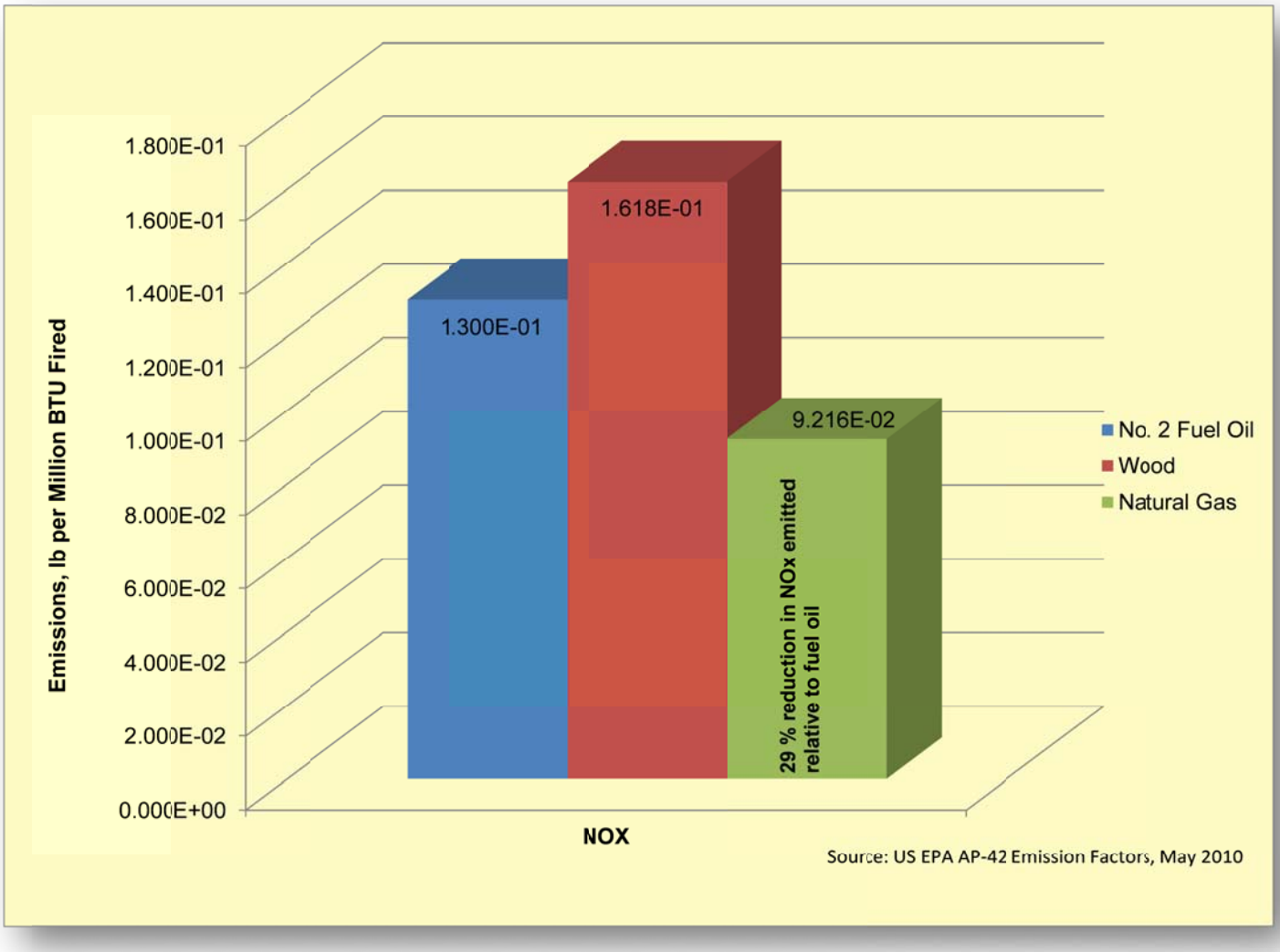


Figure 10
Comparison of Particulate Matter (PM_{10}) Emissions per BTU Fired - Fuel Oil, Wood, and Natural Gas

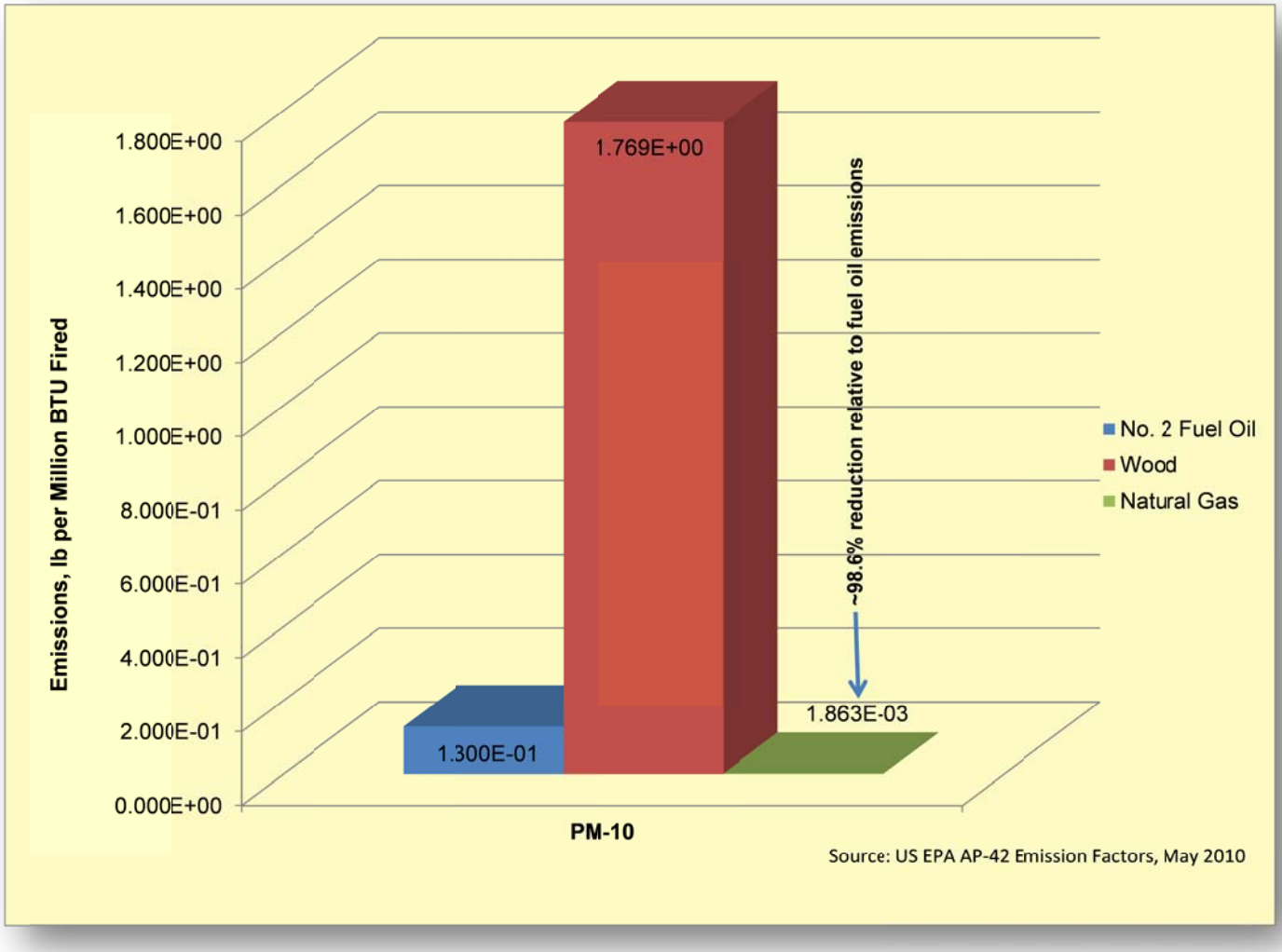


Figure 11
Comparison of Carbon Monoxide (CO) Emissions per BTU Fired - Fuel Oil, Wood, and Natural Gas

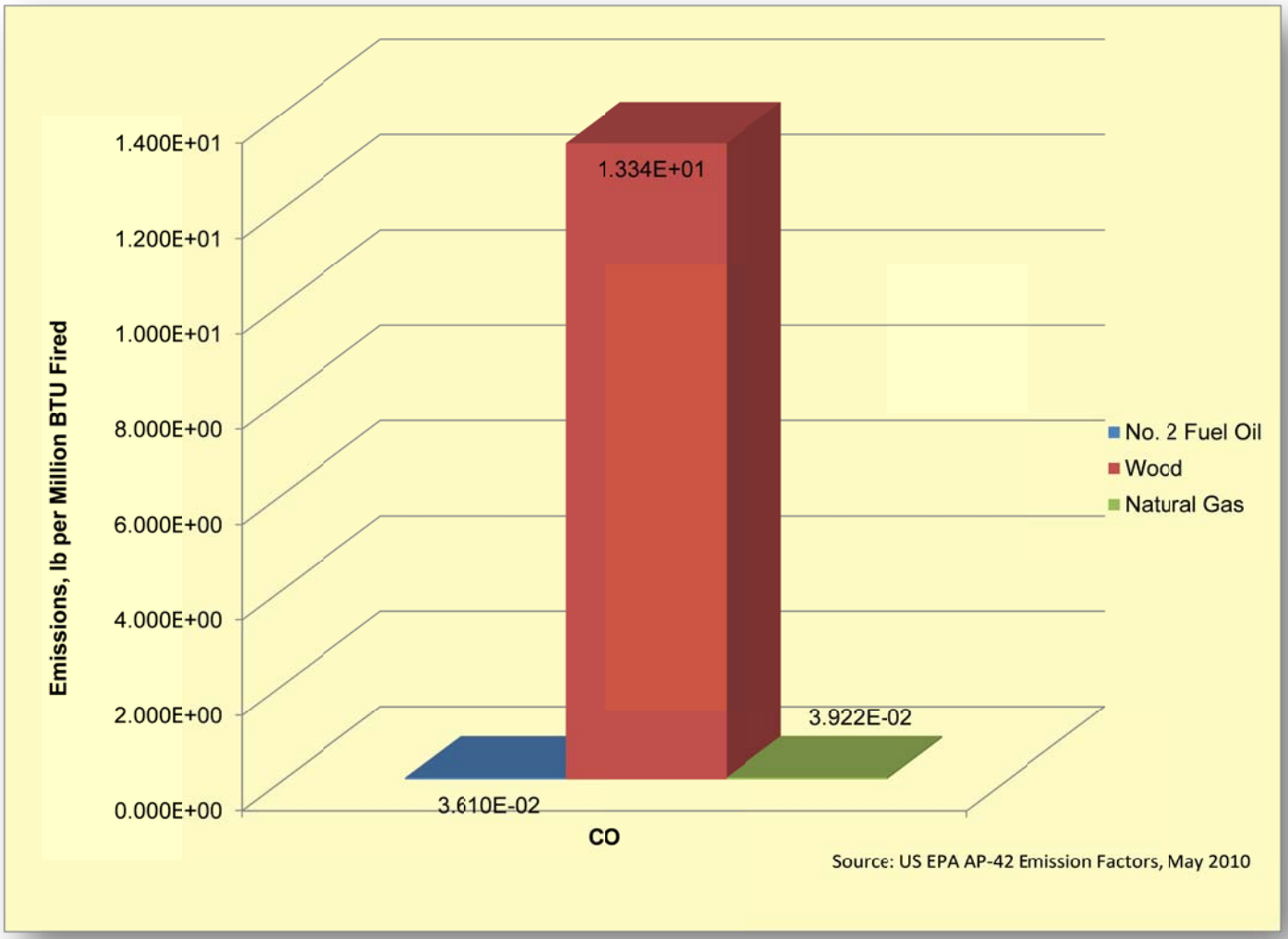


Figure 12
Comparison of Total Organic Carbon (TOC) Emissions per BTU Fired - Fuel Oil, Wood, and Natural Gas

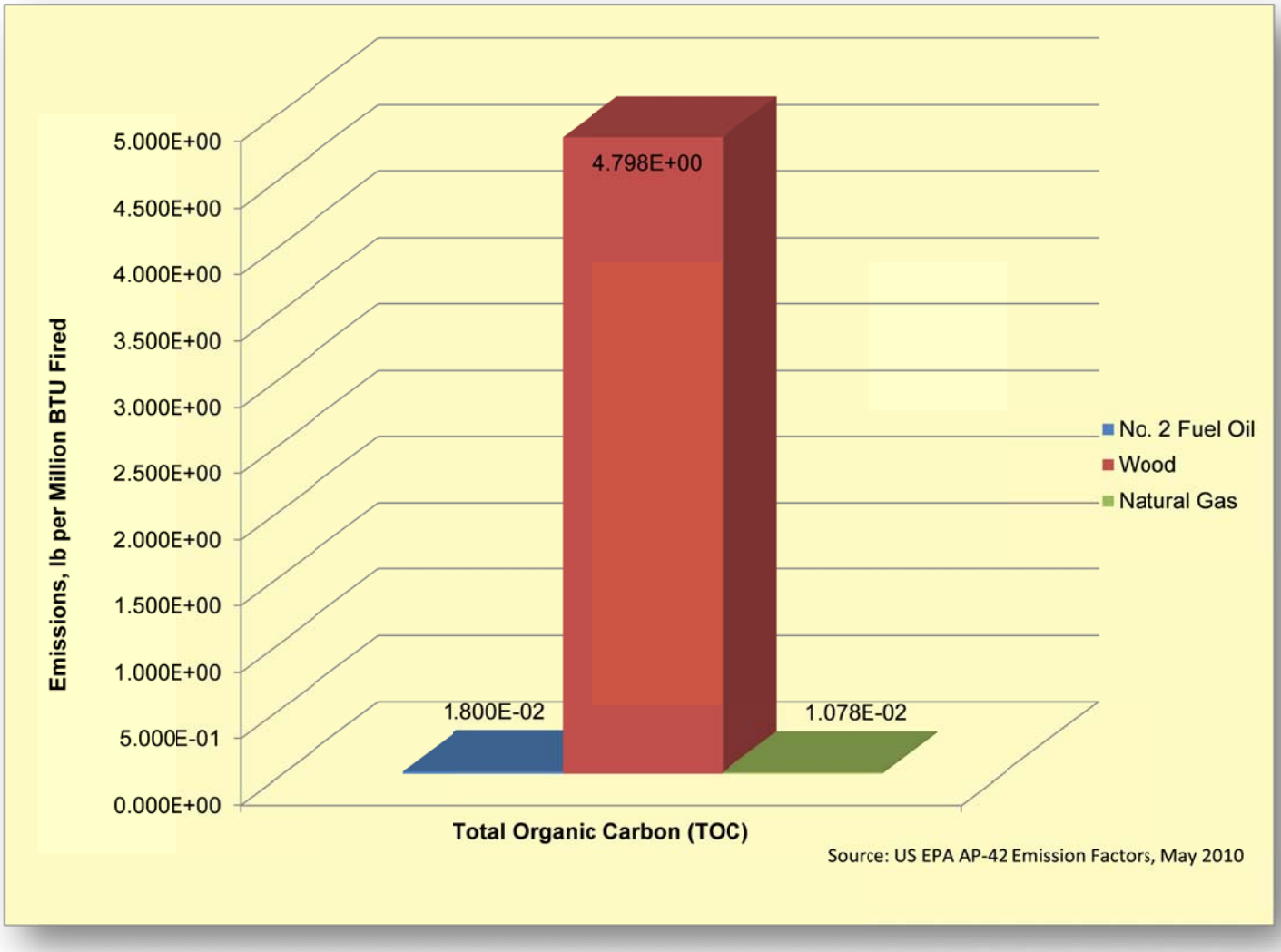
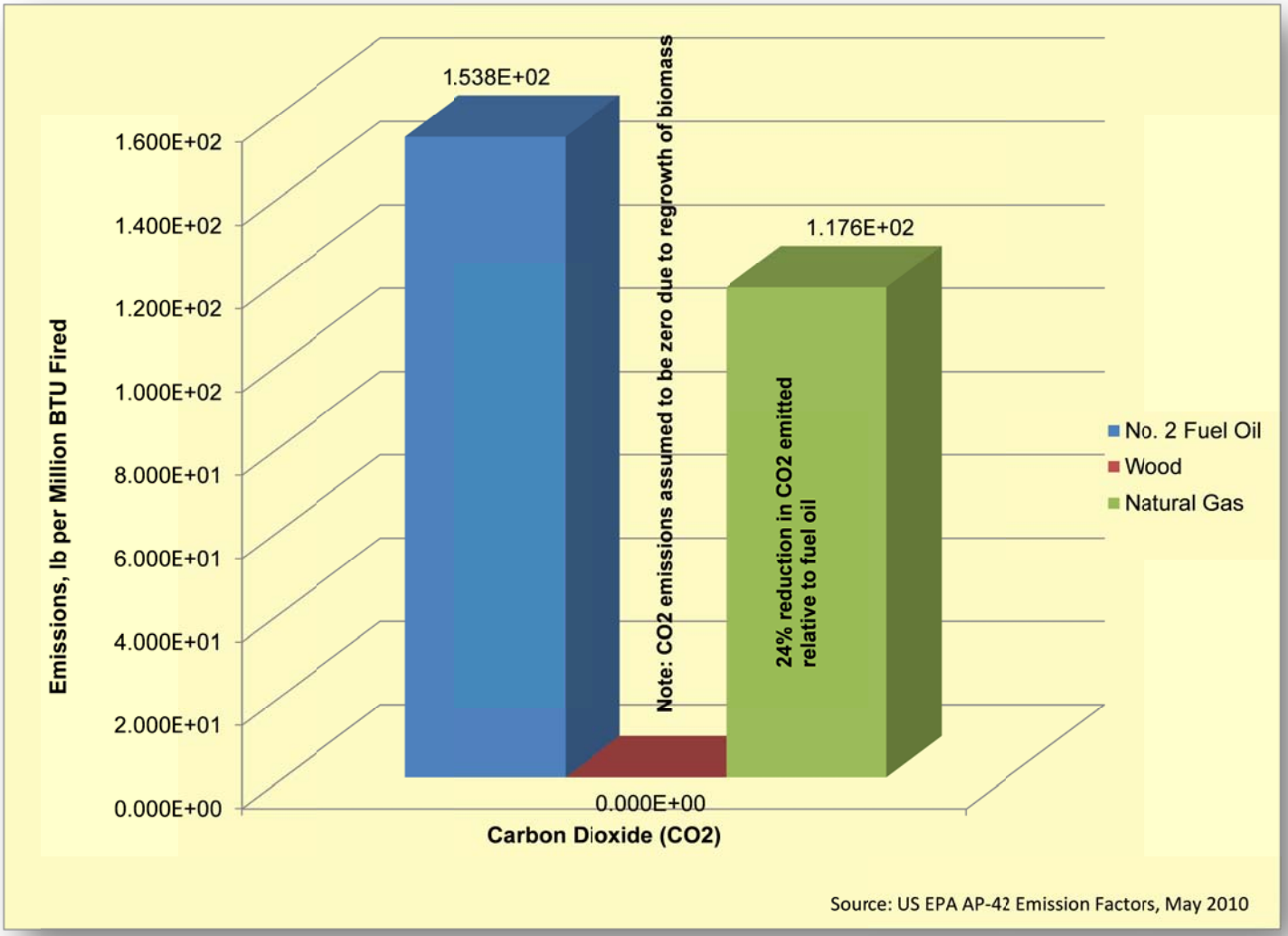


Figure 13
Comparison of Carbon Dioxide (CO_2) Emissions per BTU Fired - Fuel Oil, Wood, and Natural Gas



7. CONCLUSIONS & RECOMMENDATIONS

7.1 Bethel LCNG Substitution

- ✓ Preliminary cost modeling indicates favorable economics for replacement of diesel/fuel-oil for space heating and power generation in Bethel as a standalone project.
- ✓ The extent that capital and operating costs for transport barges and Valdez loading facilities are shared with other communities impacts the retail pricing advantages of LCNG.
- ✓ The inherent stability of LNG wholesale costs used in the model results in increasing fuel savings with time.
- ✓ The primary benefits to residents are annual fuel cost savings of 25% as a minimum, to greater than 65%, subject to the qualifications and assumptions presented.
- ✓ Additional definition of LCNG supply chain and storage/distribution components and costs is necessary to refine the retail pricing of LCNG and confirm these findings.
- ✓ Significant reductions in air emissions can be expected for priority pollutants (SO_2, NOx), hazardous air pollutants (primarily metals, and various organic compounds) and climate change gases (CO_2) relative to current fuels (fuel-oil).

7.2 Fairbanks Natural Gas Substitution

- ✓ The potential of a large capacity natural gas pipeline proximate to Fairbanks offers residents very substantial fuel savings. Wholesale gas priced at approximately $0.75 per diesel equivalent gallon speaks strongly of the benefits that residents in Railbelt communities potentially could expect from this project.
- ✓ Significant reductions in air emissions can be expected for priority pollutants (SO_2, NOx, CO and PM) and hazardous air pollutants (metals, and poly-aromatic compounds) and climate change gases (CO_2) relative to current fuels (fuel-oil and wood).

8. DISCLAIMER

This study was prepared for AGPA by PDC Harris Group using the referenced sources, and internally developed knowledge and data. Data from external sources has not been verified, and therefore we do not warrant the accuracy of conclusions

drawn based on this information. Any opinions expressed are those of PDC Harris Group.

9. APPENDICES

Appendix A – Cost Comparison of Wholesale Diesel and LNG

Appendix B – Schematic Diagram, Transport & Storage of LCNG for Rural Setting

Appendix C – Model Spreadsheets, Bethel

Appendix E – Model Spreadsheets, Fairbanks

Figure 14
Excerpt from Fairbanks Model F1

		Start-up	1	2	3	4		28	29	30
DIESEL		2021	2022	2023	2024	2025		2049	2050	2051
Predicted Diesel Price, Wholesale Lower 48 Ave., $/gal	(a)	$3.54	$3.61	$3.63	$3.71	$3.73		$5.42	$5.55	$5.69
Alaska Wholesale Price Surcharge, $/gal		$0.23	$0.24	$0.24	$0.24	$0.25		$0.36	$0.37	$0.37
Predicted Diesel Price, Wholesale Fairbanks Ave., $/gal		$3.77	$3.85	$3.87	$3.95	$3.97		$5.78	$5.92	$6.06
Predicted $/E6 BTU (HHV), FAI Diesel Wholesale		**$27.23**	**$27.80**	**$27.94**	**$28.54**	**$28.67**		**$41.72**	**$42.73**	**$43.75**
Wholesale Natural Gas										
Wellhead Value		1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00
WH-Processing (invariant)		0.26	0.26	0.26	0.26	0.26		0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17		5.60	5.73	5.87
Transport (invariant)		1.15	1.15	1.15	1.15	1.15		1.15	1.15	1.15
LNG Losses (inflation adjusted)		0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
Liquefaction (invariant)		0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
Liquids Credit (inflation adjusted)		0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
NG FAI City Gate, $/E6 BTU		**5.29**	**5.36**	**5.43**	**5.50**	**5.58**		**8.01**	**8.14**	**8.28**
Equivalent gas price, $/Diesel gallon equivalent		0.73	0.74	0.75	0.76	0.77		1.11	1.13	1.15
SAVINGS										
Savings, Diesel - LNG, $/E6 BTU (HHV)		$21.94	$22.44	$22.51	$23.03	$23.10		$33.72	$34.59	$35.47
% Savings		80.57%	80.72%	80.57%	80.72%	80.55%		80.81%	80.95%	81.08%
Annual Savings, $/yr		$ 59,489,382	$ 61,150,326	$ 61,662,578	$ 63,402,358	$ 63,897,135		$ 105,140,010	$ 108,382,754	$ 111,720,833
Total Savings, Project Life, $		**$ 2,413,791,936**								
Present Value of Savings (2021)	(g)	**$1,124,440,765**								
ENERGY DEMAND										
Heating Fuel Use,E6 BTU/yr	(e)	2711736	2725295	2738921	2752616	2766379		3118151	3133742	3149411

Figure 15
Excerpt from Fairbanks Model F2

		Start-up	1	2	3	4		28	29	30
DIESEL		2021	2022	2023	2024	2025		2049	2050	2051
Predicted Diesel Price, Wholesale Lower 48 Ave., $/gal	(a)	$3.67	$3.73	$3.79	$3.84	$3.90		$5.70	$5.83	$5.97
Alaska Wholesale Price Surcharge, $/gal		$0.23	$0.24	$0.24	$0.24	$0.25		$0.36	$0.37	$0.38
Predicted Diesel Price, Wholesale Fairbanks Ave., $/gal		$3.90	$3.97	$4.03	$4.09	$4.15		$6.06	$6.20	$6.35
Predicted $/E6 BTU (HHV), FAI Diesel Wholesale		**$28.17**	**$28.66**	**$29.10**	**$29.52**	**$29.93**		**$43.73**	**$44.78**	**$45.86**
Wholesale Natural Gas										
Wellhead Value		1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00
WH-Processing (invariant)		0.26	0.26	0.26	0.26	0.26		0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17		5.60	5.73	5.87
Transport (invariant)		1.15	1.15	1.15	1.15	1.15		1.15	1.15	1.15
LNG Losses (inflation adjusted)		0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
Liquefaction (invariant)		0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
Liquids Credit (inflation adjusted)		0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
NG FAI City Gate, $/E6 BTU		**5.29**	**5.36**	**5.43**	**5.50**	**5.58**		**8.01**	**8.14**	**8.28**
Equivalent gas price, $/Diesel gallon equivalent		0.73	0.74	0.75	0.76	0.77		1.11	1.13	1.15
SAVINGS										
Savings, Diesel - LNG, $/E6 BTU (HHV)		$22.88	$23.30	$23.67	$24.02	$24.36		$35.73	$36.64	$37.58
% Savings		81.22%	81.30%	81.34%	81.36%	81.37%		81.69%	81.82%	81.95%
Annual Savings, $/yr		$ 62,034,878	$ 63,495,887	$ 64,839,219	$ 66,105,173	$ 67,377,350		$ 111,396,478	$ 114,821,411	$ 118,346,984
Total Savings, Project Life, $		**$ 2,548,598,605**								
Present Value of Savings (2021)	(g)	**$1,184,320,513**								
ENERGY DEMAND										
Heating Fuel Use,E6 BTU/yr	(e)	2711736	2725295	2738921	2752616	2766379		3118151	3133742	3149411

Appendix A
Cost Comparison of Wholesale Diesel and LNG

Appendix A

Comparison of LNG & Diesel Historical Pricing Data

1. Comparison of Diesel and LNG, US and World-Wide

Table 1 provides a recent snapshot of the dramatic differences in pricing between diesel fuel and LNG, when both fuels are placed on the same basis ($/million BTU).

TABLE 1

COMPARISON OF RECENT DIESEL AND LNG PRICING, $/MILLION BTU

	Diesel (FOB US & AK)		**LNG** (landed @ destination)			
	Diesel Wholesale, US Average	Alaska Diesel, Wholesale FOB Refinery	S. Korea Imports Average	China Imports Average	US Imports, Average	Alaska Landed in Japan
Date	Feb-2011	Feb-2011	Sep-2010	Sep-2010	Feb-2011	Feb-2011
$/MM BTU	**20.96**	**22.64**	**10.41**	**6.61**	**4.16**	**12.64**
Comparison	**0.93**	**1.00**	**0.46**	**0.29**	**0.18**	**0.56**

Several points regarding the data in Table 1 should be emphasized:

- The diesel fuel costs quoted for both US average wholesale, and Anchorage wholesale are not on a landed basis (i.e. delivered to buyer's receiving destination), while the LNG values represent the landed price at the stated destination. Thus the diesel prices should be increased by $1.00 to $2.00/gallon (approximately $7.50 to $15.00 per million BTU) to reflect recent shipping costs from Alaskan refineries to Bethel users.

- The highest priced LNG, delivered to So. Korea and Japan, and purchased under long term contracts which are indexed to the price of crude oil, is between 46% and 56% of the wholesale diesel price for the corresponding period, FOB Anchorage, i.e. not delivered.
- The lowest priced LNG, purchased on a spot basis, and delivered to the US during this period, is approximately 18% of the cost of Alaska diesel. This decline in US pricing reflects the remarkable impact of shale gas development, with LNG near price parity with that of pipeline gas for the first time.

Monthly pricing trends for wholesale diesel FOB Anchorage between March 2003 and November 2010 are plotted in Figure 1, following. These data were acquired from the Energy Information Agency, in units of $/gallon and converted to $/MMBtu. Obviously the steep increases in petroleum derived fuels during the Middle East/Northern Africa cultural upheaval beginning in February 2011 are not captured by these data.

Figure 2 includes the addition of pricing data for AK LNG (Nikiski liquefaction plant) landed in Japan. LNG pricing (for Japan) did not respond to the needle peak of diesel pricing in 2008, though the trend clearly indicates a price increase that more closely tracks that of diesel fuel beginning in March 2009. The latter is likely explained by a renegotiated contract, with enhanced indexing to petroleum pricing.

Figure 3 adds a synthesized trend[1] for the pricing of diesel/fuel oil delivered to Bethel, based on data supplied by Alaska Department of Commerce, Community and Economic Development (DCCED), as well as Northstar Gas Company (local Bethel distributor). Certainly it is recognized that pricing for large volumes of LNG landed in Japan does not address the true supply chain cost for bringing small volumes to Bethel. The comparison nonetheless points to the potential for large savings for substituting LCNG for diesel in rural Alaska.

Figure 4 differs from Figure 3 by the addition of average pricing for LNG landed in the lower 48, from liquefaction plants in Trinidad, Egypt, Qatar, Peru, Norway, Yemen, and Nigeria. Significant pricing differences between US exported LNG (landed in Japan) and US imported LNG are not noted until March 2009, which probably arises from the combined impacts of a renegotiated export contract, and the declining US market for LNG importation.

[1] EIA monthly data for wholesale diesel fuel FOB Anchorage were manipulated to transportation, local distribution and local distributor profit based on DCCED data.

Figure 1
Trended Fuel Prices, Alaska Diesel Wholesale & FOB Refinery

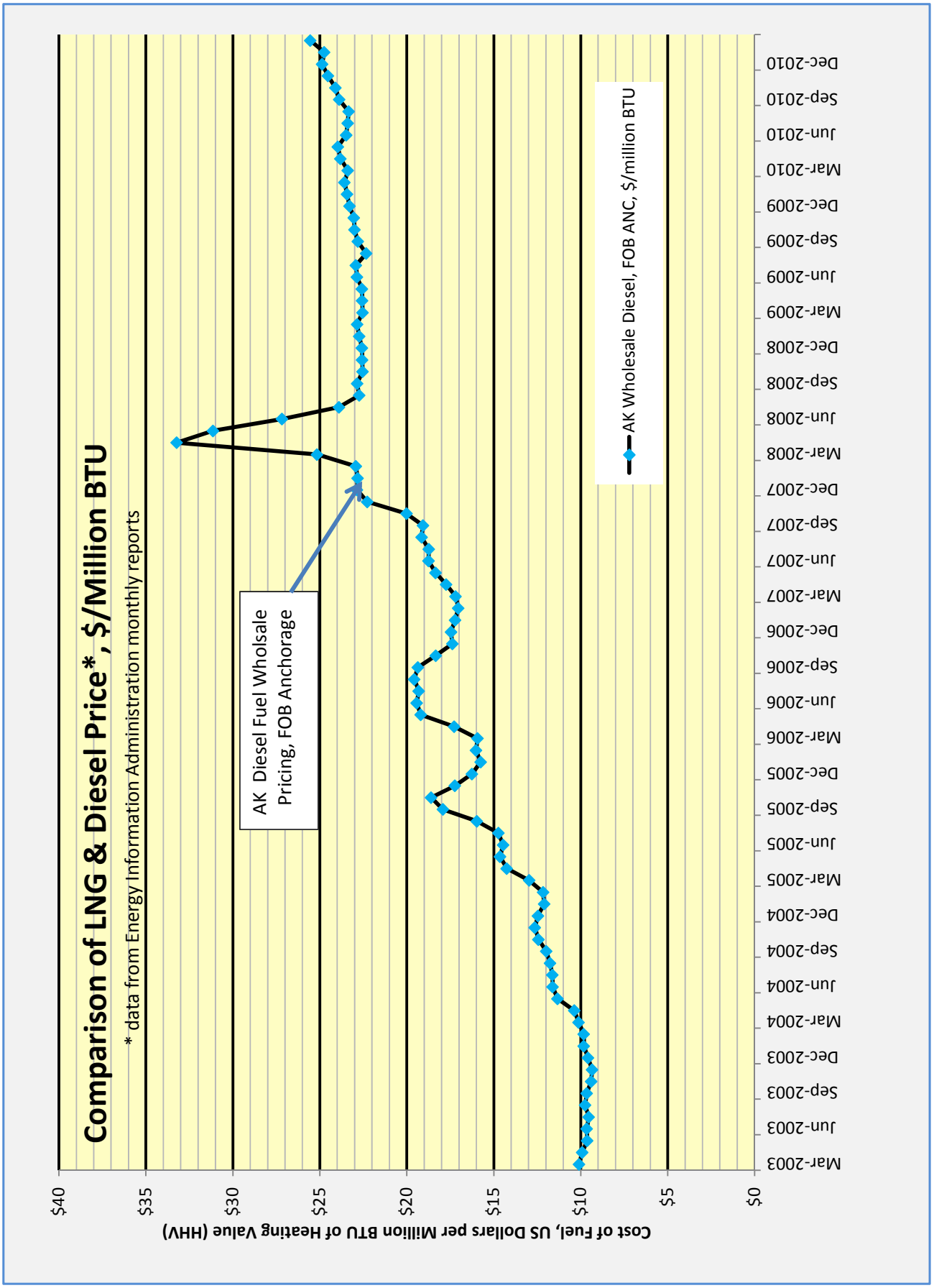


Figure 2
Trended Fuel Prices, Alaska Diesel
Pricing from Fig 1 & AK LNG Landed in Japan

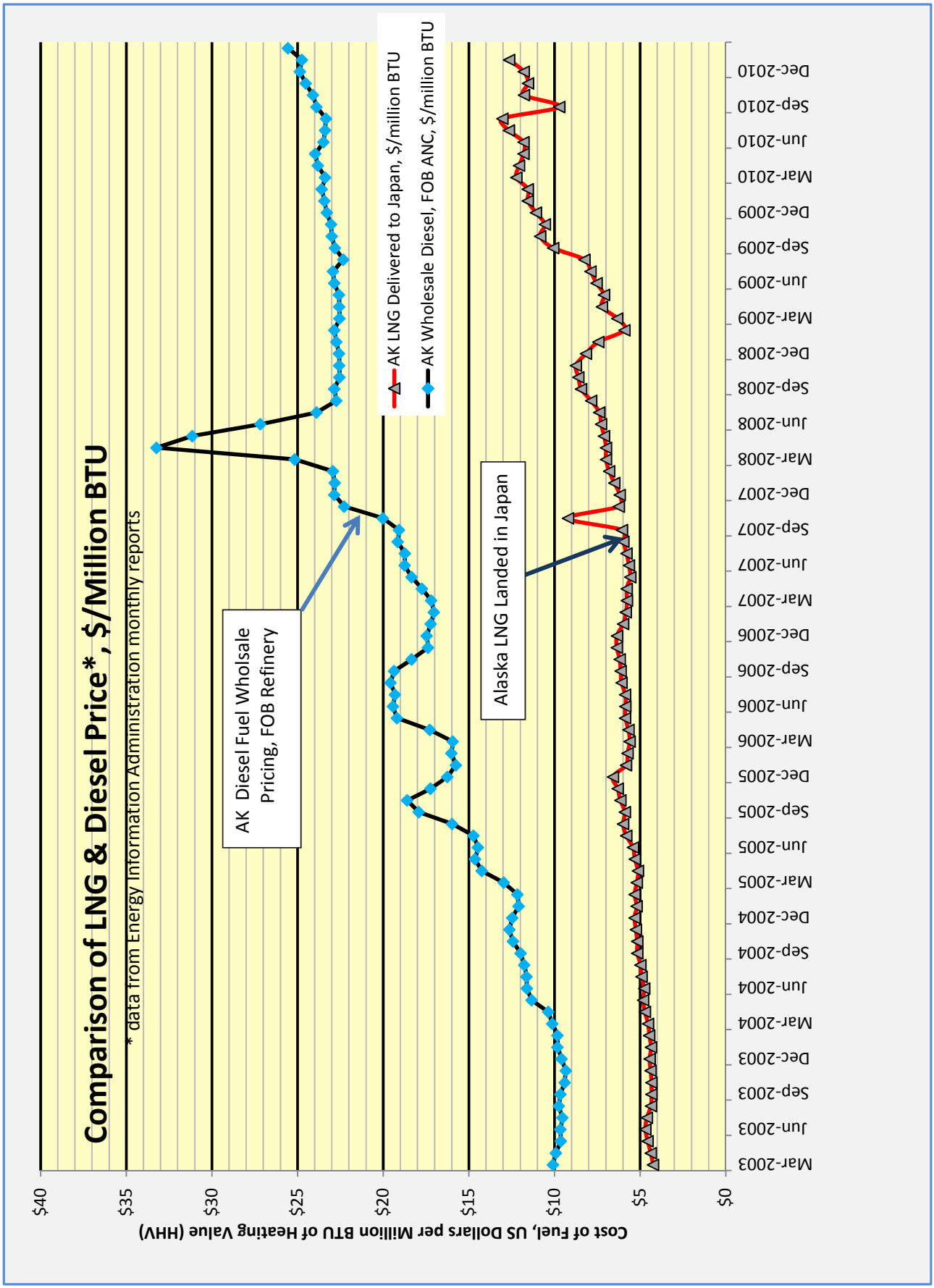


Figure 3
Trended Fuel Prices, Alaska Diesel
& LNG Pricing from Fig 2 & Adjusted Pricing
For Delivery to Bethel

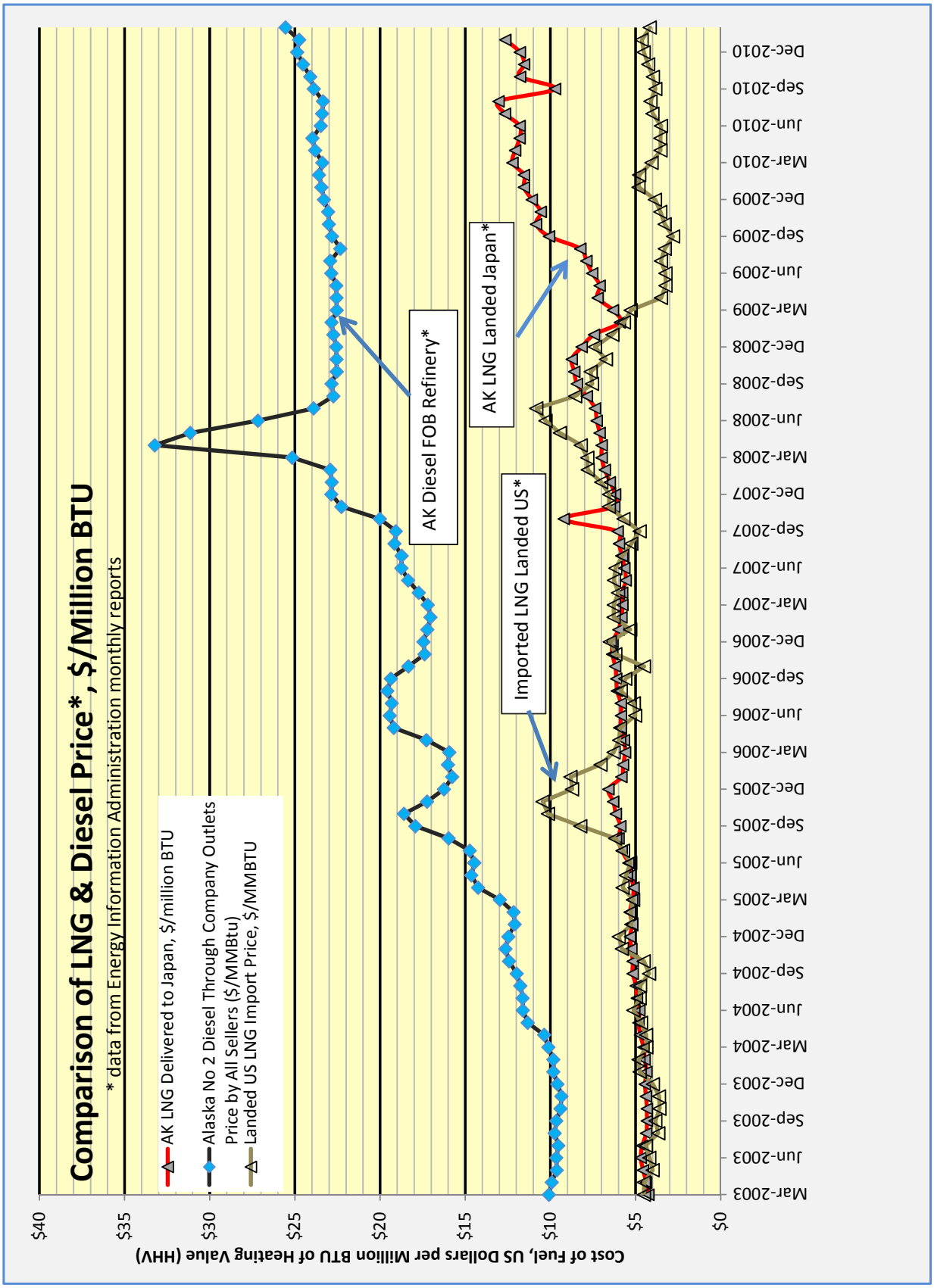
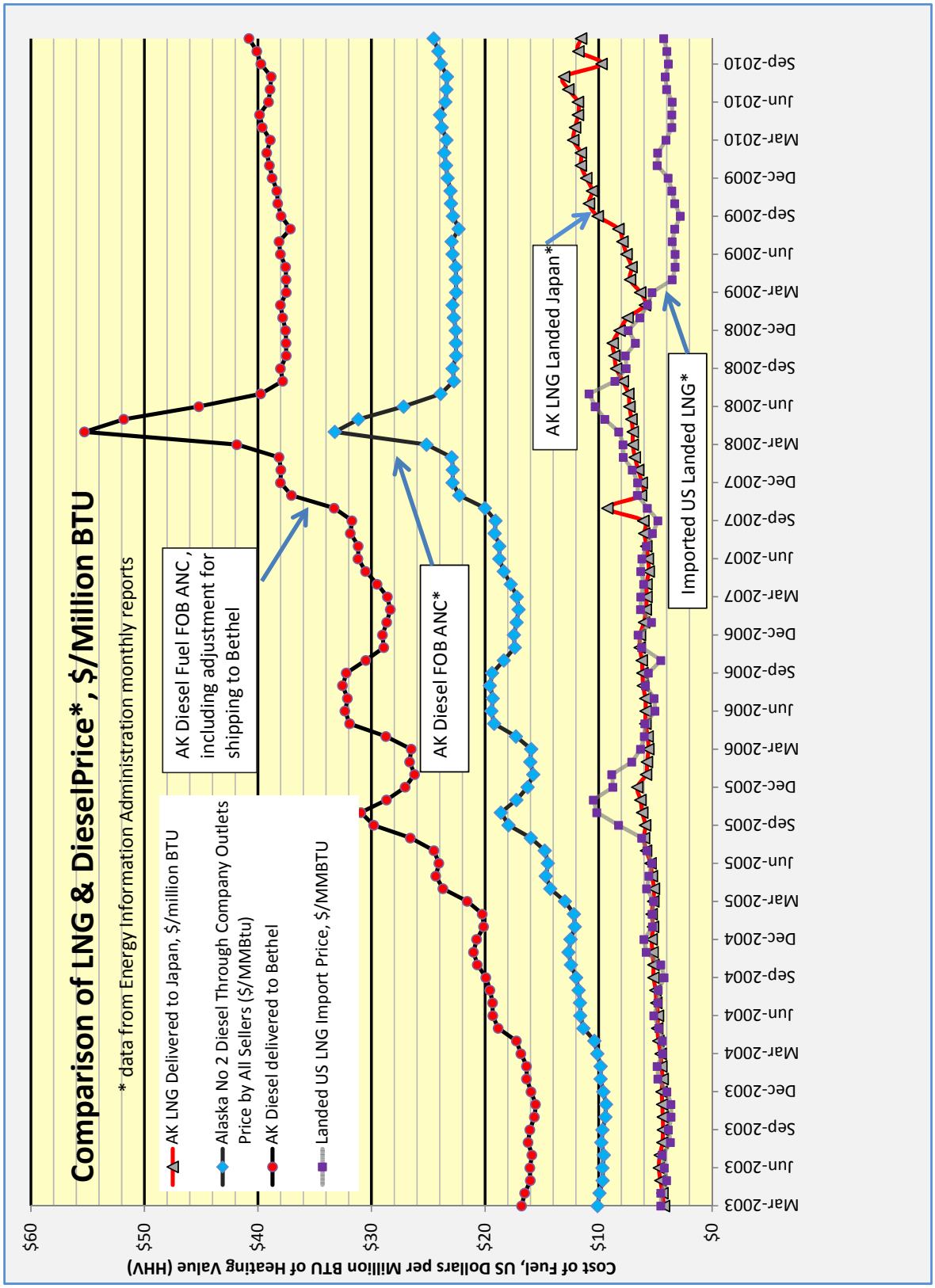


Figure 4
Trended Fuel Prices, Alaska Diesel
& LNG Pricing from Fig 3 & LNG
Landed in US



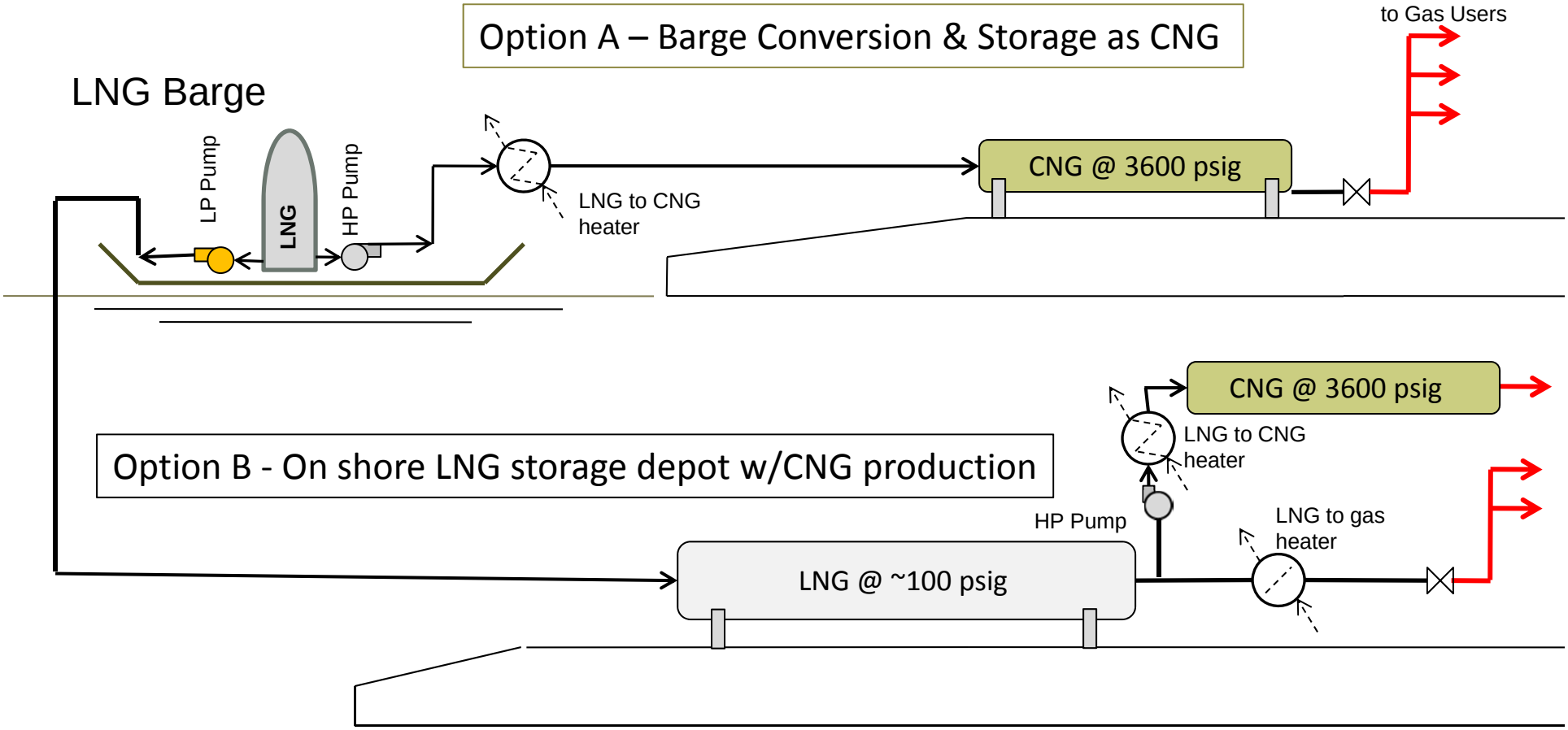
1.4 What is the Future of LNG versus Petroleum-Derived Fuel Pricing?

Will the price disparity between natural gas (LCNG) and petroleum distillates continue? Given the volatility of fuel prices during the period that this document was prepared, no one can make such predictions with confidence. However, we believe that over the longer term, natural gas will remain a bargain compared with diesel/fuel oil, for the following reasons:

- The lower 48 states now enjoy a huge surplus of natural gas, primarily as a result of developing tight sands and shale completion technologies. It is estimated that this surplus and the reserves brought on-line to replace declining wells will be adequate for the next 25 years, as a minimum.
- The cost to produce and transport LNG is declining world-wide. Stranded natural gas reserves are located in numerous tidewater locations, thus ensuring adequate LNG supply for the long term.
- Political and cultural tensions in the Middle East and North Africa are not likely to subside for many years, heightening the impact of an already tight petroleum market.
- Development of US off-shore/Outer Continental Shelf petroleum reserves is currently stalled, and will likely be permitted in selected areas only; placing further pressure on petroleum and its derived fuels. World-wide demand for diesel fuel is strong, and supply surplus is tight. Pricing for gasoline, diesel, fuel oil and other distillates are not likely to experience advantages relative to natural gas.

Appendix B
Schematic Diagram, Transport & Storage of LCNG for Rural Setting

Rural Alaska LCNG Concept



Appendix C
Model Spreadsheets, Bethel

B1 Bethel delivery. LNG FOB Valdez is based on Wood Mac (note i) Cost Buildup. Same nominal delivery and retail markup in $/gal as diesel

Report Reference: Figure 1, Case B1

LNG Cost Buildup, Wood Mac Study, pg. 15

WH Processing	0.26
Processing & Shrinkage	2.22
Transport	1.70
LNG Losses	0.4
Liquefaction	4.00
Liquids Credit	-0.67
LNG FOB Valdez, $/E6 BTU	**7.91**
Basis Year	2010
Annual Inflation:	1.024

Properties

Diesel HHV, BTU/gal.	138490	100.00%
Diesel LHV, BTU/gal.	129490	93.50%
WTI Oil BTU/gal.	6.00E+06	

	min	max	mean
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437
CNG density @ 3600 psig, lb/ft^3			12.1

Transport & Markup Diesel to Bethel (2009-2010 Season)

	$/gal		%		$/E6 BTU (HHV)	
	Individual (j)	Cumulative	Individual	Cumulative	Individual	Cumulative
Fuel, FOB Refinery	2.40	2.40	54.92%	54.92%	17.33	17.33
Delivery & Offload	0.50	2.90	11.44%	66.36%	3.61	20.94
Sales Tax @ 6%	0.26	3.16	5.95%	72.31%	1.88	22.82
Retail Markup	1.21	4.37	27.69%	100.00%	8.74	31.55

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$4.74	$4.79	$4.85	$4.90	$4.96	$5.00	$5.06	$5.13	$5.21	$5.27	$5.39	$5.52	$5.66
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$34.19	$34.57	$34.99	$35.37	$35.79	$36.10	$36.56	$37.03	$37.62	$38.04	$38.95	$39.89	$40.85
LNG & CNG	(b)													
WH-Processing (invariant)		0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24	3.32	3.40	3.48	3.57	3.65	3.74	3.83
Transport (invariant)		1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57	0.58	0.60	0.61	0.63	0.64	0.66	0.67	0.69
Liquefaction (invariant)		4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96	-0.98	-1.00	-1.03	-1.05	-1.08	-1.10	-1.13	-1.16
LNG FOB Valdez, $/E6 BTU		**8.49**	**8.55**	**8.61**	**8.68**	**8.74**	**8.81**	**8.88**	**8.95**	**9.02**	**9.09**	**9.17**	**9.25**	**9.32**
LNG & CNG Price Stack														
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74	8.81	8.88	8.95	9.02	9.09	9.17	9.25	9.32
Delivery & Offload, $/E6 BTU (HHV)	(d)	4.69	4.80	4.91	5.03	5.15	5.28	5.40	5.53	5.67	5.80	5.94	6.08	6.23
Sales Tax @ 6% of FOB + Delivery		0.79	0.80	0.81	0.82	0.83	0.85	0.86	0.87	0.88	0.89	0.91	0.92	0.93
Retail Markup	(f)	11.34	11.61	11.89	12.18	12.47	12.77	13.08	13.39	13.71	14.04	14.38	14.72	15.08
Retail Price LNG/CNG, $/E6 BTU		25.31	25.77	26.23	26.71	27.20	27.70	28.21	28.74	29.28	29.83	30.39	30.97	31.56
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$8.88	$8.80	$8.75	$8.65	$8.59	$8.40	$8.34	$8.29	$8.34	$8.21	$8.56	$8.92	$9.28
% Savings		25.98%	25.46%	25.02%	24.47%	24.00%	23.27%	22.82%	22.38%	22.17%	21.59%	21.98%	22.36%	22.73%
Annual Savings, $/yr		$ 5,287,494	$ 5,264,385	$ 5,263,199	$ 5,229,247	$ 5,215,926	$ 5,127,705	$ 5,117,003	$ 5,107,834	$ 5,165,081	$ 5,112,641	$ 5,356,384	$ 5,607,700	$ 5,866,810
Total Savings, Project Life, $		**$ 229,038,410**												
Present Value of Savings (2021)	(g)	**$101,895,709**												
ENERGY DEMAND														
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209	610245	613296	616363	619445	622542	625655	628783	631927

INFLATION FACTORS

No. of years from 2010		11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation factor	(h)	1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73

NOTES:

(a) 2021 - 2030 values from AEA projection, medium pricing (Saylor & Foster, ISER, 2010). Post 2030 assumes 2.4% inflation
(b) Assumes LNG Base Year Value = $8.50/E6 BTU DES Asia less $0.59/E6 BTU per page 15 Wood Mac
(d) Based on diesel delivery cost per gallon (2010), with 2.4% inflation from 2010, and penalty for LNG energy density.
(e) Assumes 0.5% annual growth due to population growth + higher per capita use.
(f) Using same $/E6 BTU as diesel/fuel oil in 2010, with inflation adjustment.
(g) Discount rate = 5.0%
(h) Inflation constant @ 2.4%/yr.
(i) Wood Mackenzie, "Alaskan LNG Exports Competitiveness Study" 27 July 2011.
(j) Szymoniak et al, "Components of Alaska Fuel Costs: An Analysis of Market Factors and Characteristics that Influence Rural Fuel Prices", Institute of Social and Economic Research (ISER), Univ. of Alaska, February 2010.

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$5.79	$5.93	$6.07	$6.22	$6.37	$6.52	$6.68	$6.84	$7.00	$7.17	$7.34	$7.52	$7.70	$7.88	$8.07	$8.27	$8.47	$8.67
$41.83	$42.83	$43.86	$44.91	$45.99	$47.09	$48.22	$49.38	$50.57	$51.78	$53.02	$54.29	$55.60	$56.93	$58.30	$59.70	$61.13	$62.60
0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
3.92	4.02	4.11	4.21	4.31	4.42	4.52	4.63	4.74	4.86	4.97	5.09	5.21	5.34	5.47	5.60	5.73	5.87
1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
0.71	0.72	0.74	0.76	0.78	0.80	0.81	0.83	0.85	0.87	0.90	0.92	0.94	0.96	0.99	1.01	1.03	1.06
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
-1.18	-1.21	-1.24	-1.27	-1.30	-1.33	-1.36	-1.40	-1.43	-1.47	-1.50	-1.54	-1.57	-1.61	-1.65	-1.69	-1.73	-1.77
9.41	**9.49**	**9.57**	**9.66**	**9.75**	**9.84**	**9.93**	**10.03**	**10.13**	**10.23**	**10.33**	**10.43**	**10.54**	**10.65**	**10.76**	**10.88**	**11.00**	**11.12**
9.41	9.49	9.57	9.66	9.75	9.84	9.93	10.03	10.13	10.23	10.33	10.43	10.54	10.65	10.76	10.88	11.00	11.12
6.38	6.53	6.69	6.85	7.01	7.18	7.35	7.53	7.71	7.90	8.09	8.28	8.48	8.68	8.89	9.10	9.32	9.55
0.95	0.96	0.98	0.99	1.01	1.02	1.04	1.05	1.07	1.09	1.10	1.12	1.14	1.16	1.18	1.20	1.22	1.24
15.44	15.81	16.19	16.58	16.97	17.38	17.80	18.22	18.66	19.11	19.57	20.04	20.52	21.01	21.52	22.03	22.56	23.10
32.17	32.79	33.42	34.07	34.74	35.42	36.12	36.84	37.57	38.32	39.09	39.87	40.68	41.50	42.35	43.21	44.10	45.01
$9.66	$10.04	$10.43	$10.84	$11.25	$11.67	$12.10	$12.54	$13.00	$13.46	$13.93	$14.42	$14.92	$15.43	$15.95	$16.48	$17.03	$17.59
23.09%	23.45%	23.79%	24.13%	24.46%	24.78%	25.09%	25.40%	25.70%	25.99%	26.28%	26.56%	26.83%	27.10%	27.36%	27.61%	27.86%	28.10%
$ 6,133,945	$ 6,409,340	$ 6,693,239	$ 6,985,891	$ 7,287,554	$ 7,598,492	$ 7,918,979	$ 8,249,294	$ 8,589,727	$ 8,940,574	$ 9,302,141	$ 9,674,743	$ 10,058,704	$ 10,454,357	$ 10,862,046	$ 11,282,122	$ 11,714,950	$ 12,160,903
635086	638262	641453	644660	647884	651123	654379	657651	660939	664244	667565	670903	674257	677628	681017	684422	687844	691283

24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64

B2 Same as Case B1, with cost estimate basis for LNG Delivery & Retail Markup (reference Wood Mac Study, note i)

Report Reference: Figure 1, Case B2

Properties

Diesel HHV, BTU/gal.	138490	100.00%	
Diesel LHV, BTU/gal.	129490	93.50%	
WTI Oil BTU/gal.	6.00E+06		
	min	**max**	**mean**
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437

LNG Cost Buildup, Wood Mac Study, pg. 15 (2010 $/E6 BTU)

WH Processing	0.26
Processing & Shrinkage	2.22
Transport	1.70
LNG Losses	0.4
Liquefaction	4.00
Liquids Credit	-0.67
LNG FOB Valdez	**7.91**
Basis Year 2010	
Annual Inflation:	1.024

Transport & Markup Diesel to Bethel (2009-2010 Season)

	$/gal		%		$/E6 BTU (LHV)	
	Individual	**Cumulative**	**Individual**	**Cumulative**	**Individual**	**Cumulative**
Fuel, FOB Refinery	2.40	2.40	54.92%	54.92%	18.53	18.53
Delivery & Offload	0.50	2.90	11.44%	66.36%	3.86	22.40
Sales Tax @ 6%	0.26	3.16	5.95%	72.31%	2.01	24.40
Retail Markup	1.21	4.37	27.69%	100.00%	9.34	33.75

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$4.74	$4.79	$4.85	$4.90	$4.96	$5.00	$5.06	$5.13	$5.21	$5.27	$5.39	$5.52	$5.66
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$34.19	$34.57	$34.99	$35.37	$35.79	$36.10	$36.56	$37.03	$37.62	$38.04	$38.95	$39.89	$40.85
LNG & CNG	(b)													
WH-Processing		0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24	3.32	3.40	3.48	3.57	3.65	3.74	3.83
Transport		1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57	0.58	0.60	0.61	0.63	0.64	0.66	0.67	0.69
Liquefaction		4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96	-0.98	-1.00	-1.03	-1.05	-1.08	-1.10	-1.13	-1.16
LNG FOB Valdez, $/E6 BTU		**8.49**	**8.55**	**8.61**	**8.68**	**8.74**	**8.81**	**8.88**	**8.95**	**9.02**	**9.09**	**9.17**	**9.25**	**9.32**
LNG & CNG Price Stack														
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74	8.81	8.88	8.95	9.02	9.09	9.17	9.25	9.32
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43	5.54	5.66	5.78	5.91	6.04	6.19	6.33	6.49
Sales Tax @ 6% of FOB + Delivery		0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.90	0.91	0.92	0.93	0.95
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11	8.12	8.13	8.14	8.15	8.16	8.18	8.19	8.21
Retail Price LNG/CNG, $/E6 BTU		22.41	22.58	22.75	22.94	23.13	23.33	23.53	23.75	23.97	24.21	24.45	24.71	24.97
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$11.78	$11.99	$12.23	$12.43	$12.66	$12.78	$13.02	$13.28	$13.64	$13.83	$14.50	$15.18	$15.88
% Savings		34.46%	34.68%	34.97%	35.15%	35.38%	35.39%	35.63%	35.86%	36.27%	36.36%	37.23%	38.06%	38.87%
Annual Savings, $/yr		$ 7,013,712	$ 7,171,338	$ 7,354,842	$ 7,509,585	$ 7,689,008	$ 7,797,626	$ 7,987,899	$ 8,183,881	$ 8,450,491	$ 8,611,658	$ 9,073,283	$ 9,546,780	$ 10,032,393
Total Savings, Project Life, $		**$ 375,737,136**												
Present Value of Savings (2011)	(g)	**$163,926,539**												
ENERGY DEMAND														
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209	610245	613296	616363	619445	622542	625655	628783	631927
INFLATION FACTORS														
No. of years from 2010		11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation factor	(h)	1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73

NOTES:

(a) 2021 - 2030 values from AEA projection, 'medium pricing' (Saylor & Foster, ISER, 2010). Post 2030 assumes 2.4% inflation

(b) Assumes LNG Base Year Value = $8.50/E6 BTU DES Asia less $0.59/E6 BTU per page 15 Wood Mac

(d) Derived on "Case B, Delivery Estimate" worksheet.

(e) Assumes 0.5% annual growth due to population growth + higher per capita use.

(f) Developed on Retail Markup Worksheet

(g) Discount rate = 5.0%

(h) Inflation constant @ 2.4%/yr.

(i) Wood Mackenzie, "Alaskan LNG Exports Competitiveness Study" 27 July 2011.

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$5.79	$5.93	$6.07	$6.22	$6.37	$6.52	$6.68	$6.84	$7.00	$7.17	$7.34	$7.52	$7.70	$7.88	$8.07	$8.27	$8.47	$8.67
$41.83	$42.83	$43.86	$44.91	$45.99	$47.09	$48.22	$49.38	$50.57	$51.78	$53.02	$54.29	$55.60	$56.93	$58.30	$59.70	$61.13	$62.60
0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
3.92	4.02	4.11	4.21	4.31	4.42	4.52	4.63	4.74	4.86	4.97	5.09	5.21	5.34	5.47	5.60	5.73	5.87
1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
0.71	0.72	0.74	0.76	0.78	0.80	0.81	0.83	0.85	0.87	0.90	0.92	0.94	0.96	0.99	1.01	1.03	1.06
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
-1.18	-1.21	-1.24	-1.27	-1.30	-1.33	-1.36	-1.40	-1.43	-1.47	-1.50	-1.54	-1.57	-1.61	-1.65	-1.69	-1.73	-1.77
9.41	**9.49**	**9.57**	**9.66**	**9.75**	**9.84**	**9.93**	**10.03**	**10.13**	**10.23**	**10.33**	**10.43**	**10.54**	**10.65**	**10.76**	**10.88**	**11.00**	**11.12**
9.41	9.49	9.57	9.66	9.75	9.84	9.93	10.03	10.13	10.23	10.33	10.43	10.54	10.65	10.76	10.88	11.00	11.12
6.65	6.82	7.00	7.19	7.39	7.59	7.80	8.03	9.36	9.65	9.96	10.28	10.61	10.96	11.33	11.71	12.11	12.53
0.96	0.98	0.99	1.01	1.03	1.05	1.06	1.08	1.17	1.19	1.22	1.24	1.27	1.30	1.33	1.36	1.39	1.42
8.22	8.24	8.26	8.28	8.30	8.32	8.35	8.37	8.40	8.42	8.45	8.48	8.51	8.54	8.57	8.60	8.64	8.68
25.25	25.53	25.83	26.14	26.46	26.80	27.15	27.51	29.05	29.49	29.95	30.43	30.93	31.45	31.99	32.55	33.13	33.74
$16.58	$17.30	$18.03	$18.77	$19.53	$20.29	$21.08	$21.87	$21.51	$22.28	$23.07	$23.86	$24.67	$25.48	$26.31	$27.15	$28.00	$28.86
39.64%	40.39%	41.11%	41.80%	42.46%	43.10%	43.71%	44.29%	42.55%	43.04%	43.50%	43.95%	44.37%	44.76%	45.13%	45.48%	45.80%	46.11%
$ 10,530,370	$ 11,040,957	$ 11,564,406	$ 12,100,968	$ 12,650,894	$ 13,214,438	$ 13,791,854	$ 14,383,395	$ 14,219,459	$ 14,802,615	$ 15,398,840	$ 16,008,297	$ 16,631,141	$ 17,267,524	$ 17,917,587	$ 18,581,464	$ 19,259,281	$ 19,951,152
635086	638262	641453	644660	647884	651123	654379	657651	660939	664244	667565	670903	674257	677628	681017	684422	687844	691283

24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64

B3 Same as Case B2, with predicted Diesel pricing using ISER 'HIGH' range forecast (reference Wood Mac Study, note i)

Report Reference: Figure 1, Case B3

Properties

Diesel HHV, BTU/gal.	138490	100.00%
Diesel LHV, BTU/gal.	129490	93.50%
WTI Oil BTU/gal.	6.00E+06	

	min	max	mean
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437

LNG Cost Buildup, Wood Mac Study, pg. 15 (2010 $/E6 BTU)

WH Processing	0.26
Processing & Shrinkage	2.22
Transport	1.70
LNG Losses	0.4
Liquefaction	4.00
Liquids Credit	-0.67
LNG FOB Valdez	**7.91**
Basis Year 2010	
Annual Inflation:	1.024

Transport & Markup Diesel to Bethel (2009-2010 Season)

	$/gal		%		$/E6 BTU (LHV)	
	Individual	Cumulative	Individual	Cumulative	Individual	Cumulative
Fuel, FOB Refinery	2.40	2.40	54.87%	54.87%	18.53	18.53
Delivery & Offload	0.50	2.90	11.43%	66.30%	3.86	22.40
Sales Tax @ 6%	0.17	3.07	3.98%	70.28%	1.34	23.74
Retail Markup	1.30	4.37	29.72%	100.00%	10.04	33.78

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$7.44	$7.53	$7.63	$7.70	$7.79	$7.87	$7.94	$8.03	$8.13	$8.21	$8.40	$8.60	$8.81
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$53.72	$54.38	$55.07	$55.56	$56.22	$56.84	$57.37	$58.00	$58.68	$59.25	$60.67	$62.13	$63.62
LNG & CNG	(b)													
WH-Processing		0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24	3.32	3.40	3.48	3.57	3.65	3.74	3.83
Transport		1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57	0.58	0.60	0.61	0.63	0.64	0.66	0.67	0.69
Liquefaction		4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96	-0.98	-1.00	-1.03	-1.05	-1.08	-1.10	-1.13	-1.16
LNG FOB Valdez, $/E6 BTU		**8.49**	**8.55**	**8.61**	**8.68**	**8.74**	**8.81**	**8.88**	**8.95**	**9.02**	**9.09**	**9.17**	**9.25**	**9.32**
LNG & CNG Price Stack														
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74	8.81	8.88	8.95	9.02	9.09	9.17	9.25	9.32
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43	5.54	5.66	5.78	5.91	6.04	6.19	6.33	6.49
Sales Tax @ 6% of FOB + Delivery		0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.90	0.91	0.92	0.93	0.95
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11	8.12	8.13	8.14	8.15	8.16	8.18	8.19	8.21
Retail Price LNG/CNG, $/E6 BTU		$ 22.41	$ 22.58	$ 22.75	$ 22.94	$ 23.13	$ 23.33	$ 23.53	$ 23.75	$ 23.97	$ 24.21	$ 24.45	$ 24.71	$ 24.97
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$31.31	$31.80	$32.32	$32.63	$33.09	$33.52	$33.83	$34.25	$34.71	$35.04	$36.22	$37.42	$38.65
% Savings		58.28%	58.48%	58.69%	58.72%	58.86%	58.96%	58.98%	59.05%	59.14%	59.14%	59.70%	60.23%	60.75%
Annual Savings, $/yr		$ 18,633,504	$ 19,021,078	$ 19,430,465	$ 19,713,550	$ 20,093,775	$ 20,453,242	$ 20,749,855	$ 21,109,027	$ 21,497,974	$ 21,813,830	$ 22,659,902	$ 23,529,041	$ 24,421,818
Total Savings, Project Life, $		**$ 886,433,544**												
Present Value of Savings (2011)	(g)	**$397,184,212**												
ENERGY DEMAND														
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209	610245	613296	616363	619445	622542	625655	628783	631927

INFLATION FACTORS

No. of years from 2010		11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation factor	(h)	1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73

NOTES:

(a) 2021 - 2030 values from AEA projection, 'high pricing' (Saylor & Foster, ISER, 2010). Post 2030 assumes 2.4% inflation

(b) Assumes LNG Base Year Value = $8.50/E6 BTU DES Asia less $0.59/E6 BTU per page 15 Wood Mac

(d) Derived on "Case B, Delivery Estimate" worksheet.

(e) Assumes 0.5% annual growth due to population growth + higher per capita use.

(f) Developed on Retail Markup Worksheet

(g) Discount rate = 5.0%

(h) Inflation constant @ 2.4%/yr.

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$9.02	$9.24	$9.46	$9.69	$9.92	$10.16	$10.40	$10.65	$10.91	$11.17	$11.44	$11.71	$11.99	$12.28	$12.57	$12.88	$13.19	$13.50
$65.14	$66.71	$68.31	$69.95	$71.63	$73.35	$75.11	$76.91	$78.75	$80.64	$82.58	$84.56	$86.59	$88.67	$90.80	$92.98	$95.21	$97.49
0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
3.92	4.02	4.11	4.21	4.31	4.42	4.52	4.63	4.74	4.86	4.97	5.09	5.21	5.34	5.47	5.60	5.73	5.87
1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
0.71	0.72	0.74	0.76	0.78	0.80	0.81	0.83	0.85	0.87	0.90	0.92	0.94	0.96	0.99	1.01	1.03	1.06
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
-1.18	-1.21	-1.24	-1.27	-1.30	-1.33	-1.36	-1.40	-1.43	-1.47	-1.50	-1.54	-1.57	-1.61	-1.65	-1.69	-1.73	-1.77
9.41	**9.49**	**9.57**	**9.66**	**9.75**	**9.84**	**9.93**	**10.03**	**10.13**	**10.23**	**10.33**	**10.43**	**10.54**	**10.65**	**10.76**	**10.88**	**11.00**	**11.12**
9.41	9.49	9.57	9.66	9.75	9.84	9.93	10.03	10.13	10.23	10.33	10.43	10.54	10.65	10.76	10.88	11.00	11.12
6.65	6.82	7.00	7.19	7.39	7.59	7.80	8.03	9.36	9.65	9.96	10.28	10.61	10.96	11.33	11.71	12.11	12.53
0.96	0.98	0.99	1.01	1.03	1.05	1.06	1.08	1.17	1.19	1.22	1.24	1.27	1.30	1.33	1.36	1.39	1.42
8.22	8.24	8.26	8.28	8.30	8.32	8.35	8.37	8.40	8.42	8.45	8.48	8.51	8.54	8.57	8.60	8.64	8.68
$ 25.25	$ 25.53	$ 25.83	$ 26.14	$ 26.46	$ 26.80	$ 27.15	$ 27.51	$ 29.05	$ 29.49	$ 29.95	$ 30.43	$ 30.93	$ 31.45	$ 31.99	$ 32.55	$ 33.13	$ 33.74
$39.90	$41.18	$42.48	$43.81	$45.16	$46.55	$47.96	$49.40	$49.70	$51.15	$52.63	$54.13	$55.66	$57.22	$58.81	$60.43	$62.08	$63.76
61.25%	61.73%	62.19%	62.63%	63.05%	63.46%	63.86%	64.23%	63.11%	63.43%	63.73%	64.01%	64.28%	64.53%	64.77%	64.99%	65.20%	65.40%
$ 25,338,814	$ 26,280,624	$ 27,247,852	$ 28,241,115	$ 29,261,043	$ 30,308,274	$ 31,383,463	$ 32,487,271	$ 32,850,520	$ 33,976,213	$ 35,130,774	$ 36,314,824	$ 37,528,994	$ 38,773,922	$ 40,050,251	$ 41,358,632	$ 42,699,720	$ 44,074,176
635086	638262	641453	644660	647884	651123	654379	657651	660939	664244	667565	670903	674257	677628	681017	684422	687844	691283

24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64

B4 Wood Mac (note j) "Worst Case", $75/bbl WTI oil, LNG Retail Pricing same as B1 and B2.

Report Reference, Case B4 Figure 1

Properties

Diesel HHV, BTU/gal.	138490	100.00%	
Diesel LHV, BTU/gal.	129490	93.50%	
WTI Oil BTU/gal.	6.00E+06		
	min	**max**	**mean**
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437
Average Crack Ratio (i)			1.18

Estimate Transport & Markup Diesel to Bethel

Base LNG $/E6 BTU	7.91					
Basis Year	2010					
Annual Inflation:	1.024					
	$/gal		**%**		**$/E6 BTU (LHV)**	
	Individual	**Cumulative**	**Individual**	**Cumulative**	**Individual**	**Cumulative**
Fuel, FOB Refinery	2.11	2.11	53.57%	53.57%	16.27	16.27
Delivery & Offload	0.50	2.61	12.71%	66.28%	3.86	20.13
Sales Tax @ 6%	0.16	2.76	3.98%	70.26%	1.21	21.34
Retail Markup	1.17	3.93	29.74%	100.00%	9.04	30.38
TOTAL	3.93					

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Calculated Price, Retail Bethel, $/gal	(a)	$3.93	$4.03	$4.12	$4.22	$4.33	$4.43	$4.54	$4.64	$4.76	$4.87	$4.99	$5.11	$5.23
$/E6 BTU (HHV), Bethel Diesel Retail		$28.40	$29.08	$29.78	$30.50	$31.23	$31.98	$32.75	$33.53	$34.34	$35.16	$36.01	$36.87	$37.75
$/E6 BTU (LHV), Bethel Diesel Retail		$30.38	$31.11	$31.85	$32.62	$33.40	$34.20	$35.02	$35.86	$36.72	$37.61	$38.51	$39.43	$40.38
LNG & CNG														
Wood Mackenzie Model Duplication (HHV)														
Nominal WTI Oil Price, $/bbl	(b)	$75.00	$76.80	$78.64	$80.53	$82.46	$84.44	$86.47	$88.54	$90.67	$92.85	$95.07	$97.36	$99.69
Calculated WTI Oil, $/E6 BTU		12.50	12.80	13.11	13.42	13.74	14.07	14.41	14.76	15.11	15.47	15.85	16.23	16.62
Asia LNG $/E6 BTU, DES basis	(c)	11.73	11.82	12.10	12.39	12.69	13.00	13.31	13.63	13.95	14.29	14.63	14.98	15.34
Less infl. Shipping, $/E6 BTU		0.59	$0.60	$0.62	$0.63	$0.65	$0.66	$0.68	$0.70	$0.71	$0.73	$0.75	$0.77	$0.78
Less pipe transportation, $/E6 BTU		4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18
Less liquefaction, $/E6 BTU		4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Wellhead netback, $/E6 BTU		2.96	3.04	3.30	3.58	3.86	4.15	4.45	4.75	5.06	5.38	5.70	6.04	6.38
LNG & CNG Price Stack														
LNG Price FOB Valdez, $/E6 BTU (HHV)		8.49	8.55	8.61	8.68	8.74	8.81	8.88	8.95	9.02	9.09	9.17	9.25	9.32
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43	5.54	5.66	5.78	5.91	6.04	6.19	6.33	6.49
Sales Tax @ 6% of FOB + Delivery		0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.90	0.91	0.92	0.93	0.95
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11	8.12	8.13	8.14	8.15	8.16	8.18	8.19	8.21
Retail Price LNG/CNG, $/E6 BTU		22.41	22.58	22.75	22.94	23.13	23.33	23.53	23.75	23.97	24.21	24.45	24.71	24.97
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$5.99	$6.51	$7.03	$7.56	$8.10	$8.65	$9.21	$9.78	$10.36	$10.95	$11.55	$12.16	$12.78
% Savings		21.10%	22.37%	23.60%	24.79%	25.95%	27.06%	28.14%	29.18%	30.18%	31.15%	32.09%	32.99%	33.86%
Annual Savings, $/yr		$ 3,567,490	$ 3,892,542	$ 4,226,205	$ 4,568,666	$ 4,920,114	$ 5,280,737	$ 5,650,729	$ 6,030,283	$ 6,419,595	$ 6,818,861	$ 7,228,279	$ 7,648,049	$ 8,078,372
Total Savings, Project Life, $		**$ 296,931,968**												
Present Value of Savings (2011)	(g)	**$124,303,820**												
ENERGY DEMAND														
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209	610245	613296	616363	619445	622542	625655	628783	631927

NOTES:

(a) Uses historical crack spread to estimate wholesale diesel price, transport @ $0.50/gal, and markup at approx. 29.7% of total from Case A. Subsequent years inflate at 2.4%/yr.
(b) 2021 Value from Wood MacKenzie, "Alaska LNG Exports Competitiveness Study" NY strip scenario (base case), thereafter assumes 2.4% inflation
(c) Indexation of 0.1539 from Wood Mackenzie model
(d) Based on diesel delivery cost per gallon (2010), with 2.4% inflation from 2010, and penalty for LNG energy density.
(e) Assumes 0.5% annual growth due to population growth + higher per capita use.
(f) Developed on Retail Markup Worksheet
(g) Discount rate = 5.0%
(h) Inflation constant @ 2.4%/yr.
(i) From Thies & Brown, "What Drives Fuel Prices" Federal Reserve Bank of Dallas, Economic Letter, Vol. 4, No. 9, Chart 4.
(j) Wood Mackenzie, “Alaskan LNG Exports Competitiveness Study” 27 July 2011.

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$5.35	$5.48	$5.61	$5.75	$5.89	$6.03	$6.17	$6.32	$6.47	$6.63	$6.79	$6.95	$7.12	$7.29	$7.46	$7.64	$7.83	$8.01
$38.66	$39.59	$40.54	$41.51	$42.51	$43.53	$44.57	$45.64	$46.74	$47.86	$49.01	$50.18	$51.39	$52.62	$53.88	$55.18	$56.50	$57.86
$41.35	$42.34	$43.36	$44.40	$45.46	$46.55	$47.67	$48.81	$49.99	$51.19	$52.41	$53.67	$54.96	$56.28	$57.63	$59.01	$60.43	$61.88
$102.08	$104.53	$107.04	$109.61	$112.24	$114.94	$117.70	$120.52	$123.41	$126.37	$129.41	$132.51	$135.69	$138.95	$142.29	$145.70	$149.20	$152.78
17.01	17.42	17.84	18.27	18.71	19.16	19.62	20.09	20.57	21.06	21.57	22.09	22.62	23.16	23.71	24.28	24.87	25.46
15.71	16.09	16.47	16.87	17.27	17.69	18.11	18.55	18.99	19.45	19.92	20.39	20.88	21.38	21.90	22.42	22.96	23.51
$0.80	$0.82	$0.84	$0.86	$0.88	$0.90	$0.93	$0.95	$0.97	$0.99	$1.02	$1.04	$1.07	$1.09	$1.12	$1.15	$1.17	$1.20
4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
6.73	7.09	7.45	7.83	8.21	8.60	9.01	9.42	9.84	10.27	10.72	11.17	11.64	12.11	12.60	13.10	13.61	14.13
9.41	9.49	9.57	9.66	9.75	9.84	9.93	10.03	10.13	10.23	10.33	10.43	10.54	10.65	10.76	10.88	11.00	11.12
6.65	6.82	7.00	7.19	7.39	7.59	7.80	8.03	9.36	9.65	9.96	10.28	10.61	10.96	11.33	11.71	12.11	12.53
0.96	0.98	0.99	1.01	1.03	1.05	1.06	1.08	1.17	1.19	1.22	1.24	1.27	1.30	1.33	1.36	1.39	1.42
8.22	8.24	8.26	8.28	8.30	8.32	8.35	8.37	8.40	8.42	8.45	8.48	8.51	8.54	8.57	8.60	8.64	8.68
25.25	25.53	25.83	26.14	26.46	26.80	27.15	27.51	29.05	29.49	29.95	30.43	30.93	31.45	31.99	32.55	33.13	33.74
$13.41	$14.06	$14.71	$15.37	$16.05	$16.73	$17.43	$18.13	$17.69	$18.37	$19.05	$19.75	$20.46	$21.17	$21.90	$22.63	$23.37	$24.12
34.70%	35.51%	36.28%	37.03%	37.75%	38.43%	39.10%	39.73%	37.84%	38.37%	38.88%	39.36%	39.81%	40.23%	40.64%	41.01%	41.36%	41.69%
$ 8,519,447	$ 8,971,477	$ 9,434,663	$ 9,909,206	$ 10,395,308	$ 10,893,169	$ 11,402,990	$ 11,924,967	$ 11,689,442	$ 12,198,924	$ 12,719,330	$ 13,250,759	$ 13,793,304	$ 14,347,048	$ 14,912,067	$ 15,488,424	$ 16,076,171	$ 16,675,350
635086	638262	641453	644660	647884	651123	654379	657651	660939	664244	667565	670903	674257	677628	681017	684422	687844	691283

B5 Same as Case B2, with cost estimate basis for LNG Delivery & Retail Markup. Add $1/E6 Btu to wellhead value. (reference Wood Mac Study, n

Report Reference: Figure 1, Case B5

Properties

Diesel HHV, BTU/gal.	138490	100.00%
Diesel LHV, BTU/gal.	129490	93.50%
WTI Oil BTU/gal.	6.00E+06	

	min	max	mean
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437

LNG Cost Buildup, Wood Mac Study, pg. 15 (2010 $/E6 BTU)

WH Processing		0.26
Processing & Shrinkage		2.22
Transport		1.70
LNG Losses		0.4
Liquefaction		4.00
Liquids Credit		-0.67
LNG FOB Valdez		**7.91**
Basis Year	2010	
Annual Inflation:		1.024

Transport & Markup Diesel to Bethel (2009-2010 Season)

	$/gal		%		$/E6 BTU (LHV)	
	Individual	Cumulative	Individual	Cumulative	Individual	Cumulative
Fuel, FOB Refinery	2.40	2.40	54.92%	54.92%	18.53	18.53
Delivery & Offload	0.50	2.90	11.44%	66.36%	3.86	22.40
Sales Tax @ 6%	0.26	3.16	5.95%	72.31%	2.01	24.40
Retail Markup	1.21	4.37	27.69%	100.00%	9.34	33.75

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted Diesel Price, Retail Bethel, $/gal	(a)	$4.74	$4.79	$4.85	$4.90	$4.96	$5.00	$5.06	$5.13	$5.21	$5.27	$5.39	$5.52	$5.66
Predicted $/E6 BTU (HHV), Bethel Diesel Retail		$34.19	$34.57	$34.99	$35.37	$35.79	$36.10	$36.56	$37.03	$37.62	$38.04	$38.95	$39.89	$40.85
LNG & CNG	(b)													
Wellhead Value (inflation adjusted)		1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73
WH-Processing		0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24	3.32	3.40	3.48	3.57	3.65	3.74	3.83
Transport		1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
LNG Losses (inflation adjusted)		0.52	0.53	0.54	0.56	0.57	0.58	0.60	0.61	0.63	0.64	0.66	0.67	0.69
Liquefaction		4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Liquids Credit (inflation adjusted)		-0.87	-0.89	-0.91	-0.93	-0.96	-0.98	-1.00	-1.03	-1.05	-1.08	-1.10	-1.13	-1.16
LNG FOB Valdez, $/E6 BTU		**9.79**	**9.88**	**9.98**	**10.07**	**10.17**	**10.27**	**10.37**	**10.48**	**10.59**	**10.70**	**10.81**	**10.93**	**11.05**
LNG & CNG Price Stack														
LNG Price FOB Valdez, $/E6 BTU (HHV)		9.79	9.88	9.98	10.07	10.17	10.27	10.37	10.48	10.59	10.70	10.81	10.93	11.05
Delivery & Offload, $/E6 BTU (HHV)	(d)	5.03	5.12	5.22	5.32	5.43	5.54	5.66	5.78	5.91	6.04	6.19	6.33	6.49
Sales Tax @ 6% of FOB + Delivery		0.89	0.90	0.91	0.92	0.94	0.95	0.96	0.98	0.99	1.00	1.02	1.04	1.05
Retail Markup	(f)	8.08	8.08	8.09	8.10	8.11	8.12	8.13	8.14	8.15	8.16	8.18	8.19	8.21
Retail Price LNG/CNG, $/E6 BTU		23.79	23.99	24.20	24.41	24.64	24.87	25.12	25.37	25.64	25.91	26.20	26.49	26.80
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$10.41	$10.58	$10.79	$10.95	$11.15	$11.23	$11.44	$11.65	$11.98	$12.13	$12.76	$13.40	$14.05
% Savings		30.44%	30.61%	30.84%	30.97%	31.15%	31.10%	31.29%	31.47%	31.84%	31.89%	32.75%	33.59%	34.39%
Annual Savings, $/yr		$ 6,194,721	$ 6,328,497	$ 6,487,458	$ 6,616,942	$ 6,770,372	$ 6,852,240	$ 7,014,983	$ 7,182,634	$ 7,420,087	$ 7,551,248	$ 7,981,994	$ 8,423,713	$ 8,876,622
Total Savings, Project Life, $		**$ 335,386,438**												
Present Value of Savings (2011)	(g)	**$145,746,753**												
ENERGY DEMAND														
Heating + Electrical Use,E6 BTU/yr	(e)	595215	598191	601182	604188	607209	610245	613296	616363	619445	622542	625655	628783	631927
INFLATION FACTORS														
No. of years from 2010		11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation factor	(h)	1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73

NOTES:

(a) 2021 - 2030 values from AEA projection, 'medium pricing' (Saylor & Foster, ISER, 2010). Post 2030 assumes 2.4% inflation

(b) Assumes LNG Base Year Value = $8.50/E6 BTU DES Asia less $0.59/E6 BTU per page 15 Wood Mac

(d) Derived on "Case B, Delivery Estimate" worksheet.

(e) Assumes 0.5% annual growth due to population growth + higher per capita use.

(f) Developed on Retail Markup Worksheet

(g) Discount rate = 5.0%

(h) Inflation constant @ 2.4%/yr.

(i) Wood Mackenzie, "Alaskan LNG Exports Competitiveness Study" 27 July 2011.

ote i)

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$5.79	$5.93	$6.07	$6.22	$6.37	$6.52	$6.68	$6.84	$7.00	$7.17	$7.34	$7.52	$7.70	$7.88	$8.07	$8.27	$8.47	$8.67
$41.83	$42.83	$43.86	$44.91	$45.99	$47.09	$48.22	$49.38	$50.57	$51.78	$53.02	$54.29	$55.60	$56.93	$58.30	$59.70	$61.13	$62.60
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64
0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
3.92	4.02	4.11	4.21	4.31	4.42	4.52	4.63	4.74	4.86	4.97	5.09	5.21	5.34	5.47	5.60	5.73	5.87
1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
0.71	0.72	0.74	0.76	0.78	0.80	0.81	0.83	0.85	0.87	0.90	0.92	0.94	0.96	0.99	1.01	1.03	1.06
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
-1.18	-1.21	-1.24	-1.27	-1.30	-1.33	-1.36	-1.40	-1.43	-1.47	-1.50	-1.54	-1.57	-1.61	-1.65	-1.69	-1.73	-1.77
11.17	**11.30**	**11.43**	**11.56**	**11.69**	**11.83**	**11.97**	**12.11**	**12.26**	**12.41**	**12.57**	**12.73**	**12.89**	**13.05**	**13.22**	**13.40**	**13.58**	**13.76**
11.17	11.30	11.43	11.56	11.69	11.83	11.97	12.11	12.26	12.41	12.57	12.73	12.89	13.05	13.22	13.40	13.58	13.76
6.65	6.82	7.00	7.19	7.39	7.59	7.80	8.03	9.36	9.65	9.96	10.28	10.61	10.96	11.33	11.71	12.11	12.53
1.07	1.09	1.11	1.12	1.14	1.17	1.19	1.21	1.30	1.32	1.35	1.38	1.41	1.44	1.47	1.51	1.54	1.58
8.22	8.24	8.26	8.28	8.30	8.32	8.35	8.37	8.40	8.42	8.45	8.48	8.51	8.54	8.57	8.60	8.64	8.68
27.12	27.45	27.79	28.15	28.52	28.91	29.31	29.72	31.32	31.81	32.33	32.86	33.42	34.00	34.60	35.22	35.87	36.54
$14.71	$15.38	$16.06	$16.76	$17.47	$18.19	$18.92	$19.66	$19.25	$19.97	$20.69	$21.43	$22.18	$22.93	$23.70	$24.48	$25.26	$26.06
35.16%	35.91%	36.63%	37.32%	37.98%	38.62%	39.23%	39.81%	38.07%	38.56%	39.03%	39.47%	39.89%	40.28%	40.65%	41.00%	41.33%	41.63%
$ 9,340,943	$ 9,816,895	$ 10,304,699	$ 10,804,578	$ 11,316,753	$ 11,841,447	$ 12,378,881	$ 12,929,276	$ 12,722,996	$ 13,262,576	$ 13,813,955	$ 14,377,260	$ 14,952,608	$ 15,540,112	$ 16,139,872	$ 16,751,983	$ 17,376,525	$ 18,013,570
635086	638262	641453	644660	647884	651123	654379	657651	660939	664244	667565	670903	674257	677628	681017	684422	687844	691283

24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64

Appendix D

Model Spreadsheets, Fairbanks

F1 Fairbanks Wholesale Comparison, IEA Reference Diesel costs w/ adjustment to AK wholesale & $1.00/E6 BTU wellhead gas value

Report Reference: Figure 3, Case F1

Lower 48 Wholesale Diesel price, $/E6 BTY (Feb 2011)	20.96 (d)
AK Wholesale Diesel price, $/E6 BTY (Feb 2011)	22.64 (d)

NG Wholesale Cost Buildup, based on Wood Mac Study, pg. 15 (i).

Wellhead Value	1.00			
WH Processing	0.26			
Processing & Shrinkage	2.22			
Transport	1.15	Transport to Valdez		$ 1.70
LNG Losses	0.00	Miles to Valdez		800
Liquefaction	0.00	Miles to Fairbanks		540
Liquids Credit	0.00	Ratio FAI miles/Valdez Miles		0.675
NG Wholesale City Gate FAI, $/	**4.63**	Central Oil Furnaces in FAI	(b)	21134
Basis Year 2010		Ave Oil Furnace consump.	(b)	938
Annual Inflation:	1.024	FAI Oil Furnace Use, BTU/yr		2.567E+12
Annual demand growth	1.005			

Properties

Diesel HHV, BTU/gal.	138490	100.00%	
Diesel LHV, BTU/gal.	129490	93.50%	
WTI Oil BTU/gal.	6.00E+06		
	min	**max**	**mean**
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437
CNG density @ 3600 psig, lb/ft^3			12.1

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted Diesel Price, Wholesale Lower 48 Ave., $/gal	(a)	$3.54	$3.61	$3.63	$3.71	$3.73	$3.75	$3.80	$3.82	$3.87	$3.83	$3.84	$3.85	$3.85
Alaska Wholesale Price Surcharge, $/gal		$0.23	$0.24	$0.24	$0.24	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25
Predicted Diesel Price, Wholesale Fairbanks Ave., $/gal		$3.77	$3.85	$3.87	$3.95	$3.97	$4.00	$4.05	$4.07	$4.12	$4.09	$4.09	$4.10	$4.10
Predicted $/E6 BTU (HHV), FAI Diesel Wholesale		**$27.23**	**$27.80**	**$27.94**	**$28.54**	**$28.67**	**$28.87**	**$29.26**	**$29.39**	**$29.77**	**$29.50**	**$29.55**	**$29.60**	**$29.64**
Wholesale Natural Gas														
Wellhead Value		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WH-Processing (invariant)		0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24	3.32	3.40	3.48	3.57	3.65	3.74	3.83
Transport (invariant)		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
LNG Losses (inflation adjusted)		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
Liquefaction (invariant)		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
Liquids Credit (inflation adjusted)		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
NG FAI City Gate, $/E6 BTU		**5.29**	**5.36**	**5.43**	**5.50**	**5.58**	**5.65**	**5.73**	**5.81**	**5.89**	**5.97**	**6.06**	**6.15**	**6.24**
Equivalent gas price, $/Diesel gallon equivalent		0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.80	0.82	0.83	0.84	0.85	0.86
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$21.94	$22.44	$22.51	$23.03	$23.10	$23.21	$23.53	$23.58	$23.88	$23.53	$23.49	$23.46	$23.40
% Savings		80.57%	80.72%	80.57%	80.72%	80.55%	80.42%	80.42%	80.23%	80.21%	79.75%	79.49%	79.23%	78.95%
Annual Savings, $/yr		$ 59,489,382	$ 61,150,326	$ 61,662,578	$ 63,402,358	$ 63,897,135	$ 64,540,086	$ 65,741,831	$ 66,213,997	$ 67,400,531	$ 66,736,467	$ 66,957,717	$ 67,195,670	$ 67,361,805
Total Savings, Project Life, $		**$ 2,413,791,936**												
Present Value of Savings (2021)	(g)	**$1,124,440,765**												
ENERGY DEMAND														
Heating Fuel Use,E6 BTU/yr	(e)	2711736	2725295	2738921	2752616	2766379	2780211	2794112	2808083	2822123	2836234	2850415	2864667	2878990

INFLATION FACTORS

No. of years from 2010		11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation factor	(h)	1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73
Energy growth factor		1.06												

(a) 2021 - 2035 from EIA Petroleum Products forecast, "Reference Case" (data for: "Transportation Fuel, Diesel Fuel (distillate fuel oil) 6/" . 2036 thru 2050 inflation factor =2.4%/yr.
(b) Sierra Research, '2010 Fairbanks Home Heating Survey', June 2010
(d) EIA data and PDC Harris Group fuel cost Snapshot June 2011.docx,
(e) Calculated from 2010 Fairbanks Home Heating Survey. Assumes 0.5% annual growth due to population growth + higher per capita use.
(f)
(g) Discount rate = 5.0%
(h) Inflation constant @ 2.4%/yr.
(i) Wood Mackenzie, "Alaskan LNG Exports Competitiveness Study" 27 July 2011.
(j) Szymoniak et al, "Components of Alaska Fuel Costs: An Analysis of Market Factors and Characteristics that Influence Rural Fuel Prices", Institute of Social and Economic Research (ISER), Univ. of Alaska, February 2010.

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$3.87	$3.89	$3.98	$4.08	$4.18	$4.28	$4.38	$4.48	$4.59	$4.70	$4.82	$4.93	$5.05	$5.17	$5.29	$5.42	$5.55	$5.69
$0.25	$0.26	$0.26	$0.27	$0.27	$0.28	$0.29	$0.29	$0.30	$0.31	$0.32	$0.32	$0.33	$0.34	$0.35	$0.36	$0.37	$0.37
$4.13	$4.15	$4.25	$4.35	$4.45	$4.56	$4.67	$4.78	$4.89	$5.01	$5.13	$5.26	$5.38	$5.51	$5.64	$5.78	$5.92	$6.06
$29.80	**$29.94**	**$30.65**	**$31.39**	**$32.14**	**$32.91**	**$33.70**	**$34.51**	**$35.34**	**$36.19**	**$37.06**	**$37.95**	**$38.86**	**$39.79**	**$40.75**	**$41.72**	**$42.73**	**$43.75**
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
3.92	4.02	4.11	4.21	4.31	4.42	4.52	4.63	4.74	4.86	4.97	5.09	5.21	5.34	5.47	5.60	5.73	5.87
1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
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	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
6.33	**6.42**	**6.52**	**6.62**	**6.72**	**6.82**	**6.93**	**7.04**	**7.15**	**7.26**	**7.38**	**7.50**	**7.62**	**7.75**	**7.87**	**8.01**	**8.14**	**8.28**
0.88	0.89	0.90	0.92	0.93	0.95	0.96	0.97	0.99	1.01	1.02	1.04	1.06	1.07	1.09	1.11	1.13	1.15
$23.48	$23.51	$24.13	$24.77	$25.42	$26.09	$26.78	$27.48	$28.19	$28.93	$29.68	$30.45	$31.24	$32.05	$32.87	$33.72	$34.59	$35.47
78.76%	78.54%	78.73%	78.91%	79.09%	79.27%	79.44%	79.61%	79.77%	79.93%	80.09%	80.24%	80.39%	80.53%	80.67%	80.81%	80.95%	81.08%
$ 67,922,479	$ 68,368,773	$ 70,528,527	$ 72,752,018	$ 75,041,106	$ 77,397,704	$ 79,823,783	$ 82,321,371	$ 84,892,555	$ 87,539,481	$ 90,264,360	$ 93,069,467	$ 95,957,141	$ 98,929,791	$ 101,989,897	$ 105,140,010	$ 108,382,754	$ 111,720,833
2893385	2907852	2922391	2937003	2951688	2966447	2981279	2996185	3011166	3026222	3041353	3056560	3071843	3087202	3102638	3118151	3133742	3149411

24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64

F2 Fairbanks Wholesale Comparison, IEA 'High Economic Growth' Diesel costs w/ adjustment to AK wholesale & $1.00/E6 BTU wellhead gas value

Report Reference: Figure 1, Case B1

Lower 48 Wholesale Diesel price, $/E6 BTY (Feb 2011)	20.96 (d)
AK Wholesale Diesel price, $/E6 BTY (Feb 2011)	22.64 (d)

NG Cost Buildup, Wood Mac Study, pg. 15

Wellhead Value	1.00			
WH Processing	0.26			
Processing & Shrinkage	2.22			
Transport	1.15	Transport to Valdez		$ 1.70
LNG Losses	0.00	Miles to Valdez		800
Liquefaction	0.00	Miles to Fairbanks		540
Liquids Credit	0.00	Ratio FAI miles/Valdez Miles		0.675
NG Wholesale City Gate FAI, $/	**4.63**	Central Oil Furnaces in FAI	(b)	21134
Basis Year 2010		Ave Oil Furnace consump.	(b)	938
Annual Inflation:	1.024	FAI Oil Furnace Use, BTU/yr		2.567E+12
Annual demand growth	1.005			

Properties

Diesel HHV, BTU/gal.	138490	100.00%	
Diesel LHV, BTU/gal.	129490	93.50%	
WTI Oil BTU/gal.	6.00E+06		
	min	**max**	**mean**
LNG Vaporized, BTU/std ft^3 (enriched for Asia)	1060	1130	1095
LNG density, lb/ft^3	45.04	47.13	46.085
LNG HHV, BTU/gal		86213	85300
LNG LHV, BTU/gal			75437
CNG density @ 3600 psig, lb/ft^3			12.1

		Start-up	1	2	3	4	5	6	7	8	9	10	11	12
DIESEL		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted Diesel Price, Wholesale Lower 48 Ave., $/gal	(a)	$3.67	$3.73	$3.79	$3.84	$3.90	$3.93	$3.93	$3.95	$3.98	$3.98	$4.02	$4.05	$4.05
Alaska Wholesale Price Surcharge, $/gal		$0.23	$0.24	$0.24	$0.24	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25	$0.26	$0.26
Predicted Diesel Price, Wholesale Fairbanks Ave., $/gal		$3.90	$3.97	$4.03	$4.09	$4.15	$4.18	$4.18	$4.20	$4.23	$4.24	$4.27	$4.30	$4.30
Predicted $/E6 BTU (HHV), FAI Diesel Wholesale		**$28.17**	**$28.66**	**$29.10**	**$29.52**	**$29.93**	**$30.20**	**$30.16**	**$30.32**	**$30.57**	**$30.59**	**$30.84**	**$31.07**	**$31.07**
Wholesale Natural Gas														
Wellhead Value		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WH-Processing (invariant)		0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Processing & Shrinkage (inflation adjusted)		2.88	2.95	3.02	3.09	3.17	3.24	3.32	3.40	3.48	3.57	3.65	3.74	3.83
Transport (invariant)		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
LNG Losses (inflation adjusted)		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
Liquefaction (invariant)		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
Liquids Credit (inflation adjusted)		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
NG FAI City Gate, $/E6 BTU		**5.29**	**5.36**	**5.43**	**5.50**	**5.58**	**5.65**	**5.73**	**5.81**	**5.89**	**5.97**	**6.06**	**6.15**	**6.24**
Equivalent gas price, $/Diesel gallon equivalent		0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.80	0.82	0.83	0.84	0.85	0.86
SAVINGS														
Savings, Diesel - LNG, $/E6 BTU (HHV)		$22.88	$23.30	$23.67	$24.02	$24.36	$24.55	$24.43	$24.51	$24.68	$24.62	$24.78	$24.92	$24.83
% Savings		81.22%	81.30%	81.34%	81.36%	81.37%	81.28%	81.00%	80.84%	80.73%	80.47%	80.35%	80.21%	79.92%
Annual Savings, $/yr		$ 62,034,878	$ 63,495,887	$ 64,839,219	$ 66,105,173	$ 67,377,350	$ 68,250,018	$ 68,266,417	$ 68,815,091	$ 69,643,859	$ 69,820,274	$ 70,625,734	$ 71,387,622	$ 71,486,094
Total Savings, Project Life, $		**$ 2,548,598,605**												
Present Value of Savings (2021)	(g)	**$1,184,320,513**												
ENERGY DEMAND														
Heating Fuel Use,E6 BTU/yr	(e)	2711736	2725295	2738921	2752616	2766379	2780211	2794112	2808083	2822123	2836234	2850415	2864667	2878990

INFLATION FACTORS

No. of years from 2010		11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation factor	(h)	1.30	1.33	1.36	1.39	1.43	1.46	1.50	1.53	1.57	1.61	1.65	1.68	1.73
Energy growth factor		1.06												

NOTES:

(a) 2021 - 2030 from EIA Petroleum Products forecast, Reference Case (data for: "Transportation Fuel, Diesel Fuel (distillate fuel oil) 6/"

(b) Sierra Research, '2010 Fairbanks Home Heating Survey', June 2010

(d) EIA data and PDC Harris Group fuel cost Snapshot June 2011.docx,

(e) Calculated from 2010 Fairbanks Home Heating Survey. Assumes 0.5% annual growth due to population growth + higher per capita use.

(f)

(g) Discount rate = 5.0%

(h) Inflation constant @ 2.4%/yr.

(i) Wood Mackenzie, “Alaskan LNG Exports Competitiveness Study” 27 July 2011.

13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$4.06	$4.09	$4.18	$4.28	$4.39	$4.49	$4.60	$4.71	$4.82	$4.94	$5.06	$5.18	$5.30	$5.43	$5.56	$5.70	$5.83	$5.97
$0.26	$0.26	$0.27	$0.27	$0.28	$0.28	$0.29	$0.30	$0.31	$0.31	$0.32	$0.33	$0.34	$0.34	$0.35	$0.36	$0.37	$0.38
$4.32	$4.35	$4.45	$4.56	$4.67	$4.78	$4.89	$5.01	$5.13	$5.25	$5.38	$5.51	$5.64	$5.78	$5.91	$6.06	$6.20	$6.35
$31.18	**$31.38**	**$32.13**	**$32.90**	**$33.69**	**$34.50**	**$35.33**	**$36.17**	**$37.04**	**$37.93**	**$38.84**	**$39.77**	**$40.73**	**$41.71**	**$42.71**	**$43.73**	**$44.78**	**$45.86**
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
3.92	4.02	4.11	4.21	4.31	4.42	4.52	4.63	4.74	4.86	4.97	5.09	5.21	5.34	5.47	5.60	5.73	5.87
1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
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	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
6.33	**6.42**	**6.52**	**6.62**	**6.72**	**6.82**	**6.93**	**7.04**	**7.15**	**7.26**	**7.38**	**7.50**	**7.62**	**7.75**	**7.87**	**8.01**	**8.14**	**8.28**
0.88	0.89	0.90	0.92	0.93	0.95	0.96	0.97	0.99	1.01	1.02	1.04	1.06	1.07	1.09	1.11	1.13	1.15
$24.85	$24.95	$25.61	$26.28	$26.97	$27.67	$28.40	$29.14	$29.89	$30.67	$31.46	$32.27	$33.11	$33.96	$34.83	$35.73	$36.64	$37.58
79.70%	79.53%	79.71%	79.88%	80.05%	80.22%	80.38%	80.54%	80.70%	80.85%	81.00%	81.15%	81.29%	81.43%	81.56%	81.69%	81.82%	81.95%
$ 71,910,796	$ 72,554,829	$ 74,836,481	$ 77,185,420	$ 79,603,608	$ 82,093,066	$ 84,655,874	$ 87,294,173	$ 90,010,165	$ 92,806,116	$ 95,684,359	$ 98,647,296	$ 101,697,396	$ 104,837,203	$ 108,069,333	$ 111,396,478	$ 114,821,411	$ 118,346,984
2893385	2907852	2922391	2937003	2951688	2966447	2981279	2996185	3011166	3026222	3041353	3056560	3071843	3087202	3102638	3118151	3133742	3149411

24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
1.77	1.81	1.85	1.90	1.94	1.99	2.04	2.09	2.14	2.19	2.24	2.29	2.35	2.40	2.46	2.52	2.58	2.64

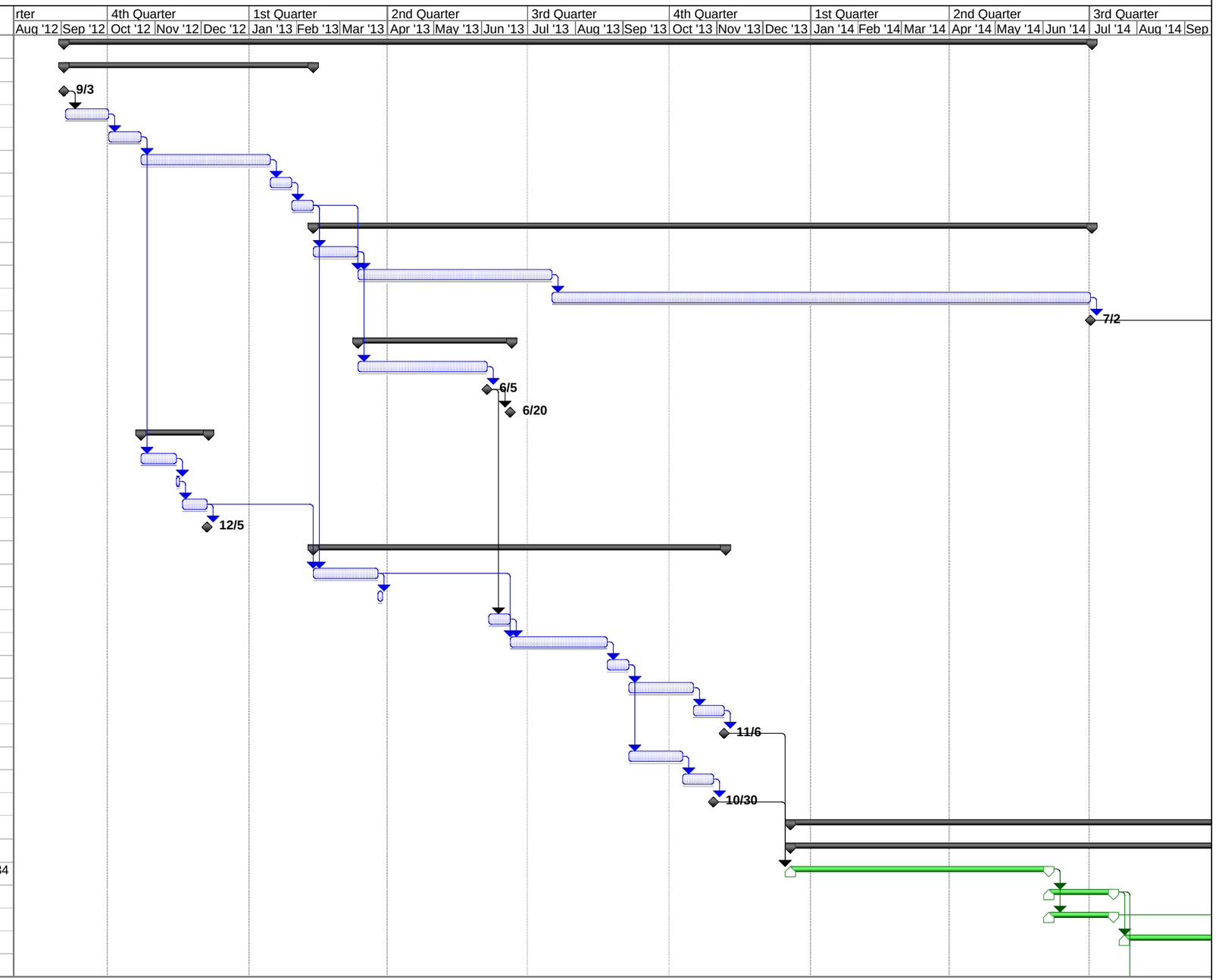
Appendix B

Preliminary Project Schedule

AEA Emerging Technology Grant Application
Preliminary Schedule
LCNG - A Bridge to Reduced Energy Costs for Rural Alaska

PDC Harris Group LLC

ID	Task Name	Duration	Predecessors
1	**Phase 1 - Pre-Deployment**	**478 days?**	
2	**System Design**	**116 days**	
3	Project Kickoff	1 day	
4	On-Site Survey and Field Data Processing	20 days	3
5	* Develop Design Basis Memo	15 days	4
6	* Develop Discipline Specific Design Packages	60 days	5
7	Design Review	10 days	6
8	* Finalize Concept Design	10 days	7
9	**Permitting**	**362 days**	
10	Long Lead Permit Assessment	21 days	8
11	* Long Lead Permit Application	90 days	10,8
12	* Permit Application Review and Processing	250 days	11
13	* Permit Granted	1 day	12
14	*** Engage LNG Suppliers/Purchase Negotiations**	**72 days?**	
15	LNG Supply Negotiations	60 days	10
16	LNG Purchase Agreement Short Term Pilot	1 day?	15
17	LNG Purchase Agreement Long Term Deployment	1 day?	16FS+10 days
18	**Technical Readiness Assessment Plan**	**32 days?**	
19	Experimental Design - Diesel Test Bed	17 days	5
20	* Develop Test Bed Program Cost	2 days	19
21	Assessment Plan, Develop	12 days	20
22	* Issue TRL Assessment Plan	1 day?	21
23	**Project Financing Plan**	**192 days?**	
24	Prepare Construction Cost Estimate	30 days	8,21
25	* Review & Approve Capital Estimate	3 days	24
26	Estimate O&M and LNG Costs	10 days	16
27	Proforma Economic Model, Test and Run	45 days	24,26
28	* Review & Approve Economic Model	10 days	27
29	Prepare Project Financing Plan	30 days	28
30	* Review & Approve Financing Plan	14 days	29
31	* Project Financing Plan Complete	1 day?	30
32	Prepare Commercialization Plan	25 days	28
33	*Review & Approve Commercialization Plan	14 days	32
34	* Project Commercialization Plan Complete	1 day?	33
35	**Phase 2 - Deployment**	**585 days?**	
36	**Design and Bid Activities**	**211 days?**	
37	LCNG Facility Detailed Design	6 mons	31FS+30 days,34
38	Bid Packages, Fabrication	30 days	37
39	Bid Packages, Construction	30 days	37
40	Procure Equipment	50 days	38FS+5 days
41	Award Construction	1 day?	39FS+60 days



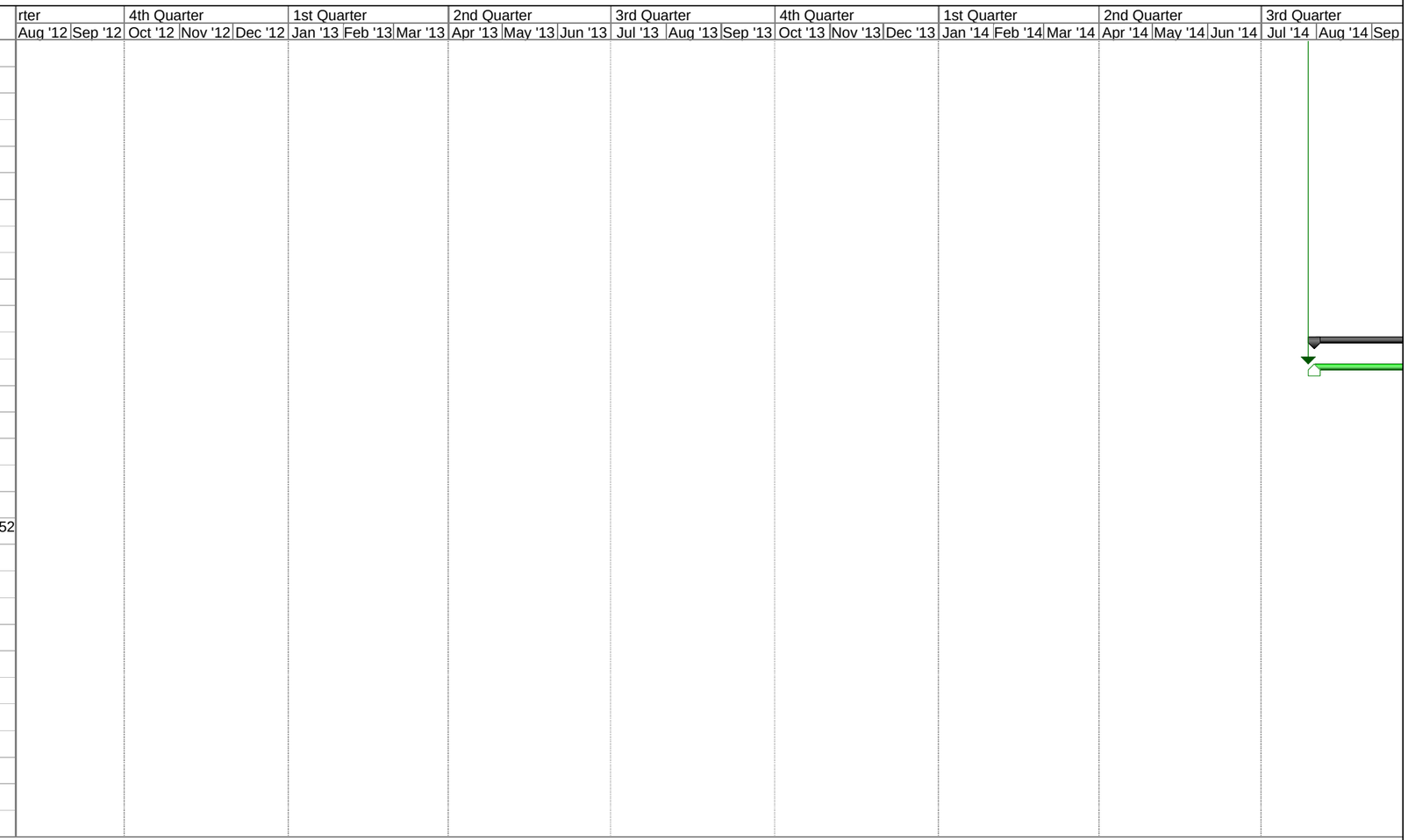
Project: AEA Grant Sched2_24_2012.
Date: Wed 2/29/12

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External MileTask | Split

AEA Emerging Technology Grant Application
Preliminary Schedule
LCNG - A Bridge to Reduced Energy Costs for Rural Alaska

PDC Harris Group LLC

ID	Task Name	Duration	Predecessors
42	**Construct Pilot Scale Plant in Bethel**	**132 days**	**13,41**
43	Kick-Off Meeting	1 day	
44	Construction of Pilot LCNG Systems	6 mons	43
45	Commission and Checkout	2 wks	43,44
46	Commence Operation	1 day	45
47	**TRL Assess, Test Engine-Generator @ ACEP**	**47 days?**	
48	Install Engine Modifications	10 days	40
49	Calibrate Controls & Monitoring System	8 days	48
50	Run Test Cycle	21 days	49
51	Compile Test Report	7 days	50
52	Issue Test Report	1 day?	51
53	**LNG Delivery Barge**	**181 days?**	
54	Fabrication	8 mons	38FS+10 days
55	Sea Trails	10 days	54
56	Delivery	10 days	55
57	Begin LNG Delivery	1 day?	56
58	Plant Performance and Cost Monitoring	40 wks	46,57
59	Update Financing Plan	21 days	58
60	Update Commercialization Plan	20 days	46FS+1 day,59,52
61	Deployment of Commercial Scale Complete	1 day?	60
62	**Phase 3 - Post Deployment**	**382 days**	**60FS+30 days**
63	Design/Bid Hub/Satellite System	120 days	61
64	Construct Hub/Satellite System	150 days	63
65	Complete Commercialization Plan	30 days	64
66	Continued Performance Monitoring	40 wks	63
67	**Conclusions & Recommendations**	**62 days**	
68	Develop Draft Report	30 days	65,66
69	Present to AEA & Stakeholders	1 day	68
70	Finalize Report	30 days	69
71	Issue Final Report	1 day	70



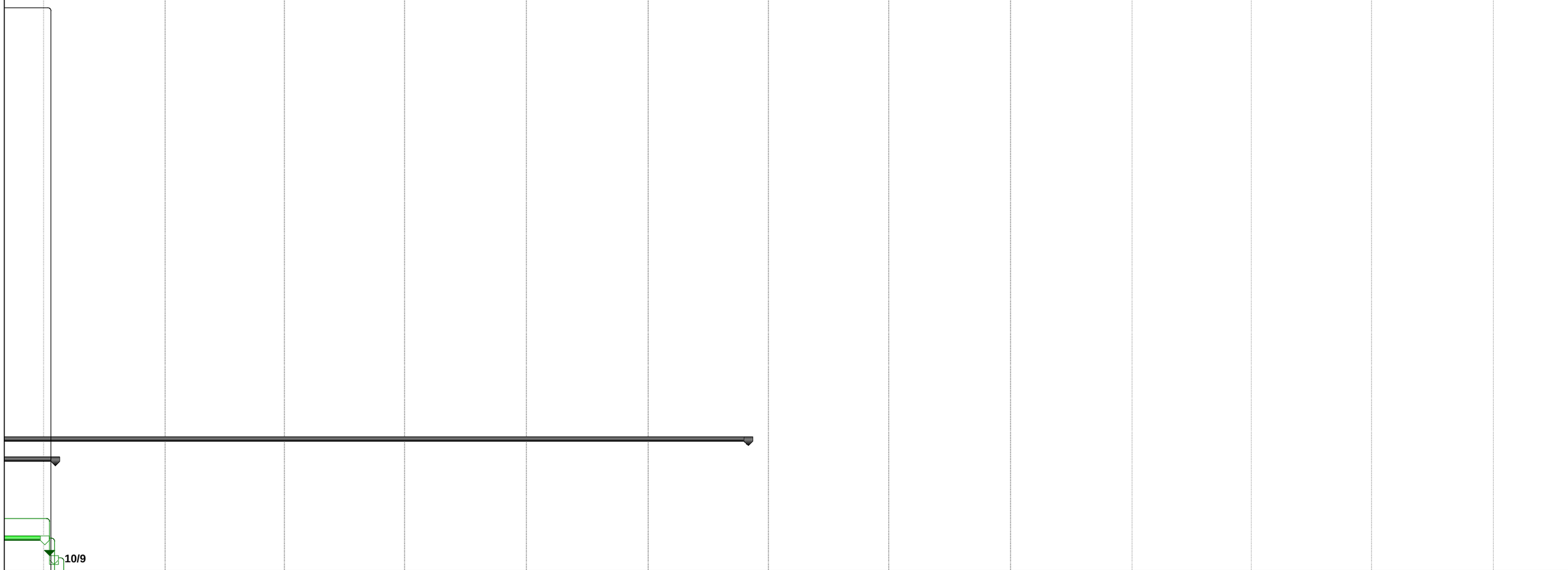
Project: AEA Grant Sched2_24_2012.
Date: Wed 2/29/12

Task | Progress | Summary | External Tasks | Split
Split | Milestone | Project Summary | External MileTask

AEA Emerging Technology Grant Application
Preliminary Schedule
LCNG - A Bridge to Reduced Energy Costs for Rural Alaska

PDC Harris Group LLC

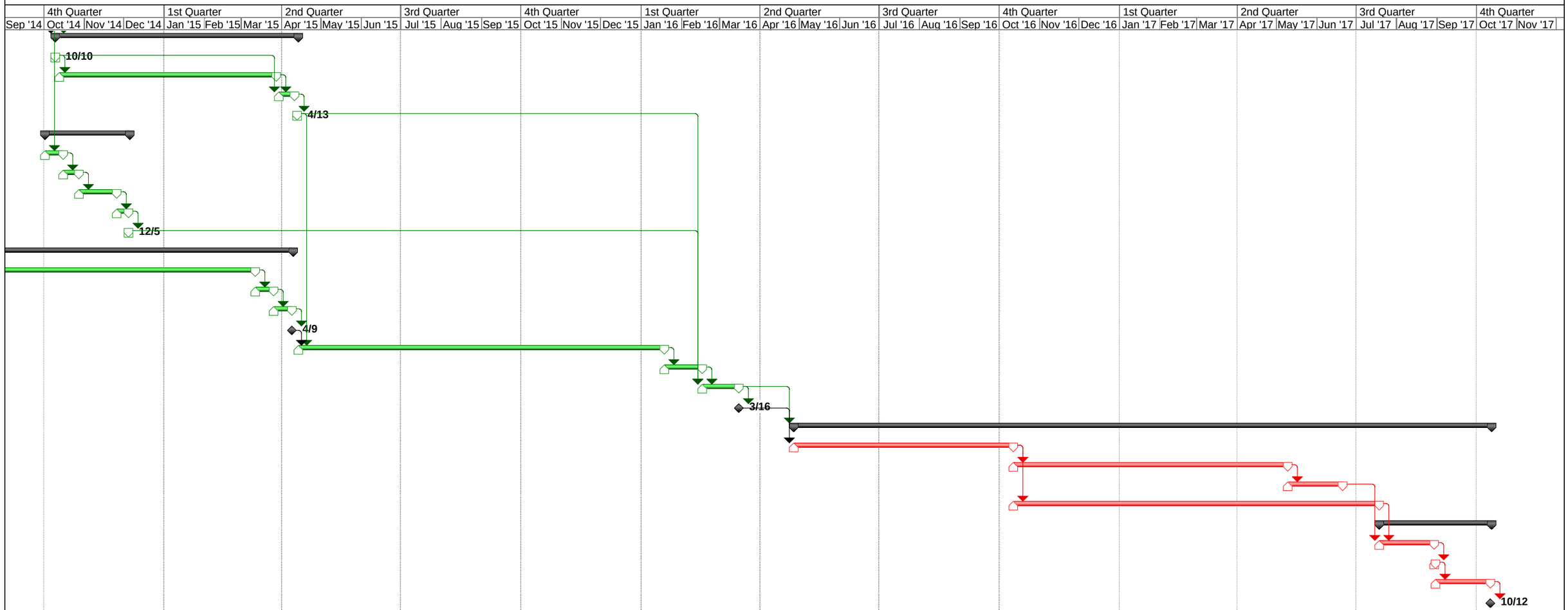
	4th Quarter			1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			1st Quarter			2nd Quarter			3rd Quarter			4th Quarter	
Sep '14	Oct '14	Nov '14	Dec '14	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Jan '16	Feb '16	Mar '16	Apr '16	May '16	Jun '16	Jul '16	Aug '16	Sep '16	Oct '16	Nov '16	Dec '16	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17



Project: AEA Grant Sched2_24_2012.
Date: Wed 2/29/12

Task		Progress		Summary		External Tasks		Split	
Split		Milestone		Project Summary		External MileTask			

AEA Emerging Technology Grant Application
Preliminary Schedule
LCNG - A Bridge to Reduced Energy Costs for Rural Alaska



Project: AEA Grant Sched2_24_2012.
Date: Wed 2/29/12

Task		Progress		Summary		External Tasks		Split	
Split		Milestone		Project Summary		External MileTask			

Appendix C

Project & Cost Report System

PDC HARRIS GROUP

ENERGY STRATEGIC BUSINESS UNIT

PROGRESS AND COST REPORT SYSTEM

INTRODUCTION

The PDC Harris Group is committed to providing its clients with efficient and well managed projects by utilization of proven tracking and reporting systems. Proper planning, budgeting, scheduling, and monitoring are key elements in the management process and are essential in executing each project. At the heart of these systems for the Energy Strategic Business Unit is the Progress and Cost Report (PCR), which integrates an earned-value-based project control system with up to date job expenditure data from accounting records. This document outlines the purpose of, responsibilities for and reporting of the PCR:

Purpose of the PCR Manual

The purpose of this manual is to:

- Illustrate and describe HGI's standardized approach to reporting for project progress and cost tracking;
- Present definition and guidelines for the application of the standard corporate Engineering Code of Accounts;
- Define the Earned Value Concept, its principles and its applications to progress reporting;
- Describe the guidelines and techniques involved in creating a project status system for a project;
- Discuss the information contained in the PCR and provides guidelines for data analysis;
- Provide guidelines for the appropriate use of the PCR's analytical tools to produce an accurate forecast and to develop a basis for corrective action; and,
- Give examples of both progress and cost reports.

Responsibility for Implementation

All projects greater than 1,000 hours and lasting more than 2 months shall provide a PCR to Management. The HGI Operations Manager is responsible for ensuring that all project management personnel utilize the PCR system, unless a project is determined by senior management to be specifically exempt.

Once the PCR is in place on a project, updating, analyzing and reporting functions are requird at least monthly, or at more frequent intervals, depending on the project schedule and particular needs of the project. The project manager is responsible for implementation and maintaining the PCR for his project in cooperation with the project engineer and discipline leads. The Project Controls Group assists in preparing and maintaining the system.

WORK BREAKDOWN STRUCTURE

Definition

The Work Breakdown Structure (WBS) is a hierarchical structure of cost centers which subdivides a project from top to bottom into successively greater levels of detail. A WBS provides a consistent structure for project control on all HGI projects, and facilitates the compilation of historical cost data for future use.

The first step in project control is to define the project scope by dividing the project into its quantifiable and statusable elements, using a WBS. The Engineering and Construction Project Management book by A.E. Kerridge and C.H. Vervalin states:

> "The WBS establishes the framework for contract execution, cost reporting, schedule and technical performance."

According to ANSI/EIA-748-A-1998 (reaffirmed 2002) a Work Breakdown Structure is defined as:

> "A product-oriented division of program tasks depicting the breakdown of work scope for work authorization, tracking, and reporting purposes."

The HGI WBS consists of two distinct elements within projects: the "numerical task or sub-project codes" and the "Engineering Code of Accounts". HGI has the capability to utilize sub jobs and / or tasks within a Project. These each have particular benefits in subdividing projects into identifiable areas. The Deltek Vision accounting system provides actual expenditure reports and invoicing reports for Sub-jobs separately while and tasks are enumerated separately and then summarized in single progress and invoicing reports. The sub-jobs may be closed when completed so are useful for projects with definite phases. The task codes may used to define the major elements into which the project will be divided for execution and control purposes. The quantity of sub-jobs and task codes is governed by project size and complexity and requirements. The task structure for projects may be provided in some cases by customers based on their requirements for identification of specific areas., The first task code for a biofuels project, for example, might be the power island facilities and the second task code could be the fuel handling facilities.

The second element of detail consists of codes derived from the appropriate application for the HGI Engineering Standard Code of Account. This detail defines the project scope in terms of work discipline and deliverables. A copy is included for reference, refer to Exhibit 1.

These account codes are structured to provide increasing levels of detail that facilitate data collection for cost control, serve as a checklist for all major items of costs associated with a project, and provide uniformity in feedback of cost information that can be utilized in preparing future cost estimates. Hours and associated costs are collected at the most detailed level. Refer to Exhibit 6. The codes go from general to specific. Cost Code 3236C, for example, identifies a Mechanical Engineer performing mechanical calculations utilizing specialty software.

The five character code, e.g. 3236C, is comprised of numeric characters each providing successively more detailed information.

(3) – Discipline – Mechanical

(2) – Activity Performer – Engineer

(3) – Work Product Category – Design

(6) – Work Product – Mechanical Calculations

(C) – Specific Billing Category – Specialty Software

The use of this hierarchal structure, allows HGI to maintain and summarize man-hours and dollars at all levels of detail. The uniform use of these cost codes provide continuity between projects, estimates, time sheets and project status. All project members must understand the importance of accurate time charging in achieving that goal. If project members are thoroughly familiar with the estimate, the WBS and the Engineering Code of Accounts, they will charge time more accurately. The project Engineering Code of Accounts and instructions on its application must be conveyed to the entire team. The project Engineering Code of Accounts will be approved by Project controls Manager, documented in the Project Procedure Manual, and rigorously enforced during the weekly timesheet approval process.

ORIGINAL AND CURRENT BUDGETS

Definition

The estimate that was developed prior to the start of a project is used as a basis for developing the Control Budget. The Control Budget may be very similar to the estimate but it allocates all; items in appropriate places for instance any late added items or global adjustments that were applied as a result of management review prior to approval are incorporated into specific cost codes. The control budget lists all deliverables and establishes a detailed accounting for tracking and control purposes. The Control budget on a Project is referred to as the The approved project budget is referred to as the Original Budget. The Original Budget total man-hours and dollars are firm and are not adjusted except through the use of change orders approved by the client (External) or internally approved changes (External.)

The estimate that was developed prior to the start of a project is used as a basis for developing the Control Budget. The Control Budget may be very similar to the estimate but it allocates all items to their appropriate places including a complete listing of deliverables. It also incorporates into specific cost codes any specific final adjustments, any late added items or global adjustments that were applied as a result of management review prior to approval of the estimate. The control budget lists all deliverables and establishes a detailed accounting for tracking and control purposes. The Control budget on a Project is referred to as the The approved project budget is referred to as the Original Budget. The Original Budget total man-hours and dollars are firm and are not adjusted except through the use of change orders approved by the client (External) or internally approved changes (External.)

An External Change Order is a change to an incremental portion or portions or the Original Budget which also changes the total. An External Change Order is generally initiated by the project team in reaction to an action or decision by the client. Once the impact of the change order is known, the client may or may not approve the scope change. If the scope change is approved, the budget revision is included in the “Change Orders” column for both hours and dollars on all PCR tabular reports.

An Internal Change Order is an adjustment to the distribution of the Original Budget. This type of change order is used to document adjustments to individual accounts. These adjustments may be made by reducing contingency to cover items that HGI should have included in the Original Budget breakdown, but which were not specifically identified, or to move budget from one account or one discipline to another. These are shown in the "Transfers" column in all PCR tabular reports.

The addition of the Original Budget plus Internal changes (transfers) plus approved change order adjustments equal the Current Budget, against which the project is measured and tracked. The Original Budget and adjustments will always be shown in reports separately so that the adjustments can be seen.

EARNED VALUE CONCEPT

Definition

Earned Value is an established and proven concept and it is defined in the Engineering and Construction Project Management book by A.E. Kerridge and C.H. Vervalin:

> "The Earned Value Concept implies the measurement of accomplished work at any time in the course of the project in terms of budgets planned for that work."

According to ANSI/EIA-748-A-1998 (reaffirmed 2002) Earned Value Management System it is defined as:

> "The value of completed work expressed in terms of the budget assigned to that work"

HGI prescribes to the following definition:

> "The earned value concept represents actual accomplishments (earned man-hours) measured against a predetermined standard (budget man-hours), and it is independent of actual man-hours expended."

The Earned Value approach serves as the basis for generating overall project progress and performance measurement.

EVALUATING EARNED PROGRESS "PERCENT COMPLETE"

Definition

The Earned progress is the value of work performed measured against the Current Budget.

The PCR includes a percent complete field and the user must input the percent complete for each line item in order to calculate the total earned man-hours.

The following example shows how the piping design lead might status the general arrangement drawings using the HGI milestone technique.

Guidelines have been established as an aid in evaluating the actual physical percent t complete for general categories of deliverable. See attached Engineering Progress Milestones (Exhibit 5).

Actual physical percents complete are assigned to each budgeted item. The percent complete multiplied by the budget equals the earned value. All items are summed at the WBS, cost code, discipline and summary levels and divided by their respective summed budgets to arrive at earned value for each level.

For example, if we assume that each of the following drawings is budgeted for 100 hours and the earned hours have been calculated as follows:

Drawing	Budget	%	Earned Hours
General Arrangement "A"	100	85	85
General Arrangement "B"	100	50	50
General Arrangement "C"	100	25	25
General Arrangement "D"	100	30	30
General Arrangement "E"	100	10	10
Total	500	40	200

The PCR sums the total earned hours to 200 and the percent complete for cost code 70630 is 200 earned man-hours divided by 500 budgeted man-hours or 40% complete.

ACCOUNTING INTERFACE

Actual Hours and Dollars

Project man-hour expenditures are input directly into Deltek Vision by project members when they code their man-hours on weekly timesheets. This coding will be in accordance with predetermined cost codes contained in the Project Procedure Manual. All timesheets are reviewed by the Project Manager or their designate before being entered into the HGI accounting system. Once approved and entered, the man-hour charges are automatically captured by Deltek Vision which is also configured around the established Engineering Code of Accounts.

Timesheets are completed each Friday and the actual hours and costs are available in Vision. Project PCR users can then access actual expenditures as needed. The actual hours and costs from Vision will include period and cumulative expenditures. Hours and costs will be electronically segregated into their proper cost code.

Actual man-hours are not used for statusing work products, but they are used in calculating Efficiency (also referred to as Performance Factors or Productivity), one of the tools used in forecasting the Estimate to Complete and Total Forecast hours.

On the cost side of the PCR, actual dollars are divided by the actual man-hours to derive a cumulative hourly rate per cost code. Hourly rates are used to compute ETC costs. This process is further discussed in the section entitled "Estimate to Complete."

Note that for lump sum or fixed price projects, these reports are internal to HGI. Customers generally receive only physical progress data.

ANALYSIS

Efficiency

The ratio of earned man-hours to actual man-hours is used to analyze the performance of the work to date. Typically, for example, the man-hours for general arrangement drawings are charged to cost code 70630. If 175 man-hours are charged against that cost code and the earned man-hours are 200, then the Efficiency is 1.14.

Performance Factor: (204 hours earned / 175 hours expended) = 1.14

Budget = 1.00, less than 1.00 is over budget, over 1.0 is under budget.

ESTIMATE TO COMPLETE

Definition

The remaining man-hours to complete the work products are referred to as the Estimate to Complete man-hours. These man-hours can be determined by several methods:

1. If the discipline leader plans to evaluate the drawings on an individual basis, then the following method will apply:

   - Each drawing is evaluated to determine the remaining man-hours required. This is an analysis without regard to the budget.

2. If the discipline leader plans to evaluate on an account basis, then the following methods will apply:

   - Budgeted man-hours minus earned man-hours without a adjusting for efficiency. This technique is usually applied when the percent complete is less than 30%.

   - Budgeted man-hours minus earned man-hours divided by a forecasted efficiency. Using this method allows for fine-tuning the estimate to complete by assessing whether the efficiency is expected to remain static, improve or deteriorate through the end of project.

When calculating Estimate to Complete dollars, the Project Controls Representative must evaluate the dollars per man-hour to be used for extending the estimate to complete man-hours realizing that through different phases of a project the actual discipline dollars per man-hour may fluctuate widely. Ideally, the average rate will equal the current budgeted rate at project completion. Evaluating current data and available personnel is essential to forecasting final dollars per man-hour.

TOTAL FORECAST

Definition

Once the Estimate to Complete hours and costs are calculated, calculating the Total Forecast hours is a simple step:

- Total Forecast hours are equal to the Estimate to Complete hours plus Actual hours.
- Total Forecast costs are calculated in the same manner.

HISTORICAL ESTIMATING DATA

The Discipline Managers will obtain final reports from the Progress and Cost Report system after a project is completed and will use the information for future engineering estimates (see Exhibit 8). A key point to remember is that the quality of information in the PCR will only be as accurate as the coded time charges reflect. The Discipline Leads, Project Engineers and Project Managers must review and edit man-hour charges on a weekly basis. Inaccurate time charges cannot be allowed to accumulate.

DEFINITIONS

The Progress and Cost Report System is best defined by the source and content of information presented in the program's reports. All of the program's reports are prepared and presented in a standard format, containing the same column headings. All data is tabulated and summarized in the Progress and Cost Report Summary similar to Figure 1. Each of the columns is numerically labeled and their contents are defined below.

COLUMN	DESCRIPTION
1	ACCOUNT CODE

The account code consists of the Cost Code applied from the Engineering Code of Accounts only, or in an area/sub-job/department designation and a cost code.

TASK	-	COST C0DE
01	-	52300

Areas/sub-jobs or departments may be defined for each project.

The PDC Harris GroupStandard Engineering Code of Accounts (Exhibit 1) is common to all projects. It should not be changed for individual projects; however, it can be supplemented with additional cost codes.

2 DESCRIPTION

The Progress and Cost Report Summary descriptions are a Harris Group standard and are common to all projects. They are designated by the first digit of the cost code and are as follows:

1 – Project
2 – Construction Services
3 – Mechanical/Piping
4 – Process
5 – Electrical
6 – Control Systems
7 – Piping
8 – Civil/Structural
9 – Expenses

Descriptions in the detail reports refer to cost code titles for each type of effort and groups of drawings with additional descriptions for specific deliverables.

3 ORIGINAL BUDGET LABOR HOURS

The Original Budget Labor Hours is the baseline estimate of hours required for the described item.

4 CHANGE ORDER LABOR HOURS

The Change Order Labor Hours are the hours used to adjust the Current Budget based on approved change orders.

5 TRANSFERS

The Transfers Column contains all hours included in Internal Change Orders or other adjustments that may be made within a discipline or between disciplines.

Transfers of hours may be made to adjust for a variety of items, for example, redistribution of hours when the content of a budgeted number of drawings is consolidated into fewer drawings or when design planned for a specific discipline can be consolidated or better represented in another discipline.

6 CURRENT BUDGET LABOR HOURS

The Current Budget is a summation of the Original Budget, Change Order and Transfer hours.

All Project progress (earned hours) is measured against the Current Budget.

7 ACTUAL HOURS

Actual hours and costs are obtained from Deltek Vision and are input by cost code. This can be accomplished manually or by electronic transfer.

8 PERCENT COMPLETE

The Percent Complete is input for each budgeted work item.

The Percent Complete is a subjective assessment of the quantity of work completed for each item, irrespective of actual hours expended. Guidelines have been established as an aid in evaluating the actual physical percent complete for general categories of deliverable. See attached Engineering Progress Milestones (Exhibit 5).

9 EARNED HOURS

Earned hours are calculated by multiplying the Current Budget by the Percent Complete for each budgeted work item.

10 ESTIMATE TO COMPLETE

At the beginning of a project, the Estimate to Complete is equal to the Current Budget. Subsequently, the Estimate to Complete hours may be calculated by using the Current Budgeted man-hours minus earned man-hours with or without adjusting for efficiency. Estimated hours to complete may also be input manually after making a more specific assessment (or re-estimate).

11 TOTAL FORECAST

The Total Forecast hours are a summation of the Actual and Estimate to Complete hours.

12 VARIANCE

The Variance is the difference between the Current Budget and the Total Forecast.

13 EFFICIENCY (EARNED/ACTUAL)

The Efficiency is calculated by dividing Earned hours by Actual hours.

14 LABOR RATE BUDGET

The Labor Rate Budget is equal to the Original Budget dollars divided by the Original Budget Labor Hours. (The Labor Rate Budget is originally used to extend the Estimated Hours for the project in arriving at the Original Budget.)

15 LABOR RATE ADJUSTED BUDGET

The Labor Rate Adjusted Budget is equal to the Current Budget dollars divided by the Current Budget Labor Hours.

16 LABOR RATE ACTUAL

The Labor Rate Actual is calculated by dividing Actual Cost by Actual Labor Hours expended.

17 LABOR RATE ESTIMATE TO COMPLETE

The Labor Rate Estimate to Complete is the hourly rate used to extend the Estimated to Complete Hours. The rate is based on the Current Budget Rate but may be adjusted to reflect the actual rate expected to be experienced on the project.

18 LABOR RATE TOTAL FORECAST

The Labor Rate Total Forecast is equal to the Total Forecast dollars divided by the Total Forecast labor hours.

19 ORIGINAL BUDGET $$

The Original Budget is the original budgeted dollar value of the project.

20 CHANGE ORDER $$

The Change Order $$ is the dollar value of approved Change Orders.

21 TRANSFERS $

The Transfers column contains the dollar value of Transfers

22 CURRENT BUDGET $$

The Current Budget $$ is the summation of Original Budget, Change Orders, and Transfers.

23 ACTUAL COST

The Actual Cost is the dollar value of actual expenditures for the project.

24 ESTIMATE TO COMPLETE

The Estimate to Complete is the Product of Estimate to Complete hours times the Labor Rate Estimate to Complete and is the dollar value of remaining work to be accomplished for project completion.

25 TOTAL FORECAST $$

The Total Forecast is the summation of Actual cost plus the Estimate to Complete and is the predicted value of the project at completion.

26 VARIANCE TO CURRENT BUDGET

The Variance to Current Budget is the difference between the Current Budget and the Total Forecast.

PROGRESS AND COST REPORT (PCR)

Numerous sub-reports are generated and presented to management. They are collectively referred to as the PCR. Included are a Memorandum that summarizes pertinent facts dealing with the progress of the project (Exhibit 2), the Progress and Cost Report Summary report (figure 1), an Engineering Progress Curve (Exhibit 3), a Man-hour Plan histogram and curve (Exhibit 4), a detailed Progress and Cost Report (Exhibit 6), and a Change Request / Change Order Log (Exhibit 7), Summary (Exhibit 8).

The various elements of the PCR reports combine to provide a sound basis for management of any project. A summary schedule is also usually attached as part of the PCR (See the Scheduling Manual for specifics in how the same earned value techniques are used to control the time elements of projects.)

HISTORICAL DATA

The collection of data in a standardized way as provided by the PCR system makes it possible to gain insight into the average or normal expenditures of hours and costs in doing projects. An example of data collected in this way is presented in Exhibit 8, a “Compressor Station Historical Man-hour Summary.”

Figure 1

Progress and Cost Report Summary

Biomass Repowering Project
Project No: 65XXX.02

Week Ending: 07/01/05

1	2	3	4	5	6	7	8	9	10	11	12	13
Cost Code	Discipline	Original Budget Labor Hours	Change Order Labor Hours	Transfers	Current Budget Labor Hours	Actual Labor Hours	% Complete	Earned Labor Hours	Estimate to Complete	Total Forecast	Variance	To Date Efficiency (Earned / Actual)
11000	Project Managment	650	0.0		650.0	396	61.0%	396.5	254	650	(1)	1.00
12000	Project Engineer	1,300	0.0		1,300.0	417	32.0%	416.0	884	1,301	1	1.00
13000	Design Coordinator	0	0.0		0.0	0	0.0%	0.0	0	0	0	0.00
14000	CAD Op / Drafter	0	0.0		0.0	0	0.0%	0.0	0	0	0	0.00
16000	Eng'g Assist. / Doc Control	1,000	30.0		1,030.0	208	21.0%	216.3	814	1,022	(8)	1.04
17000	Est / Sch / Cost Control	300	10.0		310.0	94	29.0%	89.9	220	314	4	0.96
18000	Procurement	0	0.0		0.0	0	0.0%	0.0	0	0	0	0.00
10000	Subtotal Management	3,250	40	0	3,290	1,115	34.0%	1,119	2,171	3,286	(4)	1.00
30000	Mechanical	2,918	429.0	(10.0)	3,337.0	933	29.6%	987.4	2,350	3,282	(55)	1.06
40000	Process	0	0.0		0.0	0	0.0%	0.0	0	0	0	0.00
50000	Electrical	5,171	168.0		5,339.0	531	10.0%	532.0	4,807	5,338	(2)	1.00
60000	Controls	1,342	16.0		1,358.0	141	9.8%	133.0	1,225	1,366	8	0.94
70000	Piping	2,290	179.0	10.0	2,479.0	592	14.2%	352.2	2,127	2,719	240	0.59
80000	Civil / Structural	4,617	529.0		5,146.0	1,157	20.2%	1,040.1	4,106	5,262	116	0.90
	Total Disciplines	**16,338**	**1,321**	**0**	**17,659**	**3,353**	**17.2%**	**3,045**	**14,614**	**17,967**	**308**	**0.91**
95230	CAD/Computer											
95110	Sub Consultants/Training											
95290	H/O Expenses											
	SUBTOTALS	**19,588**	**1,361**	**0**	**20,949**	**4,468**	**19.9%**	**4,163**	**16,786**	**21,253**	**304**	**0.93**
	SUBTOTALS-ENGINEERING	**19,588**	**1,361**	**0**	**20,949**	**4,468**	**19.9%**	**4,163**	**16,786**	**21,253**	**304**	**0.93**
20000	Construction	3,010	0.0	0.0	3,010.0			0.0	3,010	3,010	0	0.00
95290	Field Expenses											
	SUBTOTALS-FIELD ASSISTANCE	**3,010**	**0**	**0**	**3,010**	**0**	**0.0%**	**0**	**3,010**	**3,010**	**0**	**0.00**
	TOTALS	**22,598**	**1,361**	**0**	**23,959**	**4,468**	**17.4%**	**4,163**	**19,796**	**24,263**	**304**	**0.93**

PENDING CHANGE ORDERS

Week Ending: 07/01/05

14	15	16	17	18	19	20	21	22	23	24	25	26
Labor Rate Budget	Labor Rate Adj. Budget	Labor Rate Actual	Labor Rate Estimate To Complete	Labor Rate Total Forecast	Original Budget $$	Change Order $$	Transfer $	Current Budget $$	Actual Cost	Estimate To Complete	Total Forecast $$	Variance to Current Budget
$137.85	0.00	$132.00	$137.85	$134.28	$89,600	$ -		$89,600	$52,272	$34,944	$87,216	($2,384)
$112.00	0.00	$112.00	$112.00	$112.00	$145,600	$ -		$145,600	$46,704	$99,008	$145,712	$112
$0.00	0.00	$0.00	$0.00	$0.00	$0	$ -		$0		$0	$0	$0
$0.00	0.00	$0.00	$0.00	$0.00	$0	$ -		$0		$0	$0	$0
$80.00	87.00	$70.99	$80.00	$78.17	$80,000	$ 2,610		$82,610	$14,766	$65,096	$79,862	($2,748)
$112.00	112.00	$112.00	$112.00	$112.00	$33,600	$ 1,120		$34,720	$10,528	$24,651	$35,179	$459
$0.00	0.00	$0.00	$0.00	$0.00	$0	$ -		$0		$0	$0	$0
$107.32	93.25	$111.45	$107.32	$105.88	$348,800	$3,730	$0	$352,530	$124,270	$223,699	$347,969	($4,561)
$114.32	105.92	$116.49	$114.32	$114.94	$333,600	$ 45,439	$ (1,143)	$379,039	$108,623	$268,618	$377,240	($1,799)
$0.00	0.00	$0.00	$0.00	$0.00	$0	$ -		$0		$0	$0	$0
$97.76	92.93	$80.77	$97.76	$96.07	$505,500	$ 15,612		$521,112	$42,849	$469,917	$512,765	($8,347)
$112.00	101.63	$112.00	$112.00	$112.00	$150,300	$ 1,626		$151,926	$15,792	$137,196	$152,988	$1,062
$112.01	108.46	$101.16	$112.01	$109.65	$256,500	$ 19,415	$ 1,143	$275,915	$59,889	$238,220	$298,109	$22,194
$101.91	95.18	$115.14	$101.91	$104.81	$470,500	$ 50,351		$520,851	$133,156	$418,416	$551,571	$30,720
$105.06	**100.26**	**$107.47**	**$105.06**	**$105.34**	**$ 1,716,400**	**$ 132,443**	**$ -**	**$ 1,848,843**	**$360,308**	**$ 1,532,367**	**$ 1,892,674**	**$ 43,831**
$6.63	$6.66	$1.38	$6.63	$5.75	$129,900	$ 642		$130,542	$27,097	$95,038	$122,135	($8,407)
$0.77	$0.77	$0.00	$0.77	$0.71	$15,000	$ -		$15,000		$15,000	$15,000	$0
$1.05	$1.13	$0.48	$1.05	$1.04	$20,600	$ 1,586		$22,186	$9,420	$12,766	$22,186	$0
$113.88	**101.69**	**$116.64**	**$113.88**	**$112.92**	**$ 2,230,700**	**$ 138,401**	**$ -**	**$ 2,369,101**	**$521,095**	**$ 1,878,869**	**$ 2,399,964**	**$ 30,863**
$113.88	**101.69**	**$116.64**	**$113.88**	**$112.92**	**$ 2,230,700**	**$ 138,401**	**$ -**	**$ 2,369,101**	**$521,095**	**$ 1,878,869**	**$ 2,399,964**	**$ 30,863**
$110.00	0.00	$0.00	$110.00	$110.00	$331,100	$ -	$ -	$331,100		$331,100	$331,100	$0
$1.95	$1.95	$0.00	$1.95	$1.80	$38,200	$ -	$ -	$38,200	$0	$38,200	$38,200	$0
$122.69	**0.00**	**$0.00**	**$122.69**	**$122.69**	**$ 369,300**	**$ -**	**$ -**	**$ 369,300**	**$ -**	**$ 369,300**	**$ 369,300**	**$ -**
$115.05	**101.69**	**$116.64**	**$115.05**	**$114.13**	**$ 2,600,000**	**$ 138,401**	**$ -**	**$ 2,738,401**	**$ 521,095**	**$ 2,248,169**	**$ 2,769,264**	**$ 30,863**

Exhibit 2

Memorandum

DATE: June 6, 2011

TO: Glenn Boonstra (summary set)
John Duffy (full set)
Ron Wankner (full set)
Gary Durbin (full set)
Jim Gabriel (full set)
Bill Ward (summary set)

FROM: Tim Wakefield

RE: Progress Update, Week Ending March 26, 2004
XxxxxxxxxXxxxxxxx Project, Job No. 65XXX.00

Attached are the Progress and Cost Report Summary, Engineering Progress and Manpower Loading graphs, Project Change Notice/Change Order Log, and PCR Summary by Discipline as the "Summary Set". The "Full Set" includes the PCR detail.

The current budget is $1,803,259 made up of an original budget of$ 1,728,335 and approved Change Orders valued at $79,828. The project is experiencing an overall project efficiency of 0.92 and forecasting an ending efficiency of 0.92, which compare to last month's values of 0.87 and 0.90 respectively. There are 18 Change Orders pending approval by the Joint Venture and Client totaling 2,386 hours that when approved and added to the current budget of 19,372 hours will restore the current efficiency value to nearly 1.0. (see Change Notice Log). Note that some transfers have been made recently from the Construction Budget that are not yet reflected in this report.

Total project progress was 90.0% compared to 75.9% last month versus 89.1% originally planned (see Engineering Progress graph). Again, good progress was made this period in mechanical, electrical, piping and controls and civil/structural disciplines. All equipment procurement is complete. Some vendor data is still required for final completion and removal of holds on some drawings. While the majority of drawings have been issued, completion of all work will continue through next period. Construction is to begin in April as scheduled.

If you have any questions, please advise.

(CONT'D) DATE: November 3, 2003

TO: Glenn Boonstra (summary set)
John Duffy (full set)
Ron Wankner (full set)
Gary Durbin (full set)
Jim Gabriel (full set)
Bill Ward (summary set)

FROM: Tim Wakefield

RE: Progress Update, Week Ending October 24, 2003
XxxxxxxxxXxxxxxxx Project, Job No. 65098.00

cc: Jim Eck (Mech/Process Lead)
Tommy Woodruff (Electrical Lead)
Gene Kellar (Controls Lead)
Anthony Gardunio (Piping Lead)
Bob Lofland (Civil/Structural Lead)
File 2.04

Exhibit 3

Biomass Repowering Project

Harris Group Inc.
Project 65XXX.02

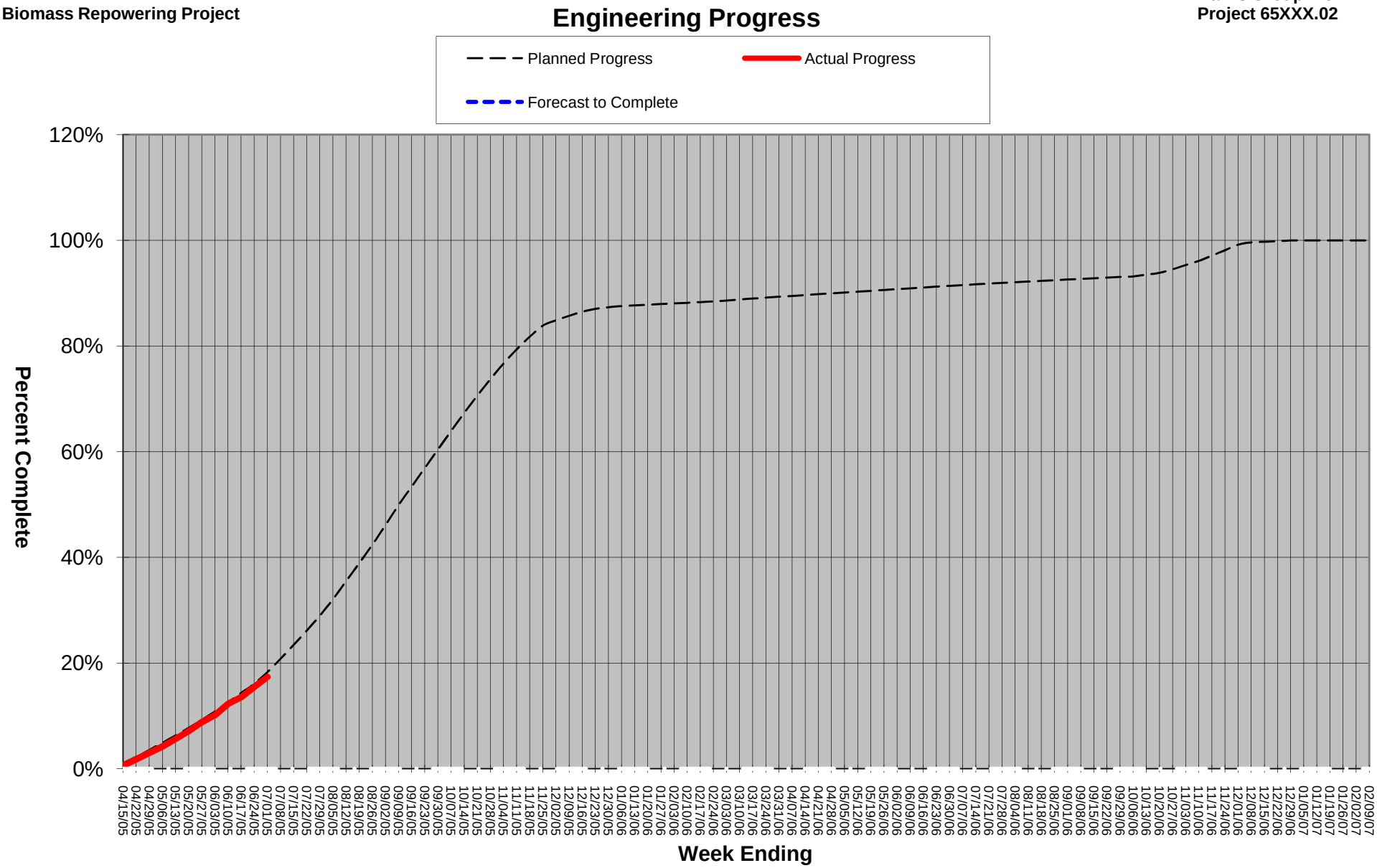
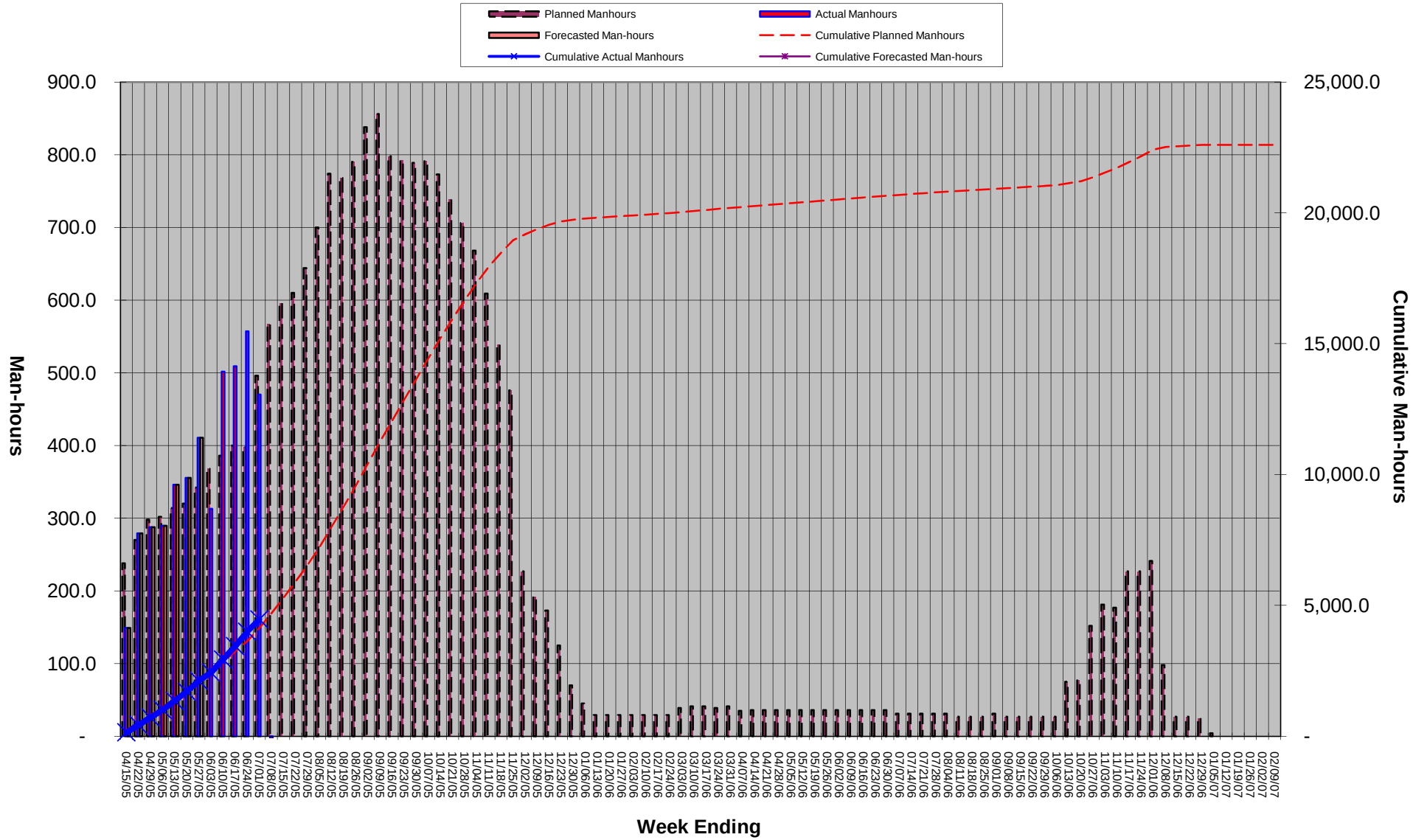


Exhibit 4

Biomass Repowering Project

Man-hour Plan

Harris Group Inc.
Project 65XXX.02



DENVER OFFICE
ENGINEERING PROGRESS MILESTONES

DRAWING MILESTONES:	CIVIL/ STRUCT	MECH	PIPING ORTHO'S	PIPING ISO'S	ELECT	ELECT CONNECT	INSTRUM
DRAWING STARTED	20%	25%	20%	50%	25%	10%	10%
COMPLETE UNCHECKED	70%	40%	60%	70%	60%	70%	60%
CHECKING COMPLETE	75%	60%	80%	85%	75%	80%	75%
CHECKING/COMMENTS INCORPORATED	85%	85%	90%	90%	85%	85%	80%
APPROVED FOR CONSTRUCTION/ CLIENT APPROVAL	95%	90%	95%	95%	90%	90%	90%
AREA CONSTRUCTED	100%	100%	100%	100%	100%	100%	100%

OTHER ENGINEERING DOCUMENTS:	STUDIES	SPECS	REVISION	G.A.'S	PFD'S	P&ID'S
START	10%	20%	A	15%	20%	10%
ISSUED FOR REVIEW & CHECKING	60%	30%	B	30%	50%	30%
ISSUED HGI APPROVED	75%	40%	C	50%	70%	40%
CLIENT APPROVAL RECEIVED	85%	50%	D	75%	80%	60%
ISSUED APPROVED FOR BID	100%	60%	AFC	85%	90%	80%
BIDS EVALUATED		70%	REV 1	95%	95%	90%
CONFORMED FOR PURCHASE		90%	REV 2	100%	100%	100%
VENDOR DRAWINGS REVIEWED		100%				

DENVER OFFICE
ENGINEERING PROGRESS MILESTONES

PROCUREMENT & CONTRACTS:	P.O.'S	CONTRACT
BIDDERS LIST APPROVAL	5%	10%
INQUIRY DOCUMENTS COMPLETE & ISSUED	25%	50%
BIDS RECEIVED & EVALUATED	30%	70%
ISSUED FOR APPROVAL	35%	80%
APPROVAL RECEIVED TO AWARD	40%	90%
ORDER ISSUED/DOCUMENTS CONFORMED	50%	100%
VENDOR DRAWINGS RECEIVED	60%	
VENDOR DRAWINGS APPROVED	70%	
DELIVERY TO JOB SITE	90%	
ORDER CLOSED	100%	

Exhibit 7

CHANGE REQUEST / CHANGE ORDER LOG

HARRIS GROUP INC.

Client Name: XXXXXX Corporation | **Project No. XXXXX.00**
Project Title: XXXXXXX Project | **Date: December 19, 2002**
Project Location: CA

			Change Request					Change Order						
Change Order No.	Change Request No.	Change Description	Initiator "Name/Co."	Sent to XXXXXX for Approval Date	XXXXXX Response Date	XXXXXX Response Days	XXXXXX Response "Approved / Denied"	Schedule Impact (days)	Labor Hours	Labor Dollars	Expenses	Total Cost	Approved Cost	Status / Comments
Original Budget									**8,142**	**$ 779,387**	**$ 45,613**	**$ 825,000**	**$ 825,000**	
XXXXXX Approved Change Orders:														
No CO Contrct Adjust	CR01	This Change Request is to implement cost reduction changes proposed by XXXXXX during the March 12, 2002 meeting at Harris Group offices.	G. Baxter / XXXXXX	03/13/02	03/27/02	14	Approved	14	676	$ 67,523	$ 4,056	$ 71,579	**$ 71,579**	Approved by XXXXXX as adder to Contract 3/27/02
CO01	CR03	This Change Request is to revise P&ID's per XXXXXX comments to Feather River P&ID's on 3/20/02	G. Baxter / XXXXXX	03/27/02	04/02/02	6	Approved	0	250	$ 24,044	$ 1,511	$ 25,555	**$ 25,555**	Approved by XXXXXX as adder to Contract 5/1/02
CO02	CR02	Change requested by XXXXXX for HGI to complete the steel connection details for Feather River.	Andy Remely / XXXXXX	04/01/02	04/02/02	1	Approved	0	180	$ 17,356	$ 1,080	$ 18,436	**$ 18,436**	Approved by XXXXXX as adder to Contract 5/1/02
CO03	CR04	Revisions to "Copy and Issue" drawings due to GE 480 Volt MCC configurations changing from standard developed for Yuba City. The Feather River GE MCC configuration was not similar to the Lambie GE MCC either.	N.J. Schell / HGI	04/23/02	05/10/02	17	Approved	2	24	$ 2,256	$ 144	$ 2,400	**$ 2,400**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO04	CR05	This change is required for HGI to revise its cable code list to XXXXXX's revised cable specification	John Holland / HGI	04/27/02	05/10/02	13	Approved	0	48	$ 4,444	$ 288	$ 4,732	**$ 4,732**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO05	CR07	XXXXXX has requested for HGI to administer, review, and approve XXXXXX's subcontractor design for Fire Protection. HGI's effort is not in the base Peaker scope	G. Swoboda / HGI	05/06/02	05/20/02	14	Approved	0	0	$ -	$ 3,850	$ 3,850	**$ 3,850**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO06	CR08	Delay due to the TAS vendor as-builts were not received from client on due date. Promised on 4/19/02 did not received until 5/2/02. This is a day for day delay.	G. Woodruff / HGI	05/10/02	05/20/02	10	Approved	9	0	$ -		$ -	**$ -**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO07	CR09	The City of Yuba City is requiring that we install a testing block and bypass as shown on their Standard Detail 410. Yuba City also requires that ductile iron pipe be used from the city water main tie point to the FREC property boundary.	Q. Bailey / HGI	05/25/02	05/28/02	3	Approved	5	28	$ 2,492	$ 308	$ 2,800	**$ 2,800**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO08	CR11	Relocate East-West Section of fire loop to north side of Demin. Treatment Area per Dillingham / XXXXXX request for constructibility.	D. Denton / HGI	05/30/02	06/04/02	5	Approved	0	32	$ 3,012	$ 1,292	$ 4,304	**$ 4,304**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO09	CR12	This change is to revise the Civil Site Plan and incorporate additional information requested by the City of Yuba City. This change also allows for providing mylar copies of off-site plans with signature block for the City Engineer	D. Denton / HGI	05/31/02	06/03/02	3	Approved	3	16	$ 1,512	$ 88	$ 1,600	**$ 1,600**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/12/02

CHANGE REQUEST / CHANGE ORDER LOG

HARRIS GROUP INC.

Client Name: XXXXXX Corporation | **Project No. XXXXX.00**
Project Title: XXXXXXX Project | **Date: December 19, 2002**
Project Location: CA

			Change Request					Change Order						
Change Order No.	Change Request No.	Change Description	Initiator "Name/Co."	Sent to XXXXXX for Approval Date	XXXXXX Response Date	XXXXXX Response Days	XXXXXX Response "Approved / Denied"	Schedule Impact (days)	Labor Hours	Labor Dollars	Expenses	Total Cost	Approved Cost	Status / Comments
CO10	CR14 FREC	XXXXXX has requested that HGI provide vendor-expediting services for vendor information needed by HGI.	G. Swoboda / HGI	06/10/02	06/10/02	0	Approved	0	60	$ 6,240	$ 360	$ 6,600	**$ 6,600**	Submitted to XXXXXX week of 6/10/02, approved via G. Baxter email 7/3/02
CO11	CR16	This change is for engineering scope for a Security Raceway System and Exterior Perimeter Lighting System.	G. Swoboda / HGI	06/27/02	07/01/02	4	Approved	0	90	$ 8,254	$ 540	$ 8,794	**$ 8,794**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO12	CR13	Gas compressor enclosure changes:The Yuba City enclosure foundation is not duplicated at Feather River. Impacted Rev 0 to Rev 1	P. Faulkner / HGI	06/13/02	07/09/02	26	Approved	0	32	$ 3,128	$ 192	$ 3,320	**$ 3,320**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO13	CR17	Revised Air Compressor Layouts	D. Denton / HGI	07/03/02	07/26/02	23	Approved	0	143	$ 13,087	$ 858	$ 13,945	**$ 13,945**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO14	CR21 FREC	HGI to provide 30 additional hours of vendor-expediting services.	G. Swoboda / HGI	07/30/02	07/31/02	1	Approved	0	8	$ 832	$ 48	$ 880	**$ 880**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO15	CR22	Change due to SCR foundation 1" lower than HGI design	P.J. Trompeter / XXXXXX	07/30/02	08/05/02	6	Approved	0	40	$ 3,728	$ 240	$ 3,968	**$ 3,968**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO16	CR23	Flow gas meter to be Re-installed at Fuel Gas Filter Skid	G. Baxter / XXXXXX	08/06/02	08/14/02	8	Approved	0	25	$ 2,362	$ 150	$ 2,512	**$ 2,512**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO17	CR24rev1	Incorporate Gas Enclosure from Yuba City to Feather River	D. Denton / HGI	08/15/02	09/26/02	42	On Hold	0	70	$ 6,406	$ 420	$ 6,826	**$ 6,826**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO18	CR25	This change is to allow for welded steel connections in lieu of previously designed bolted steel connections.	D. Denton / HGI	08/26/02	09/26/02	31	Approved	0	48	$ 4,500	$ 288	$ 4,788	**$ 4,788**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
CO19	CR27	Add controls for security lighting	G. Swoboda / HGI	10/01/02	10/01/02	0	Approved	9	16	$ 1,420	$ 96	$ 1,516	**$ 1,516**	Signed by emp Included in XXXXXX C.O. # 0002 11/7/02
		Subtotal XXXXXX Approved Change Orders						**42**	**1,786**	**$ 172,596**	**$ 15,809**	**$ 188,405**	**$ 188,405**	
Current Budget (Including Approved Change Orders)								**42**	**9,928**	**$ 951,983**	**$ 61,422**	**$ 1,013,405**	**$ 1,013,405**	

Change Orders Submitted to XXXXXX Pending Final Approval:

CO20	CR28	Additional 100 hours of field services and expenses for Blaine Pritchett at the site.	G. Swoboda / HGI	10/22/02	10/23/02	1	Approved	0	137	$ 14,262	$ 1,552	$ 15,814		CO invoiced on actuals as job no. 65049.02 Month-end December '02
CO22		PG&E requires 125 KV versus 115 KV connecting voltage. HGI to redo studies and calculations.	B. Patel / XXXXXX	12/18/02	12/18/02	0	Approved	0	46	$ 5,574	$ 276	$ 5,850	$ 5,850	Approved by site 12/18/02. Overnight to A. Andersen 12/20/02
		Subtotal Change Orders Pending Client Approval						**0**	**46**	**$ 5,574**	**$ 276**	**$ 5,850**	**$ 5,850**	
Current Budget (Including Change Orders Pending Client Approval)								**42**	**9,974**	**$ 957,557**	**$ 61,698**	**$ 1,019,255**	**$ 1,019,255**	

Exhibit 7

CHANGE REQUEST / CHANGE ORDER LOG

HARRIS GROUP INC.

Client Name: XXXXXX Corporation | **Project No. XXXXX.00**
Project Title: XXXXXXX Project | **Date: December 19, 2002**
Project Location: CA

			Change Request					Change Order						
Change Order No.	Change Request No.	Change Description	Initiator "Name/Co."	Sent to XXXXXX for Approval Date	XXXXXX Response Date	XXXXXX Response Days	XXXXXX Response "Approved / Denied"	Schedule Impact (days)	Labor Hours	Labor Dollars	Expenses	Total Cost	Approved Cost	Status / Comments
Identified Change Requests (CR's):														
		Subtotal Identified Project Change Requests CR's)						**0**	**0**	**$ -**	**$ -**	**$ -**		
Internal/Rejected/Cancelled Changes:														
	CR06	XXXXXX has requested that a "holds" list be established for each project.	G. Baxter / XXXXXX	05/02/02	05/10/02	8	Denied	0	32	$ 3,200		$ 3,200		CR cancelled
	CR10	XXXXXX has requested the addition of a fuel gas drain bottle.	Q. Bailey / HGI	05/28/02	06/07/02	10	Denied	0	33	$ 3,300		$ 3,300		CR cancelled
	CR15	XXXXXX has requested several (3 or 4) full size 3D drawings of XXXXXXX Project from several different angles to be made by HGI.	B. Martin / XXXXXX	06/11/02	06/11/02	0	Denied	0	52	$ 5,500		$ 5,500		Denied by XXXXXX 6/11/02
	CR18	Revise Engineering & Design to Incorporate Los Esteros Oil/Water Separator	G. Swoboda / HGI	07/16/02				0	40	$ 4,000		$ 4,000		CR cancelled 7/26/02 per XXXXXX
	CR19	This change is in response to XXXXXX's request for HGI to provide Ortho's and Sections, Detail Sheets, detailed vendor review, supports, and stress analysis for all small bore pipe to be installed.	XXXXXX	07/23/02	07/26/02	3	Denied	0	614	$ 61,400		$ 61,400		Approval based on Dillingham authorization to pay XXXXXX for service
	CR20	XXXXXX has requested the Circuit Schedules be converted to an Excel format and submitted to the field each Friday until Electrical Engineering is substantially complete for each Peaker Project.	G. Baxter / XXXXXX					0	7	$ 700		$ 700		Internal per GJS 7/26/02
	CR26	Change required to revise BOP wiring diagrams and circuit schedule.	G. Swoboda / HGI	09/05/02	09/18/02	13	Denied	0	30	$ 3,000		$ 3,000		Emailed to XXXXXX for direction 9/5/02 - Cancelled per XXXXXX to be done in field
CO21		Provide electronic copies of equipment packages.	Q. Bailey / HGI	12/13/02				0	45	$ 2,709	$ 270	$ 2,979		Emailed CO to XXXXXX site 12/13/02
		Subtotal Internal/Rejected/Cancelled Changes:						**0**	**853**	**$ 83,809**	**$ 270**	**$ 84,079**		

Exhibit 8
XXXX.00 XXXXX Compressor Station Historical Man-hour Summary

Account Code		Quantity	Hours	Hours per Deliverable	% of Discipline	% of Job
Management/Support Staff		**344.98**	**2,171**	**6.3**	**100.0%**	**13.2%**
1100x	Project Management	344.98	285	0.8	13.1%	1.7%
1200x	Project Engineer	344.98	663	1.9	30.5%	4.0%
1600x	Engineering Assistant	344.98	638	1.8	29.4%	3.9%
1700x	Project Controls	344.98	243	0.7	11.2%	1.5%
1800x	Procurement	344.98	342	1.0	15.8%	2.1%
Mechanical		**13.66**	**753**	55.1	**100.0%**	**4.6%**
3013x	General		11		1.5%	0.1%
3014x	Cross Discipline Review		4		0.5%	0.0%
3033x	Mechanical Calculations		155	12.0	20.6%	0.9%
3038x	Data Sheets		143		19.0%	0.9%
3040x			8		1.1%	0.0%
3043x	Deliverables List		3		0.4%	0.0%
3044x	Mechanical Equipment List	1	39	39.0	5.2%	0.2%
3045x	Line List	0.33	57	172.7	7.6%	0.3%
3046x	Specialty Items List	0.33	9	27.3	1.2%	0.1%
3050x			13		1.7%	0.1%
3051x	Drawing Checking		10		1.3%	0.1%
3052x	Rework		4		0.5%	0.0%
3054x	P&ID's		8		1.1%	0.0%
3057x	Equipment/Mechanical Details		49		6.5%	0.3%
3073x	Design Criteria	1	1	1.0	0.1%	0.0%
3075x	Technical Specifications	11	9	0.8	1.2%	0.1%
3085x	Bid Evaluations		43		5.7%	0.3%
3087x	Vendor Data Review		187		24.8%	1.1%
Process		**13.66**	**1,424**	**104.2**	**100.0%**	**8.7%**
4010x			18		1.3%	0.1%
4030x			136	136.0	9.6%	0.8%
4031x	Design Checking		75		5.3%	0.5%
4033x	Process Calculations		20		1.4%	0.1%
4038x	Data Sheets		157		11.0%	1.0%
4040x			15		1.1%	0.1%
4045x	Line List	0.33	5	15.2	0.4%	0.0%
4046x	Specialty Items List	0.33	5	15.2	0.4%	0.0%
4050x			361		25.4%	2.2%
4051x	Drawing Checking		133	10.2	9.3%	0.8%
4053x	PFD	1	26	26.0	1.8%	0.2%
4054x	P&ID's	12	225	18.8	15.8%	1.4%
4058x			25		1.8%	0.2%
4070x			4		0.3%	0.0%
4075x	Technical Specifications		25		1.8%	0.2%
4200x			112		7.9%	0.7%
4231x			82		5.8%	0.5%
Electrical		**91**	**4,106**	**45.1**	**100.0%**	**25.1%**
5013x	Support/Supervision/Admin		44		1.1%	0.3%
5015x	Client Reviews		28		0.7%	0.2%
5019x	Trips		21		0.5%	0.1%
5032x	Rework		14		0.3%	0.1%
5033x	Electrical Calculations		84		2.0%	0.5%
5035x	Design Sheets		307		7.5%	1.9%
5036x	Electrical Sketches		15		0.4%	0.1%
5038x	Data Sheets		45		1.1%	0.3%
5040x			40		1.0%	0.2%
5043x	Deliverables List		23		0.6%	0.1%
5044x	Load List	1	13	13.0	0.3%	0.1%
5045x	Circuit/Conduit Schedule	19	579	30.5	14.1%	3.5%
5046x	Schedules: Heat Trace, Lighting, Panel	3	59	19.7	1.4%	0.4%
5050x			144		3.5%	0.9%
5051x	Drawing Checking		118	1.9	2.9%	0.7%
5053x	Std Notes & Details	5	9	1.8	0.2%	0.1%
5054x	One-Lines	5	182	36.4	4.4%	1.1%
5055x	Schematics	9	321	35.7	7.8%	2.0%
5056x	Physical Plan - U.G.	2	490	245.0	11.9%	3.0%
5057x	Physical Plan - A.G.	40	990	24.8	24.1%	6.0%
5058x	Wiring/Connection Diagrams	7	366	52.3	8.9%	2.2%
5070x			63		1.5%	0.4%
5075x	Technical Specifications - Discipline		5		0.1%	0.0%
5076x	Technical Specifications - Others		51		1.2%	0.3%
5085x	Bid Evaluations		27		0.7%	0.2%
5087x	Vendor Data Review		30		0.7%	0.2%
5090x	Field Support		6		0.1%	0.0%
5450x			32		0.8%	0.2%

Exhibit 8
XXXX.00 XXXXX Compressor Station Historical Man-hour Summary

Account Code		Quantity	Hours	Hours per Deliverable	% of Discipline	% of Job
Control Systems		**35**	**1,036**	**29.6**	**100.0%**	**6.3%**
6010x			206		19.9%	1.3%
6030x			9		0.9%	0.1%
6038x	Data Sheets		236		22.8%	1.4%
6040x			9		0.9%	0.1%
6044x	Instrument Index	1	45	45.0	4.3%	0.3%
6050x			68		6.6%	0.4%
6052x	Rework		18		1.7%	0.1%
6054x	P&ID Input/Review		46	3.8	4.4%	0.3%
6055x	Loop Diagrams	9	151	16.8	14.6%	0.9%
6056x	Panel Layout	8	219	27.4	21.1%	1.3%
6057x	Control Diagrams	17	19	1.1	1.8%	0.1%
6087x	Vendor Data Review	n/a	10		1.0%	0.1%
Piping		**138.66**	**4,037**	**29.1**	**100.0%**	**24.6%**
7000x			23		0.6%	0.1%
7013x			96		2.4%	0.6%
7015x			8		0.2%	0.0%
7030x			8		0.2%	0.0%
7032x	Rework		51		1.3%	0.3%
7034x	Stress Analysis		165		4.1%	1.0%
7035x	Hangar Design		39		1.0%	0.2%
7045x	Line List	0.33	22	66.7	0.5%	0.1%
7046x	Specialty List	0.33	8	24.2	0.2%	0.0%
7050x			124		3.1%	0.8%
7051x	Drawing Checking		2		0.0%	0.0%
7052x	Rework		219		5.4%	1.3%
7053x	Piping Plans (Ortho's)	16	2,686	167.9	66.5%	16.4%
7054x	Piping Sections & Details	19	137	7.2	3.4%	0.8%
7055x	Yard Piping		-		0.0%	0.0%
7056x	Isometric Drawings	102	308	3.0	7.6%	1.9%
7057x	Pipe Hangars				0.0%	0.0%
7074x	Piping Materials Specification	1	1	1.0	0.0%	0.0%
7079x	Spec Input for Switch to CO-ADE		135		3.3%	0.8%
7091x	Field Support - Checking	n/a	5		0.1%	0.0%
Civil Structural		**53**	**2,860**	**54.0**	**100.0%**	**17.5%**
8010x			81		2.8%	0.5%
8013x	Support/Supervision/Admin		26		0.9%	0.2%
8030x			270		9.4%	1.6%
8031x	Design Checking		126		4.4%	0.8%
8033x	GA / General Notes & Details		10		0.3%	0.1%
8034x	Site Work Design		61		2.1%	0.4%
8035x	Foundation Design		457		16.0%	2.8%
8037x	Supports/Non-Building		15		0.5%	0.1%
8050x			98		3.4%	0.6%
8051x	Drawing Checking		169		5.9%	1.0%
8053x	GA / General Notes & Details	1	80	80.0	2.8%	0.5%
8054x	Site Work	5	118	23.6	4.1%	0.7%
8055x	Foundation Drawings	33	994	30.1	34.8%	6.1%
8056x	Building Superstructure		10		0.3%	0.1%
8057x	Supports Drawings	8	159	19.9	5.6%	1.0%
8058x	Architectural Drawings	6	84	14.0	2.9%	0.5%
8070x	Specifications		26		0.9%	0.2%
8080x			19		0.7%	0.1%
8090x	(Field Support)		9		0.3%	0.1%
A100	(Architectural Manager)	n/a	48		1.7%	0.3%
Total Project Labor		**345**	**16,387**	**47.5**	**100.0%**	**100.0%**
Expenses:						
5210	Travel & Subsistence					
5220	Outside Printing & Reproduction					
5290	OtherReimbursable Expenses					
Total Project Including Expenses		**345**	**16,387**	**47.5**	**100.0%**	**100.0%**

Appendix D

City of Bethel Resolution & Action Memorandum

City of Bethel Action Memorandum

Action memorandum No.	12-13		
Date action introduced:	2-14-2012	Introduced by:	Mayor Joseph Klejka
Date action taken:	2-14-2012	X Approved	Denied
Confirmed by:			

SUBJECT/ACTION: Approve The Preliminary Grant Application Submission Regarding The Liquefied Natural Gas (LNG) Project.

Route to:	Department/Individual:	Initials:	Remarks:
X	City Manager		
X	Finance		

Attachment(s): Phase 1 Application for Emerging Energy Technology Grant to Alaska Energy Authority AEA-11-027; Potential Benefits to Alaskans from State-Owned Gasline/LNG Project.

Amount of fiscal impact		Account information:
No fiscal impact at this point in the project. If approved, minimal staff time would need to be provided.	No fiscal impact.	
	Funds are budgeted for.	
	Funds are not budgeted. Budget modification is required.	

Description of the Project

PDC Harris Group LLC, is interested in working with the City of Bethel to bring Liquefied Compressed Natural Gas (LCNG) to this region. The collaborated effort would first consist of PDC Harris Group applying for an Emerging Energy Technology Grant (EETG) which is due the first part of March 2012 and would require the approval of the council. Following the competitive review of the application, the Alaska Energy Authority may award a grant to perform the first stage of the project, which consists of capital cost estimate, operating costs estimates and a consumer gas pricing structure.

After the completion of step or stage one, PDC Harris Group and the City of Bethel would look for additional funding through state and federal granting options to perform stage two. Stage two would include Proof of Concept Demonstration and Confirmation of Economics (grant 3). This stage would include a LNG Storage depot, barge, gasification and offloading systems, storage vessels, pressure letdown stations and low/medium pressure distribution piping. Also during this stage one or more home furnaces or boilers would need to be converted to gas-firing and a diesel engine-generator converted to gas/diesel blending with appropriate metering. Additionally, it is the intent of this project to use City facilities as part of the test project meaning conversion of some city owned facilities.

Action memorandum No.	12-13		
Date action introduced:	2-14-2012	Introduced by:	Mayor Joseph Klejka
Date action taken:	2-14-2012	X Approved	Denied
Confirmed by:			

The third stage of the project is expected to be funded by additional state or federal grants or through municipal bonds. This stage would be large scale development and further build-out in Bethel and to the satellite villages.

Application History

In 2009, the Denali Commission released a public solicitation entitled the Emerging Energy Technology Grant (EETG). This competitive solicitation, with a total funding opportunity of $4M, (which has grown to 8.5 M for the 2012 application period) targeted alternative and renewable emerging energy technology proposals such as Liquefied Natural Gas (LNG) from Alaska applicants. The goal was to develop technology having the potential of widespread deployment in Alaska to reduce energy costs for all. A maximum of 1.5M is awarded by the Alaska Energy Authority, per project.

In 2009 Council approved Resolution 9-26 supporting a joint application for a liquefied and compressed natural gas pilot study and projects as a bridge solution to high energy process in rural Alaska.

In 2009 the application was not considered due to a technicality. PDC Harris Group LLC, also issued an application in 2011 on behalf of the joint collaboration which was approved by the Bethel City Council through AM 11-15. During the 2011 round of applications, over 50 applications were submitted. The application process for 2011 was put on hold until March of 2012.

City of Bethel Contribution

If the current council determined to move forward with the partnership, the City should expect to designate one employee who would work with PDC Harris Group a few hours every month. The City would also be responsible for the flow of funds however PDC Harris Group would prepare the reporting document and present them to the City of Bethel for submission.

General Information

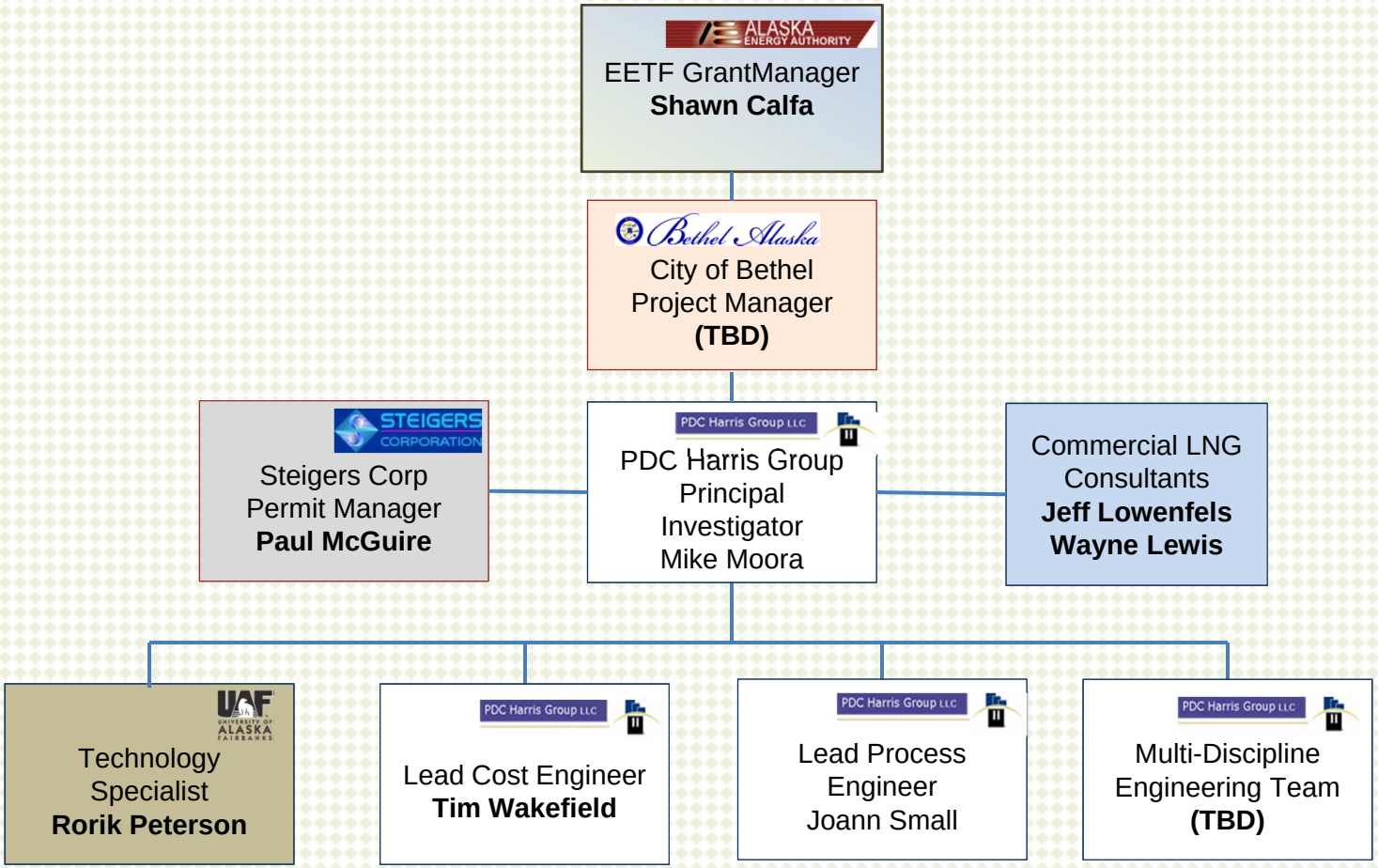
On behalf of PDC Harris Group, Mike Moora would be willing to meet with the council to provide additional information on the history of the project as well as the benefits in moving forward. This however could not take place until late March.

Appendix E

Organization Chart & Key Resumes

Appendix E – Organization Chart

LCNG Phase 1 Organization



MICHAEL W. MOORA, P.E.

PROCESS ENGINEER

University of Utah, MS Fuels & Chemical Engineering

Drexel University, MS Environmental Engineering

Rutgers University, BS Mechanical/Aerospace Engineering

BACKGROUND

Mike Moora is a registered Process Engineer and Project Manager with over 30 years of experience in a broad spectrum of process and environmental remediation industries. He has executed projects in diverse areas such as North Slope production and utility systems, natural gas treatment, synthesis gas production, flue gas cleanup, RCRA waste treatment, remedial designs/actions, radioactive waste immobilization, wastewater treatment, synthetic fuels pilot development, chemicals production and biotechnology development.

Mr. Moora has design experience including: Feasibility and economic analysis, conceptual design and optimization studies, process design development and flow sheet simulation, detailed engineering, purchase specifications, project management, equipment procurement and fabrication inspection, HAZOP analysis and relief valve design/documentation, operating manuals/operator training, facility commissioning, technology assessment and due diligence investigations, air emissions control and air quality permitting.

SELECTED EXPERIENCE

General Manager, PDC Harris Group LLC, Anchorage, AK. Responsible for business development, project management and operations support for this energy business–sector joint venture. Business development and project management work included:

- BP Exploration (Alaska) Inc: numerous power and resource development projects 2006 to present, including: Project Manager, Liberty Rig Power Generation Module Cooling System Modifications. Project Sponsor, Central North Slope Power Generation – Appraise Stage Study. Project Sponsor, Milne Point Interim Power Generation Appraise Stage Engineering Services. Pre-concept analysis of gas turbine generator alternatives. Project Manager, Milne Point Heavy Oil Pilot Power Generation Select Stage Engineering Services. Concept level analysis of 1 to 1.5 MW transportable/modular power generation. Project Manager for a generator replacement project at BPXA's Milne Point.
- Doyon Utilities, Fairbanks AK: Project Manager, Ft Greely Boiler steam blow temporary piping design. Piping design, stress analysis, support design and selection of steam silencer. Project Manager, Ft. Greely Boiler Upgrade and SCADA system design.
- Municipality of Anchorage, Municipal Light & Power, PIC for Generation Engineering Term Contract. Numerous task orders including: Principal in Charge, Plant 1 Black Start Generator concept and detailed design

services. Project Manager/Lead Process Engineer for Waste Heat Recovery Project involving rejection of heat from existing and new generation assets to Anchorage Water and Wastewater utility. Project Manager/Lead Process Engineer for Unit 3 Fuel Gas Booster Compressor improvements. Project Manager for feasibility and concept level engineering development of a 2 x 1 GE 6FA combustion turbine power generation system.

- Chugach Electric Association: Project Manager, South-central Project Waste Heat Recovery Assessment. Lead specifications development to support the upgrade of the turbine control system for Unit 5 gas turbine system at Beluga River Station. Project Manager for Bernice Lake Power Plant Water Injection System.

LICENSES AND CERTIFICATION

— Professional Engineer Registration, Colorado

— Registered Environmental Manager

— University of Alaska, Arctic Engineering Short Course, November 2001

— Currently enrolled in Project Management Institute training for PMP

TECHNICAL PAPERS

"The Design of a Commercial RCRA Incinerator - Where the Regulations Are Taking Us", Presented at the Colorado Hazardous Waste Management Society, Fall 1991, Denver, CO.

"Design and Environmental Permitting Challenges for the Ft. Wainwright, Alaska Power Plant Fabric Filter System", Presented at the Air and Waste Management Association Conference, Orlando FL, June 24 - 28 2001.

R Fedich, D McCaffrey, M Moora and R Ungs, *"Upgrade Your Tail Gas Treating Unit With FLEXSORB SE Plus",* Paper presented at the 2003 Brimstone Sulfur Recovery Symposia, Vail Colorado, September 2003.

"LCNG – A Bridge Solution to High Energy Costs in Rural Alaska", Presentation to the Cold Regions Design Forum, Fairbanks, AK, February 2011.

Jo Ann R. Small
Senior Process Engineer, PE

Texas A & M University, BS – Chemical Engineering

BACKGROUND

Jo Ann Small has over 22 years of experience in process engineering. Her experience includes the detailed design of grassroots and retrofit projects involving Sulfur Recovery Units (SRU), Tail Gas Treating Units (TGTU), Sour Water Strippers (SWS), Amine Units (ARU), petrochemical process units, upstream oil and gas and industrial facilities.

Ms. Small's responsibilities have included computer simulation, proposal development, heat and material balance, process flow diagrams, piping and instrument diagrams, equipment sizing, refractory material specification, hydraulic calculations, utilities and chemical/catalyst summaries and safety systems.

SELECTED EXPERIENCE

Oil & Gas (Upstream)

Zhaikkunai: Process evaluation of Gas Treatment Plant (Stabilizer, Amine, SRU, Glycol, Deethanizer and Debutanizer) for alternate feeds.

EnCana Oil & Gas (USA) Inc.: Process evaluation of 3 phase separator and associated piping.
Chevron Mid-Continent Business Unit: Equipment & Line sizing. Equipment to include
2 & 3-phase separators, heater treaters, tankage and pumps.

Petroleum Refining

Premcor: Schedule A design of new SRU and TGTU Process Engineer.

Marathon Ashland Petroleum: Sour Water Stripper Expansion Study.

Rayong, Thailand: Evaluation of existing SRUs and TGTUs

Lucky Engineering Co., Ltd: Schedule A design of Amine Regeneration Unit.

Koch Refining: Evaluation of existing TGTU with specialty solvent.

Suncor: Schedule A design of new SRU and TGTU.

Premcor: Flare study for possible expansion.

SRM International: Process Design of 10,000 gpd Biodiesel unit. Including PFDs heat and material balance and equipment data sheets.

ConocoPhillips: Process Design of Sulfur Recovery Unit and Tail Gas Treating Unit.

Monsanto, Nitro, WV – Expansion of a sulfur recovery unit from a two reactor unit to a three reactor unit.

Du Pont Company, Deer Park, TX – Process evaluation of an existing sulfur recovery unit for a new feed.

Allied Corporation, Anacortes, WA – Process study of an existing sulfur recovery unit for a new feed.

Total Petroleum, Ardmore, OK – Process evaluation of an existing sulfur recovery unit for a new feed.

CITGO Petroleum Corp., Lake Charles, LA – Process design for the conversion of a Stretford to a 400 LTD SULFTEN) System.

Valero Refining Co., Corpus Christi, TX – Process design fro a 280 LTD grassroots SULFTEN System.

Amoco, Whiting, IN – Process design for the conversion of a Stretford to a SULFTEN System.

Texaco, Wilmington, CA – Process design for the conversion of a Stretford a SULFTEN System.

Exxon, Big Escambia Creek, AL – Process design of a grassroots SULFTEN System.

Champlin Petroleum Co., Wilmington, CA – Process design for the conversion of a Stretford to a SULFTEN System.

Champlin Petroleum Co., Corpus Christi, TX – Process design of an 80 LTD SCOT Unit.

Husky Oil, Cheyenne, WY – Process study of two existing amine units for new feeds.

Champlin Petroleum Co., Wilmington, CA – Process evaluation of amine unit expansion 120 to 200 LTD.

PROFESSIONAL/TECHNICAL TRAINING

CO_2 Surface Facilities Course, HYSYS, BR&E, TSWEET, ProSim, ProMax, STX & ACX,
Tray Design Software

PROFESSIONAL REGISTRATIONS

TIMOTHY L. WAKEFIELD, JR.

PROJECT CONTROLS SPECIALIST

Colorado State University, BS Industrial Construction Management

BACKGROUND

Tim Wakefield has over 30 years of experience in project control and management of minerals, power, natural gas and pharmaceutical projects. His background includes preparation of detailed cost estimates, procurement, expediting, construction inspections, accounting, subcontract administration, warehousing, forecasts, cash flows, development and maintenance of schedules, cost trends, and cost and commitment reporting systems. He has been involved in a variety of projects including gold, silver, copper, uranium, nickel, lead, iodine, coal, soda ash, power, natural gas and pharmaceuticals in Australia, Argentina, Chile, Peru, Guatemala, Namibia, Kazakhstan, Uzbekistan, Siberia, Tajikistan, Canada, Florida, Indiana, Kansas, Kentucky, New York, South Carolina, and western United States, including Alaska and Hawaii. Services were provided in the home office and at numerous job sites.

SELECTED EXPERIENCE

- Project Controls Specialist responsible for planning and cost control for a new power plant in Indiana. The plant utilizes six LM6000 combustion turbine generators in simple cycle. Scope also included support to construction and on-site engineering and administrative services.
- Project Controls Specialist responsible for preparation of estimates and cash flow forecasts for two proposals to DOE in response to the Clean Coal Power Initiative Program Solicitation.
- Project Controls Specialist responsible for the capital cost estimate for a 500 MW power plant in California. The plant utilizes two Frame 7FA natural gas combustion turbine generators in combined cycle.
- Project Controls Specialist responsible for the estimated capital costs and cash flow forecast included in a study for both new construction and retrofitting of coal-fired utility power plants. The study included emissions controls, including SO_X, NO_X and mercury environmental controls.
- Project Controls Specialist responsible for planning, cost control and capital cost estimating for the design and construction of two peaker power plants located on Staten Island, New York, approximately one-half mile apart in the Bloomfield area and interconnecting with a Consolidated Edison switchyard a few miles away by way of a single new 138-kV power line. The power plants are simple-cycle facilities fired on natural gas, each using a Pratt & Whitney TwinPac combustion-turbine generator plus a Pratt & Whitney PowerPac

combustion-turbine generator, both with selective catalytic reduction ("SCR"). The combined output at each site is approximately 80 MW.

PROFESSIONAL AFFILIATIONS

The Association for the Advancement of Cost Engineering
Sigma Lambda Chi (National Construction Honorary)

EMPLOYMENT

Bateman Engineering, Inc.
Davy McKee Corporation

STEIGERS CORPORATION

DIRECTOR OF PROJECTS

Senior Environmental Scientist

PAUL W. McGUIRE

CREDENTIALS

EDUCATION

BS Resource Conservation; 1993
University of Montana
Wetland Soils and Hydrology Training; 2001
Wetland Training Institute
Wetland Delineation Certification Training; 2001, Wetland Training Institute
NEPA Training Course; 2003
Federal Highways Administration
Project Management Training; 2004
Wynlee Crisp, P.E.
Writing Effective NEPA Documents, 2006
The Shipley Group
Managing the NEPA Process, 2006
The Shipley Group
NEPA Process, Endangered Species Act, Section 106, 2009
The Shipley Group

SPECIALIZATION

Environmental Permitting and Compliance
Planning/Due Diligence
Wetlands/Mitigation
Wastewater
Air Quality
Stream Restoration
Land Management
Threatened and Endangered Species
Biological Data Collection
NEPA

PROFESSIONAL SUMMARY

Mr. McGuire has over 15 years of experience in the environmental field, during which time he has managed and developed environmental programs for mining, transportation, power generation and transmission, land management, land development, corridor, and water resources projects. Mr. McGuire is experienced in the management, coordination, and development of environmental studies, impact assessments, feasibility and fatal flaw analyses, wetland assessments, air quality assessments, and preparation of a wide variety of federal, state, and local environmental permits. Mr. McGuire's responsibilities currently include the management and oversight of Steigers Corporation Project Operations. Mr. McGuire's experience allows him to quickly address issues and to develop programs, permits, and documents to meet specific project needs. These skills have made him a successful representative of the client's interests while meeting the requirements of the regulatory agencies.

PROFESSIONAL HISTORY

2010 to Present, Steigers Corporation
Director of Projects
2002 - 2010, Morrison-Maierle, Inc.
Natural Resources Market Group Leader
1999-2002, Steigers Corporation
Environmental Scientist
1993-1994, N.A. Resource Management
Environmental Scientist

RELEVANT EXPERIENCE

Rainbow Redevelopment Project, PPL Montana, Great Falls, MT. Senior Project Manager responsible for management, oversight, technical review, and development of the environmental compliance program for the redevelopment of a 100-year-old 60-MW Hydropower facility located on the Missouri River. Project redevelopment included replacement of all power generating infrastructure excluding dam replacement or alteration. The environmental regulatory program included compliance with all federal, state, and local requirements, including Federal Energy Regulatory Commission license; Section 401, 402, and 404 Clean Water Act; Section 10 of the Rivers and Harbors Act; Threatened and Endangered and State-listed sensitive species, coordination with Montana Fish, Wildlife and Parks regarding an existing conservation easement; coordination for compliance with Section 106 of the National Historic Preservation Act; as well as compliance with several Montana Department of Environmental Quality, County, and other regulatory requirements. Provided oversight and technical review for all biological data collection, report preparation, and permit application preparation. Provided client coordination between the owner, engineer, and multiple subconsultants. Responsible for ongoing environmental compliance during project construction, including site inspections and monitoring and assisting the contractor and PPL with permit modifications and renewals, and new applications for unanticipated project requirements.

Hyalite Transmission Main and Raw Water Intake Project, Bozeman, MT. Project Manager responsible for coordinating, scheduling, and assisting with the environmental regulatory program for replacement of an instream municipal drinking water intake structure, design and construction of a fish ladder on the existing dam within U.S. Forest Service land, and construction of a 3.5-mile-long raw water transmission line for the City of Bozeman. The project included a comprehensive evaluation of four independent proposed routes. Coordinated and assisted with the evaluation and QA/QC of the data collected. Coordinated and assisted with the development of final project reports. Provided assessment of regulatory requirements associated with pipeline, fish ladder and intake structure construction. Developed documentation to complete the Section 404 and 124 permitting process. Coordinated approval from the U.S. Forest Service specialists, including the landscape architect, wildlife biologist, fisheries biologist, botanist, recreation coordinator, and NEPA coordinator. Developed a Decision Memo for the U.S. Forest Service for NEPA compliance.

Permitability/Fatal Flaw Assessments, Seward, AK, Healy, AK, Bearcreek, MT, Pinckneyville, IL, Somerset, CO. Coordinated and prepared several permitting and environmental assessments and fatal flaw analyses for a variety of power generating facilities. These documents varied in detail and length to meet the needs of each client. However, each study included an assessment of all major permits or approvals required for development and a detailed assessment of the NEPA process These evaluations included development of preliminary environmental information volumes to assess applicability of NEPA. Prepared brief reviews for a 12-MW coal-fired power plant in Seward, Alaska and a 125-MW coal-fired power plant in Bearcreek, Montana. Also prepared lengthy studies for a 45-MW gas-fired power plant in Anchorage, Alaska, a 1,500-MW coal-fired power plant in Pinckneyville, Illinois, a 200-MW coal-fired power plant in Healy, Alaska, and a coalmine methane energy recover project in Somerset, Colorado. These evaluations included an assessment of permitting requirements, difficulty, cost, and schedule.

RELEVANT EXPERIENCE cont.

Knik Arm Power Plant Repowering Project, Anchorage, AK. Project Coordinator responsible for the environmental compliance effort for repowering a natural-gas-fired cogeneration power facility in Anchorage Alaska. Acted as principle contact and liaison between client and federal, state, and local agencies. Developed permit applications in accordance with applicable permitting requirements, including Air Quality Construction permit application, National Pollutant Discharge Elimination System Industrial Wastewater Discharge permit application, Alaska Department of Fish and Game Fish Habitat permit application. Coordinated with the U.S. Army Corps of Engineers to determine the applicability of Section 404 and Section 10 permitting requirements and to minimize those requirements. Completed a NEPA review, which included developing a preliminary environmental information volume to assess NEPA requirements. This project also required completing a wetlands delineation; coordinating a site remediation project; preparing, coordinating, and overseeing a contaminated sediment sample collection and testing program (including Alaska Department of Fish and Game and U.S. Army Corps of Engineers permitting); preparing a Site Investigation Report to evaluate the results of the sediment sample laboratory analysis; evaluating water rights; and completing an Alaska Division of Governmental Coordination Coastal Zone Consistency Review to meet the requirements of the Coastal Zone Management Act. Extensive study of potential impacts to salmonids (thermal impacts, fish passage, entrainment, spawning habitat, in-stream flows), impacts to regional airports (exhaust plume), dam safety, geologic stability of the site, public safety, and extensive public involvement were some of the more significant issues addressed during the management of this project.

Yankee Gulch Sodium Minerals Project, Parachute, CO. Assisted with the development of a nahcolite solution mining operation that included a 1,200-acre 30-year mine facility on Bureau of Land Management property, a 44-mile-long buried two circuit product pipeline, a processing and calcining facility, and a railspur for product distribution. Developed, or assisted with the development of the following: Colorado Division of Minerals and Geology Mining and Reclamation permit (including a reclamation plan), county special use permits for two counties, a state National Pollutant Discharge Elimination System permit, Class I, Class III, and Class V Underground Injection Control permits, Bureau of Land Management Mine Plan and revised Mine Plan, Emergency Response Plan, Pipeline Plan of Development, a Section 404 Nationwide 12 permit for the 44-mile-long pipeline, county and Public Utilities Commission approval for installation of several railroad crossings, application for several rights-of-way, and NEPA environmental information support documentation. Prepared and completed environmental evaluations to meet requirements for NEPA compliance. Provided document preparation assistance for development of an Environmental Impact Statement. Also developed, or assisted with the development of the following support documentation: Groundwater and Surface Water monitoring Plan; Subsidence Monitoring Plan; Wildlife Monitoring and Mitigation Plan; Stormwater Pollution Prevention Plan; Spill Prevention, Control, and Countermeasure Plan; and Environmental Compliance Document preparation.

Great Falls Area 100kV Generation Interconnection Replacement Project, PPL Montana, Great Falls, MT. Senior Project Manager responsible for the environmental compliance program of a 13.1-mile 100kV transmission line. The transmission line corridor is part of five hydro facilities on the Missouri River. Developed a comprehensive environmental plan to meet all federal, state, and local regulatory requirements, including Clean Water Act Section 401 and Section 404 and Rivers and Harbors Act Section 10. Managed and assisted in the preparation, technical review, and submittal of supporting environmental documentation and permit applications for federal, state, and local requirements, including FERC compliance. Project development included close coordination with the project owner, design engineer and other contractors to develop a design plan that met project objectives while minimizing compliance requirements.

Mystic Lake FERC Compliance, West Rosebud Creek, MT. Senior Project manager responsible for the ongoing Federal Energy Regulatory Commission license compliance requirements for the Mystic Lake hydroelectric facility. Compliance requirements to date have included coordination with U.S. Forest Service to develop and complete a riparian vegetation study, a weed infestation study, a bald and golden eagle study, and a harlequin duck survey.

Seep Ridge Road Environmental Assessment, Vernal, UT. Senior Project Manager responsible for the coordination, oversight, and technical review for the preparation of an Environmental Assessment for NEPA compliance for a 46-mile-long road reconstruction project. Management oversight included the completion of biological review, development of project alternatives, agency coordination, and cumulative impacts analysis. Coordinated the development of design alternatives and mitigation measures to meet the requirements of the Bureau of Land Management, U.S. Fish and Wildlife Service, and the State Division of Wildlife Resources for impacts to vegetation, wildlife, livestock and grazing, Threatened and Endangered species, and aquatic resources.

Kalispell Armory Phase I and Phase II, Kalispell, MT. Staff Supervisor responsible for completion of a Phase I Environmental Property Assessment using the ASTM 1527 Standard. Provided project oversight, QA, and coordination. Following preparation of the Phase I, it was concluded that a petroleum release was likely located within the property. Completed a Phase II with continued biannual monitoring, data collection and evaluation, and reporting.

Rorik A. Peterson

Assoc. Professor, Mechanical Engineering
University of Alaska Fairbanks
PO Box 755905
Fairbanks, Alaska 99775-5905
(907) 474-5593
Fax: (907) 474-7290
rapeterson@alaska.edu

Education:

- Univ. California, San Diego. B.S. Chemical Engineering 1994.
- Univ. Colorado, Boulder. M.S. Chemical Engineering 1996.
- Univ. Colorado, Boulder. Ph.D. Chemical Engineering 1999.
- Dissertation title: *Differential frost heave manifest as patterned ground - modeling, laboratory and field studies*

Professional/Research Experience:

- 2011 – current: Assoc. Professor, Mechanical Engineering, Univ. Alaska, Fairbanks.
- 2004 – 2011: Asst. Professor, Mechanical Engineering, Univ. of Alaska, Fairbanks.
- 2001-2004: Research Programmer, Remote Sensing and Volcanology, Geophysical Institute, Univ. Alaska, Fairbanks.
- 2000-2001: Postdoctoral Research Associate, Institute of Arctic Biology and The Geophysical Institute, Univ. Alaska, Fairbanks.
- 1999-2000: Postdoctoral Research Associate, Oxford Centre for Industrial and Applied Mathematics, University of Oxford, UK.
- 1999: Postdoctoral Research Associate, Center for Membrane Applications and Separations Technology, Univ. Colorado, Boulder.
- 1997-1999: Graduate Research Assistant, Institute for Arctic and Alpine Research and Dept. of Chemical Engineering, Univ. Colorado, Boulder.
- 1995-1997: Graduate Research Assistant, Center for Separations using Thin Films and Dept. of Chemical Engineering, Univ. Colorado, Boulder.

Past & Current Research Grants:

- *Preservation of Traditional Ice Cellars in Permafrost – PI – Jan. 2010 - May 2011 – ExxonMobil - $60,000*
- *Phase II of the KEA Pillar Mountain Wind Project – co-I (1 of 2) – May 2009 - Sept. 2010 – Kodiak Electric Association – $100,000*
- *Comprehensive Evaluation of Bridge Anti-icing Technologies* – Co-I (1 of 3) 2007 – AKDOT – $65,928
- *Automating a Volcanic Ash Forecast System with Improved Visualization Tools for Increased Public Accessibility* – PI – 2006 – UCAR – $8874.
- *Fiberoptic Cable on Tundra – PI – Aug. 2009 – Aug. 2012 – NSF – $200,000*
- *Wind-Diesel Systems for Alaska – co-I (1 of 7) – July 2010 - June 2013 – DOE $3 million*

Relevant Publications:

- R Peterson, B Stunder, R Servranckx, P Webley (2011) “Chapter 9: Volcanic Cloud Dispersion Models”, in *Monitoring Volcanoes in the North Pacific*, Springer Praxis 500 pp ISBN 9783540241256.
- RA Peterson (2010) “Assessing the role of differential frost heave in the origin of periglacial patterned ground” *Quaternary Research* doi:10.1016/j.yqres.2010.08.003
- RA Peterson and WB Krantz (2008) “Differential frost heave model for patterned ground formation: Corroboration with observations along a North American arctic transect” *J. Geophys. Res*. **113**, G03S04, doi:10.1029/2007JG000559
- RA Peterson. (2008) “Stability analysis and numerical simulation of differential frost heave” *Mathematical Geosciences,* **40**(3), 277-298, doi:10.1007/s11004-008-9150-z
- RA Peterson and WB Krantz. (2003) "A mechanism for differential frost heave and its implications for patterned ground formations." *J. Glaciology*, **49** (164) , 69-80
- RA Peterson, DA Walker, VE Romanovsky, JA Knudson, MK Raynolds and WB Krantz. (2003) "A differential frost heave model: cryoturbation-vegetation interactions", *Permafrost - proceedings of the 8th International Conference on Permafrost* Phillips, Springman, Arenson (eds). pp. 885-890
- RA Peterson, AR Greenberg, LJ Bond, and WB Krantz. (1998) "Use of Ultrasonic TDR for real-time, noninvasive measurement of compressive strain during membrane compaction." *Desalination* **116** (2), 115-122.

Collaborators:

- Dr. Julian Murton, University of Sussex, UK (arctic geology)
- Dr. William B Krantz, Univ. Cincinnati and Nanyang Tech. Univ. Singapore (arctic geology, separations)
- Dr. Kenneth Dean, Geophysical Institute, University of Alaska, Fairbanks (volcanic ash transport)
- James Boschma, Boschma Research (hydrokinetics)

Appendix F

Budget Form

Appendix F – Grant Budget Form

Emerging Energy Technology Fund

LCNG as a Bridge to Reduced Energy Costs in Rural AK

Milestone or Task	Anticipated Completion Date	EET Fund Grant Funds	Grantee Matching Funds	Source of Matching Funds: Cash/In Kind/Federal Grants Other/State Grants/ Other	TOTALS
Phase 1 Predeployment					
GRANTEE MANAGEMENT					
Weekly Oversight Participation	n/a	$8,140	$0	None	$8,140
SYSTEM DESIGN					
Project Kickoff & Field Survey	3-Sep-12	$22,336	$7,445	In Kind	$29,782
Prreliminary Design + Design Basis Memo	22-Oct-12	$38,712	$12,904	In Kind	$51,616
Process Flow Sheets + Equip Sizing	10-Dec-12	$34,728	$11,576	In Kind	$46,304
Equipment Layout	21-Dec-12	$26,687	$8,896	In Kind	$35,582
Equipment Lists + Vendor Quotes	14-Jan-12	$25,582	$8,527	In Kind	$34,109
Technical Readiness & Test Plan Development	5-Dec-12	$31,397	$0	None	$31,397
Capital & Operating Cost Estimates	25-Mar-13	$34,144	$11,381	In Kind	$45,525
Emissions Calculations	11-Feb-13	$11,128	$3,709	In Kind	$14,837
PERMITS & COMMERCIAL PLANS					
Assessment Study	12-Mar-13	$56,548	$18,849	In Kind	$75,397
Permit Planning & Applications	16-Jul-13	$231,112	$77,037	In Kind	$308,149
PROJECT FINANCING PLAN	6-Nov-13	$59,257	$19,752	In Kind	$79,009
Negotiate LNG Supply	20-Sep-13	$35,879	$0	None	$35,879
COMMERCIALIZATION PLAN	30-Oct-13	$74,699	$24,900	In Kind	$99,598
TRAVEL, PHASE 1	Various	$27,773	$0	None	$27,773
TOTALS:		**$718,120**	**$204,977**		**$923,098**
		$709,980	22.21%		
Budget Categories					
Direct Labor & Benefits		$8,140	$0	In-Kind	$8,140
Travel & Per Diem		$27,773	$0	None	$27,773
Equipment		$0	$0		$0
Materials and Supplies		$0	$0		$0
Contractual Services		$682,208	$204,977	In Kind	$887,185
Other		$0	$0		$0
TOTALS:		**$718,120**	**$204,977**		**$923,098**

Appendix G

Certification of Matching Funds

Appendix F

Matching Funds Certification

The undersigned do hereby certify that the matching funds specified in the application for AEA's Emerging Energy Technology Fund (AEA-12-047) will be provided by PDC Harris Group LLC, as engineering contractor to the City of Bethel.

Steven M Theno, Executive Director — Date: 2/29/2012

William E. Ward, Executive Director — Date: FEB 27, 2012

Appendix H

University of Alaska Budget Form

UNIVERSITY OF ALASKA FAIRBANKS
Center for Research Services - Office of Sponsored Programs
University of Alaska Fairbanks, P.O. Box 757270, Fairbanks, Alaska 99775-7270

Andrew Gray, CRA
Director
Tel (907) 474-1851
Fax (907) 474-5444
amgray@alaska.edu
www.uaf.edu/osp/

27 February 2012

Mike Moora
PDC Harris Group LLC
2700 Gambell St, Suite 500
Anchorage, AK 99503

Re: Letter of Commitment for Liquefied & Compressed Natural Gas (LCNG) as a Bridge Solution to Reducing Energy Costs in Rural Alaska

Dear Mr. Moora:

University of Alaska Fairbanks is pleased to collaborate with PDC Harris Group LLC on the proposal entitled "Liquefied & Compressed Natural Gas (LCNG) as a Bridge Solution to Reducing Energy Costs in Rural Alaska," which is being submitted to Alaska Energy Authority EETF Program. The Principal Investigator from UAF is Rorik Peterson, associate professor in Mechanical Engineering, INE.

The appropriate administrative and programmatic personnel at UAF are aware of the pertinent federal regulations and policies, and we are prepared to enter into a subcontract with PDC Harris Group LLC that ensures compliance with all such policies, should this proposal be funded. A statement of work is outlined in the proposal, and our itemized budget for this subaward is attached.

If you need additional information, please feel free to call my office at (907) 474-1851.

Sincerely,

Andrew M. Gray
Director
Office of Sponsored Programs
University of Alaska Fairbanks

UNIVERSITY OF ALASKA FAIRBANKS

PROJECT TITLE: Sub: Liquefied & Compressed Natural Gas (LCNG) as a Bridge Solution to Reducing Energy Costs in Rural AK — **DEPT #:** INEa
PI: Rorik Peterson
START: 8/15/2012 — **BANNER #:** s165
END: 8/14/2013

Be sure to select the appropriate F&A rate on line 130.
Version 09/10/2010

ACCT							Year 1	Total Project
	SALARIES AND WAGES						**Hours**	
				Hourly Wage	**Leave Rate**	**Yearly Increase**		
1000	**Senior Personnel**							
	Total Number of Hours	Employee Name						
	160.00	Rorik Peterson	F9 - Faculty (UNAC)		1.7%	1.035	160.0 $9,790	**$9,790**
				Total Senior Personnel			$9,790	$9,790
				Total Other Personnel			$0	$0
						TOTAL SALARIES AND WAGES	**$9,790**	**$9,790**
1900	**FRINGE BENEFITS**							
	Senior Personnel	Rorik Peterson	F9 - Faculty (UNAC)		31.6%		$3,094	**$3,094**
				Total Senior Personnel			$3,094	**$3,094**
				Total Other Personnel			$0	**$0**
						TOTAL FRINGE BENEFITS	**$3,094**	**$3,094**
						TOTAL SALARIES AND BENEFITS	**$12,884**	**$12,884**
2000	**TRAVEL**		**Number**					
	1. Domestic Travel	**Description**	Yr 1 Yr 2 Yr 3 Yr 4 Yr 5	**Item Cost**	**Yearly Increase**			
	Select Travel Cost from List				0		$0	**$0**
	Select Travel Cost from List				0		$0	**$0**
	Select Travel Cost from List				0		$0	**$0**
				Total Domestic Travel			$0	$0
			Number		**Increase**			
						TOTAL TRAVEL	**$0**	**$0**
3000	**CONTRACTUAL SERVICES**	**Description**						
	Journal Publication Page Charges - 3332						$0	**$0**
	Consultants - 3005						$0	**$0**
3021/				**Total Other Contractual Srvs**			$0	**$0**
3028	**Subawards subject to F&A (first $25,000)**							
						TOTAL CONTRACTUAL SERVICES	**$0**	**$0**
4000	**COMMODITIES**	**Description**						
	Select Commodity from List						$0	**$0**
						TOTAL COMMODITIES	**$0**	**$0**
	A. MTDC (total costs subject to F&A)						**$12,884**	**$12,884**
	B. Facilities and Administration (F&A)			**Enter other rates manually**		**25.0%**	**$3,221**	**$3,221**
	C. Total Costs Exempt from F&A						**$0**	**$0**
	D. Total Direct Costs (A+C)						**$12,884**	**$12,884**
	E. Total Sponsor Request (B+D)						**$16,105**	**$16,105**

Budget Justification

The following narrative corresponds with budget requests for UAF Rorik Peterson's involvement (subaward) with the proposal, "Liquefied & Compressed Natural gas (LCNG) as a Bridge Solution to Reducing Energy Costs in Rural Alaska," submitted to the Alaska Energy Authority by PDC Harris Group LLC.

Salaries

Senior Personnel. Funding to support a total of 160 hours is requested for the Principal Investigator (Peterson) of this project. Per UAF policy, faculty receive leave benefits at a rate of 1.7%, calculated on salary. *Total cost to project: $9,790.*

Fringe Benefits

Staff benefits are applied according to UAF's benefit rates for FY12, which are negotiated with the Office of Naval Research (ONR) annually. Rates are 31.6% for senior salaries.

Total cost to project: $3,094.

Indirect Costs

Facilities and Administrative (F&A) Costs are calculated according to the existing MOA between UA and the State of Alaska, at a rate of 25% of Modified Total Direct Costs for research projects. MTDC includes Total Direct Costs minus tuition another student support, subaward amounts over $25,000 and equipment. A copy of the agreement is available at:
http://www.alaska.edu/cost-analysis/downloads/Negotiated/FY12-13_State_FA_Neg.pdf
Total cost to project: $3,221.