Landfill Gas Utilization Economic Evaluation for Anchorage Regional Landfill

Anchorage, Alaska

Prepared for

Municipality of Anchorage

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APPENDICES

1 INTRODUCTION

The Municipality of Anchorage (MOA) has retained EMCON/OWT, Inc. to perform an economic evaluation of its landfill gas (LFG) beneficial use options. The evaluation is based on the anticipated LFG recovery rates and considers the cost of design, equipment procurement, equipment installation, revenue streams, potential government subsidies, and operations and maintenance (O&M) for the proposed facilities.

This LFG beneficial use study was supported in part by funding from the US Department of Energy Regional Program Grant No. DE-FG51-02R0211317. This funding does not constitute any endorsement by the US Department of Energy of the results of the study.

The LFG beneficial use options evaluated for this study are described below. Due to the poor financial performance of the electrical generation option, two scenarios were generated. The first electrical generation scenario included costs to construct and maintain the LFG collection system; the second scenario did not. All of the subsequent beneficial use options included costs to construct and maintain the LFG collection system. The Anchorage Regional Landfill is required by Federal New Source Performance Standards to install and operate such a system.

Due to the difficulty in assessing the value of intangible items such as positive public relations for the Municipality as a result of using LFG as a beneficial use, these items are not included in this economic evaluation. The Municipality may want to consider the value of such intangible items in its final decision to proceed or not proceed with a project.

1.1 Option 1 – Electricity Generation

Option 1 involves electrical generation with a series of internal combustion engines that are designed to ignite LFG. Electricity generated by the engines may be sold to a local utility at its avoided cost rates.

1.2 Option 2 –Transmission of LFG to Enstar Natural Gas Pipeline

Option 2 includes compression and transmission of LFG into a high-pressure natural gas pipeline, which runs adjacent to the landfill (990 feet way). Enstar Natural Gas Company owns the natural gas pipeline. For this option we have reviewed the clean-up requirements and required operating pressure of the pipeline.

1.3 Option 3 – Transmission of LFG to Eagle River School

Option 3 includes compression of LFG in a low-pressure pipeline and then transmitted approximately 0.6 miles to the Eagle River School campus for use in its boilers. The Eagle River School boilers would be modified to allow burning of dual fuels (LFG and natural gas).

1.4 Option 4 – Transmission of LFG to National Guard Facilities

Option 4 includes compression of LFG in a low-pressure pipeline and then transmitted approximately 2.7 miles to the National Guard facilities for use in its boilers. National Guard boilers would be modified to allow burning of dual fuels (LFG and natural gas).

1.5 Option 5 – Transmission of LFG to Fort Richardson Facilities

Option 5 includes compression of LFG in a low-pressure pipeline and then transmitted approximately 5.1 miles to Ft. Richardson for use in its boilers. Ft. Richardson boilers would be modified to allow burning of dual fuels (LFG and natural gas).

1.6 Option 6 – Transmission of LFG to Existing Municipal Light & Power (ML&P) Plant (George M. Sullivan No. 2).

Option 6 includes compression of LFG in a low-pressure pipeline and then transmitted approximately 6.75 miles for use in ML&P's closest operating electrical plant equipment. ML&P equipment would be modified to allow burning of dual fuels (LFG and natural gas).

1.7 Option 7 – Transmission of LFG to Proposed Municipal Light & Power (ML&P) at Fossil Creek.

Option 7 includes compression of LFG in a low-pressure pipeline and then transmitted approximately 2.1 miles to the proposed Fossil Creek facility for use in its electrical generation equipment. ML&P equipment would be modified to allow burning of dual fuels (LFG and natural gas).

1.8 Option 8 – Treatment of Liquid Generated or Collected at the Anchorage Landfill

Option 8 includes the utilization of LFG to treat liquids generated or collected at the Anchorage Regional Landfill. These liquids include leachate generated at the landfill and glycol collected and disposed of by the Municipality. Due to unfavorable preliminary financial estimates, less detailed discussions of these options are contained in subsequent sections of this report. .

2 ESTIMATED LANDFILL GAS GENERATION

EMCON/OWT used its proprietary LFG generation model to estimate the quantity of LFG that will be generated at the Anchorage Regional Landfill.

2.1 Model Input

The LFG model is based on waste inflow, waste composition, waste moisture, and the potential for air intrusion. The input for the LFG model was determined based on site-specific data provided by Anchorage Regional Landfill. Assumptions were made based on EMCON/OWT's knowledge of the landfill and nationwide studies of municipal solid waste. The input for the LFG generation model is provided in Appendix 1.

2.2 Model Output

The LFG generation model output is also provided in Appendix 1. The annual utilizable quantity of LFG (as shown in the LFG generation model output) was used over the 10-year project life in the economic evaluation. The model output indicates that the average quantity of LFG generated over the 10-year project life is approximately 1,383 scfm (Year 1: 1,101 scfm and Year 10: 1,632 scfm). This utilizable quantity of LFG represents the quantity of LFG expected to be delivered to the blower/flare facility by the LFG collection and control system over the 10-year project life.

All LFG flow rates quoted above are the expected generation rate. The actual quantity of LFG that may be available for beneficial use may be slightly less than the reported generation rates. This reduction of LFG collected versus generated is known as the "collection efficiency." Collection efficiency is determined based on LFG well spacing, cover type, cover maintenance, percent of sideslopes allowing air intrusion, and maintenance of the LFG collection system. Typical collection efficiencies reported for geomembrane lined and capped sites are 90 to 95%. Typical collection efficiencies reported for capped soil and poorly operated LFG collection systems is 60 to 65%. Based on our review of the plans for LFG collection system design and MOA staff members' extensive knowledge of LFG design, construction, operations, and their high standards for each of these disciplines, EMCON/OWT feels a collection efficiency of 75% is very achievable. Therefore, the model output indicates that the average quantity of collectable LFG over the 10-year project life is approximately 1,037 scfm (Year No.1: 826 scfm and Year No. 10: 1,224 scfm).

3 LANDFILL GAS CHARACTERIZATION AND UTILIZATION

3.1 Landfill Gas Characterization and Utilization for Electrical Generation Equipment

LFG contains many contaminants that have detrimental effects on LFGTE collection, processing, and distribution equipment. The control of these contaminants can create secondary air compliance issues related LFGTE plant emissions.

Beside the corrosive properties of LFG caused by contaminants (e.g., hydrogen sulfide, formation of carbonic acid, etc.,), siloxanes are probably the most troublesome contaminate for electrical generation equipment. Siloxane testing is now becoming well known as a primary maintenance and engine performance problem. Siloxane levels can range from low part per billion by volume (ppbv) levels to several hundred part per million by volume (ppmv). The reduction of siloxanes to silica dioxide is <u>inevitable</u> as the gas is burned to produce power and heat.

Siloxanes can cause significant operational problems on LFG utilization projects (e.g., microturbines, internal combustion engines, fuel cells, large-scale turbines, catalyst systems, etc.). The impact of the silica deposition and abrasion is different at every landfill, but can have a significant maintenance cost impact on equipment.

Most LFGTE projects use internal combustion (IC) engines to generate electricity. The silica dioxide can reduce head life; plate out and cause bypass of valves, score cylinders and liners; shorten life of spark plugs; cause increased oil changes; reduce the online power production time and profit; poison catalyst; produce incomplete combustion products; and lower engine and/or turbine efficiency.

Having knowledge of all these, EMCON/OWT had the LFG tested for its basic fuel, volatile organic compounds (VOCs), siloxane, and sulfur components. The results of this testing are briefly discussed below. The complete laboratory analysis and a possible "clean-up" process are contained in Appendix 2.

Upon review of data from the samples, it appears this site may be a suitable candidate for power generation using standard internal combustion (IC) engine technology. Currently, only the removal of siloxanes should be considered to extend the operational life, reduce the operational costs, and improve the uptime of the anticipated power generation. Further testing is recommended after collection wells are installed to check the blend of fuel components along with VOC and siloxanes.

3.2 Landfill Gas Utilization for Boilers

The effects of burning the methane gas recovered from a landfill can be divided into the following four main categories:

- Effects on boiler efficiency,
- Effect on maximum boiler output capacity or production,
- Effects due to individual compounds in LFG stream, and
- Design changes needed to accommodate using LFG.

3.2.1 Effects on Boiler Efficiency

Typically LFG is introduced into burners that were designed for natural gas having an energy content of 980 to 1,020 Btu/dscf (dry standard cubic foot). LFG has an energy content typically of 400 to 600 Btu/dscf. It can be shown by calculation that converting a boiler from natural gas to LFG will reduce the boiler efficiency by approximately 1%. This theoretical drop in efficiency is partially offset by a decreased exhaust gas temperature due to the increased radiative heat transfer coefficient of the combustion gases due to the increased levels of CO_2 in the fuel gas. It should be noted that this decrease in efficiency is less than the change to other fuels (i.e. changing from #2 fuel oil to natural gas is a reduction of over 3% in efficiency).

3.2.2 Effect on Maximum Boiler Output Capacity or Production

Because of the lower heating value per cubic foot of LFG, a higher volume of fuel introduction to the burner is required for equal heat input. Typically twice as many cubic feet of LFG must be fed as natural gas to get the same Btu input to the burner. The net effect of this is to increase the total volume of exhaust gas in the stack. This is an increase of roughly 10% volume flow of gas in the stack. On a boiler where the combustion air fan is exactly sized for the burner rated input this would have the net effect of reducing the maximum energy input by 10% when firing LFG. However, properly sized burners typically have combustion air fans, which are oversized by 20% or more to account for variations in stack design and installation. In addition, boilers normally operate at 75% or less of capacity and 100% capacity are only used during warm-up from light off and this decrease in capacity is usually not detectable in operation. It should be noted that during the typical boiler tuning the boiler maximum firing rate is reduced to 85% to 90% of name plate capacity in order to achieve optimal firing at the lower firing rates. Because the fuel component of both LFG and natural gas is methane the amount of combustion air required to burn 1 MMBtu of methane gas is equal to the amount required to burn 1 MCF of natural gas (natural gas is measured in

MCF or thousand cubic feet which at 1,000 Btu/cf by specification gives 1 MCF = 1 MMBtu) so that there is no net increase in combustion air required when changing fuels for equal heat input.

3.2.3 Effects Due to Individual Compounds in LFG Stream

The major components of LFG are methane (CH_4), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) and other trace components primarily water vapor (H_2O), non-methane organic compounds (NMOCs), hydrogen sulfide (H_2S), and siloxane (SiOx).

Methane is the primary energy component of LFG and is consumed during the combustion process. The combustion process is carefully regulated and is required to be controlled in such a manner that combustion products such as carbon monoxide (CO), nitrous oxides (NO_x), and unburned hydrocarbons (CH_4 and NMOC) are minimized.

A major environmental benefit of burning LFG is that methane when released into the atmosphere is 21 times more effective at heat retention that carbon dioxide or in other words burning the methane contained in LFG has a net effect of reducing the total amount of greenhouse gases released from a landfill by a factor of 20. It is recognized by the US EPA that for each 1 MMBtu of LFG that is burned and not released from the landfill there is a net reduction of 1 ton of equivalent CO2 released into the atmosphere. In a typical large project this reduction will be in the hundreds of thousands of tons of CO2 reductions per year.

The carbon dioxide and nitrogen in the gas stream are inert and have no effect on the combustion process other than to:

(i) cool the theoretical flame temperature thereby decreasing efficiency as described above, and;
(ii) increase the total volume of exhaust gases, which must be removed by the combustion air fan thereby decreasing maximum input as described above.

(2) It is important to note that the nitrogen in the fuel gas stream is not the same as what is commonly referred to as fuel born nitrogen, which is typically found in both liquid and solid fuels in the form of nitrates. In those cases the fuel bound nitrogen will add to the total NOx production of the boiler. Because the nitrogen in the fuel stream is non-reactive as well as the carbon dioxide they both act to reduce the flame temperature, which has the net effect of reducing the amount of prompt NOx formed in the combustion process. Burner manufacturers such as COEN document a total NOx reduction of up to 30% when burning LFG versus natural gas. This reduction is due to the cooler flame temperatures in the combustion zone, which has the same effect as flue gas recirculation (FGR) without the performance and maintenance penalties associated with FGR.

(3) Because of the nature of gas recovery at a landfill there is always trace amounts of water vapor present (from 0.3% to 3% by volume) in the fuel gas stream. While the water has no effect on combustion and is negligible when compared to the approximately 15% water vapor present in the exhaust gas due to the combustion of the hydrogen component of the methane contained in the LFG there is no net effect on the boiler proper. However, care must be taken to prevent water accumulation in the gas delivery piping and gas train especially when this piping is located out of doors in cold environments.

(4) In the gas stream from a typical landfill there are varying amounts of NMOCs, which can vary from as little as 100 ppmv to over 2,000 ppmv. Since all the species that may be found in LFG are hydrocarbons they are nearly completely destroyed in the combustion process. There are no significant detrimental effects due to the presence of NMOCs in the LFG stream.

(5) Hydrogen sulfide (H_2S) is another trace compound, which is typically found in LFG and is a poisonous gas at elevated concentrations. Typical levels of H_2S in methane gas streams are close to 10 ppmv, which is high enough to be detectable by its distinct sour (rotten egg) odor. Typical natural gas has up to 3 ppmv of H_2S, which puts both fuels on roughly equal footing as to the potential for harm. H_2S is converted to SO_2 during the combustion process.

(6) Siloxane often is found in LFG and can vary from a few parts per billion to many parts per million. Siloxane is a gas that contains bound silicon. Upon reaching typical combustion temperatures it is converted into silicon dioxide, which forms a very light non-toxic dust that typically passes through the boiler. In most applications small accumulations of this dust are removed annually and disposed of. The only problems noted with this dust are on boilers with serrated fin or tight spaced fin economizers, which act as particulate filters and can become plugged with the silica dust. The silica dust does not adhere to most surfaces and is removed by light brushing or air pressure. Economizers with wide fin spacing (i.e. less than 3 fins per inch) typically do not plug with the silica dust.

3.2.4 Design changes needed to accommodate using LFG

In most situations LFG will be introduced to a boiler that already exists. The following are design changes or modifications that should be examined. Not all of these will be required on any given installation and it is possible that very minimal modifications will be required. When new equipment is purchased to burn LFG, the manufacturer will be responsible for the required design to adequately burn LFG. It should be noted that the following assume that the LFG is being used in a existing gaseous fuel (typically natural gas) fired boiler or process burner, in cases where the burner is used with liquid or solid fuels then the manufacturer of the burner should be contacted for specific recommendations.

(1) Because of the increased volume of fuel required to match energy input, LFG is normally introduced into an existing burner through a separate gas train with separate modulating gas control valve. Typically, if the same burner ring is to be used then the feed pressure of the gas to the ring is increased a factor of 1.5 to 4 times that of natural gas.

(2) Since the energy content of LFG can vary by as much as 20%, an oxygen trim system should be considered for larger (over 10 MMBtu/hr input) burners and boilers. In these larger installations the increase in efficiency due to oxygen trim will normally pay for itself in less than a year due to increased boiler efficiency.

(3) Installations where there is less LFG available than the maximum required input of the boiler, a co-fire system can be employed. Co-fire systems have oxygen trim and will allow for maximum consumption of LFG while allowing for the boiler to reach full fire when needed.

(4) In installation where continuity of service is desired, minimal control modifications can be made so that loss of LFG availability will cause an automatic transfer to natural gas or other back up fuel.

(5) In some burners (particularly larger or liquid fueled burners), a new gas-firing ring will need to be added specifically for LFG.

(6) On newer installations, many manufacturers have experience with burning LFG due to its similarity to sewage treatment plant digester gas. Most boiler manufacturers have an existing design for digester gas. Digester gas differs from LFG only in its much higher concentration of H_2S.

(7) Typically the pilot will continue to be fired with natural gas. In installations where LFG is the only fuel a propane pilot is normally used.

The preceding is intended as guides to use in evaluating the potential use of LFG as a fuel and not as specific design recommendations. At this time, no "clean up" for the boiler fuel application is being considered. A qualified engineer should be employed on any project to insure the safe and successful use of LFG as an alternative fuel.

4 POTENTIAL LFGTE PROJECT SUBSIDIES

As part of this study EMCON/OWT researched the availability of governmental subsidies that exist to help offset the cost of LFGTE system development. A list of the potential subsidies that were researched is provided below.

4.1 Federal Renewable Energy Tax Credits

Federal Renewable Energy Tax Credits, also known as "Section 29 tax credits," are not available at this time. In the past, tax credits were available for projects that used landfill gas as a fuel. Credits that were beneficial to tax payers were valued at $1.00. Landfill gas equivalent to 1 million Btus was one credit. For comparison purposes, the past program (expiring) values the credit at $1.059 per million Btu. Federal legislation will be necessary for this program to become available again. Whether or not such legislation passes in 2004 is speculative at best given the political situation and the upcoming presidential election.

The 108th Congress debated energy bill legislation without success. Whether or not an energy bill passes in 2004 is debatable and what the bill will contain is, again, speculative. The bill that was progressing in 2003 valued landfill gas as a tax credit; the suggested value was $3 per barrel of oil equivalent. This made the tax credit associated with landfill gas used in an energy project at $0.50 per million Btu. The bill also limited the amount of LFG that can be used to create a tax credit to only 200,000 ft cubed per day.

4.2 Renewable Energy Production Incentive (REPI)

REPI funds are available to help subsidize LFGTE development costs for entities that are not typically eligible for tax credits (e.g., public agencies such as the Municipality of Anchorage). Since its inception, REPI funds have designated LFG as a second tier renewable energy. Renewable energy sources, such as wind power, are given a higher priority when distributing funds. Second tier energy sources receive funds only after the available funds are distributed to higher tier renewable energy sources. While LFG projects have received REPI funds in the past, EMCON/OWT has not included this subsidy in the financial pro forma contained in subsequent sections. If the MOA does develop the LFGTE project using internal funds, annual REPI applications should be submitted.

4.3 Discussion of Potential Valuable Landfill Gas Attributes

This brief discussion is included to demonstrate that the attributes associated with landfill gas can be a valuable asset to the owner. Any activity associated with a landfill and its landfill gas should be undertaken with this knowledge. Any decisions should take into account the current situation as it relates to the attributes discussed below. The situation may change in the near future due to local, regional, national, and international politics.

4.3.1 Valuable Attributes of Landfill Gas

Landfill gas is a valuable commodity due to its source, municipal solid waste, and its main constituent, methane. LFG is recognized as a renewable energy by the US DOE, USEPA, most state energy programs, and the international bodies working to control global warming. Electricity produced from LFG or beneficial use of the LFG can be a source of credit that can have many values. While the areas for credit or value are still developing across the United States and around the world, the following discussion will assist the Municipality of Anchorage in understanding the value of these attributes and will suggest approaches for how to proceed.

4.3.2 Renewable Energy Credits

A Renewable Energy Credit (REC) is an attribute that is given to landfill gas by those states that have legislated renewable portfolio standards (RPS). Generally, electricity produced by LFG is considered to have an ancillary REC attribute due to the avoided use of fossil fuel. For each megawatt of electricity produced from LFG, one REC unit is produced. States that have legislated a RPS generally allow RECs from LFG projects to be used to attain compliance with the mandated portfolio standard. A portfolio standard generally requires a pre-established percentage of energy produced from renewable sources be sold by the power suppliers.

Electricity suppliers attain compliance with the mandated RPS through free-market purchase of RECs from generators, who are sometimes referred to as Qualified Facilities. RECs have been purchased for $4.50 to $40.00 per REC in Massachusetts, New Jersey, and most recently Connecticut. Recent discussions (January 2004) with environmental REC brokers reveal a weak market for RECs in areas not required to utilize them, such as Alaska. The price suggested was $1.00 per REC for these “weak” areas.

RECs may be sold and “wheeled” to other states from non-RPS states[1].[2]. These “deals” are not lucrative at this time, with potential prices in the range of $1 to $2 per REC. This

[1] Personal communication: Ana Giovinetto, Evolution Markets, and B. K. Maillet Shaw EMCON January 2004

is due to the voluntary market in states with no requirement to supply RECs in their electricity portfolios. Buyers may be difficult to identify. According to one broker, the market is probably oversold. It does show, however, that a national market is emerging.

4.4 Greenhouse Gas Credit Values

While there are few regulatory drivers in the United States for a greenhouse gas (GHG) credit market, there is a great deal of activity at the state level to develop mandatory carbon dioxide reduction programs. There are few regulatory requirements for utilities, industries, and businesses to reduce their GHG emissions; therefore, there is currently little incentive to purchase GHG offsets.

Some trades of CO_2E (calculated on a CO_2 equivalent basis) have taken place despite the negative situation relative to required CO_2 reductions. Companies will occasionally need CO_2E offsets. Oregon and Massachusetts have requirements for new energy producers to offset some or all of their CO_2 emissions. LFG has played a role in at least one of these situations in the Commonwealth of Massachusetts. The Energy Facility Siting Council (of Massachusetts) required Mirant Energy to pay $300,000 for CO_2E credits for reconstruction of a power plant.

Greenhouse gas credits are the attributes assigned by climate change programs to the reductions in GHG emissions that are above the required levels, if any. Projects undertaken to reduce GHG gasses qualify as GHG credits. They are generally referred to as carbon dioxide equivalents or CO_2E. The issue of whether or not the landfill is required to control the landfill gas is very important to the creation of credits. Landfills that are required to reduce the LFG may not have any credits available due to the additionally[3] requirement.

Discussions regarding GHG or climate change are occurring across this country. Most state programs, such as those found in Oregon, Massachusetts, California, Connecticut, and New Hampshire, see the need for a federal program with widespread inter-sector trading of CO_2E. This bodes well for existing and future LFG-to-energy projects. The project owner should have the mechanisms in place to properly track and document the LFG used and credits generated. The US Department of Energy (DOE) 1605B program is an excellent way to start this process. The program is currently being improved to ensure better information and that CO_2E credits are registered. The revisions will be in place within the year. DOE's program requires gas measurement, gas generation documentation, and equipment calibration. Regular data collection from the project

[2] Personal communication between Natsource, Matt Williamson and B.K. Maillet, Shaw EMCON, January 2004

[3] Additionally: Kyoto protocol and other protocols such as the World Resource Institute and World Business Council for Sustainable Development will not allow credits from projects.

should be collected and maintained. As the data is filed with DOE, the credits will be available for others to view and perhaps acquire.

At a recent SWANA LFG conference in San Antonio, Texas, Carl Bartone, a World Bank Environmental Consultant, described his work in developing LFG to Energy projects in Central and South America. He also described the value of the CO_2E that will be the commodity traded in the GHG arena. Bartone reports that the cost of producing a CO_2E is in the range of \$3 to \$4 per TCO_2E from the Prototype Carbon Fund (PCF) data. He also reports that in a 2002 report, the PCF has suggested that the marginal cost of compliance with CO_2 reductions is on the order of \$15 per TCO_2E. The consensus of experts around the world is that LFG is a valuable commodity to be tracked and documented in order to obtain the value of the credits as programs develop.

4.5 Trading Brokers

There are many traders that can handle the sale or transfer of LFG energy project attributes. Evolution Markets, Cantor-Fitzgerald, and Natsource are among them. As the project develops, the brokers should be made aware of the project details and schedule. They may be able to place sales or commitments in advance with additional revenue for the project. EMCON/OWT can prepare the introductions and information necessary for the brokers to understand the project. Additional information on their services may be found at the following web sites:

- Natsource: www.natsource.com
- Evolution Markets: www.evomarkets.com
- Cantor Fitzgerald: www.cantor.com
- Ecosecurities: www.ecosecurities.com

None of the above subsidies have been included in the financials contained in the subsequent section.

5 ECONOMIC ANALYSIS

5.1 Project Assumptions and Analysis

The following assumptions have been made for the purpose of comparing each of the beneficial use options:

- The project pro forma period of 10 years (2006-2015) is commonly used for landfill gas to energy financial feasibility analysis. As analysis periods go to 15 years or longer, there is greater uncertainty inherent in making financial predictions that far into the future. Also, Internal Revenue Service depreciation tables allowed owners to use 10-year depreciation for tax purposes and this further supported 10 years as an industry practice. It must be noted that the equipment, with proper maintenances, may be fully operable for longer periods. The pro formas include the depreciation methods and lives as outlined in GASB 34 (government accounting standards). The Summary page of each pro forma includes the basic MUSA and depreciation assumptions and the 10-year total MUSA contribution.

- An annual inflation rate of 2 percent

- Financial pro formas were developed at a breakeven or slight positive cash flow, as MOA wishes to encourage the beneficial use of LFG generated at its landfill.

- Since the Municipal Utility Service Assessment that applies to Enterprise Fund entities (such as the landfill), the pro formas incorporate the asset net book value based millage rate (16 mils) and the revenue based 1.25% contribution.

- Two scenarios were analyzed for electrical generation. One of the scenarios excludes costs to design, permit, construct, operate, and maintain the LFG collection system, and the other includes these costs. All subsequent options include the costs to design, permit, construct, operate, and maintain the LFG collection system.

- Project financing, permitting, and construction will occur during 2005. Actual beneficial use revenues will begin on January 1, 2006.

Production, capital, revenue, and O&M cost assumptions are provided for each of these options in the following sections.

5.2 Option 1 – Electricity Generation

To determine the economic feasibility of an electrical generation plant at the Anchorage Regional Landfill, the number of engines that could be brought on-line at the site is first determined. For this facility we recommend using Caterpillar engine/generator sets, primarily because the landfill operations already use a significant amount of CAT equipment and also because CAT engines have a good history of performance with LFG. Based on the requirements of CAT G3516LE engines, a total of three engines could initially be brought into service for electrical generation. Three engines require approximately 918 scfm of LFG at a 50% methane concentration and will generate a gross 804 kW each. An additional generator can be brought on-line for every 306 scfm of LFG extracted. The decision to bring more generators on-line can be made at a later date.

Capital and O&M costs for the engines are based on the utilization of three engines to produce electricity. As shown in the financial pro-forma statement for this option (see Appendix 3), the electricity sold by three CAT G3516LE engines is 195,070-megawatt hours from 2006 to 2015 assuming 95% on-line and 3% plant loads are used by the plant. It is assumed that the electricity generated will be sold to a local utility.

Utility deregulation is not currently available in Alaska; therefore, power must be sold to local utilities. If enacted, deregulation will allow retail wheeling of your power on local utility distribution lines. This allows you to sign up customers (through a licensed power broker) and sell power to them instead of the customers purchasing the power from local utilities. The idea of wheeling is to provide power to a customer at a lower cost than the utilities, but at a higher rate than they would receive if you had an avoided cost contract.

The power lines directly adjacent to the Anchorage Regional Landfill are owned by Matanuska Electric Association (MEA). However, MEA is contractually obligated to buy all of its power from Chugach Electric until 2014. Currently, MEA purchases power at a rate of 5.9 cents per kWh (average avoided cost of electrical generation and transmission). Based on recent discussions with Chugach Power (Peter Poray), they have verbally quoted an average electrical generation avoided cost of 4.2-cents per kWh. However, Chugach is only willing to sign new power purchase agreements (PPA) in the 3-cent per kWh range. The avoided cost provided above may vary over the next several years, thereby affecting the economic analysis.

Since power cannot be sold directly to MEA, power must be wheeled to Chugach using MEA power lines. Wheeling charges for the pro formas contained in Appendix 3 assume a wheeling rate of $0.005/kWh and an interconnection cost of $250,000.

With three CAT generators operating at 95% availability and 3% plant loads, approximately 20.07 million kWh will be available for sale each year. During the years 2006 through 2008 it is expected that gas availability will result in slightly lower production rates of 17.1 to 19.2 million kWh until the landfill's gas recovery rate is sufficient for full loading of the engine. As directed by MOA staff, we have developed our pro formas on a breakeven basis. The breakeven point for the scenario that includes GCCS construction and operations is 5.47 cents per kWh. The breakeven point for the scenario excluding GCCS construction and operations is 4.81 cents per kWh.

In order for the MOA to sell wholesale or retail power it will need licensing as a qualified facility (QF) by the Federal Energy Regulatory Commission (FERC). QF applications are typically prepared for all LFG-to-Energy projects. Having QF status forces the local utility to purchase excessive power generated but not sold to a retail customer at avoided rates.

5.2.1 Option 1A – Electrical Generation Using Engine Generator Sets Including Costs of Gas Collection System Installation and Annual O&M Expenses

1. **LFG VOLUMES –** The project consists of three CAT Triton Powerpacks with CAT 3516LE engines. Fuel requirements are 306 scfm (50% methane content) per engine. Initial recoverable gas is estimated at 826 scfm, which will result in slightly reduced kWh output; however, by 2009 the engines will have sufficient fuel for full load operation. Future gas recovery estimates indicate that additional engine generator sets could be added, however, our pro forma is based on three units throughout the project life.

2. **REVENUES** – Based on the projected power generation, 195.07 million kWhs could be sold over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a power sales rate of 5.47 cent per kWh, escalated 1% per year. At this rate, the anticipated revenue for the ten-year period will be $11,176,000.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, generation equipment, gas processing equipment and, interconnect with utility transmission grid will be approximately $4,109,000.

4. **O&M COSTS** – The O&M costs inclusive of the wellfield, generation equipment, gas processing, and interconnect, as well as general and administrative costs, are projected to be $6,327,000 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sale price of 5.47 cents per kWh will be $11,176,000. Over the same time period, the projected expenses, including cost of ownership, will be $10,860,000.

5.2.2 Option 1A – Electrical Generation Using Engine Generator Sets <u>Excluding</u> Costs of Gas Collection System Installation and Annual O&M Expenses

1. **LFG VOLUMES –** No change.

2. **REVENUES** – Based on the projected power generation, 195.07 million kWhs could be sold over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a power sales rate of 4.81 cent per kWh, escalated 1% per year. At this rate, the anticipated revenue for the ten-year period will be $9,827,000.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, generation equipment, gas processing equipment, and interconnect with utility transmission grid will be approximately $3,207,000.

4. **O&M COSTS** – The O&M costs inclusive of the wellfield, generation equipment, gas processing, and interconnect, as well as general and administrative costs, are projected to be $6,048,000 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sale price of 4.81 cents per kWh will be $9,827,000. Over the same time period, the projected expenses, including cost of ownership, will be $9,584,000.

5.3 Option 2 – Transmission of LFG to Enstar Natural Gas Pipeline

An Enstar Natural Gas Company pipeline exists approximately 990 feet east of the proposed blower and flare station location. A topographic map is provided in Appendix 4 that displays the pipe routing and tie-in location for this option. A cross-section of this pipe routing is also contained in the same appendix.

Based on discussions with Mr. Andrew D. White of Enstar, this natural gas pipeline operates at a maximum of 900-psig pressure. Mr. White also indicated that it is Enstar's policy to only accept gas into its system that has a heating value of approximately 1,000 Btu's per cubic foot. Since raw LFG typically has a heating value of 400 to 550 Btu/cf, cleaning up the MOA LFG to remove carbon dioxide and air will be required.

A financial pro forma was calculated using industry-accepted figures (see Appendix 5). For this scenario, it was assumed that this end user could utilize all generated LFG. Results of this estimate indicate the following:

1. **LFG VOLUMES –** For the year 2006, the projected flow of LFG recovered is 826 scfm or 209,000 mmBtus. After clean up of the gas, only 160,000 mmBtus (77% conversion to saleable Btu's) will be available for injection into the pipeline.

2. **REVENUES** – Based on the projected flows per year, assuming a 95% utilization factor and 77% conversion to saleable Btu's, 2,009,000 mmBtus could be recovered and processed for sale over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a sales price of $4.32 per mmBtu, escalated 2% per year. At this price, the anticipated revenue for the ten-year period will be $9,571,094.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, pipeline (990 feet), purchase compressors, and cleanup equipment will be approximately $2,995,000.

4. **O&M COSTS** – The O&M costs inclusive of the wellfield, pipeline, compressor, cleanup equipment, and electrical, as well as general and administrative costs, are projected to be $5,605,654 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sale price of $4.32 will be $9,571,094. Over the same time period, the projected expenses, including cost of ownership, will be $8,935,635.

Further evaluation of this beneficial use option appears to be unnecessary. The primary reasons this option is not economically feasible are as follows:

1 Enstar requires "clean up" of the LFG. This adds significant capital and O&M costs.

2. The existing Enstar line is operated at a maximum of 900-psig pressure. Compression of gas to 900 psig adds significant capital and takes a significant amount of electric power.

5.4 Option 3 - Transmission of LFG to Eagle River School

An economic analysis was performed to determine the feasibility of constructing a pipeline to the Eagle River School and transporting LFG to the site for use in its boilers. The proposed boiler specifications for Eagle River School are provided in Appendix 6. A topographic map is provided in Appendix 7 that displays the pipe routing and tie-in location for this option. A cross-section of this pipe routing is also contained in the same appendix. Initial discussions with the School District were very encouraging, and they are open to the idea of utilizing LFG. However, after further analysis, the school would only utilize a small portion of the available LFG.

A detailed economic analysis for this scenario was calculated using industry-accepted figures (see Appendix 8). Results of this financial pro forma indicate the following:

1. **LFG VOLUMES –** Based on the past consumption of LFG at a similar existing school in the area, Eagle River School is anticipated to require an estimated flow of 105 scfm at 50% methane.

2. **REVENUES** – Based on the projected demand per year, 265,420 mmBtus could be sold over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a sales price of $18.87 per mmBtu, escalated 2% per year. At this price, the anticipated revenue for the ten-year period will be $5,484,108.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, pipeline (2.0797 miles), purchase compressors, and end user upgrades will be approximately $2,186,000.

4. **O&M COSTS –** The O&M costs inclusive of the wellfield, pipeline, and compressor, and electrical as well as general and administrative costs, are projected to be $2,653,798 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sales price of $18.87 will be $5,484,108. Over the same time period, the projected expenses, including cost of ownership, will be $5,085,151.

Further evaluation of this beneficial use option appears to be unnecessary. The primary reasons this option is not economically feasible are as follows:

1. Eagle Valley School gas demand is too low and is not consistent throughout the year. Most of the demand is during the winter months. This condition does not generate enough cash to offset capital and O&M costs.

2. The length of the pipeline is too long to justify the small amount of gas demanded. This adds significant capital costs

5.5 Option 4 – Transmission of LFG to National Guard

An economic analysis was performed to determine the feasibility of constructing a pipeline to the National Guard facilities and transporting LFG to the site for use in its boilers. A topographic map is provided in Appendix 9 that displays the pipe routing and tie-in location for this option. A cross-section of this pipe routing is also contained in the same appendix. Initial discussions with the National Guard were very encouraging, and they are open to the idea of utilizing LFG. Natural gas consumption, equipment make and model numbers, etc., provided by the National

Guard revealed that only a few pieces of equipment are suitable for conversion to utilize LFG (i.e., four Weil-McLain Boilers that use Gordon Piatt Burners). Because of this, the demand for LFG during warmer months of the year is substantially below the LFG production rate. A detailed economic analysis for this scenario was calculated using industry-accepted figures (see Appendix 10). For this scenario, it was assumed only a portion of the generated LFG could be utilized by the National Guard. Results of this financial pro forma indicate the following:

1. **LFG VOLUMES –** For the year 2006, the projected flow of LFG recovered is 826 scfm. However, the National Guard Armory's seasonal gas demand is such that the Armory annual usage of LFG would be approximately 650 scfm.

2. **REVENUES** – Based on the projected flows per year assuming a 95% utilization factor, 1,643,000 mmBtus could be recovered for sale over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will required a sales price of $3.45 per mmBtu, escalated 2% per year. At this price, the anticipated revenue for the ten-year period will be $6,198,000.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, pipeline (2.734 miles), purchase compressors, and end user upgrades will be approximately $2,492,000.

4. **O&M COSTS –** The O&M costs inclusive of the wellfield, pipeline, and compressor, and electrical as well as general and administrative costs, are projected to be $2,969,000 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sales price of $3.45 will be $6,198,000. Over the same time period, the projected expenses, including cost of ownership, will be $5,742,000.

5.6 Option 5 – Transmission of LFG to Fort Richardson

An economic analysis was performed to determine the feasibility of constructing a pipeline to Fort Richardson and transporting LFG to the site for use in its boilers. A topographic map is provided in Appendix 11 that displays the pipe routing and tie-in location for this option. A cross-section of this pipe routing is also contained in the same appendix.

Initial discussions with Ft. Richardson were very encouraging, and they are open to the idea of utilizing LFG. The natural gas demand for Ft. Richardson vastly exceeds the generation rate of LFG from the Anchorage Regional Landfill. A listing of the over 500 natural gas burning pieces of equipment (shown in Appendix 11) was provided by Ft.

Richardson staff (Debra S. Breindel). Of these nearly 500 pieces of equipment, 4 large Cleave-Brooks boilers appear to be best suited for conversion to operate on LFG. Cleaver-Brooks boilers have a good history of being converted to LFG use, and the ones at Ft. Richardson are located in one single location (Building No. 726). This single high gas demand location is ideal for LFG utilization and eliminates the need for elaborate and costly gas delivery infrastructure.

A detailed economic analysis for this scenario was calculated using industry-accepted figures (see Appendix 13). For this scenario, it was assumed that this end user could utilize all the generated LFG. Results of this financial pro forma indicate the following:

1. **LFG VOLUMES –** For the year 2006, the projected flow of LFG recovered is 826 scfm. It is assumed that Fort Richardson Building #726 would use all available gas.

2. **REVENUES** – Based on the projected flows per year, assuming a 95% utilization factor, 2,620,000 mmBtus could be recovered for sale over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a sales price of $2.72 per mmBtu, escalated 2% per year. At this price, the anticipated revenue for the ten-year period will be $7,861,211.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, pipeline (5.1454 miles), purchase compressors, and end user upgrades will be approximately $3,256,000.

4. **O&M COSTS** – The O&M costs inclusive of the wellfield, pipeline, and compressor, and electrical as well as general and administrative costs, are projected to be $3,564,149 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sales price of $2.72 will be $7,861,211. Over the same time period, the projected expenses, including cost of ownership, will be $7,189,410.

5.7 Option 6 – Transmission of LFG to Existing ML&P Facility (George M. Sullivan Power Plant No. 2)

An economic analysis was performed to determine the feasibility of constructing a pipeline to the nearest existing ML&P facility and transporting LFG to the site for use in its natural gas burning equipment (boilers, gas turbines, etc.). A topographic map is provided in Appendix 14 that displays the pipe routing and tie-in location for this option. A cross-section of this pipe routing is also contained in the same appendix. Initial discussions with ML&P were encouraging, and they are open to the idea of utilizing LFG.

However, after further analysis, the nearest plant was determined to be over six miles away.

It is preferred that a low-pressure piece of equipment be utilized for the LFG delivered to this power plant. Preliminary discussions with ML&P staff indicated that a low-pressure end use could most likely be identified. If a low-pressure piece of equipment is not available and a high-pressure application is required to be utilized, the cost of pressurization will substantially increase capital expenditures. For this option, it was assumed a low pressure could be identified.

A detailed economic analysis for this scenario was calculated using industry-accepted figures (see Appendix 15). For this scenario, it was assumed that this end user could utilize all the generated LFG. Results of this financial pro forma indicate the following:

1. **LFG VOLUMES –** For the year 2006, the projected flow of LFG recovered is 826 scfm. It is assumed that the George M. Sullivan Power Plant would use all available gas.

2. **REVENUES** – Based on the projected flows per year, assuming a 95% utilization factor, 2,620,000 mmBtus could be recovered for sale over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a sales price of $2.86 per mmBtu, escalated 2% per year. At this price, the anticipated revenue for the ten-year period will be $8,256,531.

3. **CAPITAL COSTS** – The capital cost to construct the wellfield, pipeline (6 miles), purchase compressors, and end user upgrades will be approximately $3,527,000.

4. **O&M COSTS –** The O&M costs inclusive of the wellfield, pipeline, and compressor, and electrical as well as general and administrative costs, are projected to be $3,598,169 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sales price of $2.86 will be $8,256,531. Over the same time period, the projected expenses, including cost of ownership, will be $7,522,934.

5.8 Option 7 – Transmission of LFG to Proposed ML&P Facility (Fossil Creek Power Plant)

An economic analysis was performed to determine the feasibility of constructing a pipeline to a ML&P proposed facility at Fossil Creek and transporting LFG to the site for use in its electrical generating equipment. A topographic map is provided in Appendix

16 that displays the pipe routing and tie-in location for this option. A cross-section of this pipe routing is also contained in this same appendix. Initial discussions were held with ML&P, and they are very open to the idea of utilizing LFG because they could incorporate LFG use into their design. Again, it was assumed a low-pressure application could be identified for the proposed power plant. If a low-pressure piece of equipment is not available and a high-pressure application is required to be utilized, the cost of pressurization will substantially increase capital expenditures.

A detailed economic analysis for this scenario was calculated using industry-accepted figures (see Appendix 17). For this scenario, it was assumed that this end user could utilize all the generated LFG. Results of this financial pro forma indicate the following:

1. **LFG VOLUMES –** For the year 2006, the projected flow of LFG recovered is 826 scfm. It is assumed that the proposed Fossil Creek Power Plant would use all available gas.

2. **REVENUES** – Based on the projected flows per year, assuming a 95% utilization factor, 2,620,000 mmBtus could be recovered for sale over the next 10 years. To break even or produce a slight positive cash flow (including wellfield construction and O&M costs) will require a sales price of $2.14 per mmBtu, escalated 2% per year. At this price, the anticipated revenue for the ten-year period would be $6,194,794.

3. **CAPITAL COSTS –** The capital cost to construct the wellfield, pipeline (2.0797 miles), purchase compressors, and end user upgrades will be approximately $2,285,000.

4. **O&M COSTS –** The O&M costs inclusive of the wellfield, pipeline, and compressor, and electrical as well as general and administrative costs, are projected to be $3,165,628 over the 10-year project life.

5. **SUMMARY –** Over the 10-year project life, the expected revenues at a sales price of $2.14 will be $. Over the same time period, the projected expenses, including cost of ownership, will be $5,713,379.

5.9 Option 8- Treatment of Liquid Generated or Collected at the Anchorage Regional Landfill

5.9.1 Leachate Evaporation Using LFG

Leachate generated by the landfill is currently accumulated by a collection system and transported to an off-site wastewater treatment plant owned and operated by the

Municipality of Anchorage. Leachate evaporation utilizing LFG has been conducted as part of this study to enable the Municipality to compare the evaporation costs to its current disposal costs.

Option 8 involves disposing of leachate by the proposed flare facility to incorporate EMCON/OWT's patented Leachate Evaporator (E-Vap). The E-Vap evaporates leachate and the off vapors are destroyed in an enclosed flare, thus eliminating the need for complex treatment of leachate.

Prior to performing a detailed economic analysis of this option, a rough estimate was calculated using industry-accepted figures. The results of this rough estimate determined the following:

1. On average, the leachate collection system at the Anchorage Regional Landfill has collected approximately 7,000,000 gallons per year since 1990.Pending implementation of design changes currently under consideration (including complete recirculation) may significantly reduce this volume.

2. Collection, transport, and disposal costs are limited to transportation and are in the range of 2 to 3 cents per gallon.

3. Typical costs for treatment of collected leachate by our patented E-Vap technology are higher than 3 cents per gallon.

Based on current leachate collection rates, a 20,000-gpd-leachate evaporator would be needed. Recent pro forma for this size unit (with a flare) indicated a disposal cost of approximately 6.8 cents per gallon. Again, the landfill is currently hauling leachate to the city sewage treatment plant for a cost of less than 3 cents for trucking and no cost from the treatment plant. Therefore, further evaluation of this beneficial use option appears to be unnecessary.

5.9.2 Glycol Recycling Using LFG

At the request of the MOA, EMCON/OWT has briefly reviewed the feasibility of utilizing LFG to recycle glycol collected at the landfill. The option of recycling glycol utilizing LFG has been included as a part of this study so the Municipality can compare the recycling costs to its current disposal costs.

Prior to performing a detailed economic analysis of this option, a rough estimate was calculated using industry-accepted figures. The results of this rough estimate determined the following:

1. On an annual basis, the Municipality receives $8,400 for the collection and disposal of 12,000 gallons of glycol ($0.70 per gallon) from its customers.

2. The Municipality's annual disposal costs for the 12,000 gallons are $35,000.
3. Engineering design, permitting, equipment procurement, construction, startup and commissioning a fully developed project cost for a glycol distillation system and heating device will be greater than $300,000.
4. O&M costs of 5% of capital investment will be approximately $15,000 per year
5. 6000 gpy of glycol could be recovered and sold at a price of $2.50 per gallon, generating an annul income of only $15,000.
6. The payback period for the $300,000 investment exceeds generally accepted accounting practices.

An initial pro forma was developed for the potential glycol scenario and is contained in Appendix 18. This pro forma indicated that at a $4.50 per gallon resale price, the required breakeven quantity is 14,700 gallons per year. Because of processing constraints, this equates to collecting nearly 30,000 gallons of waste glycol per year. Again, the MOA currently collects approximately 12,000 gallons per year. Additionally, MOA is concerned about competing with other private entities for other sources of waste glycol. Therefore, further evaluation of this beneficial use option appears to be unnecessary.

6 SUMMARY OF FINDINGS

A summary of the findings for each of the options presented in Section 5 is provided below:

- LFG modeling indicates that sufficient recoverable quantities of LFG are present to support 2.4 MW electricity generation **(Option No. 1).** The electricity produced can be sold to several different local utilities, including Municipal Light & Power.

  Negotiation of an electric sales agreement with the a local utility is necessary under this option. These negotiations are quite often a long and difficult process and are typically more difficult with the absence of a local or state renewable energy portfolio standard.

  The most lucrative electric sale potential appears to be with MEA (currently buying power at from Chugach at 5.9 cent per kW) At this rate, a LFGTE project would breakeven (LFG collection/flaring costs included in pro forma: 5.84 cents per kW) or be profitable (LFG collection/flaring costs included in pro forma: 4.81 cents per kW). Because MEA is obligated to purchase all their power from Chugach Electric until 2014, a special exemption will be required. It is anticipated that renewable energy requirement will soon be requested by the federal government at local military bases. If this requirement is requested the probability of obtaining this exemption or a direct sale to another utility or the federal government is drastically increase.

- The capital and O&M to operate a high Btu LFG plant and inject the LFG into Enstar's nearby pipeline (**Option No. 2**) is not economically feasible.

- The capital and O&M to operate a LFG pipeline to the Municipality of Anchorage Eagle Valley School (**Option No. 3**) is not economically feasible.

- The sale of medium Btu LFG to the National Guard (**Option No. 4**) may be economically feasible, but there appears to be more lucrative options available (see Option Nos. 5, 6 and 7).

- Sale of a medium Btu LFG to ML&P, Ft. Richardson (**Option No. 5**), appears to economically feasible and provides just slightly better financial results than the sale of LFG to George M. Sullivan Power Plant No. 2 (Option No. 6) The boiler identified for conversion are new pieces of equipment and are planned for long term use on the base. However, Fort Richardson has been included on previous base realignment and closure (BRAC) lists and therefore could present considerable financial risk if closed. In addition, negotiating a gas sales agreement with the Federal government and the equipment operator (i.e., Honeywell) may be more troublesome than other options.

- Sale of medium Btu LFG to ML& P's George M. Sullivan Power Plant No. 2 (**Option No. 6**) appears to be economically feasible. Only the sale of LFG to the proposed Fossil Creek Facility (Option No.7) substantially outperforms this option. Since this plant already exists and is owned by the MOA, this option may present the least amount of risk.

- Sale of medium Btu LFG to ML& P's proposed Fossil Creek Facility (**Option No. 7**) appears to be economically feasible. This option appears to be the most economically feasible, but does present the risk of delayed construction or even never being built.

- **Option 8,** utilizing LFG to treat on-site liquid (leachate and glycol) is not economically feasible.

7 LIMITATIONS

The services described in this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, expressed or implied, is made. These services were performed consistent with our agreement with the Municipality of Anchorage. This report is solely for the use and information of Anchorage Regional Landfill unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.'

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, nor the use of segregated portions of this report.

The LFG generation modeling techniques used by EMCON/OWT and the LFG industry are, by definition, hypothetical, and can only be used as a very general tool for producing a range of estimates to aid in determining the direction of further investigations. Actual LFG generation and collection rates are dependent on many variables, including: refuse composition, moisture, pH, cover soil permeability, well spacing, continuing fill rates, etc.. Typically these parameters are not well defined at the time of modeling and/or differ somewhat from those actually experienced during future site operation.

The LFG generation modeling provided herein was performed with today's current standards of practice and no warranty or representation, expressed or implied, is made, as to the actual LFG production that will occur in the future. Opinions and recommendations contained in this report are based on the information available and certain assumptions that were deemed reasonable when our services were performed. We are not responsible for the impacts of any changes in information, site operations or methods that may change in the future.

APPENDIX 1

LANDFILL GAS GENERATION MODEL

LANDFILL GAS GENERATION MODEL INPUT SUMMARY
Municipality Of Alaska (Moderately Dry/Moderately Wet)

General Information

Analysis performed by:	Erik C. Korsmo
Project number:	
Date of analysis:	01/19/04

Analysis Timeframe

Opening year of the landfill:	1987
Closing year of the landfill:	2043
Analysis performed through the year:	2100

Site Operating Conditions

Refuse moisture condition:	Moderately Dry
Refuse temperature:	90 °F
Average compacted refuse density:	1,200 lb/cy

LFG System Recovery Efficiency

ID Number	Recovery Efficiency	Effective Period
1	70%	1987 - 2100

Waste Stream Composition

Component	Composition 1	Composition 2
Organics		
Food waste	9.0%	N/A
Garden waste	19.0%	N/A
Paper waste	33.0%	N/A
Other organics	7.0%	N/A
Organic Subtotal	68.0%	N/A
Inorganics	32.0%	N/A
Total	100.0%	N/A

Generation Rate Properties

Rapid subgroup conversion time:	4 yrs
Intermediate subgroup conversion time:	33 yrs
Slow subgroup conversion time:	120 yrs

EPA Modeling Parameters

Methane generation potential (L_o):	6,000 ft^3/Mg
Methane generation rate (k):	0.02 yr^{-1}
NMOC concentration (C_{NMOC}):	4,000 ppmv

Summary of Results

Municipality Of Alaska (Moderately Dry/Moderately Wet)

Year	Annual Refuse Acceptance Rate (tons)	Cumulative Refuse Acceptance Rate (tons)	Upper limit of LFG Generation Rate (scfm)	Lower limit of LFG Generation Rate (scfm)	Upper limit of LFG Recovery Rate (scfm)	Lower limit of LFG Recovery Rate (scfm)	Average LFG Generation Rate (scfm)	EPA LFG Recovery Rate (scfm)
1987	25,053	25,053	0	0	0	0	0	0
1988	184,644	209,697	3	2	2	1	2	7
1989	191,885	401,581	23	15	16	11	20	59
1990	201,797	603,378	45	29	31	21	39	112
1991	196,115	799,493	82	54	58	38	71	166
1992	224,296	1,023,788	127	83	89	58	110	218
1993	223,047	1,246,835	184	120	129	84	160	277
1994	233,982	1,480,817	251	164	176	115	219	334
1995	240,884	1,721,701	331	216	231	151	287	393
1996	227,815	1,949,516	417	272	292	191	363	453
1997	251,990	2,201,506	507	331	355	232	441	509
1998	250,657	2,452,163	599	390	419	273	521	569
1999	280,866	2,733,028	683	446	478	312	594	629
2000	279,760	3,012,788	770	502	539	352	670	695
2001	279,666	3,292,454	854	557	598	390	743	760
2002	304,592	3,597,046	938	612	657	428	816	824
2003	284,400	3,881,446	1,023	667	716	467	889	893
2004	300,000	4,181,446	1,103	719	772	504	959	956
2005	300,000	4,481,446	1,186	773	830	541	1,031	1,021
2006	300,000	4,781,446	1,266	826	886	578	1,101	1,085
2007	300,000	5,081,446	1,345	877	942	614	1,170	1,148
2008	300,000	5,381,446	1,423	928	996	649	1,237	1,210
2009	300,000	5,681,446	1,497	976	1,048	683	1,302	1,270
2010	300,000	5,981,446	1,568	1,023	1,098	716	1,364	1,330
2011	300,000	6,281,446	1,636	1,067	1,145	747	1,423	1,388
2012	300,000	6,581,446	1,701	1,109	1,191	777	1,479	1,445
2013	300,000	6,881,446	1,763	1,150	1,234	805	1,533	1,501
2014	300,000	7,181,446	1,822	1,188	1,275	832	1,584	1,555
2015	300,000	7,481,446	1,877	1,224	1,314	857	1,632	1,609
2016	300,000	7,781,446	1,930	1,259	1,351	881	1,678	1,661
2017	300,000	8,081,446	1,980	1,292	1,386	904	1,722	1,713
2018	300,000	8,381,446	2,028	1,323	1,420	926	1,764	1,764
2019	300,000	8,681,446	2,073	1,352	1,451	947	1,803	1,813
2020	300,000	8,981,446	2,117	1,380	1,482	966	1,841	1,862
2021	300,000	9,281,446	2,158	1,407	1,510	985	1,876	1,909
2022	300,000	9,581,446	2,197	1,433	1,538	1,003	1,910	1,956
2023	300,000	9,881,446	2,234	1,457	1,564	1,020	1,942	2,001
2024	300,000	10,181,446	2,269	1,480	1,588	1,036	1,973	2,046
2025	300,000	10,481,446	2,303	1,502	1,612	1,051	2,002	2,090
2026	300,000	10,781,446	2,334	1,522	1,634	1,066	2,030	2,133

Summary of Results
Municipality Of Alaska

(continued)

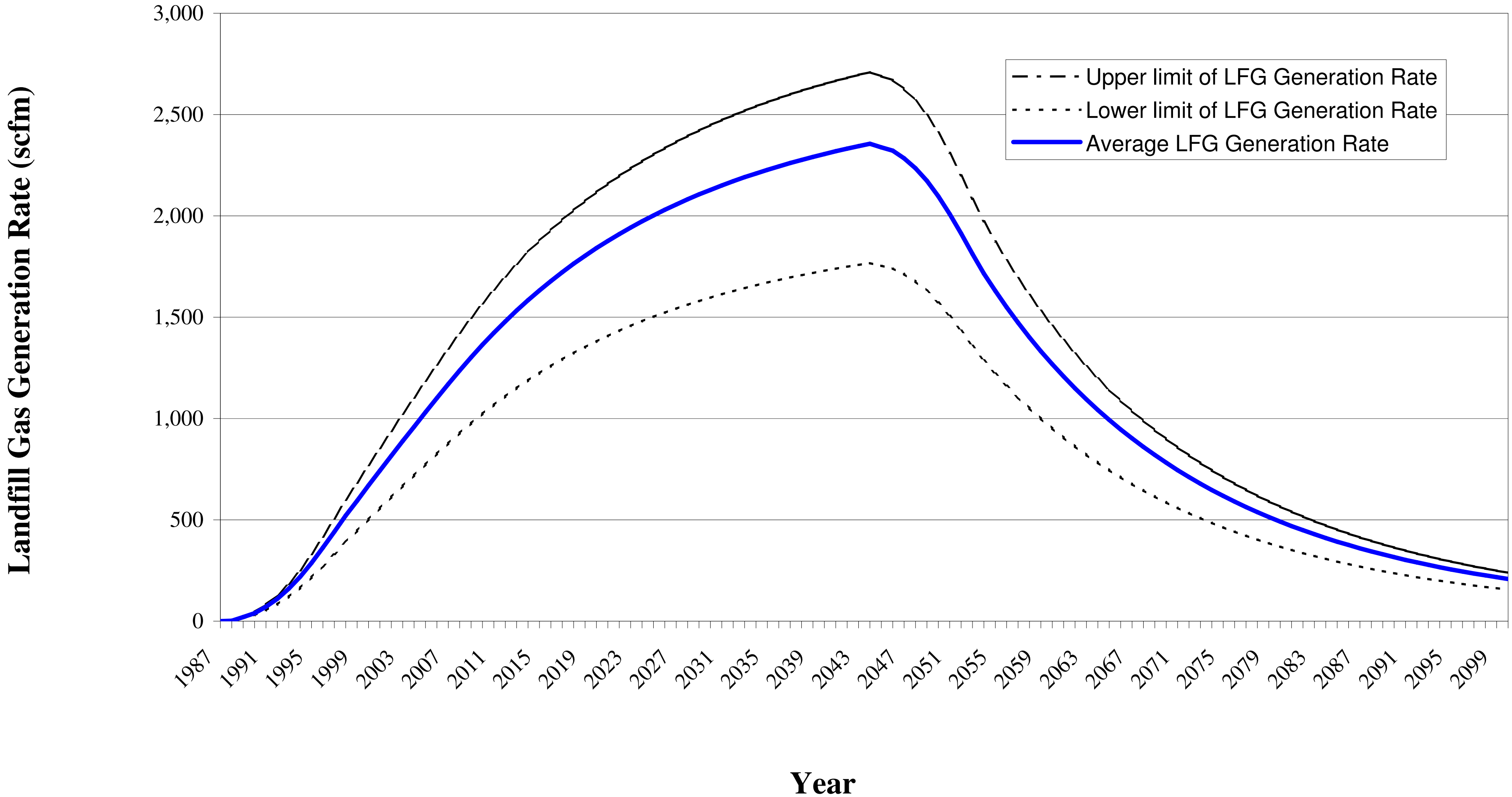
Year	Annual Refuse Acceptance Rate (tons)	Cumulative Refuse Acceptance Rate (tons)	Upper limit of LFG Generation Rate (scfm)	Lower limit of LFG Generation Rate (scfm)	Upper limit of LFG Recovery Rate (scfm)	Lower limit of LFG Recovery Rate (scfm)	Average LFG Generation Rate (scfm)	EPA LFG Recovery Rate (scfm)
2027	300,000	11,081,446	2,365	1,542	1,655	1,080	2,056	2,175
2028	300,000	11,381,446	2,394	1,561	1,676	1,093	2,082	2,217
2029	300,000	11,681,446	2,421	1,579	1,695	1,105	2,106	2,257
2030	300,000	11,981,446	2,448	1,596	1,713	1,117	2,128	2,297
2031	300,000	12,281,446	2,473	1,613	1,731	1,129	2,150	2,336
2032	300,000	12,581,446	2,496	1,628	1,748	1,140	2,171	2,374
2033	300,000	12,881,446	2,519	1,643	1,763	1,150	2,191	2,412
2034	300,000	13,181,446	2,541	1,657	1,779	1,160	2,209	2,448
2035	300,000	13,481,446	2,561	1,671	1,793	1,169	2,227	2,484
2036	300,000	13,781,446	2,581	1,683	1,807	1,178	2,244	2,519
2037	300,000	14,081,446	2,600	1,696	1,820	1,187	2,261	2,554
2038	300,000	14,381,446	2,618	1,707	1,832	1,195	2,276	2,588
2039	300,000	14,681,446	2,635	1,718	1,844	1,203	2,291	2,621
2040	300,000	14,981,446	2,651	1,729	1,856	1,210	2,305	2,653
2041	300,000	15,281,446	2,667	1,739	1,867	1,217	2,319	2,685
2042	300,000	15,581,446	2,681	1,749	1,877	1,224	2,332	2,717
2043	300,000	15,881,446	2,696	1,758	1,887	1,231	2,344	2,747
2044			2,709	1,767	1,896	1,237	2,356	2,777
2045			2,689	1,754	1,882	1,227	2,338	2,722
2046			2,670	1,741	1,869	1,219	2,322	2,668
2047			2,626	1,713	1,838	1,199	2,284	2,616
2048			2,570	1,676	1,799	1,173	2,235	2,564
2049			2,499	1,630	1,749	1,141	2,173	2,513
2050			2,412	1,573	1,688	1,101	2,097	2,463
2051			2,311	1,507	1,618	1,055	2,009	2,414
2052			2,200	1,434	1,540	1,004	1,913	2,367
2053			2,084	1,359	1,459	951	1,812	2,320
2054			1,973	1,287	1,381	901	1,715	2,274
2055			1,874	1,222	1,312	856	1,630	2,229
2056			1,781	1,162	1,247	813	1,549	2,185
2057			1,693	1,104	1,185	773	1,473	2,141
2058			1,610	1,050	1,127	735	1,400	2,099
2059			1,532	999	1,072	699	1,332	2,057
2060			1,458	951	1,020	666	1,268	2,017
2061			1,388	905	971	633	1,207	1,977
2062			1,321	862	925	603	1,149	1,938
2063			1,258	820	881	574	1,094	1,899
2064			1,198	782	839	547	1,042	1,862
2065			1,142	745	799	521	993	1,825
2066			1,088	710	762	497	946	1,789

Summary of Results
Municipality Of Alaska

(continued)

Year	Annual Refuse Acceptance Rate (tons)	Cumulative Refuse Acceptance Rate (tons)	Upper limit of LFG Generation Rate (scfm)	Lower limit of LFG Generation Rate (scfm)	Upper limit of LFG Recovery Rate (scfm)	Lower limit of LFG Recovery Rate (scfm)	Average LFG Generation Rate (scfm)	EPA LFG Recovery Rate (scfm)
2067			1,037	676	726	473	902	1,753
2068			989	645	692	451	860	1,719
2069			942	615	660	430	820	1,684
2070			899	586	629	410	782	1,651
2071			857	559	600	391	745	1,618
2072			818	533	572	373	711	1,586
2073			780	509	546	356	678	1,555
2074			744	485	521	340	647	1,524
2075			710	463	497	324	618	1,494
2076			678	442	475	310	590	1,464
2077			648	422	453	296	563	1,435
2078			618	403	433	282	538	1,407
2079			591	385	414	270	514	1,379
2080			565	368	395	258	491	1,352
2081			540	352	378	246	469	1,325
2082			516	336	361	235	449	1,299
2083			493	322	345	225	429	1,273
2084			472	308	330	215	410	1,248
2085			451	294	316	206	392	1,223
2086			432	282	302	197	376	1,199
2087			413	270	289	189	359	1,175
2088			396	258	277	181	344	1,152
2089			379	247	265	173	330	1,129
2090			363	237	254	166	316	1,107
2091			348	227	243	159	302	1,085
2092			333	217	233	152	290	1,063
2093			320	208	224	146	278	1,042
2094			306	200	214	140	266	1,022
2095			294	192	206	134	255	1,001
2096			282	184	197	129	245	982
2097			270	176	189	123	235	962
2098			260	169	182	119	226	943
2099			249	163	174	114	217	924
2100			239	156	168	109	208	906

Municipality Of Alaska
Landfill Gas Generation Rate (M.Dry/M.Wet)



MUNICIPALITY OF ALASKA LFG SENSITIVITY GENERATION RESULTS

Description	**Temp.**	**Lag Time**			**Conversion Time**			**Peak Results (scfm)**				**Present Results (scfm)**			
		Rapid	Moderate	Slow	Rapid	Moderate	Slow	Year	Upper LFG	Lower LFG	Average	Year	Upper LFG	Lower LFG	Average
Dry	< 80	1	1	2	7	80	200	2056	1,156	754	809	2004	160	105	139
Dry/M.Dry	< 80	1	1	2	6	60	170	2044	1,190	776	1,035	2004	224	146	195
M.Dry/Dry	< 80	0	1	1	6	60	170	2048	2,116	1,380	1,840	2004	462	301	401
M.Dry	**< 80**	**0**	**1**	**1**	**5**	**40**	**140**	**2044**	**2,482**	**1,619**	**2,158**	**2004**	**944**	**616**	**821**
(R) M. Dry/M.Wet	80	0	1	1	4	33	120	2044	2,591	2,253	1,690	2004	1,055	688	918
(R) M. Dry/M.Wet	**90**	**0**	**1**	**1**	**4**	**33**	**120**	**2044**	**2,709**	**1,767**	**2,356**	**2004**	**1,103**	**719**	**959**
(R) M.Wet/M.Dry	80	0	0	1	4	33	120	2044	3,285	2,142	2,856	2004	1,703	1,111	1,481
(R) M.Wet/M.Dry	**90**	**0**	**0**	**1**	**4**	**33**	**120**	**2044**	**3,474**	**2,266**	**3,021**	**2004**	**1,801**	**1,175**	**1,566**
(R) M.Wet	80	0	0	1	3	25	100	2044	3,321	2,166	2,888	2004	2,087	1,361	1,814
(R) M.Wet	90	0	0	1	3	25	100	2044	3,513	3,055	2,291	2004	2,207	1,439	1,919

(R) = Assumes Recirculation Activities
Bold = Output Attached

Default Values	**Lag Time**			**Conversion Time**		
Description	Rapid	Moderate	Slow	Rapid	Moderate	Slow
Dry	1	1	2	7	80	200
M.Dry	0	1	1	5	40	140
M.Wet	0	0	1	3	25	100
Wet	0	0	0	2	15	70

Purpose: Determine the future LFG generation for the Municipality of Anchorage - Regional Landfill, based on the existing information provided by the owner.

Methodology: Utilizing EMCON's LFGM, vary the moisture and temperature parameters to determine the most accurate representation of the existing and future LFG generation.

Prepared By: Erik C. Korsmo Date: 1/20/2004

Checked By: Douglas M. Gatrell Date: 1/20/2004

Notes:

1. EMCON assumes refuse temperature to be approximately 65 degrees F. based on owner provided information.
2. EMCON assumes recirculation will raise temperature of refuse 10 - 15 degrees F.
3. EMCON Modeling does not recognize any significant influence in Unit Gas Yield for temperatures below 80 degrees F.
4. EMCON-LFGM proprietary model was utilized for the generation rates. Complete output information is available upon request.
5. EMCON assumes the filling rates would continue at 300,000 tons/year until year 2043.

APPENDIX 2

LABORATORY ANALYSIS AND POSSIBLE “CLEAN-UP” PROCESS

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Air Toxics Ltd. Introduces the Electronic Report

Thank you for choosing Air Toxics Ltd. To better serve our customers, we are providing your report by e-mail. This document is provided in Portable Document Format which can be viewed with Acrobat Reader by Adobe.

This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630

(916) 985-1000 .FAX (916) 985-1020
Hours 8:00 A.M to 6:00 P.M. Pacific
E-mail to:samplereceiving@airtoxics.com

@ AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0311168A

Work Order Summary

CLIENT:	Mr. Paul Tower Applied Filter Technology 19524 75th Ave SE Snohomish, WA 98296	**BILL TO:**	Mr. Paul Tower Applied Filter Technology 19524 75th Ave SE Snohomish, WA 98296
PHONE:	360-668-6021	**P.O. #**	
FAX:	360-668-7017	**PROJECT #**	826931.04002003 SHAW/EMCON-Anchorage Regional
DATE RECEIVED:	11/11/03	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	11/19/03		

FRACTION #	**NAME**	**TEST**	**RECEIPT VAC./PRES.**
01A	301B	Modified TO-14A	Tedlar Bag
02A	Lab Blank	Modified TO-14A	NA
03A	CCV	Modified TO-14A	NA
04A	LCS	Modified TO-14A	NA

CERTIFIED BY: Linda L. Freeman DATE: 11/24/03

Laboratory Director

Certfication numbers: AR DEQ, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/03, Expiration date: 06/30/04
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
Modified TO-14A
Applied Filter Technology
Workorder# 0311168A

One 1 Liter Tedlar Bag sample was received on November 11, 2003. The laboratory performed analysis via modified EPA Method TO-14A using GC/MS in the full scan mode. The method involves concentrating up to 0.5 liters of air. The concentrated aliquot is then flash vaporized and swept through a water management system to remove water vapor. Following dehumidification, the sample passes directly into the GC/MS for analysis. See the data sheets for the reporting limits for each compound.

Method modifications taken to run these samples include:

Requirement	***TO-14A***	***ATL Modifications***
Continuing Calibration criteria	</= 30% Difference	</= 30% Difference with two allowed out to </= 40% Difference; flag and narrate outliers
Initial Calibration criteria	RSD<30%	RSD</=30%, two compounds allowed up to 40%.
Moisture control	Nafion Dryer	Multisorbent trap
Blank acceptance criteria	<0.20 ppbv	<Reporting Limit
Primary ions for Quantification	Freon 114: 85, Carbon Tetrachloride: 117, Trichloroethene: 130, Ethyl Benzene, m,p- and o-Xylene: 91	Freon 114: 135, Carbon Tetrachloride: 119, Trichloroethene: 95, Ethyl Benzene, m,p- and o-Xylene: 106
Dilutions for Initial Calibration	Dynamic dilutions or static using canisters	Syringe dilutions
BFB absolute abundance criteria	Within 10% of that from previous day.	CCV internal standard area counts are compared to ICAL, corrective action for > 40% D
Sample Load Volume	400 mL	Varied to 200 mL

Receiving Notes

The chain of custody information for sample 301B did not match the entry on the sample tag. The discrepancy was noted in the Login email and the information on the chain of custody was used to process and report the sample.

Analytical Notes

There were no analytical discrepancies.

Definition of Data Qualifying Flags

Eight qualifiers may have been used on the data analysis sheets and indicates as follows:

B - Compound present in laboratory blank greater than reporting limit (background subtraction no performed).

J - Estimated value.

E - Exceeds instrument calibration range.

S - Saturated peak.

Q - Exceeds quality control limits.

U - Compound analyzed for but not detected above the reporting limit.

UJ- Non-detected compound associated with low bias in the CCV

N - The identification is based on presumptive evidence.

File extensions may have been used on the data analysis sheets and indicates as follows:

a-File was requantified

b-File was quantified by a second column and detector

r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

SAMPLE NAME: 301B

ID#: 0311168A-01A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111125**	**Date of Collection: 11/10/03**
Dil. Factor:	**133**	**Date of Analysis: 11/12/03 01:12 AM**

Compound	Rpt. Limit (ppbv)	Rpt. Limit (uG/m3)	Amount (ppbv)	Amount (uG/m3)
Freon 12	66	330	3400	17000
Freon 114	66	470	130	900
Vinyl Chloride	66	170	4600	12000
Bromomethane	66	260	Not Detected	Not Detected
Chloroethane	66	180	1600	4400
Freon 11	66	380	2600	15000
1,1-Dichloroethene	66	270	86	340
Freon 113	66	520	150	1100
Methylene Chloride	66	230	15000	52000
1,1-Dichloroethane	66	270	9600	39000
cis-1,2-Dichloroethene	66	270	2300	9200
Chloroform	66	330	Not Detected	Not Detected
1,1,1-Trichloroethane	66	370	390	2200
Carbon Tetrachloride	66	420	Not Detected	Not Detected
Benzene	66	220	1300	4200
1,2-Dichloroethane	66	270	Not Detected	Not Detected
Trichloroethene	66	360	620	3400
1,2-Dichloropropane	66	310	Not Detected	Not Detected
cis-1,3-Dichloropropene	66	310	Not Detected	Not Detected
Toluene	66	250	5200	20000
trans-1,3-Dichloropropene	66	310	Not Detected	Not Detected
1,1,2-Trichloroethane	66	370	Not Detected	Not Detected
Tetrachloroethene	66	460	Not Detected	Not Detected
1,2-Dibromoethane (EDB)	66	520	Not Detected	Not Detected
Chlorobenzene	66	310	Not Detected	Not Detected
Ethyl Benzene	66	290	69	300
m,p-Xylene	66	290	96	420
o-Xylene	66	290	Not Detected	Not Detected
Styrene	66	290	Not Detected	Not Detected
1,1,2,2-Tetrachloroethane	66	460	Not Detected	Not Detected
1,3,5-Trimethylbenzene	66	330	Not Detected	Not Detected
1,2,4-Trimethylbenzene	66	330	Not Detected	Not Detected
1,3-Dichlorobenzene	66	410	Not Detected	Not Detected
1,4-Dichlorobenzene	66	410	Not Detected	Not Detected
alpha-Chlorotoluene	66	350	Not Detected	Not Detected
1,2-Dichlorobenzene	66	410	Not Detected	Not Detected
1,3-Butadiene	66	150	Not Detected	Not Detected
Hexane	66	240	17000	62000
Cyclohexane	66	230	9300	33000
Heptane	66	280	4600	19000
Bromodichloromethane	66	450	Not Detected	Not Detected
Dibromochloromethane	66	580	Not Detected	Not Detected

AIR TOXICS LTD.

SAMPLE NAME: 301B

ID#: 0311168A-01A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111125**	**Date of Collection:**	**11/10/03**
Dil. Factor:	**133**	**Date of Analysis:**	**11/12/03 01:12 AM**

Compound	Rpt. Limit (ppbv)	Rpt. Limit (uG/m3)	Amount (ppbv)	Amount (uG/m3)
Cumene	66	330	Not Detected	Not Detected
Propylbenzene	66	330	Not Detected	Not Detected
Chloromethane	270	560	Not Detected	Not Detected
1,2,4-Trichlorobenzene	270	2000	Not Detected	Not Detected
Hexachlorobutadiene	270	2900	Not Detected	Not Detected
Acetone	270	640	910	2200
Carbon Disulfide	270	840	Not Detected	Not Detected
2-Propanol	270	660	Not Detected	Not Detected
trans-1,2-Dichloroethene	270	1100	Not Detected	Not Detected
Vinyl Acetate	270	950	Not Detected	Not Detected
2-Butanone (Methyl Ethyl Ketone)	270	800	2300	6800
Tetrahydrofuran	270	800	720	2200
1,4-Dioxane	270	970	Not Detected	Not Detected
4-Methyl-2-pentanone	270	1100	260 J	1100 J
2-Hexanone	270	1100	Not Detected	Not Detected
Bromoform	270	2800	Not Detected	Not Detected
4-Ethyltoluene	270	1300	Not Detected	Not Detected
Methyl tert-butyl ether	270	970	Not Detected	Not Detected
Ethanol	270	510	Not Detected	Not Detected

J = Estimated value.

Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
1,2-Dichloroethane-d4	105	70-130
Toluene-d8	100	70-130
4-Bromofluorobenzene	101	70-130

AIR TOXICS LTD.

SAMPLE NAME: Lab Blank

ID#: 0311168A-02A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111108a**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 03:03 PM**

Compound	Rpt. Limit (ppbv)	Rpt. Limit (uG/m3)	Amount (ppbv)	Amount (uG/m3)
Freon 12	0.50	2.5	Not Detected	Not Detected
Freon 114	0.50	3.6	Not Detected	Not Detected
Vinyl Chloride	0.50	1.3	Not Detected	Not Detected
Bromomethane	0.50	2.0	Not Detected	Not Detected
Chloroethane	0.50	1.3	Not Detected	Not Detected
Freon 11	0.50	2.8	Not Detected	Not Detected
1,1-Dichloroethene	0.50	2.0	Not Detected	Not Detected
Freon 113	0.50	3.9	Not Detected	Not Detected
Methylene Chloride	0.50	1.8	Not Detected	Not Detected
1,1-Dichloroethane	0.50	2.0	Not Detected	Not Detected
cis-1,2-Dichloroethene	0.50	2.0	Not Detected	Not Detected
Chloroform	0.50	2.5	Not Detected	Not Detected
1,1,1-Trichloroethane	0.50	2.8	Not Detected	Not Detected
Carbon Tetrachloride	0.50	3.2	Not Detected	Not Detected
Benzene	0.50	1.6	Not Detected	Not Detected
1,2-Dichloroethane	0.50	2.0	Not Detected	Not Detected
Trichloroethene	0.50	2.7	Not Detected	Not Detected
1,2-Dichloropropane	0.50	2.3	Not Detected	Not Detected
cis-1,3-Dichloropropene	0.50	2.3	Not Detected	Not Detected
Toluene	0.50	1.9	Not Detected	Not Detected
trans-1,3-Dichloropropene	0.50	2.3	Not Detected	Not Detected
1,1,2-Trichloroethane	0.50	2.8	Not Detected	Not Detected
Tetrachloroethene	0.50	3.4	Not Detected	Not Detected
1,2-Dibromoethane (EDB)	0.50	3.9	Not Detected	Not Detected
Chlorobenzene	0.50	2.3	Not Detected	Not Detected
Ethyl Benzene	0.50	2.2	Not Detected	Not Detected
m,p-Xylene	0.50	2.2	Not Detected	Not Detected
o-Xylene	0.50	2.2	Not Detected	Not Detected
Styrene	0.50	2.2	Not Detected	Not Detected
1,1,2,2-Tetrachloroethane	0.50	3.5	Not Detected	Not Detected
1,3,5-Trimethylbenzene	0.50	2.5	Not Detected	Not Detected
1,2,4-Trimethylbenzene	0.50	2.5	Not Detected	Not Detected
1,3-Dichlorobenzene	0.50	3.0	Not Detected	Not Detected
1,4-Dichlorobenzene	0.50	3.0	Not Detected	Not Detected
alpha-Chlorotoluene	0.50	2.6	Not Detected	Not Detected
1,2-Dichlorobenzene	0.50	3.0	Not Detected	Not Detected
1,3-Butadiene	0.50	1.1	Not Detected	Not Detected
Hexane	0.50	1.8	Not Detected	Not Detected
Cyclohexane	0.50	1.7	Not Detected	Not Detected
Heptane	0.50	2.1	Not Detected	Not Detected
Bromodichloromethane	0.50	3.4	Not Detected	Not Detected
Dibromochloromethane	0.50	4.3	Not Detected	Not Detected

AIR TOXICS LTD.

SAMPLE NAME: Lab Blank

ID#: 0311168A-02A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111108a**	**Date of Collection: NA**	
Dil. Factor:	**1.00**	**Date of Analysis:**	**11/11/03 03:03 PM**

Compound	Rpt. Limit (ppbv)	Rpt. Limit (uG/m3)	Amount (ppbv)	Amount (uG/m3)
Cumene	0.50	2.5	Not Detected	Not Detected
Propylbenzene	0.50	2.5	Not Detected	Not Detected
Chloromethane	2.0	4.2	Not Detected	Not Detected
1,2,4-Trichlorobenzene	2.0	15	Not Detected	Not Detected
Hexachlorobutadiene	2.0	22	Not Detected	Not Detected
Acetone	2.0	4.8	Not Detected	Not Detected
Carbon Disulfide	2.0	6.3	Not Detected	Not Detected
2-Propanol	2.0	5.0	Not Detected	Not Detected
trans-1,2-Dichloroethene	2.0	8.0	Not Detected	Not Detected
Vinyl Acetate	2.0	7.2	Not Detected	Not Detected
2-Butanone (Methyl Ethyl Ketone)	2.0	6.0	Not Detected	Not Detected
Tetrahydrofuran	2.0	6.0	Not Detected	Not Detected
1,4-Dioxane	2.0	7.3	Not Detected	Not Detected
4-Methyl-2-pentanone	2.0	8.3	Not Detected	Not Detected
2-Hexanone	2.0	8.3	Not Detected	Not Detected
Bromoform	2.0	21	Not Detected	Not Detected
4-Ethyltoluene	2.0	10	Not Detected	Not Detected
Methyl tert-butyl ether	2.0	7.3	Not Detected	Not Detected
Ethanol	2.0	3.8	Not Detected	Not Detected

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
1,2-Dichloroethane-d4	101	70-130
Toluene-d8	99	70-130
4-Bromofluorobenzene	95	70-130

AIR TOXICS LTD.

SAMPLE NAME: CCV

ID#: 0311168A-03A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111103**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 11:39 AM**

Compound	%Recovery
Freon 12	108
Freon 114	115
Vinyl Chloride	116
Bromomethane	111
Chloroethane	106
Freon 11	106
1,1-Dichloroethene	105
Freon 113	107
Methylene Chloride	101
1,1-Dichloroethane	106
cis-1,2-Dichloroethene	106
Chloroform	101
1,1,1-Trichloroethane	103
Carbon Tetrachloride	105
Benzene	105
1,2-Dichloroethane	103
Trichloroethene	108
1,2-Dichloropropane	110
cis-1,3-Dichloropropene	105
Toluene	105
trans-1,3-Dichloropropene	102
1,1,2-Trichloroethane	104
Tetrachloroethene	106
1,2-Dibromoethane (EDB)	106
Chlorobenzene	104
Ethyl Benzene	104
m,p-Xylene	106
o-Xylene	102
Styrene	104
1,1,2,2-Tetrachloroethane	99
1,3,5-Trimethylbenzene	113
1,2,4-Trimethylbenzene	103
1,3-Dichlorobenzene	99
1,4-Dichlorobenzene	99
alpha-Chlorotoluene	102
1,2-Dichlorobenzene	94
1,3-Butadiene	106
Hexane	107
Cyclohexane	107
Heptane	107
Bromodichloromethane	106
Dibromochloromethane	113

AIR TOXICS LTD.

SAMPLE NAME: CCV

ID#: 0311168A-03A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111103**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 11:39 AM**

Compound	%Recovery
Cumene	107
Propylbenzene	119
Chloromethane	109
1,2,4-Trichlorobenzene	114
Hexachlorobutadiene	114
Acetone	103
Carbon Disulfide	107
2-Propanol	106
trans-1,2-Dichloroethene	104
Vinyl Acetate	104
2-Butanone (Methyl Ethyl Ketone)	104
Tetrahydrofuran	102
1,4-Dioxane	110
4-Methyl-2-pentanone	106
2-Hexanone	107
Bromoform	111
4-Ethyltoluene	127
Methyl tert-butyl ether	102
Ethanol	115

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
1,2-Dichloroethane-d4	97	70-130
Toluene-d8	101	70-130
4-Bromofluorobenzene	101	70-130

AIR TOXICS LTD.

SAMPLE NAME: LCS

ID#: 0311168A-04A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111105**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 12:46 PM**

Compound	%Recovery
Freon 12	119
Freon 114	134 Q
Vinyl Chloride	129
Bromomethane	116
Chloroethane	135 Q
Freon 11	112
1,1-Dichloroethene	104
Freon 113	104
Methylene Chloride	99
1,1-Dichloroethane	101
cis-1,2-Dichloroethene	109
Chloroform	100
1,1,1-Trichloroethane	98
Carbon Tetrachloride	110
Benzene	117
1,2-Dichloroethane	108
Trichloroethene	108
1,2-Dichloropropane	110
cis-1,3-Dichloropropene	107
Toluene	115
trans-1,3-Dichloropropene	107
1,1,2-Trichloroethane	108
Tetrachloroethene	110
1,2-Dibromoethane (EDB)	96
Chlorobenzene	107
Ethyl Benzene	113
m,p-Xylene	112
o-Xylene	108
Styrene	113
1,1,2,2-Tetrachloroethane	96
1,3,5-Trimethylbenzene	106
1,2,4-Trimethylbenzene	94
1,3-Dichlorobenzene	90
1,4-Dichlorobenzene	87
alpha-Chlorotoluene	109
1,2-Dichlorobenzene	88
1,3-Butadiene	116
Hexane	102
Cyclohexane	101
Heptane	100
Bromodichloromethane	100
Dibromochloromethane	103

AIR TOXICS LTD.

SAMPLE NAME: LCS

ID#: 0311168A-04A

MODIFIED EPA METHOD TO-14A GC/MS FULL SCAN

File Name:	**b111105**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 12:46 PM**

Compound	%Recovery
Cumene	113
Propylbenzene	88
Chloromethane	123
1,2,4-Trichlorobenzene	102
Hexachlorobutadiene	107
Acetone	104
Carbon Disulfide	102
2-Propanol	104
trans-1,2-Dichloroethene	108
Vinyl Acetate	103
2-Butanone (Methyl Ethyl Ketone)	103
Tetrahydrofuran	100
1,4-Dioxane	107
4-Methyl-2-pentanone	102
2-Hexanone	94
Bromoform	85
4-Ethyltoluene	98
Methyl tert-butyl ether	101
Ethanol	116

Q = Exceeds Quality Control limits.

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
1,2-Dichloroethane-d4	96	70-130
Toluene-d8	99	70-130
4-Bromofluorobenzene	103	70-130

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This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0311168B

Work Order Summary

CLIENT: Mr. Paul Tower
Applied Filter Technology
19524 75th Ave SE
Snohomish, WA 98296

BILL TO: Mr. Paul Tower
Applied Filter Technology
19524 75th Ave SE
Snohomish, WA 98296

PHONE: 360-668-6021

FAX: 360-668-7017

DATE RECEIVED: 11/11/03

DATE COMPLETED: 11/20/03

P.O. #

PROJECT # 826931.04002003 SHAW/EMCON-Anchorage Regional

CONTACT: Kelly Buettner

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	301B	ASTM D-5504	Tedlar Bag
02A	Lab Blank	ASTM D-5504	NA
03A	LCS	ASTM D-5504	NA

CERTIFIED BY: Linda L. Freeman DATE: 11/21/03

Laboratory Director

Certfication numbers: AR DEQ - 03-084-0, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/03, Expiration date: 06/30/04
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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LABORATORY NARRATIVE
ASTM D-5504
Applied Filter Technology
Workorder# 0311168B

One 1 Liter Tedlar Bag sample was received on November 11, 2003. The laboratory performed the analysis of sulfur compounds via ASTM D-5504 using GC/SCD. The method involves direct injection of the air sample into the GC via a fixed 1.0 mL sampling loop. See the data sheets for the reporting limits for each compound.

Receiving Notes

The chain of custody information for sample 301B did not match the entry on the sample tag. The discrepancy was noted in the Login email and the information on the chain of custody was used to process and report the sample.

Sample 301B was received past the recommended hold time of 24 hours. The discrepancy was noted in the Login email and the analysis proceeded.

Analytical Notes

Ethyl Methyl Sulfide and n-Butyl Mercaptan coelute with 3-Methyl Thiophene. The corresponding peak is reported as 3-Methyl Thiophene.

Definition of Data Qualifying Flags

Seven qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.
File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

SAMPLE NAME: 301B

ID#: 0311168B-01A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	**b111106**	**Date of Collection: 11/10/03**
Dil. Factor:	**20.0**	**Date of Analysis: 11/11/03 12:15 PM**

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	80	15000
Carbonyl Sulfide	80	Not Detected
Methyl Mercaptan	80	94
Ethyl Mercaptan	80	180
Dimethyl Sulfide	80	Not Detected
Carbon Disulfide	80	Not Detected
Isopropyl Mercaptan	80	1900
tert-Butyl Mercaptan	80	Not Detected
n-Propyl Mercaptan	80	Not Detected
Ethyl Methyl Sulfide	80	Not Detected
Thiophene	80	Not Detected
Isobutyl Mercaptan	80	Not Detected
Diethyl Sulfide	80	Not Detected
Butyl Mercaptan	80	Not Detected
Dimethyl Disulfide	80	Not Detected
3-Methylthiophene	80	140
Tetrahydrothiophene	80	Not Detected
2-Ethylthiophene	80	Not Detected
2,5-Dimethylthiophene	80	Not Detected
Diethyl Disulfide	80	Not Detected

Container Type: 1 Liter Tedlar Bag

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SAMPLE NAME: Lab Blank

ID#: 0311168B-02A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	**b111103**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 09:29 AM**

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	Not Detected
Carbonyl Sulfide	4.0	Not Detected
Methyl Mercaptan	4.0	Not Detected
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	Not Detected
Carbon Disulfide	4.0	Not Detected
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	Not Detected
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

Container Type: NA - Not Applicable

AIR TOXICS LTD.

SAMPLE NAME: LCS

ID#: 0311168B-03A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	**b111102**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/11/03 08:34 AM**

Compound	%Recovery
Hydrogen Sulfide	110
Carbonyl Sulfide	104
Methyl Mercaptan	108
Ethyl Mercaptan	109
Dimethyl Sulfide	98
Carbon Disulfide	91
Isopropyl Mercaptan	104
tert-Butyl Mercaptan	102
n-Propyl Mercaptan	107
Ethyl Methyl Sulfide	108
Thiophene	98
Isobutyl Mercaptan	106
Diethyl Sulfide	104
Butyl Mercaptan	108
Dimethyl Disulfide	104
3-Methylthiophene	108
Tetrahydrothiophene	117
2-Ethylthiophene	112
2,5-Dimethylthiophene	112
Diethyl Disulfide	136 Q

Q = Exceeds Quality Control limits.

Container Type: NA - Not Applicable

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WORK ORDER #: 0311168C

Work Order Summary

CLIENT:	Mr. Paul Tower Applied Filter Technology 19524 75th Ave SE Snohomish, WA 98296	**BILL TO:**	Mr. Paul Tower Applied Filter Technology 19524 75th Ave SE Snohomish, WA 98296
PHONE:	360-668-6021	**P.O. #**	
FAX:	360-668-7017	**PROJECT #**	826931.04002003
DATE RECEIVED:	11/11/03	**CONTACT:**	SHAW/EMCON-Anchorage Regional Kelly Buettner
DATE COMPLETED:	11/21/03		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	301B	Modified ASTM D-1945	Tedlar Bag
02A	Lab Blank	Modified ASTM D-1945	NA
03A	LCS	Modified ASTM D-1945	NA

CERTIFIED BY: Linda L. Freeman

Laboratory Director

DATE: 11/21/03

Certfication numbers: AR DEQ - 03-084-0, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/03, Expiration date: 06/30/04
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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LABORATORY NARRATIVE
Modified ASTM D-1945
Applied Filter Technology
Workorder# 0311168C

One 1 Liter Tedlar Bag sample was received on November 11, 2003. The laboratory performed analysis via modified ASTM Method D-1945 for Methane and fixed gases in natural gas using GC/FID or GC/TCD. The method involves direct injection of up to 1.0 mL of sample. See the data sheets for the reporting limits for each compound.

Method modifications taken to run these samples include:

Requirement	***ASTM D-1945***	***ATL Modifications***
Sum of total sample components	Sum of original values should not differ from 100.0% by more than 1.0%.	Sum of original values may range between 75-125%.
Sample analysis	Equilibrate samples to 20-50° F. above source temperature at field sampling	No heating of samples is performed.
Sample calculation	Response factor is calculated using peak height for C5 and lighter compounds.	Peak areas are used for all target analytes to quantitate concentrations.
Standard preparation	Prepared by blending pure standards	Purchased blend certified to ± 5% accuracy or better
Normalization	Mathematically normalize results to equal 100%.	Unnormalized results are reported unless otherwise specified.

Receiving Notes

The chain of custody information for sample 301B did not match the entry on the sample tag. The discrepancy was noted in the Login email and the information on the chain of custody was used to process and report the sample.

Analytical Notes

The presence of Carbon Monoxide may have been masked by the Methane peak in sample 301B.

Propane and Propylene co-elute. Peak is quantitated as propane.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:

J - Estimated value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:

a-File was requantified

b-File was quantified by a second column and detector

r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

SAMPLE NAME: 301B

ID#: 0311168C-01A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	**3111304**	**Date of Collection: 11/10/03**
Dil. Factor:	**1.00**	**Date of Analysis: 11/13/03 10:15 AM**

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	2.9
Nitrogen	0.10	11
Carbon Monoxide	0.0010	Not Detected
Methane	0.00010	46
Carbon Dioxide	0.0010	32
Ethane	0.0010	Not Detected
Propane	0.0010	0.0058
Isobutane	0.0010	0.0023
Butane	0.0010	0.0011
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected

Total BTU/Cu.F. = 460
Total Sp. Gravity = 0.88

Container Type: 1 Liter Tedlar Bag

AIR TOXICS LTD.

SAMPLE NAME: Lab Blank

ID#: 0311168C-02A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	**3111303**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/13/03 09:22 AM**

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	Not Detected
Nitrogen	0.10	Not Detected
Carbon Monoxide	0.0010	Not Detected
Methane	0.00010	Not Detected
Carbon Dioxide	0.0010	Not Detected
Ethane	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected

Container Type: NA - Not Applicable

AIR TOXICS LTD.

SAMPLE NAME: LCS

ID#: 0311168C-03A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	**3111302**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/13/03 08:23 AM**

Compound	%Recovery
Oxygen	86
Nitrogen	96
Carbon Monoxide	95
Methane	93
Carbon Dioxide	94
Ethane	98
Propane	91
Isobutane	92
Butane	92
Neopentane	95
Isopentane	94
Pentane	93
C6+	92

Container Type: NA - Not Applicable

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0311168D

Work Order Summary

CLIENT:	Mr. Paul Tower Applied Filter Technology 19524 75th Ave SE Snohomish, WA 98296	**BILL TO:**	Mr. Paul Tower Applied Filter Technology 19524 75th Ave SE Snohomish, WA 98296
PHONE:	360-668-6021	**P.O. #**	
FAX:	360-668-7017	**PROJECT #**	826931.04002003 SHAW/EMCON-Anchorage Regional
DATE RECEIVED:	11/11/03	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	11/20/03		

FRACTION #	NAME	TEST
01AB	301B	Siloxanes
02A	Lab Blank	Siloxanes
03A	LCS	Siloxanes

CERTIFIED BY: Linda L. Freeman DATE: 11/21/03

Laboratory Director

Certfication numbers: AR DEQ - 03-084-0, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/03, Expiration date: 06/30/04
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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LABORATORY NARRATIVE
Siloxanes
Applied Filter Technology
Workorder# 0311168D

Two Vial samples were received on November 11, 2003. The laboratory performed analysis for siloxanes by GC/MS. A sample volume of 1.0 uL was injected directly onto the GC column. Initial results are in ug/mL. The units are converted to total micrograms (ug) by multiplying the result (ug/mL) by the total volume (mL) contained in the impinger. See the data sheets for the reporting limits for each compound.

Receiving Notes

A Temperature Blank was not included with the shipment. Temperature was measured on a representative sample and was not within 4 +/- 2 degrees C. Coolant in the form of blue ice was present. The client was notified via the login fax/email and the analysis proceeded.

Analytical Notes

A front and back impinger was received for each sample. Each impinger was analyzed separately. The results for each analyte were then additively combined and reported as a single concentration. The reported surrogate recovery is derived from the front impinger analysis only.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated Value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

SAMPLE NAME: 301B

ID#: 0311168D-01AB

SILOXANES - GC/MS

File Name:	**h111910**	**Date of Collection: 11/10/03**
Dil. Factor:	**1.00**	**Date of Analysis: 11/19/03 01:42 PM**

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	25	31
Decamethylcylopentasiloxane (D5)	25	Not Detected
Dodecamethylcyclohexasiloxane (D6)	50	Not Detected
Hexamethyldisiloxane	25	Not Detected
Octamethyltrisiloxane	25	Not Detected

Impinger Total Volume(mL): 25.0

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	76	70-130

AIR TOXICS LTD.

SAMPLE NAME: Lab Blank

ID#: 0311168D-02A

SILOXANES - GC/MS

File Name:	**h111904**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/19/03 11:01 AM**

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	1.0	Not Detected
Decamethylcylopentasiloxane (D5)	1.0	Not Detected
Dodecamethylcyclohexasiloxane (D6)	2.0	Not Detected
Hexamethyldisiloxane	1.0	Not Detected
Octamethyltrisiloxane	1.0	Not Detected

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	92	70-130

AIR TOXICS LTD.

SAMPLE NAME: LCS

ID#: 0311168D-03A

SILOXANES - GC/MS

File Name:	**h111903**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 11/19/03 10:36 AM**

Compound	%Recovery
Octamethylcyclotetrasiloxane (D4)	97
Decamethylcylopentasiloxane (D5)	96
Dodecamethylcyclohexasiloxane (D6)	Not Spiked
Hexamethyldisiloxane	102
Octamethyltrisiloxane	93

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	91	70-130

APPENDIX 3

FINANCIAL PRO FORMA FOR OPTION 1
(ELECTRICAL GENERATION)

SCENARIO - AA 2.5.1 2.4 MW POWER PLANT
MINIMUM 3% IRR ON 10 YR. CASH FLOW
INTERCONNECT ALLOWANCE = $250,000
WHEELING CHARGE = $0.005 per KWH
NO GCCS CONSTRUCTION & GCCS O&M
MUSA CONTRIBUTIONS and GASB 34 DEPRECIATION

SHAW GROUP
EMCON/OWT, INC. - DEVELOPED PROJECTS 04-May-2004

Anchorage, Alaska

ASSUMPTIONS

Gas Flow at 75% of Average Generation Rate from 1/19/04 Gas Generation Model		
Gensets installed - Recip Engines - number of units =	**3**	**Triton Power Pack 925 (CAT 3516) Low Emissions**
Gas Requirement per Genset - SCFM @ 50% Methane	**306**	**SCFM**
Power sale price per kWh =	**$0.0481**	**per KWH**
Total project installed cost.	**$3,207,000**	
Wheeling cost per kWh	**$0.0050**	**per KWH**

PROJECT DESCRIPTION:	**Triton Power Pack 925**	**POWER SALE RATE**	**$0.0481**	**per Kwh**
		POWER RATE INFLATOR	**1.00%**	**per YR.**
PROJECT CAPACITY:	**2,412 kW**	**WHEELING CHARGE**	**$0.0050**	**per kWh**
CAPITAL COST	**$1,329,602 per mW**	**GAS COST**	**$0.0000**	**per kWh**
FINANCING - loan to cost	**0.00%**	**GAS COST INFLATOR**	**2.00%**	**per YR.**
FINANCING - interest rate	**2.75%**	**O&M COST - Gen Plant**	**$0.0150**	**per Kwh gross**
GASCO OWNERSHIP	**100.00%**	**O&M COST INFLATOR**	**2.00%**	**per YR.**
UTILIZATION RATE	**95.00%**	**ENERGY GRANT per kWh**	**$0.0000**	

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FINANCIAL PERFORMANCE SUMMARY	YEAR 1		10 YEAR		15 YEAR	
	$	CENTS/KWH	$	CENTS/KWH	$	CENTS/KWH
OPERATING STATISTICS						
KILOWATT HOURS SOLD	17,125,783		195,070,475		295,433,795	
UTILIZATION FACTOR	81.05%		92.32%		93.22%	
INCOME STATEMENT						
TOTAL REVENUES	$823,750	4.81	$9,827,449	5.04	$15,267,708	5.17
COSTS OF REVENUES	485,225	2.83	5,753,893	2.95	8,967,258	3.04
GROSS PROFIT	338,525	1.98	4,073,556	2.09	6,300,450	2.13
DEPRECIATION and AMORTIZATION	458,143	2.68	3,207,000	1.64	3,207,000	1.09
ADMINISTRATIVE EXPENSE	24,713	0.14	294,823	0.15	458,031	0.16
INCOME BEFORE DEBT SERVICE	(144,330)	(0.84)	571,732	0.29	2,635,419	0.89
INTEREST COST	0	0.00	0	0.00	0	0.00
INCOME BEFORE INCOME TAXES	(144,330)	(0.84)	571,732	0.29	2,635,419	0.89
INCOME TAXES	0	0.00	0	0.00	0	0.00
TAX CREDITS	0	0.00	0	0.00	0	0.00
MUSA CONTRIBUTIONS	105,591	0.62	328,091	0.17	396,094	0.13
NET INCOME	($249,921)	(0.84)	$243,641	0.29	$2,239,325	0.89
CASH FLOW						
OPERATIONS						
NET INCOME	($249,921)	(1.46)	$243,641	0.12	$2,239,325	0.76
ADD BACK:						
DEPRECIATION and AMORTIZATION	458,143	2.68	3,207,000	1.64	3,207,000	1.09
INTEREST COSTS	0	0.00	0	0.00	0	0.00
CASH FLOW AVAILABLE FOR DEBT SERVICE	208,222	1.22	3,450,641	1.77	5,446,325	1.84
DEBT SERVICE						
PRINCIPAL PAYMENTS	0	0.00	0	0.00	0	0.00
INTEREST COSTS	0	0.00	0	0.00	0	0.00
TOTAL DEBT SERVICE	0	0.00	0	0.00	0	0.00
CASH FLOW AFTER DEBT SERVICE	208,222	1.22	3,450,641	1.77	5,446,325	1.84
INVESTMENT						
CAPITAL EXPENDITURES	(3,207,000)	(18.73)	(3,207,000)	(1.64)	(3,207,000)	(1.09)
EXISTING EQUITY IN GCCS	0	0.00	0	0.00	0	0.00
NET NEW CAPITAL EXPENDITURES	(3,207,000)	(18.73)	(3,207,000)	(1.64)	(3,207,000)	(1.09)
PROCEEDS OF FINANCING	0	0.00	0	0.00	0	0.00
NET INVESTMENT REQUIREMENTS	(3,207,000)	(18.73)	(3,207,000)	(1.64)	(3,207,000)	(1.09)
CASH AVAILABLE (REQUIRED)	($2,998,778)	(17.51)	$243,641	0.12	$2,239,325	0.76

FINANCIAL ANALYSIS	YEAR 1	10 YEAR	15 YEAR
INTERNAL RATE OF RETURN		**3.0%**	**8.3%**
SIMPLE PAYBACK in YEARS	**9.0**		
DEBT COVERAGE RATIO		**NA**	**NA**
NPV of AFTER TAX CASH FLOWS			
DISCOUNT RATE 5.00%	**($2,769,649)**	**($301,772)**	**$742,256**
DISCOUNT RATE 10.00%	**($2,656,105)**	**($844,481)**	**($296,872)**
DISCOUNT RATE 12.00%	**($2,613,224)**	**($1,000,037)**	**($573,039)**
EARNINGS BEFORE INTEREST & TAXES (EBIT)	**($144,330)**	**$571,732**	**$2,635,419**
EARNINGS BEFORE INTEREST, TAXES, DEPRECIATION & AMORTIZATION (EBITDA)	**$313,812**	**$3,778,732**	**$5,842,419**

SCENARIO - AA 2.5.2 2.4 MW POWER PLANT
MINIMUM 3% IRR ON 10 YR. CASH FLOW
INTERCONNECT ALLOWANCE = $250,000
WHEELING CHARGE = $0.005 per KWH
GCCS CONSTRUCTION & GCCS O&M INCLUDED
MUSA CONTRIBUTIONS and GASB 34 DEPRECIATION

SHAW GROUP
EMCON/OWT, INC. - DEVELOPED PROJECTS 04-May-2004

Anchorage, Alaska

ASSUMPTIONS

Gas Flow at 75% of Average Generation Rate from 1/19/04 Gas Generation Model		
Gensets installed - Recip Engines - number of units =	**3**	**Triton Power Pack 925 (CAT 3516) Low Emissions**
Gas Requirement per Genset - SCFM @ 50% Methane	**306**	**SCFM**
Power sale price per kWh =	**$0.0547**	**per KWH**
Total project installed cost.	**$4,109,000**	
Wheeling cost per kWh	**$0.0050**	**per KWH**

PROJECT DESCRIPTION:	**Triton Power Pack 925**	**POWER SALE RATE**	**$0.0547**	**per Kwh**
		POWER RATE INFLATOR	**1.00%**	**per YR.**
PROJECT CAPACITY:	**2,412 kW**	**WHEELING CHARGE**	**$0.0050**	**per kWh**
CAPITAL COST	**$1,703,566 per mW**	**GAS COST**	**$0.0000**	**per kWh**
FINANCING - loan to cost	**0.00%**	**GAS COST INFLATOR**	**2.00%**	**per YR.**
FINANCING - interest rate	**2.75%**	**O&M COST - Gen Plant**	**$0.0150**	**per Kwh gross**
GASCO OWNERSHIP	**100.00%**	**O&M COST INFLATOR**	**2.00%**	**per YR.**
UTILIZATION RATE	**95.00%**	**ENERGY GRANT per kWh**	**$0.0000**	

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FINANCIAL PERFORMANCE SUMMARY

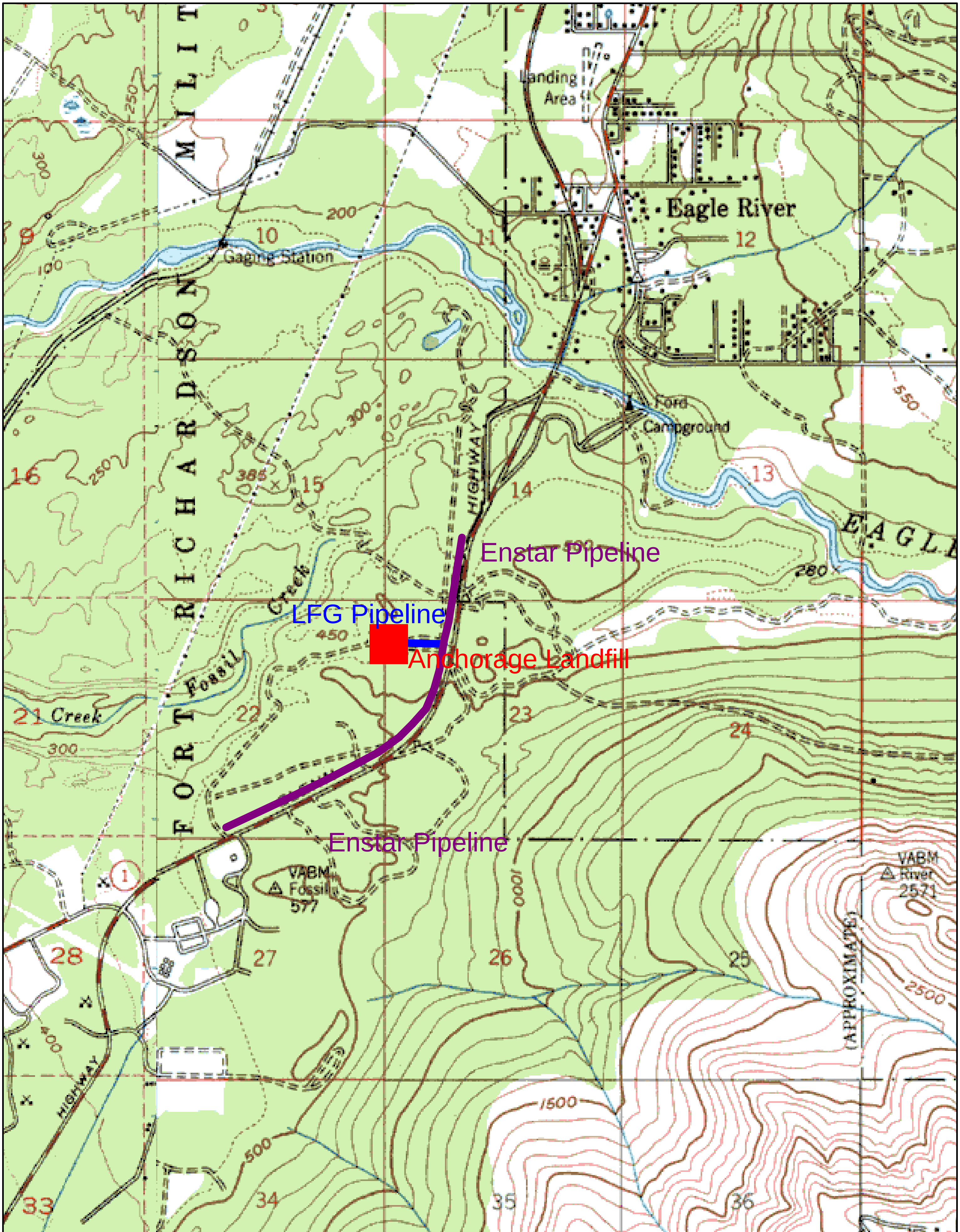
	YEAR 1		10 YEAR		15 YEAR	
	$	CENTS/KWH	$	CENTS/KWH	$	CENTS/KWH
OPERATING STATISTICS						
KILOWATT HOURS SOLD	17,125,783		195,070,475		295,433,795	
UTILIZATION FACTOR	81.05%		92.32%		93.22%	
INCOME STATEMENT						
TOTAL REVENUES	$936,780	5.47	$11,175,914	5.73	$17,362,653	5.88
COSTS OF REVENUES	506,102	2.96	5,991,698	3.07	9,342,428	3.16
GROSS PROFIT	430,678	2.51	5,184,216	2.66	8,020,225	2.71
DEPRECIATION and AMORTIZATION	549,457	3.21	4,109,000	2.11	4,109,000	1.39
ADMINISTRATIVE EXPENSE	28,103	0.16	335,277	0.17	520,880	0.18
INCOME BEFORE DEBT SERVICE	(146,882)	(0.86)	739,939	0.38	3,390,346	1.15
INTEREST COST	0	0.00	0	0.00	0	0.00
INCOME BEFORE INCOME TAXES	(146,882)	(0.86)	739,939	0.38	3,390,346	1.15
INCOME TAXES	0	0.00	0	0.00	0	0.00
TAX CREDITS	0	0.00	0	0.00	0	0.00
MUSA CONTRIBUTIONS	134,406	0.78	423,699	0.22	501,033	0.17
NET INCOME	($281,289)	(0.86)	$316,240	0.38	$2,889,313	1.15
CASH FLOW						
OPERATIONS						
NET INCOME	($281,289)	(1.64)	$316,240	0.16	$2,889,313	0.98
ADD BACK:						
DEPRECIATION and AMORTIZATION	549,457	3.21	4,109,000	2.11	4,109,000	1.39
INTEREST COSTS	0	0.00	0	0.00	0	0.00
CASH FLOW AVAILABLE FOR DEBT SERVICE	268,168	1.57	4,425,240	2.27	6,998,313	2.37
DEBT SERVICE						
PRINCIPAL PAYMENTS	0	0.00	0	0.00	0	0.00
INTEREST COSTS	0	0.00	0	0.00	0	0.00
TOTAL DEBT SERVICE	0	0.00	0	0.00	0	0.00
CASH FLOW AFTER DEBT SERVICE	268,168	1.57	4,425,240	2.27	6,998,313	2.37
INVESTMENT						
CAPITAL EXPENDITURES	(4,109,000)	(23.99)	(4,109,000)	(2.11)	(4,109,000)	(1.39)
EXISTING EQUITY IN GCCS	0	0.00	0	0.00	0	0.00
NET NEW CAPITAL EXPENDITURES	(4,109,000)	(23.99)	(4,109,000)	(2.11)	(4,109,000)	(1.39)
PROCEEDS OF FINANCING	0	0.00	0	0.00	0	0.00
NET INVESTMENT REQUIREMENTS	(4,109,000)	(23.99)	(4,109,000)	(2.11)	(4,109,000)	(1.39)
CASH AVAILABLE (REQUIRED)	($3,840,832)	(22.43)	$316,240	0.16	$2,889,312	0.98

FINANCIAL ANALYSIS

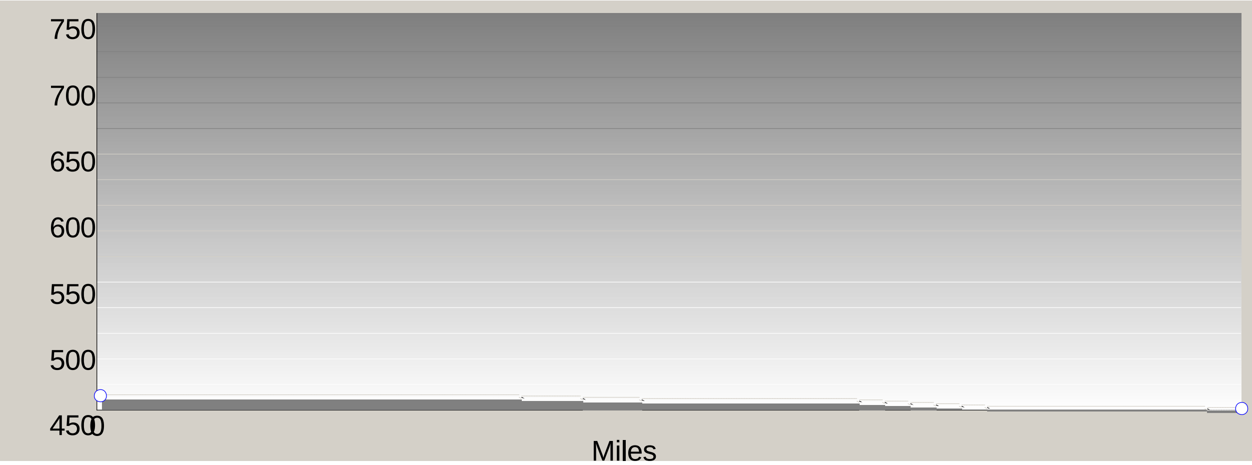
	YEAR 1	10 YEAR	15 YEAR
INTERNAL RATE OF RETURN		**3.0%**	**8.3%**
SIMPLE PAYBACK in YEARS	**9.0**		
DEBT COVERAGE RATIO		**NA**	**NA**
NPV of AFTER TAX CASH FLOWS			
DISCOUNT RATE 5.00%	**($3,548,186)**	**($381,380)**	**$959,456**
DISCOUNT RATE 10.00%	**($3,402,748)**	**($1,078,119)**	**($374,839)**
DISCOUNT RATE 12.00%	**($3,347,820)**	**($1,277,845)**	**($729,465)**
EARNINGS BEFORE INTEREST & TAXES (EBIT)	**($146,882)**	**$739,939**	**$3,390,346**
EARNINGS BEFORE INTEREST, TAXES, DEPRECIATION & AMORTIZATION (EBITDA)	**$402,575**	**$4,848,939**	**$7,499,346**

APPENDIX 4

TOPOGRAPHIC MAP FOR OPTION 2
(ENSTAR)



Enstar Pipeline
LFG Pipeline
Anchorage Landfill
Enstar Pipeline
Eagle River
Landing Area
Gaging Station
Ford Campground
FORT RICHARDSON MILIT
HIGHWAY
Fossil Creek
VABM Fossil 577
VABM River 2571
(APPROXIMATE)



Total distance:	990 feet	Climbing:	0 feet	Latitude:	000° 00' 00.0" N
		Descending:	-10 feet	Longitude:	000° 00' 00.0" E
Ground distance:	990 feet	Elevation change:	-9 feet	Elevation:	
		Min/Max:	462/472	Grade:	

APPENDIX 5

FINANCIAL PRO FORMA FOR OPTION 2
(ENSTAR)

Anchorage Medium BTU Gas Project

Pipeline Injection of High BTU Gas

Assumes ENSTAR will use all gas available

Project Proforma

April 5, 2004

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Summary of Assumptions & Financials

Assumptions

MG Price		$4.321	per mmBtu
MG Price Escalation		2.0%	
Capital Cost		$ 2,994,800	
Loan Amount		$0	
Gas Cost		$0.0000	
Gas Cost Escalation		2.0%	Annual Btu
Gas Quantity	SCFM	826	208,631
Ratio of Saleable BTUs to Input LFG BTUs		77%	159,970

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 3,630,259
Investment		$ 2,994,800
Net Cash Flow		$ 635,459
Project IRR		3.0%
NPV at rate =	2.000%	$ 191,961
NPV at rate =	2.500%	$ 94,658
NPV at rate =	2.750%	$ 47,845
NPV at rate =	3.000%	$ 2,212
Pre Tax Profits		$ 970,640
Average %		6.2%
Minimum %		-26.6%
Net Income		$ 635,459
Average %		2.3%
Minimum %		-34.8%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mil	16	$ 215,542
Gross Revenue contribution % of Revenu	1.25%	$ 119,639
		$ 335,181

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Pipeline Injection of High BTU Gas
ASSUMPTIONS to PRO FORMA

April 5, 2004

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Description			Value	Unit
Financial Information				
Project Capital Costs			$2,994,800	
Equity Contribution		100.00%	$2,994,800	
Loan		0.00%		
Principal			$0	
Term			10	years
Interest Rate			0.0%	
Interest Payments monthly during construction				
Loan Fees			0.0%	
MG Quantity	826 SCFM		208,631	mmBTU/Yr
	50.00% Methane %			
On-Stream Factors				
Utilization %			95.0%	
LFG to High BTU Conversion Ratio (Btu basis)			76.7%	
MG Price			$4.321	
MG Price escalator			2.0%	
Cost of Sales				
Cost of Methane Gas			$0.0000	per mmBTU
Cost Escalator			2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh			$80,000	Annually
Electric Escalator			2.0%	
Operating Costs			Annually	
O&M Compressor/Pipeline		per year	$ 275,000	Allow of $100,000 for high pressure compressors & condensate handling
O&M Escalator			3.0%	
Gas Separation System O&M			$ 0.35	per mmBtu
Property Insurance			1.00%	% of Value
General Liability Insurance			1.00%	% of Revenue
Administration			$25,000	
Income Taxes	Is project subject to income taxes		NO	
	Federal Tax Rate		0%	
	State Tax Rate		0.0%	Incl. In Federal

Questions	1 When do we anticipate project completion / start-up?	2006
	2 Verity Gas curve to use and recovery rate	Avg LFG at 75%
	3 Does gas curve assume 50 or 50+23 acres	73 acres
	4 Does the $15,000 include flare, blower and electrical	Includes all components of GCCS
	5 Tony had an estimate of $75/ft for pipeline. What does this include?	As per Jim use Kevin's $60
	6 No Federal Tax	

0

Anchorage Medium BTU Gas Project

Pipeline Injection of High BTU Gas **Annual Proforma**

Methane Gas Price (MG) = $ 4.32

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate	75.0%		75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
High Btu Gas Sales													
LFG to High BTU Conversion Ratio	76.68%		76.7%	76.7%	76.7%	76.7%	76.7%	76.7%	76.7%	76.7%	76.7%	76.7%	7.667594347
High Btu Sales	mmBtus		159,970	169,995	179,730	189,174	198,182	206,754	214,891	222,737	230,147	237,121	2,008,701
		Escalator											
Assumed Methane Gas Price		2%	$ 4.32	$ 4.41	$ 4.50	$ 4.59	$ 4.68	$ 4.77	$ 4.87	$ 4.96	$ 5.06	$ 5.16	
Income		Escalator											
MG Sales - Landfill Gas Production		2.0%	$691,229	$749,679	$808,785	$868,309	$927,492	$986,218	$1,046,520	$1,104,774	$1,164,542	$1,223,545	$9,571,094
Total Revenues			691,229	749,679	808,785	868,309	927,492	986,218	1,046,520	1,104,774	1,164,542	1,223,545	9,571,094
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	80,000	81,600	83,232	84,897	86,595	88,326	90,093	91,895	93,733	95,607	875,978
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			80,000	81,600	83,232	84,897	86,595	88,326	90,093	91,895	93,733	95,607	875,978
Gross Profit			611,229	668,079	725,553	783,413	840,897	897,892	956,427	1,012,879	1,070,809	1,127,938	8,695,116
Expenses - Pipeline													
O&M - Wellfield/Comp/Pipeline - per year		2.0%	275,000	280,500	286,110	291,832	297,669	303,622	309,695	315,889	322,206	328,650	3,011,173
Gas Separation System O&M	$ 0.35	2.0%	73,021	79,149	85,355	91,637	97,921	104,199	110,466	116,789	123,088	129,354	1,010,979
Property Insur. - (% of value)	1.00%	2.0%	29,948	30,547	31,158	31,781	32,417	33,065	33,726	34,401	35,089	35,791	327,922
General Liability Insur. (% of revenue)	1.00%	2.0%	6,912	7,647	8,415	9,215	10,039	10,889	11,786	12,690	13,644	14,622	105,859
Administration		2.0%	25,000	25,500	26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	273,743
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			409,881	423,343	437,048	450,995	465,106	479,377	493,827	508,486	523,319	538,295	4,729,677
Net Operating Profit			201,348	244,736	288,505	332,417	375,791	418,515	462,601	504,393	547,491	589,642	3,965,440
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			385,194	385,194	385,194	385,194	385,194	385,194	385,194	99,480	99,480	99,480	2,994,800
Net Profit Before Tax			(183,846)	(140,458)	(96,689)	(52,777)	(9,403)	33,321	77,406	404,913	448,011	490,162	970,640
			-26.6%	-18.7%	-12.0%	-6.1%	-1.0%	3.4%	7.4%	36.7%	38.5%	40.1%	10.1%
MUSA Contributions													
Millage Rate on NBV of PPE	x Prev EOY		47,917	41,754	35,591	29,427	23,264	17,101	10,938	4,775	3,183	1,592	215,542
Gross Revenue Rate	1.25%		8,640	9,371	10,110	10,854	11,594	12,328	13,082	13,810	14,557	15,294	119,639
Total Taxes			56,557	51,125	45,700	40,281	34,858	29,429	24,020	18,585	17,740	16,886	335,181
Net Income			(240,403)	(191,583)	(142,390)	(93,058)	(44,261)	3,892	53,387	386,329	430,270	473,276	635,459
			-34.8%	-25.6%	-17.6%	-10.7%	-4.8%	0.4%	5.1%	35.0%	36.9%	38.7%	6.6%

Anchorage Medium BTU Gas Project

Pipeline Injection of High BTU Gas **Annual Proforma**

Methane Gas Price (MG) = $ 4.32

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(2,994,800)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		385,194	385,194	385,194	385,194	385,194	385,194	385,194	99,480	99,480	99,480	2,994,800
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(2,994,800)	144,791	193,611	242,805	292,136	340,933	389,086	438,581	485,809	529,750	572,756	3,630,259
Cumulative After Tax Cash @	(2,994,800)	(2,850,009)	(2,656,398)	(2,413,593)	(2,121,457)	(1,780,524)	(1,391,438)	(952,857)	(467,048)	62,702	**635,459**	
Net Present Value (NPV)	**2.000%**										**$191,961**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(2,994,800)											(2,994,800)
Construction Interest												-
Bond	-											-
Cash Flow		144,791	193,611	242,805	292,136	340,933	389,086	438,581	485,809	529,750	572,756	3,630,259
												-
After Tax Cash Flow - Year	(2,994,800)	144,791	193,611	242,805	292,136	340,933	389,086	438,581	485,809	529,750	572,756	635,459
After Tax Cash Flow - Cum.	(2,994,800)	(2,850,009)	(2,656,398)	(2,413,593)	(2,121,457)	(1,780,524)	(1,391,438)	(952,857)	(467,048)	62,702	635,459	

Project IRR - on Cash Investment **3.01%**

NPV - After tax - Discount @	**2.00%**	**$191,961**	
	2.50%	**$94,658**	
	2.75%	**$47,845**	
Discount = to IRR	**3.00%**	**$2,212**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**6.16%**	**-26.60%**
After Tax	**2.27%**	**-34.78%**

Anchorage Medium BTU Gas Project
Pipeline Injection of High BTU Gas
Capital Estimate Detail

April 5, 2004

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Description			Sub-Total	Total
Gas Collection System / Compressor Facility				
Wellfield based on $12,000 per acre asuming 73 acres		$876,000		
Gas Separation System	1,350,000			
Compressor	650,000	2,000,000		
Contingency		$0	Included in above	
			$2,876,000	
Pipeline and Related Costs				
Blower Upgrade		$0	Included in GCCS	
Pipeline 990 feet @ $120 per foot		$118,800	Includes 2x factor for high pressure specifications	
D.O.T. Pipeline Safety Standards Design & Compliance		$0	Included in Pipeline estimate	
Air Compressor		$0	Included in Pipeline estimate	
Surveying		$0	Included in Pipeline estimate	
Geotechnical		$0	Included in Pipeline estimate	
Planning/Coordination/Legal		$0	Included in Pipeline estimate	
Construction Interest		$0	None assumed	
Right of Way Payment		$0	None assumed	
Wetlands Investigation		$0	Included in Pipeline estimate	
End User Upgrades		$0	Allowance	
Contingency - 10%		$0	Included in above	
			$118,800	
Project Total				**$2,994,800**

Anchorage Medium BTU Gas Project
Pipeline Injection of High BTU Gas

Depreciation & Amortization Schedules

April 5, 2004

N:\Document Control\project for jim bier\[Anchorage ENSTAR Pipelineapdx5.xls]Dep

Depreciation Amounts		Amount
Gas Treatment and Processing System		2,876,000
Pipeline and Related Costs		118,800
Construction Interest		-
	Sub-Total	**2,994,800**

	Year	Depreciation
1	2006	$385,194
2	2007	$385,194
3	2008	$385,194
4	2009	$385,194
5	2010	$385,194
6	2011	$385,194
7	2012	$385,194
8	2013	$99,480
9	2014	$99,480
10	2015	$99,480
		$2,994,800

APPENDIX 6

PROPOSED BOILER SPECIFICATIONS FOR EAGLE RIVER SCHOOL

SECTION 15451

GAS FIRED WATER HEATER

PART 1 - GENERAL

1.01 SUMMARY

A. SECTION INCLUDES

1. Gas fired water heaters.

B. RELATED SECTIONS

1. 15010 – Mechanical General Requirements.
2. 15400 – Plumbing.
3. 15450 – Plumbing Equipment.
4. 15910 – Control System Sequences of Operation.

1.02 REFERENCES

A. ASHRAE Standard 90.1 Energy Efficient Design of New Buildings Except New Low-Rise Residential Buildings.

B. ANSI Z21.10.3 - Gas Water Heaters.

C. ASME Section 8D - Pressure Vessels.

D. NFPA 54 - National Fuel Gas Code.

1.03 SUBMITTALS

A. Submit under provisions of Section 15010 – Mechanical General Requirements and Division 1.

B. Product Data:

1. Provide dimension drawings of water heaters indicating components and connections to other equipment and piping.
2. Provide gas connection requirements.
3. Provide product data of components and dimension drawings of water heater stack layout.

C. Calculations:

1. Provide water heater stack sizing calculations with product data to verify sizes shown on the drawings are appropriately sized for the necessary performance of the installed water heaters.

D. Closeout Submittals:

1. Project Record Documents: Record actual locations of components and piping configurations.
2. Operation and Maintenance Data: Include operation, maintenance, and inspection data, replacement part numbers and availability, and service depot location and telephone number.
3. Warranty: Submit manufacturer's warranty and ensure forms have been completed in Owner's name and registered with manufacturer.

1.04 QUALITY ASSURANCE

A. Manufacturer Qualifications: Company specializing in manufacturing the Products specified in this section with minimum three years documented experience.

B. Ensure products and installation of specified products are in conformance with recommendations and requirements of the following organizations:

1. American Gas Association (AGA).
2. American National Standards Institute (ANSI Z21.10.3).
3. American Society of Mechanical Engineers (ASME).
4. National Electrical Manufacturers' Association (NEMA).
5. National Sanitation Foundation (NSF).
6. Underwriters Laboratories (UL).

1.05 COMMISSIONING

A. Provide labor, materials, and equipment as required to facilitate the start up and commissioning of systems and equipment within this scope of work by factory trained service technician.

B. Provide Owner with a copy of the Start-Up Certificate as part of the Operations & Maintenance Manual.

PART 2 - PRODUCTS

2.01 POWER GAS WATER HEATER (WH-1, WH-2)

A. Provide a non-condensing, submerged fire-tube, power gas type water heater of the size and capacity shown on the drawings. Certify that the heater complies with the requirements of ASHRAE 90.1. Minimum fuel to water efficiency is 83 percent.

B. Tank:

1. ASME construction and stamp for 188 psig test pressure and National Board registered 125 psig working pressure.

2. Lining: After tank is completely fabricated and welding is complete, abrasively clean vessel to white metal, chemically clean, and line tank with a continuous, non-porous thermosetting plastic liner.
3. Provide holiday-free tank lining construction to protect tank from corrosion due to electrolytic action in water.
4. Pure, solid copper flue tubes, with PTFE coated boiler grade steel combustion chamber.
5. Accessories; ASME and AGA rated temperature and pressure relief valve, cleanout hand hole/inspection opening, drain valve with hose end fitting.
6. Tank design to allow manway-size access to enter tank for inspection and maintenance.
7. Factory installed seismic restraint eyes mounted to tank prior to application of coating. Eyes serve as bracing points for seismic zone 4 restraint.

C. Enameled sheet steel jacket over glass fiber or foam insulation. Heavy density insulation thickness and efficiency shall be as required to meet energy efficiency requirements of ASHRAE 90.1.

D. Burner: Sized and furnished by heater manufacturer for system capacity; continuous duty overload protected motor, complete gas train as indicated, manual gas shutoff valve, UL labeled. Provide: UL/IRI gas train designed for 8.0 inches to 14.0 inches range of natural gas pressure. Gas train assembled and shipped loose for field installation.

E. Controls: Provide a complete and operating control system, including the following features:

1. Upper and lower operating thermostats.
2. High temperature limiting device.
3. Flame ignition control.
4. Flame failure control.
5. Chamber pre-purging sequence.
6. Automatic gas valve(s).
7. High temperature limiting device, manual reset (Listed over-temperature gas cutoff).
8. Low water cutoff.
9. Controls UL approved, factory wired.
10. Provide control wiring diagram.
11. Operating controls shall not also be used as safety devices. Reference ASME, CSD-1.

F. Miscellaneous Features: Flame inspection port, draft regulator per manufacturer's instructions, dial thermometer, and pressure gauge mounting base, insulated sub-base when required for installation on combustible floor.

G. Warranty: 15 year tank warranty; three year heat exchanger/burner module warranty; one year cost free (labor and parts) warranty.

H. Manufacturer: PVI, or equal.

2.02 CHIMNEY (STACK)

A. Provide a complete, engineered chimney system for fired equipment, including connections and adapters to smoke outlets.

B. Provide prefabricated chimney system of the configuration shown on drawings, UL listed for the application, with the following features:

1. Listed for pressurized systems.
2. Stainless steel liner, and stainless steel outer jacket where exposed to outdoor weather.
3. Terminate stack with an exit cone.
4. Clearances from building elements in accordance with the chimney listing.

C. Provide clean-out tees, insulating roof support, drains at bottom of risers, and other appropriate items required for proper installation and/or recommended by manufacturer. Stainless steel flashing and counter-flashing.

D. Provide supports and seismic restraints in accordance with the manufacturer’s UL listing.

E. Submit product data, shop drawings, and calculations of proposed layout, as required in Part 1.

F. Manufacturer: Metalbestos, American Metal Products, Van Packer.

PART 3 - EXECUTION

3.01 INSTALLATION

A. Install water heaters in accordance with manufacturer's instructions and to AGA requirements.

B. Coordinate with plumbing piping and related fuel piping, flue gas venting and electrical work to achieve properly operating system.

C. Coordinate water heater venting with clearances to combustibles.

3.02 SEISMIC RESTRAINT

A. Provide seismic restraint of heater appropriate for Seismic Zone 4. See Section 15240 – Mechanical Sound, Vibration and Seismic Control.

3.03 COMMISSIONING

A. Perform tests and verification procedures required for the commissioning process as requested by the Owner and directed by the Owner's Commissioning Authority.

END OF SECTION 15451

SECTION 15550

HEAT GENERATION

PART 1 - GENERAL

1.01 SUMMARY

A. Section Includes:

1. This section describes specific requirements, products and methods of execution for heat generation throughout the project.

B. Related Sections:

1. 15010 – Mechanical General Requirements.
2. 15050 – Basic Mechanical Materials and Methods.
3. 15510 – Hydronic Piping and Specialties.
4. 15910 – Control System Sequences of Operation.

1.02 DESCRIPTION

A. This section describes specific requirements, products and methods of execution for interrelated systems necessary for the generation of heat which will be distributed to the locations shown. The method of distribution of this heat is specified elsewhere.

1.03 CODES

A. International Mechanical Code (IMC).

B. ASME Boilers and Pressure Vessel Code, Sections IV & VI.

C. In addition to devices mentioned specifically herein, provide automatic boiler controls listed in Table 10-C of the International Mechanical Code, and in ASME CSD-1, latest edition, together with addenda and interpretations.

1.04 SUBMITTALS

A. Product Data:

1. Submit product submittals for approval showing boiler physical and performance characteristics. Data shall include manufacturer's catalog cut sheets, and shall clearly indicate which model is being submitted on, and features and appurtenances being provided.
2. Submittals shall be in accordance with the requirements of Section 15010 – Mechanical General Requirements and Division 1.

B. Shop Drawings:

1. Submitted boiler shall be dimensionally equal to scheduled product within six inches in each dimension. Maintain clearances shown on drawings. Submit fully dimensioned shop drawings of boiler room(s) at drawing scale of 1/4 inch equals one foot zero inches or larger, showing entire boiler room, equipment and clear callouts of deviations from layout shown. Provide boiler room modifications required due to dimensional and technical deviation at no additional cost to the Contract. Submit shop drawings of proposed equipment layout and base or pad for each piece of equipment.
2. If equipment to be provided exceeds the weight of the specified equipment by more than 20 percent, or if the location is to be altered, submit shop drawings of revised structural loading, noting location of pertinent loads, and obtain approval prior to providing equipment.

1.05 WARRANTY

A. Warranty workmanship, labor, and materials for a period of one year from the date of final acceptance, without limitation, except where longer warranty periods are specified in the General Conditions of the Contract. Warranty work shall be promptly coordinated and performed at the Contractor's sole expense.

PART 2 - PRODUCTS

2.01 HOT WATER BOILER - CAST IRON (BLR-1, BLR-2)

A. Provide factory assembled, sectional wet base, water walled cast iron boilers suitable for forced draft firing. The output of each boiler shall not be less than that noted on drawings. Required capacity shall be the gross I=B=R water rating unless otherwise indicated. Provide boilers having gross outputs greater than 4700 MBH with 5 square feet of heating surface per boiler horsepower.

B. Provide the following features: Insulated metal jacket, burner mounting plate, gas tight seal between sections, flue damper assembly, ASME safety relief valve (piped down to six inches above floor), instrument panel as specified below, drain valve, flange mounted gas burner, and other items required to make boiler complete.

C. Refractory based or walled boilers are not acceptable.

D. Manufacturer: Weil-McLain, Burnham.

1. Submitted boiler shall be dimensionally equal to scheduled product within six inches in each dimension. Maintain clearances shown on drawings. Submit fully dimensioned shop drawings of boiler showing entire boiler room, equipment and clear callouts of deviations from layout shown. Provide boiler room modifications required due to dimensional and technical deviation at no additional cost to the Contract.

2.02 GAS BURNER (FOR BOILERS BLR-1, BLR-2)

A. Provide forced draft gas burner sized to match boiler rating and furnished by boiler manufacturer as part of the required complete boiler package.

B. Burner shall be fully packaged and burner mounted and wired to boiler controls.

C. Provide burner controls as follows:

1. Firing control shall be fully modulating type with a turn down capability of not less than two to one (2:1) as limited by a minimum exhaust gas temperature of 280 degrees F., with proven low-fire start.
2. Combustion and firing controls including Honeywell Model RM-7800 Flame Safeguard System with self-diagnostic capabilities and digital display readout.
3. Gas train shall be UL/IRI and designed for 13.2 inches to 27.7 inches range of natural gas pressure. Gas train assembled and shipped loose for field installation.
4. Peripheral controls including reset operating temperature controller, a high limit manually reset control, auxiliary Honeywell L4006E high limit control and a low water safety shut off control as specified later in this Section.
5. Indicators and alarms shall include: Power on, run, lock out, low gas pressure, high gas pressure and other indicating lights as applicable. Lock out indicator shall have provision for connection to a remote alarm or monitoring device.
6. Provide wiring between burner cabinet, controls and safety devices in accordance with applicable provisions of Division 16.
7. Provide panel mounted toggle switch to allow operator to manually switch between DDC and local control. The boiler controls specified in this section shall be fully coordinated with the DDC system sequences specified in Section 15910 – Control System Sequences of Operation. Burner shall be capable of accepting a 4-20 mA remote signal from DDC system.

D. Burner System shall be UL/IRI listed as a unit.

E. Manufacturer: Weishaupt, no substitutions.

2.03 LOW WATER CUTOFF

A. Provide for each boiler an automatic resetting McDonnell Miller #63 series, approved, low water cut-off wired in series with burner controls. Working pressure 50 psig. UL/FM approved. Provide for each boiler a McDonnell Miller TC-4 test and check assembly.

B. Provide for each boiler a second, manual reset McDonnell Miller #63M series, approved, low water cut-off wired in series with burner controls. Working pressure 50 psig. UL/FM approved.

C. Pipe LWCO drain down to six inches above floor.

2.04 AUXILIARY HIGH LIMIT

A. Provide a Honeywell Model L4006-E auxiliary high limit sensor for each boiler, wired to the boiler energy management system.

2.05 CHIMNEY (STACK)

A. Provide a complete, engineered chimney system for fired equipment, including connections and adapters to smoke outlets.

B. Provide prefabricated chimney system of the size and configuration shown on drawings, UL listed for the application, with the following features:

1. Listed for pressurized systems.
2. Stainless steel liner, and stainless steel outer jacket where exposed to outdoor weather.
3. Terminate stack with an exit cone.
4. Clearances from building elements in accordance with the chimney listing.

C. Provide clean-out tees, insulating roof support, drains at bottom of risers, and other appropriate items required for proper installation and/or recommended by manufacturer. Stainless steel flashing and counterflashing.

D. Provide supports and seismic restraints in accordance with the manufacturer’s UL listing.

E. Submit shop drawings of proposed layout.

F. Manufacturer: Metalbestos, American Metal Products, Van Packer.

PART 3 - EXECUTION

3.01 SETTING OF EQUIPMENT

A. Set equipment on a proper base or pad as recommended by the equipment manufacturer, compatible with the building structural system. Level equipment to within recommended tolerances. Submit shop drawings of proposed equipment layout and base.

3.02 ANCHORING

A. Anchor equipment to building structure using appropriately sized bolts. Provide seismic restraint per Section 15240 – Mechanical Sound, Vibration and Seismic Control.

3.03 RELIEF VENTING

A. Pipe gas train and pressure regulator vent lines to the outside of the building. Multiple gas train vents from a single boiler may be manifolded together. Do not combine with any of the following venting:

1. Pipe safety valve vent lines to the outside of the building. Safety valve vents for a single boiler may be manifolded together.
2. Pipe pressure relief valve vent lines to the outside of the building.
3. Pipe ignition or main burner vent lines to the outside of the building.
4. Do not combine any vents with vents from other boilers.

3.04 STRUCTURAL LOAD

A. Verify that building structure is adequately designed to support the entire operating weight of the equipment to be installed. If equipment to be provided exceeds the weight of the specified equipment by more than 20 percent, or if the location is to be altered, submit shop drawings of revised structural loading, noting location of pertinent loads, and obtain approval prior to providing equipment. Provide structural building modifications to accommodate proposed substitute equipment.

3.05 START-UP SERVICE

A. After completion of the installation, start-up the heating plant by a qualified factory representative of the boiler manufacturer, furnished by the manufacturer's Alaska sales office, and provide a start-up report by this representative, including control settings, and a performance chart of the control system furnished. Submit a letter of certification with start-up report from this representative stating that the boilers are in perfect operating order and are properly adjusted. Test safety devices and record settings. Test and record oxygen, carbon dioxide, smoke stack temperature and calculate excess air and steady state efficiency. Coordinate with lead/lag control installer, and make final lead/lag setpoint adjustments. Note set points in report. Submit final data for review. Provide two hours operating instruction to authorized owner representative by this factory start-up man.

3.06 THERMAL EXPANSION

A. Install piping to allow for normal thermal expansion and contraction. Provide anchors where necessary and as shown. Provide expansion loops, and alignment guides to suit conditions and as shown on drawings.

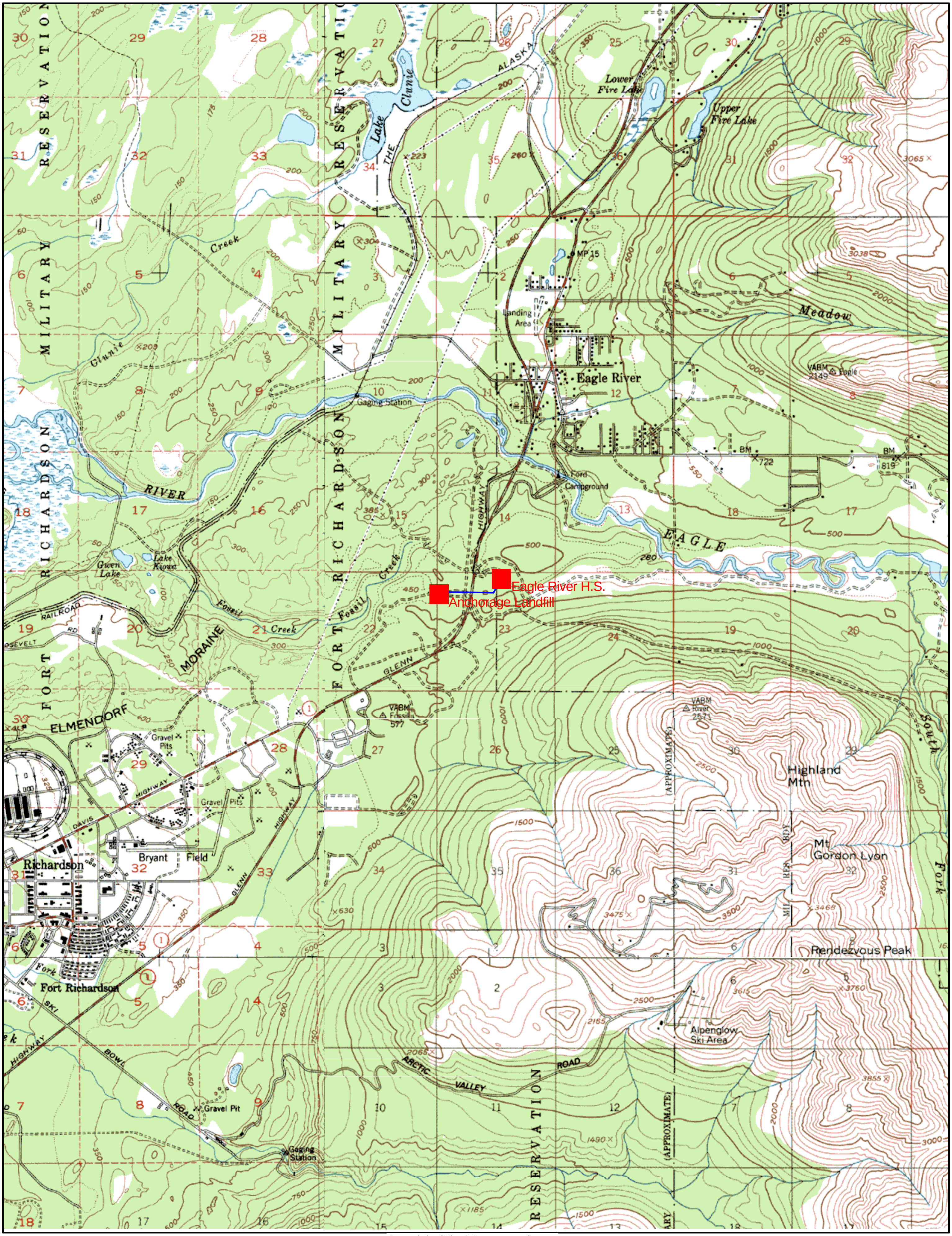
3.07 COMMISSIONING

A. Perform tests and verification procedures required for the commissioning process as requested by the Owner and directed by the Owner's Commissioning Authority.

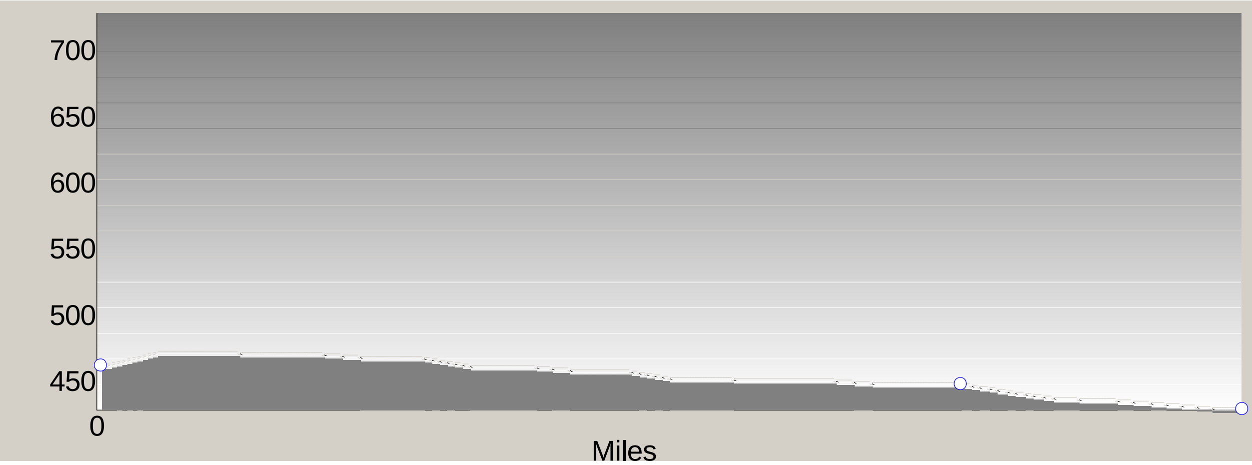
END OF SECTION 15550

APPENDIX 7

TOPOGRAPHIC MAP FOR OPTION 3
(EAGLE RIVER SCHOOL)



Eagle River H.S.
Anchorage Landfill
Eagle River
Lower Fire Lake
Upper Fire Lake
Lake Clunie
Landing Area
Gaging Station
Ford Campground
EAGLE
RIVER
Meadow
Creek
Clunie Creek
Fossil Creek
Gwen Lake
Lake Kiowa
MORAINE
GLENN HIGHWAY
ELMENDORF
Gravel Pits
Bryant Field
Richardson
Fort Richardson
Highland Mtn
Mt Gordon Lyon
Rendezvous Peak
Alpenglow Ski Area
ARCTIC VALLEY ROAD
SKI BOWL ROAD
Gravel Pit
Gaging Station
FORT RICHARDSON MILITARY RESERVATION



Total distance:	3236 feet	Climbing:	10 feet	Latitude:	000° 00' 00.0" N
		Descending:	-43 feet	Longitude:	000° 00' 00.0" E
Ground distance:	3237 feet	Elevation change:	-33 feet	Elevation:	
		Min/Max:	428/471	Grade:	

APPENDIX 8

FINANCIAL PRO FORMA FOR OPTION 3
(EAGLE RIVER SCHOOL)

Anchorage Medium BTU Gas Project

Gas Sales to Eagle River High School (under construction)

Annual Gas Demand (flow of 105 scfm) Based on Existing School Building

Project Proforma

April 5, 2004

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Summary of Assumptions & Financials

Assumptions

MG Price	$18.870	
MG Price Escalation	2.0%	
Capital Cost	$ 2,186,031	
Loan Amount	$0	
Gas Cost	$0.0000	
Gas Cost Escalation	2.0%	
Gas Quantity	105	SCFM

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 2,584,988
Investment		$ 2,186,031
Net Cash Flow		$ 398,957
Project IRR		3.0%
NPV at rate =	2.000%	$ 120,252
NPV at rate =	2.500%	$ 58,746
NPV at rate =	2.750%	$ 29,102
NPV at rate =	3.000%	$ 173
Pre Tax Profits		$ 644,279
Average %		11.3%
Minimum %		2.5%
Net Income		$ 398,957
Average %		6.7%
Minimum %		-5.7%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mil:	16	$ 176,771
Gross Revenue contribution % of Revenu	1.25%	$ 68,551
		$ 245,322

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Gas Sales to Eagle River High School (under construction)
ASSUMPTIONS to PRO FORMA

April 5, 2004

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Description				Value	Unit
Financial Information					
Project Capital Costs	2.08 mile pipeline, 8" dia.			$2,186,031	
Equity Contribution			100.00%	$2,186,031	
Loan			0.00%		
	Principal			$0	
	Term			10	years
	Interest Rate			0.0%	
	Interest Payments monthly during construction				
	Loan Fees			0.0%	
MG Quantity	105	SCFM		26,542	mmBTU/Yr
	50.00%	Methane %			
On-Stream Factors					
Utilization %				95.0%	
MG Price				$18.870	
MG Price escalator				2.0%	
Cost of Sales					
Cost of Methane Gas				$0.0000	per mmBTU
Cost Escalator				2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh				$40,000	Annually
		Electric Escalator		2.0%	
Operating Costs				Annually	
O&M Wellfield/Compressor/Pipeline			per year	$ 150,000	
		O&M Escalator		3.0%	
Property Insurance				1.00%	% of Value
General Liability Insurance				1.00%	% of Revenue
Administration				$25,000	
Income Taxes		Is project subject to income taxes		NO	
		Federal Tax Rate		0%	
		State Tax Rate		0.0%	Incl. In Federal

Anchorage Medium BTU Gas Project

Gas Sales to Eagle River High School (under constr Annual Proforma

Methane Gas Price (MG) = $ 18.87

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate	75.0%		75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
School Gas Demand													
Average SCFM			105	105	105	105	105	105	105	105	105	105	1050.502054
Average MMBTU @ 50% Methane & 95% Utilization			26,542	26,542	26,542	26,542	26,542	26,542	26,542	26,542	26,542	26,542	265,420
		Escalator											
Assumed Methane Gas Price		2%	$ 18.87	$ 19.25	$ 19.63	$ 20.02	$ 20.43	$ 20.83	$ 21.25	$ 21.68	$ 22.11	$ 22.55	
Income		Escalator											
MG Sales - Landfill Gas Production		2.0%	$500,848	$510,934	$521,019	$531,371	$542,253	$552,870	$564,018	$575,431	$586,844	$598,522	$5,484,108
Total Revenues			500,848	510,934	521,019	531,371	542,253	552,870	564,018	575,431	586,844	598,522	5,484,108
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	40,000	40,800	41,616	42,448	43,297	44,163	45,046	45,947	46,866	47,804	437,989
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			40,000	40,800	41,616	42,448	43,297	44,163	45,046	45,947	46,866	47,804	437,989
Gross Profit			460,848	470,134	479,403	488,923	498,956	508,707	518,971	529,483	539,977	550,718	5,046,119
Expenses - Pipeline													
O&M - Wellfield/Comp/Pipeline - per year		2.0%	150,000	153,000	156,060	159,181	162,365	165,612	168,924	172,303	175,749	179,264	1,642,458
Property Insur. - (% of value)	1.00%	2.0%	21,860	22,298	22,743	23,198	23,662	24,136	24,618	25,111	25,613	26,125	239,364
General Liability Insur. (% of revenue)	1.00%	2.0%	5,008	5,212	5,421	5,639	5,870	6,104	6,352	6,610	6,876	7,153	60,244
Administration		2.0%	25,000	25,500	26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	273,743
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			201,869	206,009	210,234	214,549	218,957	223,454	228,048	232,741	237,529	242,419	2,215,809
Net Operating Profit			258,979	264,124	269,169	274,374	279,998	285,253	290,923	296,743	302,448	308,299	2,830,310
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			246,460	246,460	246,460	246,460	246,460	246,460	246,460	153,603	153,603	153,603	2,186,031
Net Profit Before Tax			12,519	17,664	22,709	27,914	33,538	38,793	44,462	143,140	148,845	154,696	644,279
			2.5%	3.5%	4.4%	5.3%	6.2%	7.0%	7.9%	24.9%	25.4%	25.8%	11.7%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		34,976	31,033	27,090	23,146	19,203	15,260	11,316	7,373	4,915	2,458	176,771
Gross Revenue Rate	1.25%		6,261	6,387	6,513	6,642	6,778	6,911	7,050	7,193	7,336	7,482	68,551
Total Taxes			41,237	37,420	33,603	29,789	25,981	22,171	18,367	14,566	12,251	9,939	245,322
Net Income			(28,719)	(19,756)	(10,893)	(1,875)	7,557	16,622	26,096	128,574	136,594	144,757	398,957
			-5.7%	-3.9%	-2.1%	-0.4%	1.4%	3.0%	4.6%	22.3%	23.3%	24.2%	7.3%

Anchorage Medium BTU Gas Project

Gas Sales to Eagle River High School (under constrı Annual Proforma

Methane Gas Price (MG) = $ 18.87

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(2,186,031)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		246,460	246,460	246,460	246,460	246,460	246,460	246,460	153,603	153,603	153,603	2,186,031
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(2,186,031)	217,742	226,705	235,567	244,585	254,017	263,082	272,556	282,177	290,197	298,360	2,584,988
Cumulative After Tax Cash @	(2,186,031)	(1,968,289)	(1,741,585)	(1,506,018)	(1,261,433)	(1,007,415)	(744,333)	(471,777)	(189,600)	100,597	**398,957**	
Net Present Value (NPV)	**2.000%**										**$120,252**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(2,186,031)											(2,186,031)
Construction Interest												-
Bond	-											-
Cash Flow		217,742	226,705	235,567	244,585	254,017	263,082	272,556	282,177	290,197	298,360	2,584,988
												-
After Tax Cash Flow - Year	(2,186,031)	217,742	226,705	235,567	244,585	254,017	263,082	272,556	282,177	290,197	298,360	398,957
After Tax Cash Flow - Cum.	(2,186,031)	(1,968,289)	(1,741,585)	(1,506,018)	(1,261,433)	(1,007,415)	(744,333)	(471,777)	(189,600)	100,597	398,957	

Project IRR - on Cash Investment		**3.00%**	
NPV - After tax - Discount @	**2.00%**	**$120,252**	
	2.50%	**$58,746**	
	2.75%	**$29,102**	
Discount = to IRR	**3.00%**	**$173**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**11.27%**	**2.50%**
After Tax	**6.68%**	**-5.73%**

Anchorage Medium BTU Gas Project
Gas Sales to Eagle River High School (under construction)
Capital Estimate Detail

April 5, 2004

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Description		Sub-Total	Total
Gas Collection System / Compressor Facility			
Wellfield based on $12,000 per acre asuming 73 acres	$876,000		
Compressor	$650,000		
Contingency	$0	Included in above	
		$1,526,000	
Pipeline and Related Costs			
Blower Upgrade	$0	Included in GCCS	
Pipeline 2.0797 miles @ $51 per foot - 8" pipeline	$560,031		
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate	
Air Compressor	$0	Included in Pipeline estimate	
Surveying	$0	Included in Pipeline estimate	
Geotechnical	$0	Included in Pipeline estimate	
Planning/Coordination/Legal	$0	Included in Pipeline estimate	
Construction Interest	$0	None assumed	
Right of Way Payment	$0	None assumed	
Wetlands Investigation	$0	Included in Pipeline estimate	
End User Upgrades	$100,000	Allowance	
Contingency - 10%	$0	Included in above	
		$660,031	
Project Total			**$2,186,031**

Anchorage Medium BTU Gas Project
Gas Sales to Eagle River High School (under construction)

Depreciation & Amortization Schedules

April 5, 2004

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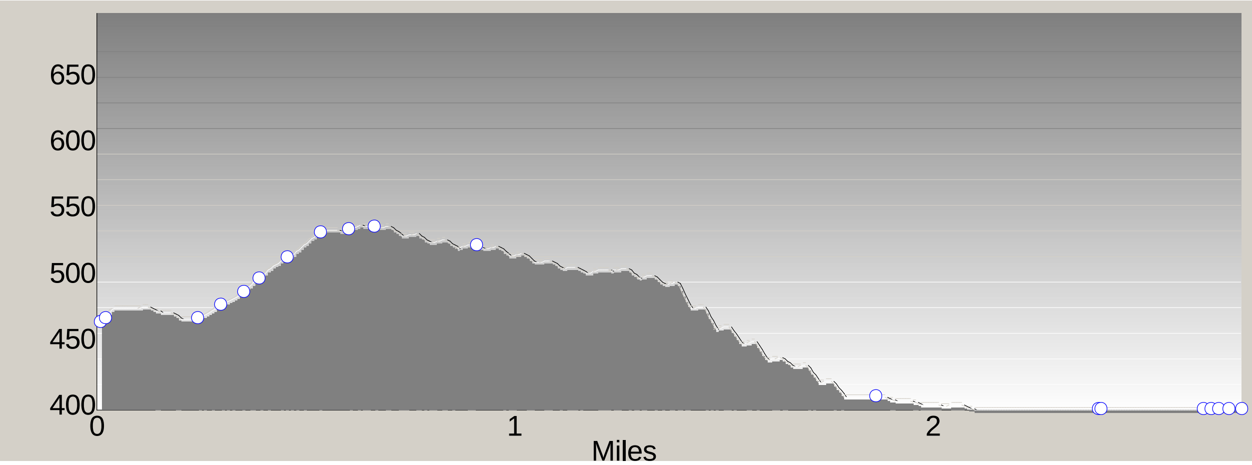
Depreciation Amounts	Amount
Gas Treatment and Processing System	1,526,000
Pipeline and Related Costs	660,031
Construction Interest	-
Sub-Total	**2,186,031**

	Year	Depreciation
1	2006	$246,460
2	2007	$246,460
3	2008	$246,460
4	2009	$246,460
5	2010	$246,460
6	2011	$246,460
7	2012	$246,460
8	2013	$153,603
9	2014	$153,603
10	2015	$153,603
		$2,186,031

APPENDIX 9

TOPOGRAPHIC MAP FOR OPTION 4
(NATIONAL GUARD)


Anchorage Landfill
National Guard Armory
Eagle River
Lower Fire Lake
Upper Fire Lake
Clunie Lake
Gaging Station
Ford Campground
Landing Area
Highland Mtn
Mt Gordon Lyon
Rendezvous Peak
Alpenglow Ski Area
Fort Richardson
Bryant Field
Gravel Pits
Green Lake
Lake Kiowa
FORT RICHARDSON MILITARY RESERVATION
GLENN HIGHWAY
ARCTIC VALLEY ROAD
ELMENDORF
MORAINE
EAGLE RIVER
Fossil Creek
Meadow



Total distance:	2 miles, 3875 feet	Climbing:	118 feet	Latitude:	000° 00' 00.0" N
		Descending:	-185 feet	Longitude:	000° 00' 00.0" E
Ground distance:	2 miles, 3883 feet	Elevation change:	-66 feet	Elevation:	
		Min/Max:	396/536	Grade:	

APPENDIX 10

FINANCIAL PRO FORMA FOR OPTION 4
(NATIONAL GUARD)

Anchorage Medium BTU Gas Project

Gas Sales to National Guard Armory

Assumes National Guard Armory Usage is Based on Historical Demand

Project Proforma

April 12, 2004

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Summary of Assumptions & Financials

Assumptions

MG Price	$3.445	
MG Price Escalation	2.0%	
Capital Cost	$ 2,492,131	
Loan Amount	$0	
Gas Cost	$0.0000	
Gas Cost Escalation	2.0%	
Gas Quantity	650	SCFM

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 2,948,009
Investment		$ 2,492,131
Net Cash Flow		$ 455,878
Project IRR		3.0%
NPV at rate =	2.000%	$ 137,924
NPV at rate =	2.500%	$ 67,757
NPV at rate =	2.750%	$ 33,940
NPV at rate =	3.000%	$ 937
Pre Tax Profits		$ 737,061
Average %		11.5%
Minimum %		3.2%
Net Income		$ 455,878
Average %		6.8%
Minimum %		-5.1%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mil:	16	$ 203,708
Gross Revenue contribution % of Revenu	1.25%	$ 77,476
		$ 281,184

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Gas Sales to National Guard Armory
ASSUMPTIONS to PRO FORMA

April 12, 2004

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Description			Value	Unit
Financial Information				
Project Capital Costs			$2,492,131	
Equity Contribution		100.00%	$2,492,131	
Loan		0.00%		
Principal			$0	
Term			10	years
Interest Rate			0.0%	
Interest Payments monthly during construction				
Loan Fees			0.0%	
MG Quantity	650 SCFM		164,297	mmBTU/Yr
	50.00% Methane %			
On-Stream Factors				
Utilization %			95.0%	
MG Price			$3.445	
MG Price escalator			2.0%	
Cost of Sales				
Cost of Methane Gas			$0.0000	per mmBTU
Cost Escalator			2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh			$40,000	Annually
	Electric Escalator		2.0%	
Operating Costs			Annually	
O&M Compressor/Pipeline		per year	$ 175,000	
	O&M Escalator		3.0%	
Property Insurance			1.00%	% of Value
General Liability Insurance			1.00%	% of Revenue
Administration			$25,000	
Income Taxes	Is project subject to income taxes		NO	
	Federal Tax Rate		0%	
	State Tax Rate		0.0%	Incl. In Federal

Questions	1 When do we anticipate project completion / start-up?	2006
	2 Verity Gas curve to use and recovery rate	Avg LFG at 75%
	3 Does gas curve assume 50 or 50+23 acres	73 acres
	4 Does the $15,000 include flare, blower and electrical	Includes all components of GCCS
	5 Tony had an estimate of $75/ft for pipeline. What does this include?	As per Jim use Kevin's $60
	6 No Federal Tax	

Anchorage Medium BTU Gas Project

Gas Sales to National Guard Armory **Annual Proforma**

Methane Gas Price (MG) = $ 3.45

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate		75.0%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
National Guard Gas Demand													
Average mmBtu		164,297	164,297	164,297	164,297	164,297	164,297	164,297	164,297	164,297	164,297	164,297	1,642,968
Average SCFM			650	650	650	650	650	650	650	650	650	650	
		Escalator											
Assumed Methane Gas Price		2%	$ 3.45	$ 3.51	$ 3.58	$ 3.66	$ 3.73	$ 3.80	$ 3.88	$ 3.96	$ 4.04	$ 4.12	
Income		Escalator											
MG Sales - Landfill Gas Production		2.0%	$566,002	$576,682	$588,182	$601,326	$612,827	$624,328	$637,471	$650,615	$663,759	$676,903	$6,198,095
Total Revenues			566,002	576,682	588,182	601,326	612,827	624,328	637,471	650,615	663,759	676,903	6,198,095
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	40,000	40,800	41,616	42,448	43,297	44,163	45,046	45,947	46,866	47,804	437,989
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			40,000	40,800	41,616	42,448	43,297	44,163	45,046	45,947	46,866	47,804	437,989
Gross Profit			526,002	535,882	546,566	558,878	569,530	580,164	592,425	604,668	616,893	629,099	5,760,107
Expenses - Pipeline													
O&M - Wellfield/Comp/Pipeline - per year		2.0%	175,000	178,500	182,070	185,711	189,426	193,214	197,078	201,020	205,040	209,141	1,916,201
Property Insur. - (% of value)	1.00%	2.0%	24,921	25,420	25,928	26,447	26,976	27,515	28,065	28,627	29,199	29,783	272,881
General Liability Insur. (% of revenue)	1.00%	2.0%	5,660	5,882	6,119	6,381	6,633	6,893	7,179	7,474	7,777	8,090	68,089
Administration		2.0%	25,000	25,500	26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	273,743
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			230,581	235,302	240,128	245,070	250,095	255,224	260,477	265,837	271,308	276,891	2,530,914
Net Operating Profit			295,421	300,580	306,439	313,808	319,434	324,940	331,948	338,830	345,584	352,208	3,229,192
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			277,070	277,070	277,070	277,070	277,070	277,070	277,070	184,213	184,213	184,213	2,492,131
Net Profit Before Tax			18,351	23,509	29,369	36,738	42,364	47,870	54,878	154,617	161,371	167,994	737,061
			3.2%	4.1%	5.0%	6.1%	6.9%	7.7%	8.6%	23.8%	24.3%	24.8%	11.9%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		39,874	35,441	31,008	26,575	22,142	17,708	13,275	8,842	5,895	2,947	203,708
Gross Revenue Rate	1.25%		7,075	7,209	7,352	7,517	7,660	7,804	7,968	8,133	8,297	8,461	77,476
Total Taxes			46,949	42,649	38,360	34,091	29,802	25,513	21,244	16,975	14,192	11,409	281,184
Net Income			(28,598)	(19,140)	(8,992)	2,647	12,562	22,357	33,634	137,642	147,179	156,586	455,878
			-5.1%	-3.3%	-1.5%	0.4%	2.0%	3.6%	5.3%	21.2%	22.2%	23.1%	7.4%

Anchorage Medium BTU Gas Project

Gas Sales to National Guard Armory **Annual Proforma**

Methane Gas Price (MG) = $ 3.45

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(2,492,131)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		277,070	277,070	277,070	277,070	277,070	277,070	277,070	184,213	184,213	184,213	2,492,131
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(2,492,131)	248,472	257,930	268,079	279,717	289,632	299,428	310,704	321,855	331,393	340,799	2,948,009
Cumulative After Tax Cash @	(2,492,131)	(2,243,659)	(1,985,729)	(1,717,650)	(1,437,933)	(1,148,301)	(848,874)	(538,169)	(216,314)	115,079	**455,878**	
Net Present Value (NPV)	**2.000%**										**$137,924**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(2,492,131)											(2,492,131)
Construction Interest												-
Bond	-											-
Cash Flow		248,472	257,930	268,079	279,717	289,632	299,428	310,704	321,855	331,393	340,799	2,948,009
												-
After Tax Cash Flow - Year	(2,492,131)	248,472	257,930	268,079	279,717	289,632	299,428	310,704	321,855	331,393	340,799	455,878
After Tax Cash Flow - Cum.	(2,492,131)	(2,243,659)	(1,985,729)	(1,717,650)	(1,437,933)	(1,148,301)	(848,874)	(538,169)	(216,314)	115,079	455,878	

Project IRR - on Cash Investment		**3.01%**	
NPV - After tax - Discount @	**2.00%**	**$137,924**	
	2.50%	**$67,757**	
	2.75%	**$33,940**	
Discount = to IRR	**3.00%**	**$937**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**11.45%**	**3.24%**
After Tax	**6.79%**	**-5.05%**

Anchorage Medium BTU Gas Project
Gas Sales to National Guard Armory
Capital Estimate Detail

April 12, 2004

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Description		Sub-Total	Total
Gas Collection System / Compressor Facility			
Wellfield based on $12,000 per acre asuming 73 acres	$876,000		
Compressor	$650,000		
Contingency	$0	Included in above	
		$1,526,000	
Pipeline and Related Costs			
Blower Upgrade	$0	Included in GCCS	
Pipeline 2.734 miles @ $60 per foot	$866,131		
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate	
Air Compressor	$0	Included in Pipeline estimate	
Surveying	$0	Included in Pipeline estimate	
Geotechnical	$0	Included in Pipeline estimate	
Planning/Coordination/Legal	$0	Included in Pipeline estimate	
Construction Interest	$0	None assumed	
Right of Way Payment	$0	None assumed	
Wetlands Investigation	$0	Included in Pipeline estimate	
End User Upgrades	$100,000	Allowance	
Contingency - 10%	$0	Included in above	
		$966,131	
Project Total			**$2,492,131**

Anchorage Medium BTU Gas Project
Gas Sales to National Guard Armory

Depreciation & Amortization Schedules
April 12, 2004
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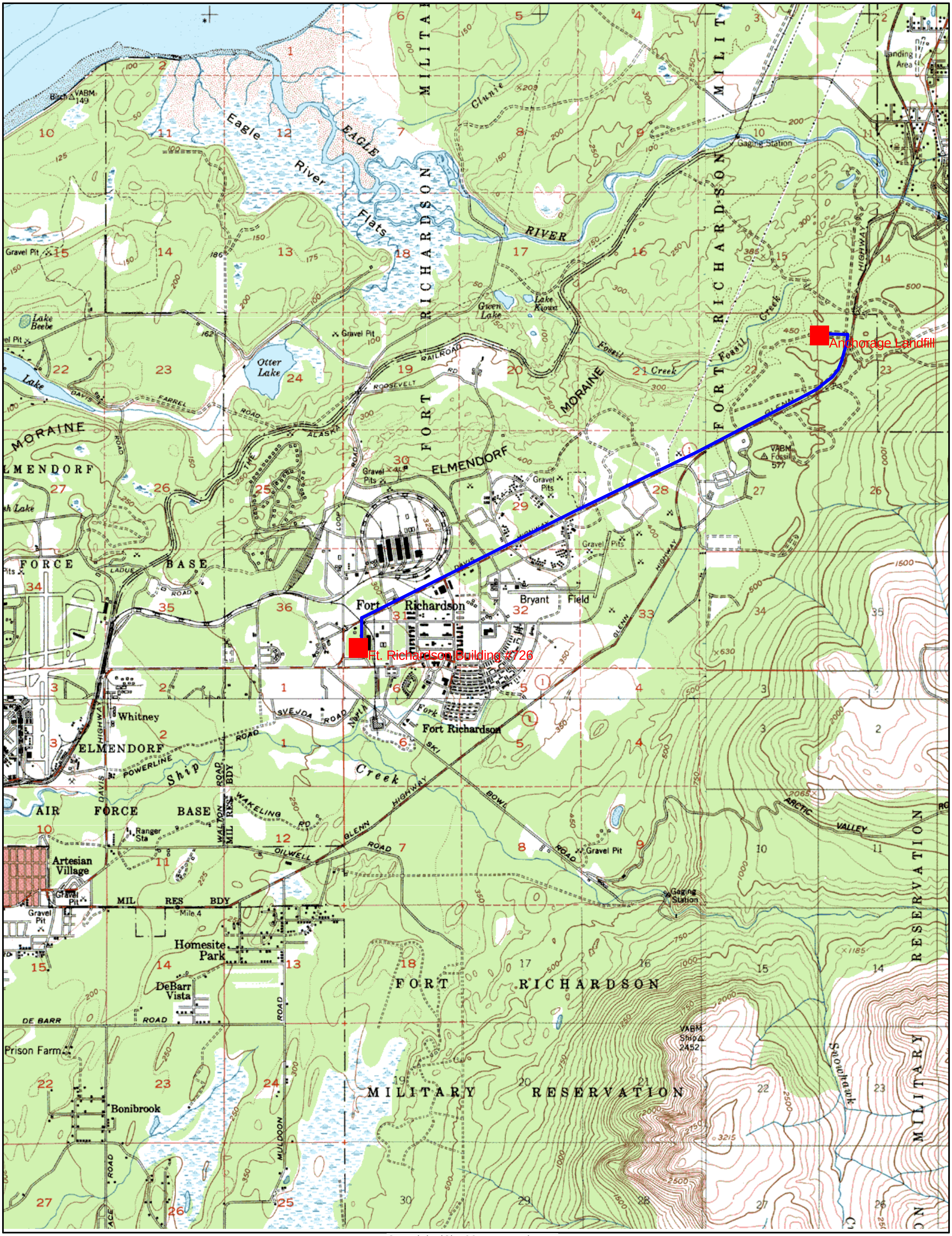
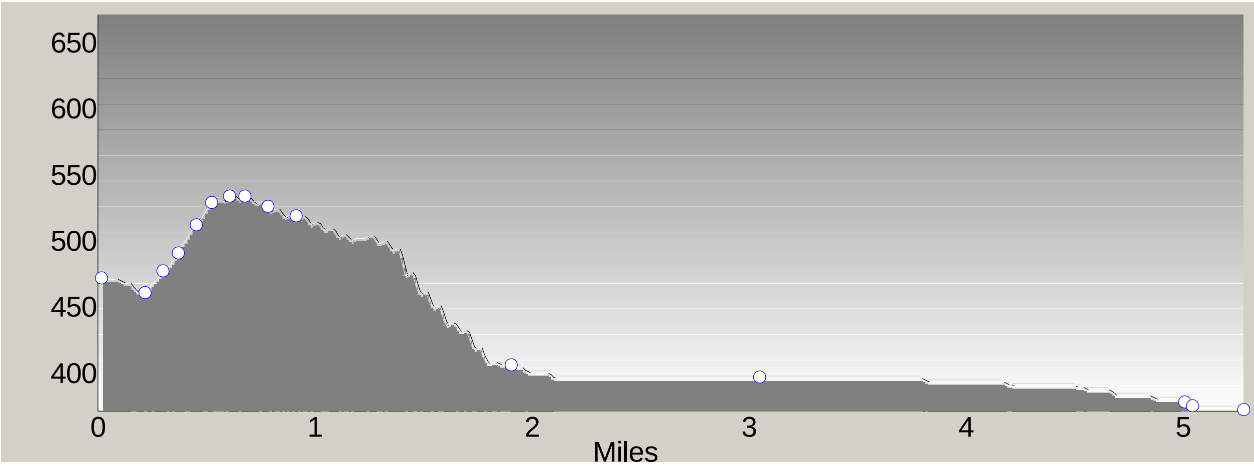
Depreciation Amounts		Amount
Gas Treatment and Processing System		1,526,000
Pipeline and Related Costs		966,131
Construction Interest		-
	Sub-Total	**2,492,131**

	Year	Depreciation
1	2006	$277,070
2	2007	$277,070
3	2008	$277,070
4	2009	$277,070
5	2010	$277,070
6	2011	$277,070
7	2012	$277,070
8	2013	$184,213
9	2014	$184,213
10	2015	$184,213
		$2,492,131

APPENDIX 11

TOPOGRAPHIC MAP FOR OPTION 5
(FT. RICHARDSON)


Anchorage Landfill
Ft. Richardson Building #726
Eagle River Flats
EAGLE RIVER
Otter Lake
Gwen Lake
Lake Kiowa
Lake Beebe
Fossil Creek
MORAINE
ELMENDORF AIR FORCE BASE
FORT RICHARDSON MILITARY RESERVATION
Fort Richardson
Bryant Field
Ship Creek
North Fork
GLENN HIGHWAY
Whitney
Artesian Village
Homesite Park
DeBarr Vista
Prison Farm
Bonibrook
ARCTIC VALLEY
Gaging Station
Landing Area
Gravel Pit
VABM Ship 2452



Total distance:	5 miles, 1446 feet	Climbing:	108 feet	Latitude:	061° 16' 10.1" N
		Descending:	-208 feet	Longitude:	149° 40' 20.4" W
Ground distance:	5 miles, 1454 feet	Elevation change:	-100 feet	Elevation:	396 feet
		Min/Max:	371/534	Grade:	0%

APPENDIX 12

LIST OF NATURAL GAS BURNING EQUIPMENT AT FT. RICHARDSON

BLDG	Boiler MFG	Startup Date	Model	Serial No	Heat Type	Burner MFG	Model	Serial No	MBH Max Input
726	Cleaver Brooks	5/15/2003	CBI700-200LE	L-101427	Steam	Cleaver Brooks	CBI700-200LE	L-101427	8,165
726	Cleaver Brooks	5/15/2003	CBI700-200LE	L-101428	Steam	Cleaver Brooks	CBI700-200LE	L-101428	8,165
726	Cleaver Brooks	5/15/2003	CBI700-200LE	L-101429	Steam	Cleaver Brooks	CBI700-200LE	L-101429	8,165
726	Cleaver Brooks	5/15/2003	CBI700-200LE	L-101430	Steam	Cleaver Brooks	CBI700-200LE	L-101430	8,165
								MBH	32,660
								MMBtu/hr	33

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
27000	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	790	0.79
27004	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
27004	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
27004	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
28008	1988	Not Avail	Not Avail	Gas	Not Avail	Not Avail	4000	4.00
28008	1988	Not Avail	Not Avail	Gas	Not Avail	Not Avail	4000	4.00
45100	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	250	0.25
45125	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	430	0.43
45580	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	3230	3.23
45594	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	540	0.54
45726	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	2170	2.17
45727	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
45730	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	250	0.25
47645	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	100	0.10
47811	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	140	0.14
47812	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	100	0.10
47813	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	100	0.10
48010	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	350	0.35
55804	1988	Not Avail	Not Avail	Gas	Not Avail	Not Avail	790	0.79
59000	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	390	0.39
59002	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	230	0.23
8	9/7/2003	Burnham	IN6	Hydronic	KIN6LNC-LE2	NA	175	0.18
53	9/3/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146944	606	0.61
54	9/3/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146954	606	0.61
55	7/16/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147129	606	0.61
57	7/23/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146949	606	0.61
58	7/23/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146945	606	0.61
201	5/7/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147143	606	0.61
202	5/7/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147139	606	0.61
203	5/1/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
204	5/5/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
206	5/5/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
207	5/5/2003	Burnham	IN11	Hydronic	KIN11LNI-LL2	NA	349	0.35
208	5/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
209	5/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
210	5/5/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
221	9/3/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
222	5/12/2003	Burnham	IN11	Hydronic	KIN11LNI-LL2	NA	349	0.35
223	5/8/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
224	5/12/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
225	5/8/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
227	5/8/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
228	5/8/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
230	5/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
231	5/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
241	5/12/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
243	11/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
244	5/13/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
245	5/16/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
247	5/14/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
249	5/14/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
250	5/16/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
252	5/12/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
261	5/19/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
262	5/19/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
264	5/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
265	5/14/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
266	5/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
268	5/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
269	5/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
270	5/14/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
272	5/19/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
273	5/19/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
281	5/20/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
282	5/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
284	5/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
285	5/20/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
287	7/31/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
288	5/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
289	7/31/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
290	5/22/2003	Burnham	IN11	Hydronic	KIN11LNI-LL2	NA	349	0.35
291	7/31/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
292	5/20/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
293	7/9/2003	Burnham	IN5	Hydronic	KIN5LNS-LE2	NA	140	0.14
300	5/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
301	5/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
302	5/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
303	5/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
304	5/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
305	5/20/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
306	5/27/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
310	5/27/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
311	5/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
312	5/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
313	5/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
314	5/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
315	5/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
320	6/4/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
321	6/4/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
322	6/9/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
323	6/3/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
324	6/5/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
325	6/5/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
326	6/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
331	6/5/2003	Burnham	IN6	Hydronic	KIN6LNC-LE2	NA	175	0.18
332	6/3/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
333	5/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
334	6/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
335	6/6/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
340	8/4/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147115	606	0.61
341	8/5/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147132	606	0.61
342	6/9/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147118	606	0.61

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
343	6/9/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147136	606	0.61
344	6/10/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147140	606	0.61
346	6/10/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147128	606	0.61
348	8/4/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147126	606	0.61
349	6/10/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147144	606	0.61
350	6/11/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147138	606	0.61
351	8/5/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147137	606	0.61
352	8/4/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147120	606	0.61
353	6/17/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147131	606	0.61
355	6/11/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147141	606	0.61
356	6/11/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147117	606	0.61
358	6/12/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146946	606	0.61
360	8/4/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147134	606	0.61
361	6/13/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147130	606	0.61
362	6/13/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147122	606	0.61
363	6/16/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147123	606	0.61
364	6/16/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147142	606	0.61
366	6/18/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147145	606	0.61
367	6/18/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147125	606	0.61
369	6/20/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147112	606	0.61
371	6/26/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147113	606	0.61
372	6/17/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147121	606	0.61
373	6/20/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147114	606	0.61
380	6/20/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147127	606	0.61
381	6/19/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147119	606	0.61
382	7/31/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147088	668	0.67
383	7/29/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147085	668	0.67
384	7/23/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146947	606	0.61
385	7/28/2003	Burnham	V905A	Hydronic	BCJR30A-12	80147083	668	0.67
386	7/18/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147087	668	0.67
387	7/17/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147133	606	0.61
388	7/16/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147086	668	0.67
389	7/14/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147089	668	0.67
390	7/7/2003	Burnham	V904A	Hydronic	BCJR30A-10	090147124	606	0.61
391	7/8/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147080	668	0.67
392	8/4/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147084	668	0.67
393	7/2/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147082	668	0.67
394	7/3/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147081	668	0.67
403	4/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
404	4/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
405	4/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
406	4/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
408	4/22/2003	Burnham	IN11	Hydronic	KIN11LNI-LL2	NA	349	0.35
409	4/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
410	4/24/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
411	4/24/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
413	4/23/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
414	4/23/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
415	4/24/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
416	4/23/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
417	4/23/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
418	4/22/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
421	4/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
422	4/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
423	4/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
424	4/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
425	4/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
426	4/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
427	4/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
428	4/25/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
429	4/25/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
430	4/25/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
431	4/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
432	4/25/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
433	7/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
434	7/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
435	7/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
436	4/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
437	7/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
438	7/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
439	4/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
440	7/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
441	7/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
442	7/31/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
443	7/31/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
455	4/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
456	4/30/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
457	5/1/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
458	5/1/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
501	4/14/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
503	4/14/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
504	4/16/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
505	4/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
506	4/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
508	4/16/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
509	4/15/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
510	4/17/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
511	4/17/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
514	4/18/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
515	4/17/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
516	4/16/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
517	4/16/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
520	4/21/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
521	7/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
522	7/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
523	7/28/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
524	6/23/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
529	5/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
530	5/29/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
531	6/4/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
533	6/4/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
537	4/18/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
538	4/18/2003	Burnham	IN10	Hydronic	KIN10LNI-LL2	NA	315	0.32
604	9/9/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147110	668	0.67
618	7/16/2003	Burnham	IN11	Hydronic	BCJR30A-10	N/A	606	0.61
656	6/24/2003	Burnham	V903A	Hydronic	BCJR30A-10	090147090	447	0.45
672	7/29/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146956	606	0.61
730	7/30/2003	Burnham	V905A	Hydronic	BCJR30A-12	120253415	668	0.67
794	6/1/2003	Burnham	V905A	Hydronic	BCJR30A-12	80147111	668	0.67
976	5/28/2003	Burnham	V1111	Hydronic	BCCR3-G-21	090100872	2,656	2.66
977	5/15/2003	Burnham	V1109	Hydronic	BCC2-G-15	080100647	2,136	2.14
1107	9/4/2003	Burnham	V905A	Hydronic	BCJR30A-12	080147147	668	0.67
1114	9/4/2003	Burnham	V904A	Hydronic	BCJR30A-10	080146952	606	0.61
M108	8/7/2003	Burnham	V1112	Hydronic	BCCR3-G-20	120206855	2,887	2.89
M108	8/7/2003	Burnham	V1112	Hydronic	BCCR3-G-20	120206856	2,887	2.89
M124	7/15/2003	Burnham	V1115	Hydronic	BCCR3-G-20	120206852	3,680	3.68
M124	7/15/2003	Burnham	V1115	Hydronic	BCCR3-G-20	120206853	3,680	3.68
M143	7/18/2003	Burnham	V1113	Hydronic	BCCR3-G-20	120206857	3,103	3.10
M143	7/18/2003	Burnham	V1113	Hydronic	BCCR3-G-20	120206858	3,103	3.10
47433	?	NA	NA	Infared	CRV B-10	NA	100	0.10
47433	?	NA	NA	Infared	CRV B-10	NA	100	0.10
47433	?	NA	NA	Infared	CRV B-10	NA	100	0.10
47433	?	NA	NA	Infared	CRV B-10	NA	100	0.10
1	9/7/2003	Burnham	V1112	Steam	BCCR3-G-25B	010307155	2,887	2.89
1	9/1/2003	Burnham	V1112	Steam	BCCR3-G-20	0101307156	2,887	2.89
2	8/14/2003	Burnham	V1113	Steam	BCCR3-G-20	090100881	3,103	3.10
3	9/6/2003	Burnham	V1106	Steam	BCJR50A-15	080147156	1,328	1.33
5	8/12/2003	Burnham	V1107	Steam	BCJR50A-15	080147069	1,586	1.59
5	8/12/2003	Burnham	V1107	Steam	BCJR50A-15	080147067	1,586	1.59
6	6/19/2003	Burnham	V1104	Steam	BCJR30A-10	080147102	836	0.84
9	8/12/2003	Burnham	V1110	Steam	BCCR2-G-20A	080100635	2,396	2.40
9	8/12/2003	Burnham	V1110	Steam	BCCR2-G-20A	080100636	2,396	2.40
56	9/12/2003	Burnham	V1112	Steam	BCCR3-G-20	090101367	2,887	2.89
297	7/21/2003	Burnham	V909A	Steam	BCJR50A-15	020354252	1,357	1.36
337	8/5/2003	Burnham	V911A	Steam	BCC2G-20B	020307764	1,323	1.32
337	8/5/2003	Burnham	V911A	Steam	BCC2G-20B	020307763	1,323	1.32
600	7/14/2003	Burnham	V1116	Steam	BCCR3-G-25	100100916	3,897	3.90
600	7/14/2003	Burnham	V1116	Steam	BCCR3-G-25	100100913	3,897	3.90
600	7/14/2003	Burnham	V1116	Steam	BCCR3-G-25	100100912	3,897	3.90
602	9/10/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100899	4,470	4.47
602	9/10/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100907	4,470	4.47
602	9/10/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100906	4,470	4.47
606	9/10/2003	Burnham	V904A	Steam	BCJR30A-10	080146948	606	0.61
620	6/30/2003	Burnham	V1115	Steam	BCCR3-G-20	090100890	3,680	3.68
620	6/30/2003	Burnham	V1115	Steam	BCCR3-G-20	090100892	3,680	3.68
622	7/2/2003	Burnham	V1115	Steam	BCCR3-G-20	090100896	3,680	3.68
622	7/7/2003	Burnham	V1115	Steam	BCCR3-G-20	090100895	3,680	3.68
624	7/7/2003	Burnham	V1115	Steam	BCCR3-G-20	120206900	3,680	3.68
624	7/7/2003	Burnham	V1115	Steam	BCCR3-G-20	120206893	3,680	3.68
626	7/8/2003	Burnham	V1115	Steam	BCCR3-G-20	120206897	3,680	3.68
626	7/8/2003	Burnham	V1115	Steam	BCCR3-G-20	120206894	3,680	3.68
628	9/3/2003	Burnham	V1115	Steam	BCCR3-G-20	120206892	3,680	3.68
628	9/3/2003	Burnham	V1115	Steam	BCCR3-G-20	120206890	3,680	3.68

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
630	9/3/2003	Burnham	V1115	Steam	BCCR3-G-20	120206896	3,680	3.68
630	9/3/2003	Burnham	V1115	Steam	BCCR3-G-20	120206901	3,680	3.68
632	9/4/2003	Burnham	V1115	Steam	BCCR3-G-20	090100891	3,680	3.68
632	9/4/2003	Burnham	V1115	Steam	BCCR3-G-20	090100894	3,680	3.68
634	6/11/2003	Burnham	V904A	Steam	BCJR30A-10	080147070	606	0.61
652	7/31/2003	Burnham	V1104	Steam	BCJR30A-10	080147101	836	0.84
654	6/17/2003	Burnham	V1107	Steam	BCJR50A-15	080147068	1,586	1.59
655	6/16/2003	Burnham	V1114	Steam	BCCR3-G-20	090100874	3,392	3.39
658	7/31/2003	Burnham	V1115	Steam	BCCR3-G-20	090100893	3,680	3.68
658	7/31/2003	Burnham	V1115	Steam	BCCR3-G-20	090100889	3,680	3.68
662	6/12/2003	Burnham	V1115	Steam	BCCR3-G-20	120206888	3,680	3.68
662	6/12/2003	Burnham	V1115	Steam	BCCR3-G-20	120206895	3,680	3.68
664	6/13/2003	Burnham	V1115	Steam	BCCR3-G-20	120206898	3,680	3.68
664	6/13/2003	Burnham	V1115	Steam	BCCR3-G-20	120206887	3,680	3.68
667	7/28/2003	Burnham	V1115	Steam	BCCR3-G-20	120206891	3,680	3.68
667	7/28/2003	Burnham	V1115	Steam	BCCR3-G-20	120206889	3,680	3.68
668	7/28/2003	Burnham	V1115	Steam	BCCR3-G-20	090100898	3,680	3.68
668	7/28/2003	Burnham	V1115	Steam	BCCR3-G-20	090100897	3,680	3.68
670	8/14/2003	Burnham	V1115	Steam	BCCR3-G-20	120206899	3,680	3.68
670	8/14/2003	Burnham	V1115	Steam	BCCR3-G-20	120206886	3,680	3.68
690	7/9/2003	Burnham	V1121	Steam	BCCR3-G-25B	100100910	5,268	5.27
690	7/9/2003	Burnham	V1121	Steam	BCCR3-G-25B	100100911	5,268	5.27
700	6/9/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100908	4,470	4.47
704	7/9/2003	Burnham	V1106	Steam	BCJR50A-15	080147157	1,328	1.33
710	7/15/2003	Burnham	IN10	Steam	KIN10LNI-LL2	64360390	315	0.32
724	6/11/2003	Burnham	V1113	Steam	BCCR3-G-20	090100880	3,103	3.10
724	6/11/2003	Burnham	V1113	Steam	BCCR3-G-20	090100875	3,103	3.10
733	4/27/2003	Burnham	V1106	Steam	BCJR50A-15	080147160	1,328	1.33
740	9/30/2003	Burnham	V1113	Steam	BCCR3-G-20	090100879	3,103	3.10
750	4/7/2003	Burnham	V1113	Steam	BCCR3-G-20	090100877	3,103	3.10
754	4/30/2003	Burnham	V1106	Steam	BCJR50A-15	080147159	1,328	1.33
755	7/3/2003	Burnham	V1104	Steam	BCJR30A-10	080147103	836	0.84
756	4/25/2003	Burnham	V1113	Steam	BCCR3-G-20	090100876	3,103	3.10
772	5/19/2003	Burnham	V1106	Steam	BCJR50A-15	120253416	1,328	1.33
778	4/29/2003	Burnham	V1113	Steam	BCCR3-G-20	090100878	3,103	3.10
784	4/28/2003	Burnham	V1113	Steam	BCCR3-G-20	090100883	3,103	3.10
789	5/1/2003	Burnham	V1106	Steam	BCJR50A-15	080147158	1,328	1.33
796	7/31/2003	Burnham	V1112	Steam	BCCR3-G-20	090101368	2,887	2.89
796	7/31/2003	Burnham	V1112	Steam	BCCR3-G-20	090101370	2,887	2.89
798	5/7/2003	Burnham	V1115	Steam	BCCR3-G-20	090100888	3,680	3.68
800	8/20/2003	Burnham	V1116	Steam	BCCR3-G-25	100100915	3,897	3.90
800	8/20/2003	Burnham	V1116	Steam	BCCR3-G-25	100100914	3,897	3.90
802	5/20/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100902	4,470	4.47
802	5/20/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100900	4,470	4.47
804	8/20/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100905	4,470	4.47
804	8/20/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100904	4,470	4.47
806	8/25/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100901	4,470	4.47
806	8/25/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100909	4,470	4.47
812	5/19/2003	Burnham	V1106	Steam	BCJR50A-15	080147155	1,328	1.33
974	8/26/2003	Burnham	V1118	Steam	BCCR3-G-25B	100100903	4,470	4.47
975	5/12/2003	Burnham	V1113	Steam	BCCR3-G-20	090100882	3,103	3.10

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
984	5/7/2003	Burnham	V1104	Steam	BCJR30A-12	080147146	1,068	1.07
986	5/8/2003	Burnham	V905A	Steam	BCJR30A-12	080147148	668	0.67
1101	7/16/2003	Burnham	V904A	Steam	BCJR30A-10	080146957	606	0.61
1102	9/11/2003	Burnham	V904A	Steam	BCJR30A-10	090147116	606	0.61
1106	9/9/2003	Burnham	V904A	Steam	BCJR30A-10	080146950	606	0.61
1108	9/11/2003	Burnham	V904A	Steam	BCJR30A-10	090147135	606	0.61
1113	9/12/2003	Burnham	V904A	Steam	BCJR30A-10	080146955	606	0.61
47430	5/20/2003	Burnham	V1111	Steam	BCCR3-G-20	9100893	2,656	2.66
47431	6/9/2003	Burnham	V1107	Steam	BCJR50A-15	N/A	1,586	1.59
47436	5/21/2003	Burnham	V904A	Steam	BCJR30A-10	080146951	606	0.61
							380,961 MBH	**380.96 MMBtu/hr**

BLDG	Boiler Start Date	Boiler MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
36012	1952	Eric City Water Tube Boilers	NA	Gas	NA	NA		187
36012	1952	Eric City Water Tube Boilers	NA	Gas	NA	NA		187
36012	1952	Eric City Water Tube Boilers	NA	Gas	NA	NA		187
36012	1952	Eric City Water Tube Boilers	NA	Gas	NA	NA		187
								748.00 MMBtu/hr

BLDG	Hot Water Heater Start Date	Hot Water Heater MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
T2	7/9/2003	NA	NA	Air	43536	200211-AKGH43018	351	0.35
53	9/3/2003	Bock	241PGES	Gas	NA	NA	200	0.20
53	9/3/2003	Bock	241PGES	Gas	NA	NA	200	0.20
54	9/3/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067118	200	0.20
54	9/3/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117314	200	0.20
55	7/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117328	200	0.20
55	7/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117324	200	0.20
57	7/23/2003	Bock	241PGES	Gas	NA	NA	200	0.20
57	7/23/2003	Bock	241PGES	Gas	NA	NA	200	0.20
58	7/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117327	200	0.20
58	7/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117305	200	0.20
201	5/7/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117330	200	0.20
202	5/7/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117331	200	0.20
203	5/1/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067085	200	0.20
204	5/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067105	200	0.20
206	5/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067082	200	0.20
207	5/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117338	200	0.20
208	5/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067104	200	0.20
209	5/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067083	200	0.20
210	5/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067099	200	0.20
221	9/3/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067107	200	0.20
222	5/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067116	200	0.20
223	5/8/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067114	200	0.20
224	5/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067111	200	0.20
225	5/8/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067108	200	0.20
227	5/8/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067109	200	0.20
228	5/8/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067110	200	0.20
230	5/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067117	200	0.20
231	5/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067115	200	0.20
241	5/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067074	200	0.20
243	11/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067095	200	0.20
244	5/13/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067103	200	0.20
245	5/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067098	200	0.20
247	5/14/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067080	200	0.20
249	5/14/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067081	200	0.20
250	5/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067079	200	0.20
252	5/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067075	200	0.20
261	5/19/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117372	200	0.20
262	5/19/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067087	200	0.20
264	5/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067078	200	0.20
265	5/14/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067096	200	0.20
266	5/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067106	200	0.20
268	5/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067113	200	0.20
269	5/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067076	200	0.20
270	5/14/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067097	200	0.20
272	5/19/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067089	200	0.20
273	5/19/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117375	200	0.20
281	5/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117371	200	0.20
282	5/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117381	200	0.20
284	5/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067088	200	0.20

BLDG	Hot Water Heater Start Date	Hot Water Heater MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
285	5/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067086	200	0.20
287	7/31/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067062	200	0.20
288	5/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067093	200	0.20
289	7/31/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067064	200	0.20
290	5/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067119	200	0.20
291	7/31/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067091	200	0.20
292	5/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067070	200	0.20
300	5/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067066	200	0.20
301	5/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067067	200	0.20
302	5/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067068	200	0.20
303	5/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067092	200	0.20
304	5/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067090	200	0.20
305	5/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067060	200	0.20
306	5/27/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067063	200	0.20
310	5/27/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067069	200	0.20
311	5/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067073	200	0.20
312	5/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067077	200	0.20
313	5/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067065	200	0.20
314	5/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067072	200	0.20
315	5/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067061	200	0.20
320	6/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117307	200	0.20
321	6/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067071	200	0.20
322	6/9/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117306	200	0.20
323	6/3/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117303	200	0.20
324	6/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117298	200	0.20
325	6/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067059	200	0.20
326	6/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117302	200	0.20
331	6/5/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755937	200	0.20
332	6/3/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117296	200	0.20
333	5/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117301	200	0.20
334	6/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117300	200	0.20
335	6/6/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067057	200	0.20
340	8/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117337	200	0.20
341	8/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117344	200	0.20
342	6/9/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067034	200	0.20
343	6/9/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117356	200	0.20
344	6/10/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117322	200	0.20
346	6/10/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117310	200	0.20
348	8/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117317	200	0.20
349	6/10/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117311	200	0.20
350	6/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117336	200	0.20
351	8/5/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117297	200	0.20
352	8/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117299	200	0.20
353	6/17/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117329	200	0.20
355	6/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117318	200	0.20
356	6/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117312	200	0.20
358	6/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117309	200	0.20
360	8/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117304	200	0.20
361	6/13/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117333	200	0.20
362	6/13/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117335	200	0.20

BLDG	Hot Water Heater Start Date	Hot Water Heater MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
363	6/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117346	200	0.20
364	6/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117334	200	0.20
366	6/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117308	200	0.20
367	6/18/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117319	200	0.20
369	6/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117316	200	0.20
371	6/26/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117320	200	0.20
372	6/17/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117321	200	0.20
373	6/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117357	200	0.20
380	6/20/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117354	200	0.20
381	6/19/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117112	200	0.20
382	7/31/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067038	200	0.20
383	7/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067124	200	0.20
384	7/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117313	200	0.20
385	7/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117315	200	0.20
386	7/18/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755940	200	0.20
387	7/17/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755941	200	0.20
388	7/16/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755934	200	0.20
389	7/14/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755936	200	0.20
390	7/7/2003	Lochinvar	RWN199PM	Gas	RJS080	ZA2585388	200	0.20
391	7/8/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755944	200	0.20
392	8/4/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117339	200	0.20
393	7/2/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755935	200	0.20
394	7/3/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755942	200	0.20
403	4/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117373	200	0.20
404	4/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117380	200	0.20
405	4/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117374	200	0.20
406	4/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117376	200	0.20
408	4/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067029	200	0.20
409	4/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117377	200	0.20
410	4/24/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117366	200	0.20
411	4/24/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117362	200	0.20
413	4/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117385	200	0.20
414	4/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117367	200	0.20
415	4/24/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117389	200	0.20
416	4/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067084	200	0.20
417	4/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117384	200	0.20
418	4/22/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117370	200	0.20
421	4/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117378	200	0.20
422	4/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067031	200	0.20
423	4/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067047	200	0.20
424	4/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117394	200	0.20
425	4/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067048	200	0.20
426	4/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ00670451	200	0.20
427	4/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117369	200	0.20
428	4/25/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067053	200	0.20
429	4/25/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117364	200	0.20
430	4/25/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117361	200	0.20
431	4/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117388	200	0.20
432	4/25/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117393	200	0.20
433	7/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117363	200	0.20

BLDG	Hot Water Heater Start Date	Hot Water Heater MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
434	7/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117368	200	0.20
435	7/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067056	200	0.20
436	4/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067058	200	0.20
437	7/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067055	200	0.20
438	7/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067052	200	0.20
439	4/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117395	200	0.20
440	7/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067049	200	0.20
441	7/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067054	200	0.20
442	7/31/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117379	200	0.20
443	7/31/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117360	200	0.20
455	4/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067046	200	0.20
456	4/30/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117383	200	0.20
457	5/1/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117382	200	0.20
458	5/1/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117392	200	0.20
501	4/14/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117387	200	0.20
503	4/14/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067050	200	0.20
504	4/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117386	200	0.20
505	4/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067045	200	0.20
506	4/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067039	200	0.20
508	4/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117390	200	0.20
509	4/15/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067041	200	0.20
510	4/17/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117391	200	0.20
511	4/17/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067102	200	0.20
514	4/18/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067032	200	0.20
515	4/17/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067100	200	0.20
516	4/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067033	200	0.20
517	4/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067037	200	0.20
520	4/21/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117359	200	0.20
521	7/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117358	200	0.20
522	7/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067042	200	0.20
523	7/28/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067101	200	0.20
524	6/23/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067094	200	0.20
529	5/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067123	200	0.20
530	5/29/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067120	200	0.20
531	6/4/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755938	200	0.20
533	6/4/2003	Lochinvar	RWN199PM	Gas	RJS080	ZB2755933	200	0.20
537	4/18/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067028	200	0.20
538	4/18/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117365	200	0.20
706	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	140	0.14
721	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	100	0.10
721	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	300	0.30
722	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	100	0.10
723	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	120	0.12
732	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	930	0.93
755	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	600	0.60
809	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
809	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
809	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
809	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	150	0.15
974	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	4320	4.32

BLDG	Hot Water Heater Start Date	Hot Water Heater MFG	Model	Heat Type	Burner Model	Burner Make	MBH Max Input	MMBtu Max Input
974	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	4320	4.32
992	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	300	0.30
1101	7/16/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117326	200	0.20
1101	7/16/2003	Lochinvar	RWN199PM	Gas	RJS081	XJ0067036	200	0.20
1102	9/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117323	200	0.20
1102	9/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067044	200	0.20
1104	Unknown	Not Avail	Not Avail	Gas	Not Avail	Not Avail	300	0.30
1106	9/9/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117332	200	0.20
1106	9/9/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117325	200	0.20
1107	9/4/2003	Bock	241PGES	Gas	NA	NA	200	0.20
1107	9/4/2003	Bock	241PGES	Gas	NA	NA	200	0.20
1108	9/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117345	200	0.20
1108	9/11/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0117352	200	0.20
1113	9/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067026	200	0.20
1113	9/12/2003	Lochinvar	RWN199PM	Gas	RJS080	XJ0067026	200	0.20
1114	9/4/2003	Bock	241PGES	Gas	NA	NA	200	0.20
1114	9/4/2003	Bock	241PGES	Gas	NA	NA	200	0.20
							52,681 MBH	**53 MMBtu/hr**

APPENDIX 13

FINANCIAL PRO FORMA FOR OPTION 5
(FT. RICHARDSON)

Anchorage Medium BTU Gas Project

Gas Sales to Ft. Richardson Building #726

Assumes Ft. Richardson will use all gas available

Project Proforma

April 5, 2004

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Summary of Assumptions & Financials

Assumptions

MG Price	$2.721	
MG Price Escalation	2.0%	
Capital Cost	$ 3,256,063	
Loan Amount	$0	
Gas Cost	$0.0000	
Gas Cost Escalation	2.0%	
Gas Quantity	826	SCFM

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 3,927,864
Investment		$ 3,256,063
Net Cash Flow		$ 671,801
Project IRR		3.0%
NPV at rate =	2.000%	$ 200,794
NPV at rate =	2.500%	$ 97,378
NPV at rate =	2.750%	$ 47,612
NPV at rate =	3.000%	$ (906)
Pre Tax Profits		$ 1,041,000
Average %		10.1%
Minimum %		-19.2%
Net Income		$ 671,801
Average %		4.9%
Minimum %		-29.6%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mil:	16	$ 270,934
Gross Revenue contribution % of Revenu	1.25%	$ 98,265
		$ 369,199

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Gas Sales to Ft. Richardson Building #726
ASSUMPTIONS to PRO FORMA

April 5, 2004

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Description		Value	Unit
Financial Information			
Project Capital Costs		$3,256,063	
Equity Contribution	100.00%	$3,256,063	
Loan	0.00%		
Principal		$0	
Term		10	years
Interest Rate		0.0%	
Interest Payments monthly during construction			
Loan Fees		0.0%	
MG Quantity 826 SCFM		208,631	mmBTU/Yr
50.00% Methane %			
On-Stream Factors			
Utilization %		95.0%	
MG Price		$2.721	
MG Price escalator		2.0%	
Cost of Sales			
Cost of Methane Gas		$0.0000	per mmBTU
Cost Escalator		2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh		$60,000	Annually
Electric Escalator		2.0%	
Operating Costs		Annually	
O&M Compressor/Pipeline	per year	$ 200,000	
O&M Escalator		3.0%	
Property Insurance		1.00%	% of Value
General Liability Insurance		1.00%	% of Revenue
Administration		$25,000	
Income Taxes Is project subject to income taxes		NO	
Federal Tax Rate		0%	
State Tax Rate		0.0%	Incl. In Federal

Questions		
	1 When do we anticipate project completion / start-up?	2006
	2 Verity Gas curve to use and recovery rate	Avg LFG at 75%
	3 Does gas curve assume 50 or 50+23 acres	73 acres
	4 Does the $15,000 include flare, blower and electrical	Includes all components of GCCS
	5 Tony had an estimate of $75/ft for pipeline. What does this include?	As per Jim use Kevin's $60
	6 No Federal Tax	

Anchorage Medium BTU Gas Project

Gas Sales to Ft. Richardson Building #726 — Annual Proforma

Methane Gas Price (MG) = $ 2.72

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate	75.0%		75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
School Gas Demand													
Average SCFM			-	-	-	-	-	-	-	-	-	-	0
Average MMBTU @ 50% Methane & 95% Utilization			-	-	-	-	-	-	-	-	-	-	-
		Escalator											
Assumed Methane Gas Price		2%	$ 2.72	$ 2.78	$ 2.83	$ 2.89	$ 2.95	$ 3.00	$ 3.06	$ 3.13	$ 3.19	$ 3.25	
Income		Escalator											
MG Sales - Landfill Gas Production		2.0%	$567,685	$616,343	$663,358	$713,018	$762,478	$808,941	$857,593	$909,237	$957,494	$1,005,066	$7,861,211
Total Revenues			567,685	616,343	663,358	713,018	762,478	808,941	857,593	909,237	957,494	1,005,066	7,861,211
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706	656,983
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706	656,983
Gross Profit			507,685	555,143	600,934	649,345	697,532	742,696	790,023	840,316	887,195	933,360	7,204,228
Expenses - Pipeline													
O&M - Wellfield/Comp/Pipeline - per year		2.0%	200,000	204,000	208,080	212,242	216,486	220,816	225,232	229,737	234,332	239,019	2,189,944
Property Insur. - (% of value)	1.00%	2.0%	32,561	33,212	33,876	34,554	35,245	35,950	36,669	37,402	38,150	38,913	356,530
General Liability Insur. (% of revenue)	1.00%	2.0%	5,677	6,287	6,902	7,567	8,253	8,931	9,658	10,444	11,219	12,011	86,949
Administration		2.0%	25,000	25,500	26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	273,743
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			263,237	268,999	274,868	280,892	287,045	293,299	299,713	306,300	312,992	319,820	2,907,166
Net Operating Profit			244,447	286,144	326,066	368,453	410,487	449,397	490,310	534,015	574,203	613,540	4,297,063
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			353,463	353,463	353,463	353,463	353,463	353,463	353,463	260,606	260,606	260,606	3,256,063
Net Profit Before Tax			(109,016)	(67,319)	(27,397)	14,990	57,023	95,934	136,846	273,409	313,597	352,934	1,041,000
			-19.2%	-10.9%	-4.1%	2.1%	7.5%	11.9%	16.0%	30.1%	32.8%	35.1%	13.2%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		52,097	46,442	40,786	35,131	29,475	23,820	18,165	12,509	8,339	4,170	270,934
Gross Revenue Rate	1.25%		7,096	7,704	8,292	8,913	9,531	10,112	10,720	11,365	11,969	12,563	98,265
Total Taxes			59,193	54,146	49,078	44,043	39,006	33,932	28,884	23,875	20,308	16,733	369,199
Net Income			(168,209)	(121,465)	(76,476)	(29,053)	18,017	62,002	107,962	249,534	293,289	336,201	671,801
			-29.6%	-19.7%	-11.5%	-4.1%	2.4%	7.7%	12.6%	27.4%	30.6%	33.5%	8.5%

Anchorage Medium BTU Gas Project

Gas Sales to Ft. Richardson Building #726 **Annual Proforma**

Methane Gas Price (MG) = $ 2.72

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(3,256,063)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		353,463	353,463	353,463	353,463	353,463	353,463	353,463	260,606	260,606	260,606	3,256,063
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(3,256,063)	185,254	231,998	276,988	324,410	371,480	415,465	461,425	510,141	553,895	596,807	3,927,864
Cumulative After Tax Cash @	(3,256,063)	(3,070,808)	(2,838,810)	(2,561,822)	(2,237,412)	(1,865,932)	(1,450,467)	(989,041)	(478,901)	74,994	**671,801**	
Net Present Value (NPV)	**2.000%**										**$200,794**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(3,256,063)											(3,256,063)
Construction Interest												-
Bond	-											-
Cash Flow		185,254	231,998	276,988	324,410	371,480	415,465	461,425	510,141	553,895	596,807	3,927,864
												-
After Tax Cash Flow - Year	(3,256,063)	185,254	231,998	276,988	324,410	371,480	415,465	461,425	510,141	553,895	596,807	671,801
After Tax Cash Flow - Cum.	(3,256,063)	(3,070,808)	(2,838,810)	(2,561,822)	(2,237,412)	(1,865,932)	(1,450,467)	(989,041)	(478,901)	74,994	671,801	

Project IRR - on Cash Investment		**3.00%**	
NPV - After tax - Discount @	**2.00%**	**$200,794**	
	2.50%	**$97,378**	
	2.75%	**$47,612**	
Discount = to IRR	**3.00%**	**($906)**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**10.11%**	**-19.20%**
After Tax	**4.92%**	**-29.63%**

Anchorage Medium BTU Gas Project
Gas Sales to Ft. Richardson Building #726
Capital Estimate Detail

April 5, 2004

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Description		Sub-Total	Total
Gas Collection System / Compressor Facility			
Wellfield based on $12,000 per acre asuming 73 acres	$876,000		
Compressor	$650,000		
Contingency	$0	Included in above	
		$1,526,000	
Pipeline and Related Costs			
Blower Upgrade	$0	Included in GCCS	
Pipeline 5.1454 miles (27,168 feet) @ $60 per foot	$1,630,063		
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate	
Air Compressor	$0	Included in Pipeline estimate	
Surveying	$0	Included in Pipeline estimate	
Geotechnical	$0	Included in Pipeline estimate	
Planning/Coordination/Legal	$0	Included in Pipeline estimate	
Construction Interest	$0	None assumed	
Right of Way Payment	$0	None assumed	
Wetlands Investigation	$0	Included in Pipeline estimate	
End User Upgrades	$100,000	Allowance	
Contingency - 10%	$0	Included in above	
		$1,730,063	
Project Total			**$3,256,063**

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Anchorage Medium BTU Gas Project

Gas Sales to Ft. Richardson Building #726

Depreciation & Amortization Schedules

April 5, 2004

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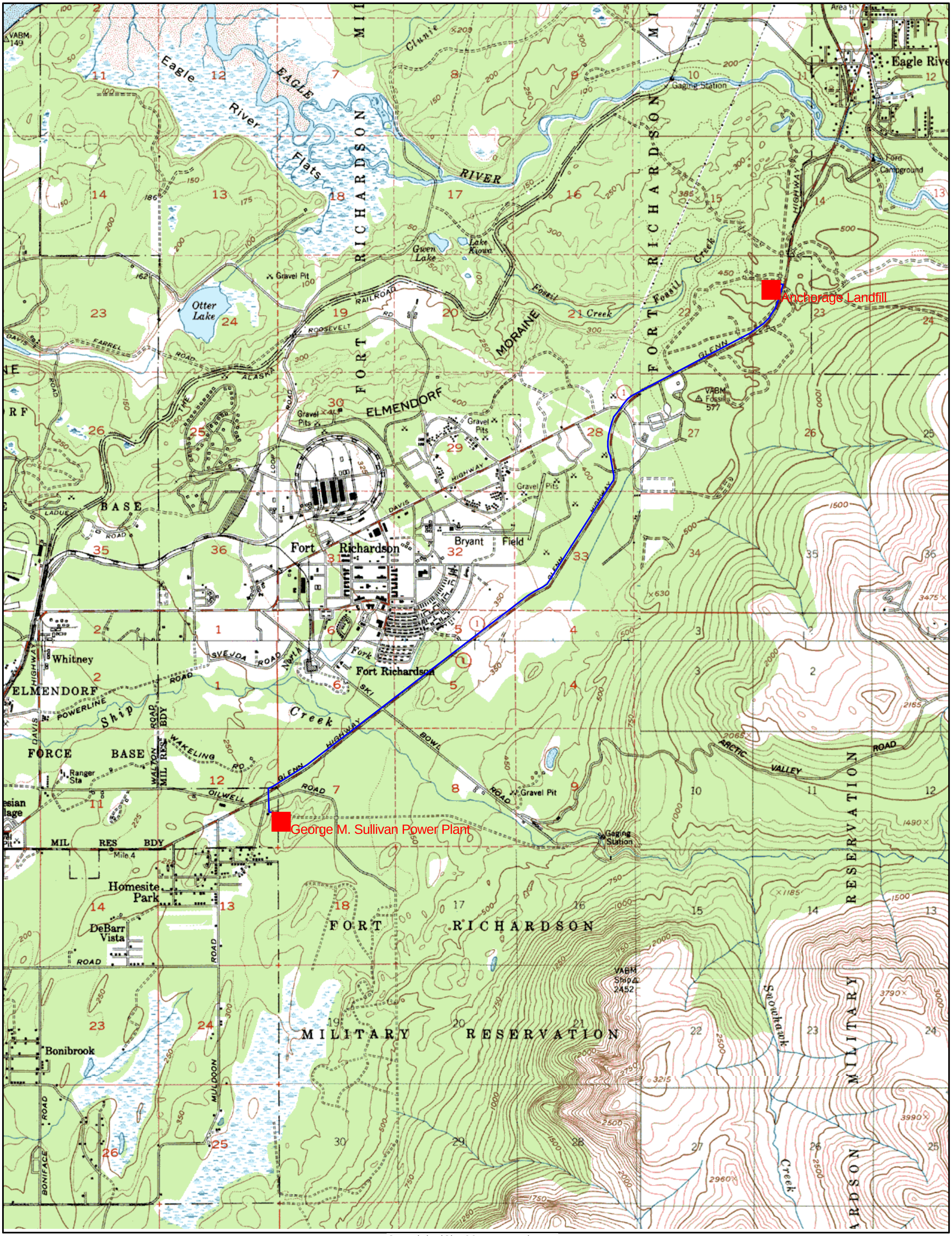
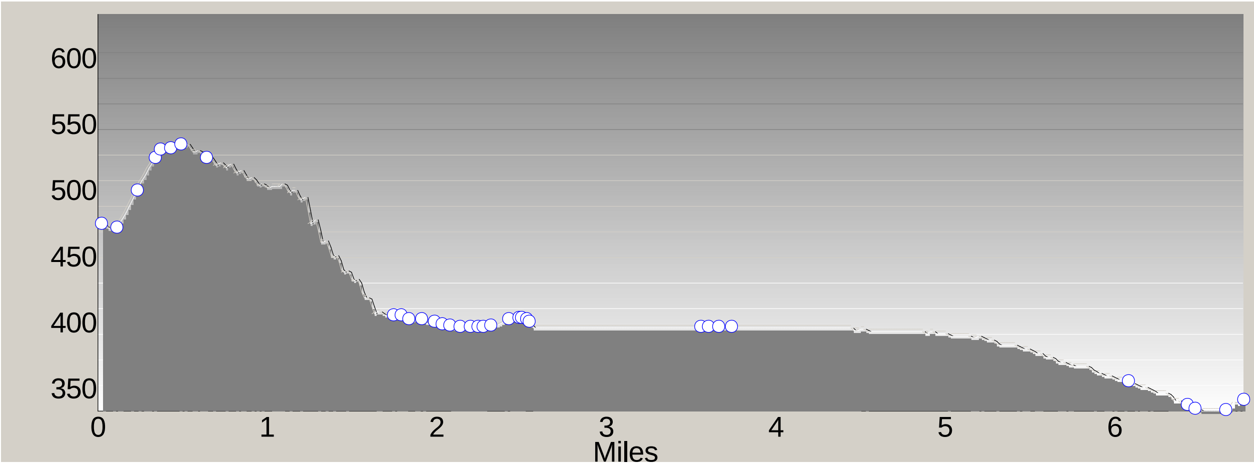
Depreciation Amounts		Amount
Gas Treatment and Processing System		1,526,000
Pipeline and Related Costs		1,730,063
Construction Interest		-
	Sub-Total	**3,256,063**

	Year	Depreciation
1	2006	$353,463
2	2007	$353,463
3	2008	$353,463
4	2009	$353,463
5	2010	$353,463
6	2011	$353,463
7	2012	$353,463
8	2013	$260,606
9	2014	$260,606
10	2015	$260,606
		$3,256,063

APPENDIX 14

TOPOGRAPHIC MAP FOR OPTION 6
(ML&P GEORGE M. SULLIVAN POWER PLANT)


Anchorage Landfill
George M. Sullivan Power Plant



Total distance:	6 miles, 3977 feet	Climbing:	115 feet	Latitude:	000° 00' 00.0" N
		Descending:	-247 feet	Longitude:	000° 00' 00.0" E
Ground distance:	6 miles, 3984 feet	Elevation change:	-132 feet	Elevation:	
		Min/Max:	333/535	Grade:	

APPENDIX 15

FINANCIAL PRO FORMA FOR OPTION 6
(ML&P GEORGE M. SULLIVAN POWER PLANT)

Anchorage Medium BTU Gas Project

Gas Sales to George M. Sullivan Power Plant

Assumes Power Plant will use all gas available

Project Proforma

April 5, 2004

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Summary of Assumptions & Financials

Assumptions

MG Price	$2.858	
MG Price Escalation	2.0%	
Capital Cost	$ 3,526,800	
Loan Amount	$0	
Gas Cost	$0.0000	
Gas Cost Escalation	2.0%	
Gas Quantity	826	SCFM

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 4,260,397
Investment		$ 3,526,800
Net Cash Flow		$ 733,597
Project IRR		3.0%
NPV at rate =	2.000%	$ 224,059
NPV at rate =	2.500%	$ 112,166
NPV at rate =	2.750%	$ 58,319
NPV at rate =	3.000%	$ 5,820
Pre Tax Profits		$ 1,131,562
Average %		10.6%
Minimum %		-18.5%
Net Income		$ 733,597
Average %		5.3%
Minimum %		-29.2%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mils	16	$ 294,758
Gross Revenue contribution % of Revenue	1.25%	$ 103,207
		$ 397,965

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Gas Sales to George M. Sullivan Power Plant
ASSUMPTIONS to PRO FORMA

April 5, 2004

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Description			Value	Unit
Financial Information				
Project Capital Costs			$3,526,800	
Equity Contribution		100.00%	$3,526,800	
Loan		0.00%		
Principal			$0	
Term			10	years
Interest Rate			0.0%	
Interest Payments monthly during construction				
Loan Fees			0.0%	
MG Quantity	826 SCFM		208,631	mmBTU/Yr
	50.00% Methane %			
On-Stream Factors				
Utilization %			95.0%	
MG Price			$2.858	
MG Price escalator			2.0%	
Cost of Sales				
Cost of Methane Gas			$0.0000	per mmBTU
Cost Escalator			2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh			$60,000	Annually
	Electric Escalator		2.0%	
Operating Costs			Annually	
O&M Compressor/Pipeline		per year	$ 200,000	
	O&M Escalator		3.0%	
Property Insurance			1.00%	% of Value
General Liability Insurance			1.00%	% of Revenue
Administration			$25,000	
Income Taxes	Is project subject to income taxes		NO	
	Federal Tax Rate		0%	
	State Tax Rate		0.0%	Incl. In Federal

Questions		
Questions	1 When do we anticipate project completion / start-up?	2006
	2 Verity Gas curve to use and recovery rate	Avg LFG at 75%
	3 Does gas curve assume 50 or 50+23 acres	73 acres
	4 Does the $15,000 include flare, blower and electrical	Includes all components of GCCS
	5 Tony had an estimate of $75/ft for pipeline. What does this include?	As per Jim use Kevin's $60
	6 No Federal Tax	

Anchorage Medium BTU Gas Project

Gas Sales to George M. Sullivan Power Plant **Annual Proforma**

Methane Gas Price (MG) = $ 2.86

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate		75.0%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
School Gas Demand													
Average SCFM			-	-	-	-	-	-	-	-	-	-	0
Average MMBTU @ 50% Methane & 95% Utilization			-	-	-	-	-	-	-	-	-	-	-
		Escalator											
Assumed Methane Gas Price		2%	$ 2.86	$ 2.92	$ 2.97	$ 3.03	$ 3.09	$ 3.16	$ 3.22	$ 3.28	$ 3.35	$ 3.42	
Income		Escalator											
MG Sales - Landfill Gas Production		2.0%	$596,267	$647,382	$696,174	$747,559	$798,663	$852,085	$902,434	$952,810	$1,005,519	$1,057,638	$8,256,531
Total Revenues			596,267	647,382	696,174	747,559	798,663	852,085	902,434	952,810	1,005,519	1,057,638	8,256,531
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706	656,983
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706	656,983
Gross Profit			536,267	586,182	633,750	683,886	733,717	785,840	834,864	883,889	935,220	985,933	7,599,548
Expenses - Pipeline													
O&M - Wellfield/Comp/Pipeline - per year		2.0%	200,000	204,000	208,080	212,242	216,486	220,816	225,232	229,737	234,332	239,019	2,189,944
Property Insur. - (% of value)	1.00%	2.0%	35,268	35,973	36,693	37,427	38,175	38,939	39,717	40,512	41,322	42,149	386,175
General Liability Insur. (% of revenue)	1.00%	2.0%	5,963	6,603	7,243	7,933	8,645	9,408	10,163	10,945	11,781	12,640	91,323
Administration		2.0%	25,000	25,500	26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	273,743
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			266,231	272,077	278,026	284,132	290,367	296,765	303,267	309,911	316,727	323,684	2,941,185
Net Operating Profit			270,037	314,105	355,724	399,754	443,350	489,075	531,597	573,978	618,493	662,249	4,658,362
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			380,537	380,537	380,537	380,537	380,537	380,537	380,537	287,680	287,680	287,680	3,526,800
Net Profit Before Tax			(110,500)	(66,432)	(24,813)	19,217	62,813	108,538	151,060	286,298	330,813	374,569	1,131,562
			-18.5%	-10.3%	-3.6%	2.6%	7.9%	12.7%	16.7%	30.0%	32.9%	35.4%	13.7%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		56,429	50,340	44,252	38,163	32,074	25,986	19,897	13,809	9,206	4,603	294,758
Gross Revenue Rate	1.25%		7,453	8,092	8,702	9,344	9,983	10,651	11,280	11,910	12,569	13,220	103,207
Total Taxes			63,882	58,432	52,954	47,507	42,058	36,637	31,178	25,719	21,775	17,823	397,965
Net Income			(174,383)	(124,865)	(77,767)	(28,290)	20,755	71,901	119,883	260,580	309,038	356,745	733,597
			-29.2%	-19.3%	-11.2%	-3.8%	2.6%	8.4%	13.3%	27.3%	30.7%	33.7%	8.9%

Anchorage Medium BTU Gas Project

Gas Sales to George M. Sullivan Power Plant **Annual Proforma**

Methane Gas Price (MG) = $ 2.86

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(3,526,800)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		380,537	380,537	380,537	380,537	380,537	380,537	380,537	287,680	287,680	287,680	3,526,800
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(3,526,800)	206,155	255,672	302,770	352,247	401,292	452,438	500,420	548,260	596,718	644,425	4,260,397
Cumulative After Tax Cash @	(3,526,800)	(3,320,645)	(3,064,973)	(2,762,203)	(2,409,956)	(2,008,664)	(1,556,226)	(1,055,806)	(507,546)	89,172	**733,597**	
Net Present Value (NPV)	**2.000%**										**$224,059**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(3,526,800)											(3,526,800)
Construction Interest												-
Bond	-											-
Cash Flow		206,155	255,672	302,770	352,247	401,292	452,438	500,420	548,260	596,718	644,425	4,260,397
												-
After Tax Cash Flow - Year	(3,526,800)	206,155	255,672	302,770	352,247	401,292	452,438	500,420	548,260	596,718	644,425	733,597
After Tax Cash Flow - Cum.	(3,526,800)	(3,320,645)	(3,064,973)	(2,762,203)	(2,409,956)	(2,008,664)	(1,556,226)	(1,055,806)	(507,546)	89,172	733,597	

Project IRR - on Cash Investment **3.03%**

NPV - After tax - Discount @	**2.00%**	**$224,059**	
	2.50%	**$112,166**	
	2.75%	**$58,319**	
Discount = to IRR	**3.00%**	**$5,820**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**10.59%**	**-18.53%**
After Tax	**5.26%**	**-29.25%**

Anchorage Medium BTU Gas Project
Gas Sales to George M. Sullivan Power Plant
Capital Estimate Detail

April 5, 2004

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Description		Sub-Total	Total
Gas Collection System / Compressor Facility			
Wellfield based on $12,000 per acre asuming 73 acres	$876,000		
Compressor	$650,000		
Contingency	$0	Included in above	
		$1,526,000	
Pipeline and Related Costs			
Blower Upgrade	$0	Included in GCCS	
Pipeline 31,680 feet @ $60 per foot	$1,900,800		
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate	
Air Compressor	$0	Included in Pipeline estimate	
Surveying	$0	Included in Pipeline estimate	
Geotechnical	$0	Included in Pipeline estimate	
Planning/Coordination/Legal	$0	Included in Pipeline estimate	
Construction Interest	$0	None assumed	
Right of Way Payment	$0	None assumed	
Wetlands Investigation	$0	Included in Pipeline estimate	
End User Upgrades	$100,000	Allowance	
Contingency - 10%	$0	Included in above	
		$2,000,800	
Project Total			**$3,526,800**

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Anchorage Medium BTU Gas Project
Gas Sales to George M. Sullivan Power Plant

Depreciation & Amortization Schedules

April 5, 2004

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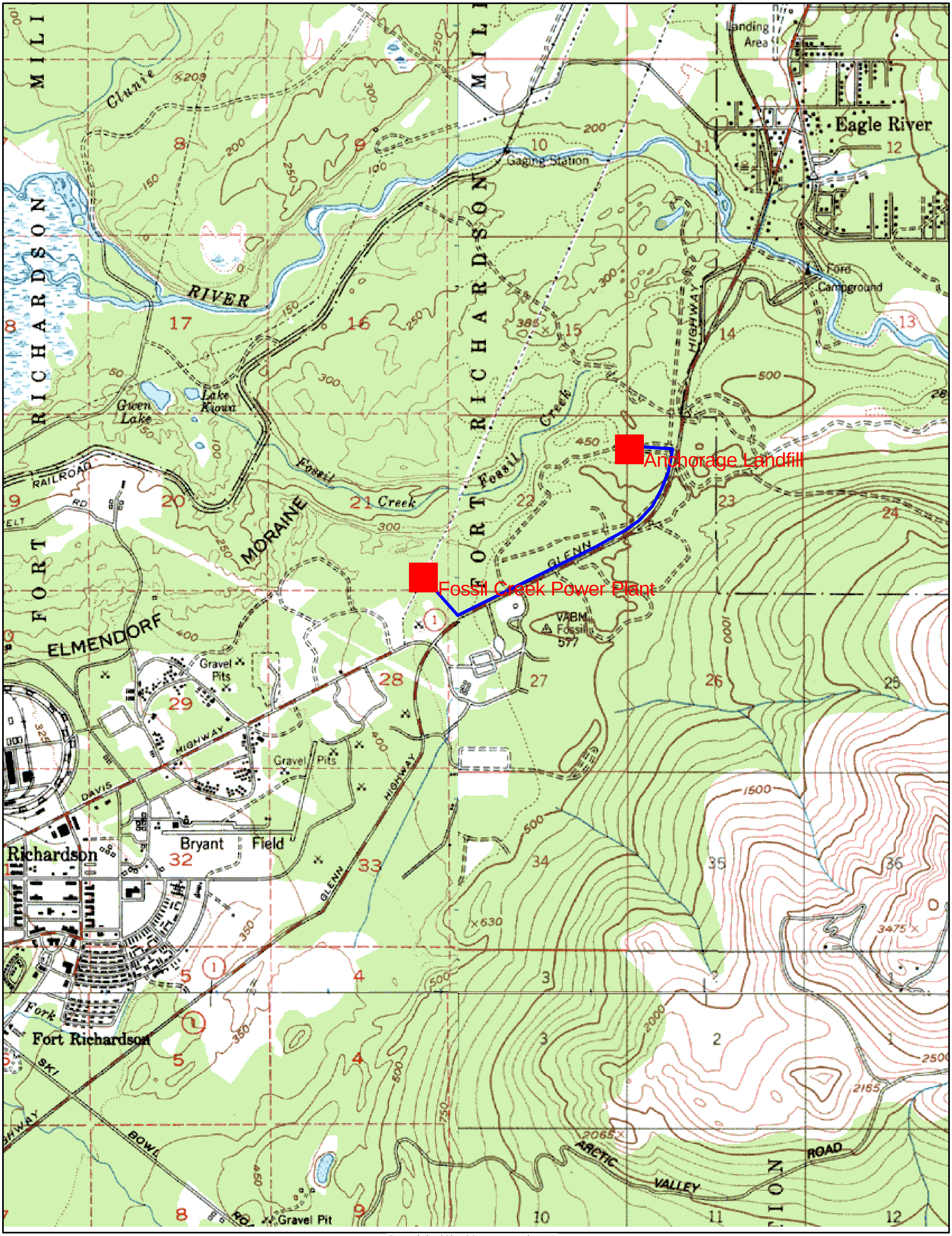
Depreciation Amounts		Amount
Gas Treatment and Processing System		1,526,000
Pipeline and Related Costs		2,000,800
Construction Interest		-
	Sub-Total	**3,526,800**

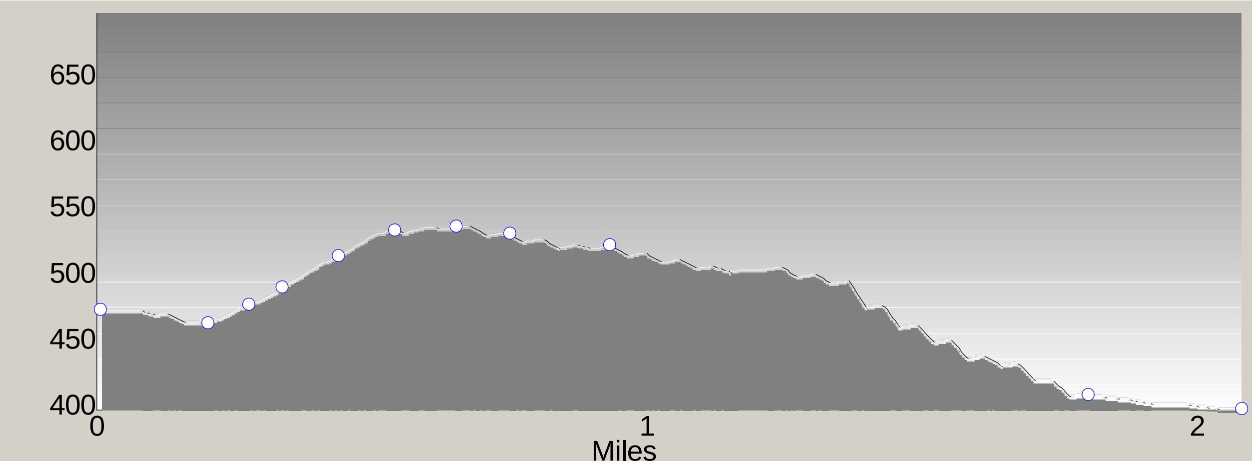
	Year	Depreciation
1	2006	$380,537
2	2007	$380,537
3	2008	$380,537
4	2009	$380,537
5	2010	$380,537
6	2011	$380,537
7	2012	$380,537
8	2013	$287,680
9	2014	$287,680
10	2015	$287,680
		$3,526,800

APPENDIX 16

TOPOGRAPHIC MAP FOR OPTION 7
(ML&P FOSSIL CREEK)



Anchorage Landfill
Fossil Creek Power Plant
Eagle River
Landing Area
Gaging Station
Ford Campground
RIVER
Clunie
Gwen Lake
Lake Kiowa
Fossil Creek
MORAINE
ELMENDORF
RAILROAD
HIGHWAY
GLENN
Gravel Pits
Bryant Field
Richardson
Fort Richardson
DAVIS
VABM Fossil 577
ARCTIC VALLEY ROAD
SKI BOWL
FORT RICHARDSON



Total distance:	2 miles, 414 feet	Climbing:	112 feet	Latitude:	000° 00' 00.0" N
		Descending:	-187 feet	Longitude:	000° 00' 00.0" E
Ground distance:	2 miles, 421 feet	Elevation change:	-75 feet	Elevation:	
		Min/Max:	396/535	Grade:	

APPENDIX 17

FINANCIAL PRO FORMA FOR OPTION 7
(ML&P FOSSIL CREEK)

Anchorage Medium BTU Gas Project

Gas Sales to Proposed Fossil Creek Powerplant

Assumes Fossil Creek will use all gas available

Project Proforma

April 5, 2004

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Summary of Assumptions & Financials

Assumptions

MG Price	$2.145	
MG Price Escalation	2.0%	
Capital Cost	$ 2,284,849	
Loan Amount	$0	
Gas Cost	$0.0000	
Gas Cost Escalation	2.0%	
Gas Quantity	826	SCFM

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 2,766,265
Investment		$ 2,284,849
Net Cash Flow		$ 481,416
Project IRR		3.0%
NPV at rate =	2.000%	$ 145,694
NPV at rate =	2.500%	$ 72,018
NPV at rate =	2.750%	$ 36,569
NPV at rate =	3.000%	$ 2,012
Pre Tax Profits		$ 744,317
Average %		8.7%
Minimum %		-21.5%
Net Income		$ 481,416
Average %		4.0%
Minimum %		-30.9%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mils	16	$ 185,467
Gross Revenue contribution % of Revenue	1.25%	$ 77,435
		$ 262,902

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Gas Sales to Proposed Fossil Creek Powerplant
ASSUMPTIONS to PRO FORMA

April 5, 2004

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Description			Value	Unit
Financial Information				
Project Capital Costs			$2,284,849	
Equity Contribution		100.00%	$2,284,849	
Loan		0.00%		
	Principal		$0	
	Term		10	years
	Interest Rate		0.0%	
	Interest Payments monthly during construction			
	Loan Fees		0.0%	
MG Quantity	826 SCFM		208,631	mmBTU/Yr
	50.00% Methane %			
On-Stream Factors				
Utilization %			95.0%	
MG Price			$2.145	
MG Price escalator			2.0%	
Cost of Sales				
Cost of Methane Gas			$0.0000	per mmBTU
Cost Escalator			2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh			$60,000	Annually
	Electric Escalator		2.0%	
Operating Costs			Annually	
O&M Compressor/Pipeline		per year	$ 175,000	
	O&M Escalator		3.0%	
Property Insurance			1.00%	% of Value
General Liability Insurance			1.00%	% of Revenue
Administration			$25,000	
Income Taxes	Is project subject to income taxes		NO	
	Federal Tax Rate		0%	
	State Tax Rate		0.0%	Incl. In Federal

Anchorage Medium BTU Gas Project

Gas Sales to Proposed Fossil Creek Powerplant   Annual Proforma

Methane Gas Price (MG) = $ 2.14

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate		75.0%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
School Gas Demand													
Average SCFM			-	-	-	-	-	-	-	-	-	-	0
Average MMBTU @ 50% Methane & 95% Utilization			-	-	-	-	-	-	-	-	-	-	-
		Escalator											
Assumed Methane Gas Price		2%	$ 2.14	$ 2.19	$ 2.23	$ 2.28	$ 2.32	$ 2.37	$ 2.42	$ 2.46	$ 2.51	$ 2.56	
Income		Escalator											
MG Sales - Landfill Gas Production		2.0%	$447,409	$485,536	$522,716	$562,519	$599,643	$639,063	$678,227	$714,608	$753,389	$791,683	$6,194,794
Total Revenues			447,409	485,536	522,716	562,519	599,643	639,063	678,227	714,608	753,389	791,683	6,194,794
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706	656,983
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706	656,983
Gross Profit			387,409	424,336	460,292	498,847	534,698	572,819	610,657	645,687	683,089	719,977	5,537,811
Expenses - Pipeline													
O&M - Wellfield/Comp/Pipeline - per year		2.0%	175,000	178,500	182,070	185,711	189,426	193,214	197,078	201,020	205,040	209,141	1,916,201
Property Insur. - (% of value)	1.00%	2.0%	22,848	23,305	23,772	24,247	24,732	25,227	25,731	26,246	26,771	27,306	250,185
General Liability Insur. (% of revenue)	1.00%	2.0%	4,474	4,952	5,438	5,970	6,491	7,056	7,638	8,209	8,827	9,461	68,516
Administration		2.0%	25,000	25,500	26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	273,743
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			227,323	232,258	237,290	242,458	247,709	253,099	258,602	264,191	269,930	275,786	2,508,645
Net Operating Profit			160,087	192,078	223,003	256,389	286,988	319,720	352,056	381,495	413,160	444,191	3,029,166
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			256,342	256,342	256,342	256,342	256,342	256,342	256,342	163,485	163,485	163,485	2,284,849
Net Profit Before Tax			(96,255)	(64,264)	(33,339)	47	30,646	63,378	95,713	218,010	249,675	280,706	744,317
			-21.5%	-13.2%	-6.4%	0.0%	5.1%	9.9%	14.1%	30.5%	33.1%	35.5%	12.0%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		36,558	32,456	28,355	24,253	20,152	16,050	11,949	7,847	5,232	2,616	185,467
Gross Revenue Rate	1.25%		5,593	6,069	6,534	7,031	7,496	7,988	8,478	8,933	9,417	9,896	77,435
Total Taxes			42,150	38,525	34,889	31,285	27,647	24,039	20,427	16,780	14,649	12,512	262,902
Net Income			(138,406)	(102,789)	(68,228)	(31,238)	2,999	39,339	75,287	201,230	235,026	268,194	481,416
			-30.9%	-21.2%	-13.1%	-5.6%	0.5%	6.2%	11.1%	28.2%	31.2%	33.9%	7.8%

Anchorage Medium BTU Gas Project

Gas Sales to Proposed Fossil Creek Powerplant   Annual Proforma

Methane Gas Price (MG) = $ 2.14

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(2,284,849)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		256,342	256,342	256,342	256,342	256,342	256,342	256,342	163,485	163,485	163,485	2,284,849
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(2,284,849)	117,936	153,553	188,114	225,104	259,341	295,682	331,629	364,715	398,511	431,679	2,766,265
Cumulative After Tax Cash @	(2,284,849)	(2,166,913)	(2,013,360)	(1,825,246)	(1,600,142)	(1,340,800)	(1,045,119)	(713,490)	(348,775)	49,736	**481,416**	
Net Present Value (NPV)	**2.000%**										**$145,694**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(2,284,849)											(2,284,849)
Construction Interest												-
Bond	-											-
Cash Flow		117,936	153,553	188,114	225,104	259,341	295,682	331,629	364,715	398,511	431,679	2,766,265
												-
After Tax Cash Flow - Year	(2,284,849)	117,936	153,553	188,114	225,104	259,341	295,682	331,629	364,715	398,511	431,679	481,416
After Tax Cash Flow - Cum.	(2,284,849)	(2,166,913)	(2,013,360)	(1,825,246)	(1,600,142)	(1,340,800)	(1,045,119)	(713,490)	(348,775)	49,736	481,416	

Project IRR - on Cash Investment		**3.01%**	
NPV - After tax - Discount @	**2.00%**	**$145,694**	
	2.50%	**$72,018**	
	2.75%	**$36,569**	
Discount = to IRR	**3.00%**	**$2,012**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**8.71%**	**-21.51%**
After Tax	**4.03%**	**-30.93%**

Anchorage Medium BTU Gas Project
Gas Sales to Proposed Fossil Creek Powerplant
Capital Estimate Detail

April 5, 2004

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Description		Sub-Total	Total
Gas Collection System / Compressor Facility			
Wellfield based on $12,000 per acre asuming 73 acres	$876,000		
Compressor	$650,000		
Contingency	$0	Included in above	
		$1,526,000	
Pipeline and Related Costs			
Blower Upgrade	$0	Included in GCCS	
Pipeline 2.0797 miles (10,981 feet) @ $60 per foot	$658,849		
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate	
Air Compressor	$0	Included in Pipeline estimate	
Surveying	$0	Included in Pipeline estimate	
Geotechnical	$0	Included in Pipeline estimate	
Planning/Coordination/Legal	$0	Included in Pipeline estimate	
Construction Interest	$0	None assumed	
Right of Way Payment	$0	None assumed	
Wetlands Investigation	$0	Included in Pipeline estimate	
End User Upgrades	$100,000	Allowance	
Contingency - 10%	$0	Included in above	
		$758,849	
Project Total			**$2,284,849**

Anchorage Medium BTU Gas Project
Gas Sales to Proposed Fossil Creek Powerplant

Depreciation & Amortization Schedules
April 5, 2004

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Depreciation Amounts		Amount
Gas Treatment and Processing System		1,526,000
Pipeline and Related Costs		758,849
Construction Interest		-
	Sub-Total	**2,284,849**

	Year	Depreciation
1	2006	$256,342
2	2007	$256,342
3	2008	$256,342
4	2009	$256,342
5	2010	$256,342
6	2011	$256,342
7	2012	$256,342
8	2013	$163,485
9	2014	$163,485
10	2015	$163,485
		$2,284,849

APPENDIX 18

FINANCIAL PRO FORMA FOR OPTION 8 (TREATMENT OF LIQUID COLLECTED AT THE ANCHORAGE REGIONAL LANDFILL)

Anchorage Medium BTU Gas Project
Glycol Distillation

Glycol Sales Gallons Needed to Breakeven at $2.50 per Gallon Sales Price

Project Proforma

April 6, 2004

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Summary of Assumptions & Financials

Assumptions

Input Volume - Glycol / Water /? Mix	55,000	Assumed for preliminary analysis, need actual.
Glycol Recovery %	50.0%	Assumed for preliminary analysis, need actual.
Glycol Sales Price per gallon	$2.50	Assumed for preliminary analysis, need actual.
Glycol Price Escalation	2.0%	
Glycol Sales Volume	**27,500**	gallons
Avoided Cost of Glycol Disposal	$ 35,000	per year
Capital Cost	$ 350,000	Assumed for preliminary analysis, need actual.
Loan Amount	$0	
Gas Cost	$0.0000	
Gas Cost Escalation	2.0%	
Gas Quantity	1,500	per pound of input
		Assumed for preliminary analysis, need actual.

Financing

Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns		**10 Years**
Total Cash Flow from Operations		$ 432,669
Investment		$ 350,000
Net Cash Flow		$ 82,669
Project IRR		3.3%
NPV at rate =	2.000%	$ 29,747
NPV at rate =	2.500%	$ 18,152
NPV at rate =	2.750%	$ 12,576
NPV at rate =	3.000%	$ 7,141
Pre Tax Profits		$ 120,827
Average %		5.6%
Minimum %		-17.5%
Net Income		$ 82,669
Average %		2.4%
Minimum %		-24.1%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate	**10 Year Totals**
Rate on Net Book Value of Assets - in mils	16	$ 22,400
Gross Revenue contribution % of Revenue	1.25%	$ 15,759
		$ 38,159

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Glycol Distillation
ASSUMPTIONS to PRO FORMA

April 6, 2004

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Description				Value	Unit
Financial Information					
Project Capital Costs				$350,000	
Equity Contribution		100.00%		$350,000	
Loan		0.00%			
	Principal			$0	
	Term			10	years
	Interest Rate			0.0%	
	Interest Payments monthly during construction				
	Loan Fees			0.0%	
MG Quantity	1,500 Btus per pound of input			660	mmBTU/Yr
	50.00% Methane %				
On-Stream Factors					
Utilization %				100.0%	
MG Price				$0.000	
MG Price escalator				2.0%	
<u>**Glycol Assumptions**</u>					
Input weight per gallon				8	
Input Volume - Glycol / Water /? Mix				55,000	
Glycol Recovery %				50.0%	
Glycol Sales Price				$2.50	per gallon
Glycol Recovery and Sales				27,500	gallons
Avoided Cost of Glycol Disposal			$	35,000	per year
Cost of Sales					
Cost of Methane Gas				$0.0000	per mmBTU
Cost Escalator				2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh				$5,000	Annually
	Electric Escalator			2.0%	
Operating Costs				Annually	
Glycol Distillation O&M		per year	$	56,363	
	O&M Escalator			3.0%	
Property Insurance				1.00%	% of Value
General Liability Insurance				1.00%	% of Revenue
Administration				$6,000	
Income Taxes	Is project subject to income taxes			NO	
	Federal Tax Rate			0%	
	State Tax Rate			0.0%	Incl. In Federal

Anchorage Medium BTU Gas Project

Glycol Distillation — **Annual Proforma**

Glycol Price $2.50 **Glycol Sales** 27,500 Gallons **Methane Gas Price (MG) =** $ -

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate	75.0%		75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
Gas Demand													
Average SCFM			2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	24.81635894
Average MMBTU @ 50% Methane			660	660	660	660	660	660	660	660	660	660	6,600
Glycol Sales Volume	gallons/yr		27,500	27,500	27,500	27,500	27,500	27,500	27,500	27,500	27,500	27,500	275,000
		Escalator											
Assumed Methane Gas Price		2%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Assumed Glycol Price		2%	$2.50	$ 2.55	$ 2.60	$ 2.65	$ 2.71	$ 2.76	$ 2.82	$ 2.87	$ 2.93	$ 2.99	
Income & Savings		Escalator											
MG Sales - Landfill Gas Production		2.0%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Glycol Sales		2.0%	$68,750	$70,125	$71,500	$72,875	$74,525	$75,900	$77,550	$78,925	$80,575	$82,225	$752,950
Avoided Cost of Glycol Disposal		2.0%	$35,000	$35,700	$37,142	$39,416	$42,665	$47,105	$53,048	$60,936	$71,396	$85,325	$507,733
Total Revenues			103,750	105,825	108,642	112,291	117,190	123,005	130,598	139,861	151,971	167,550	1,260,683
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975	54,749
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975	54,749
Gross Profit			98,750	100,725	103,440	106,985	111,778	117,485	124,968	134,117	146,113	161,574	1,205,935
Expenses - Operations													
Distillation O&M		2.0%	56,363	57,490	58,640	59,813	61,009	62,229	63,474	64,743	66,038	67,359	617,159
Property Insur. - (% of value)	1.00%	2.0%	3,500	3,570	3,641	3,714	3,789	3,864	3,942	4,020	4,101	4,183	38,324
General Liability Insur. (% of revenue)	1.00%	2.0%	1,038	1,079	1,130	1,192	1,269	1,358	1,471	1,607	1,781	2,002	13,926
Administration		2.0%	6,000	6,120	6,242	6,367	6,495	6,624	6,757	6,892	7,030	7,171	65,698
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			66,901	68,260	69,654	71,086	72,561	74,076	75,643	77,262	78,950	80,715	735,107
Net Operating Profit			31,850	32,465	33,786	35,899	39,217	43,409	49,324	56,855	67,163	80,860	470,827
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			50,000	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	350,000
Net Profit Before Tax			(18,151)	(17,535)	(16,214)	(14,101)	(10,783)	(6,591)	(676)	56,855	67,163	80,860	120,827
			-17.5%	-16.6%	-14.9%	-12.6%	-9.2%	-5.4%	-0.5%	40.7%	44.2%	48.3%	9.6%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		5,600	4,800	4,000	3,200	2,400	1,600	800	-	-	-	22,400
Gross Revenue Rate	1.25%		1,297	1,323	1,358	1,404	1,465	1,538	1,632	1,748	1,900	2,094	15,759
Total Taxes			6,897	6,123	5,358	4,604	3,865	3,138	2,432	1,748	1,900	2,094	38,159
Net Income			(25,047)	(23,657)	(21,572)	(18,705)	(14,648)	(9,729)	(3,108)	55,107	65,264	78,765	82,669
			-24.1%	-22.4%	-19.9%	-16.7%	-12.5%	-7.9%	-2.4%	39.4%	42.9%	47.0%	6.6%

PRELIMINARY

Anchorage Medium BTU Gas Project

Glycol Distillation **Annual Proforma**

Glycol Price **$2.50** **Glycol Sales** **27,500** **Gallons** **Methane Gas Price (MG) =** **$ -**

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(350,000)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		50,000	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	350,000
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(350,000)	24,953	26,343	28,428	31,295	35,352	40,271	46,892	55,107	65,264	78,765	432,669
Cumulative After Tax Cash @	(350,000)	(325,047)	(298,705)	(270,277)	(238,982)	(203,630)	(163,358)	(116,467)	(61,360)	3,904	**82,669**	
Net Present Value (NPV)	**2.000%**										**$29,747**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(350,000)											(350,000)
Construction Interest												-
Bond	-											-
Cash Flow		24,953	26,343	28,428	31,295	35,352	40,271	46,892	55,107	65,264	78,765	432,669
												-
After Tax Cash Flow - Year	(350,000)	24,953	26,343	28,428	31,295	35,352	40,271	46,892	55,107	65,264	78,765	82,669
After Tax Cash Flow - Cum.	(350,000)	(325,047)	(298,705)	(270,277)	(238,982)	(203,630)	(163,358)	(116,467)	(61,360)	3,904	82,669	

Project IRR - on Cash Investment		**3.34%**	
NPV - After tax - Discount @	**2.00%**	**$29,747**	
	2.50%	**$18,152**	
	2.75%	**$12,576**	
Discount = to IRR	**3.00%**	**$7,141**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**5.65%**	**-17.49%**
After Tax	**2.36%**	**-24.14%**

Anchorage Medium BTU Gas Project
Glycol Distillation
Capital Estimate Detail

April 6, 2004

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Description		Sub-Total	Total
Gas Collection System / Compressor Facility			
Wellfield based on $12,000 per acre asuming xx acres	$0		
Compressor	$0		
Glycol Distillation Equipment	$350,000		
Contingency	$0	Included in above	
		$350,000	
Pipeline and Related Costs			
Blower Upgrade	$0	Included in GCCS	
Pipeline 0 miles @ $60 per foot	$0		
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate	
Air Compressor	$0	Included in Pipeline estimate	
Surveying	$0	Included in Pipeline estimate	
Geotechnical	$0	Included in Pipeline estimate	
Planning/Coordination/Legal	$0	Included in Pipeline estimate	
Construction Interest	$0	None assumed	
Right of Way Payment	$0	None assumed	
Wetlands Investigation	$0	Included in Pipeline estimate	
End User Upgrades	$0	Allowance	
Contingency - 10%	$0	Included in above	
		$0	
Project Total			**$350,000**

Anchorage Medium BTU Gas Project
Glycol Distillation

Depreciation & Amortization Schedules

April 6, 2004

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Depreciation Amounts	Amount
Gas Treatment and Processing System	350,000
Pipeline and Related Costs	-
Construction Interest	-
Sub-Total	**350,000**

	Year	Depreciation
1	2006	$50,000
2	2007	$50,000
3	2008	$50,000
4	2009	$50,000
5	2010	$50,000
6	2011	$50,000
7	2012	$50,000
8	2013	$0
9	2014	$0
10	2015	$0
		$350,000

Anchorage Medium BTU Gas Project
Glycol Distillation

Glycol Sales Gallons Needed to Breakeven at $4.50 per Gallon Sales Price

Project Proforma

April 19, 2004

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Summary of Assumptions & Financials

Assumptions			
Input Volume - Glycol / Water /? Mix		29,400	Assumed for preliminary analysis, need actual.
Glycol Recovery %		50.0%	Assumed for preliminary analysis, need actual.
Glycol Sales Price per gallon		$4.50	Assumed for preliminary analysis, need actual.
Glycol Price Escalation		2.0%	
Glycol Sales Volume		**14,700**	gallons
Avoided Cost of Glycol Disposal	$	35,000	per year
Capital Cost	$	350,000	Assumed for preliminary analysis, need actual.
Loan Amount		$0	
Gas Cost		$0.0000	
Gas Cost Escalation		2.0%	
Gas Quantity		1,500	per pound of input
			Assumed for preliminary analysis, need actual.

Financing	
Principal	No Debt
Term	n/a
Interest Rate	n/a

Financial Returns			**10 Years**
Total Cash Flow from Operations		$	432,836
Investment		$	350,000
Net Cash Flow		$	82,836
Project IRR			3.3%
NPV at rate =	2.000%	$	29,901
NPV at rate =	2.500%	$	18,303
NPV at rate =	2.750%	$	12,725
NPV at rate =	3.000%	$	7,290
Pre Tax Profits		$	120,638
Average %			5.7%
Minimum %			-18.0%
Net Income		$	82,836
Average %			2.4%
Minimum %			-24.7%

MUSA Contributions (Municipal Utility Service Assessment)

	Rate		**10 Year Totals**
Rate on Net Book Value of Assets - in mils	16	$	22,400
Gross Revenue contribution % of Revenue	1.25%	$	15,402
		$	37,802

Depreciation per GASB 34	Method	Life in Years
Vehicles	St. Line	5
Support Equipment	St. Line	4
Machinery & Equipment	St. Line	7
GCCS & Pipeline	St. Line	10

Anchorage Medium BTU Gas Project
Glycol Distillation
ASSUMPTIONS to PRO FORMA

April 19, 2004

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Description					Value	Unit
Financial Information						
Project Capital Costs					$350,000	
Equity Contribution			100.00%		$350,000	
Loan			0.00%			
	Principal				$0	
	Term				10	years
	Interest Rate				0.0%	
	Interest Payments monthly during construction					
	Loan Fees				0.0%	
MG Quantity	1,500	Btus per pound of input			353	mmBTU/Yr
	50.00%	Methane %				
On-Stream Factors						
Utilization %					100.0%	
MG Price					$0.000	
MG Price escalator					2.0%	
Glycol Assumptions						
Input weight per gallon					8	
Input Volume - Glycol / Water /? Mix					29,400	
Glycol Recovery %					50.0%	
Glycol Sales Price					$4.50	per gallon
Glycol Recovery and Sales					14,700	gallons
Avoided Cost of Glycol Disposal				$	35,000	per year
Cost of Sales						
Cost of Methane Gas					$0.0000	per mmBTU
Cost Escalator					2.0%	
Electric Cost - Blower and Compressor @ .09 cents / kwh					$5,000	Annually
		Electric Escalator			2.0%	
Operating Costs					Annually	
Glycol Distillation O&M			per year	$	53,803	
		O&M Escalator			3.0%	
Property Insurance					1.00%	% of Value
General Liability Insurance					1.00%	% of Revenue
Administration					$6,000	
Income Taxes		Is project subject to income taxes			NO	
		Federal Tax Rate			0%	
		State Tax Rate			0.0%	Incl. In Federal

Anchorage Medium BTU Gas Project

Glycol Distillation — **Annual Proforma**

Glycol Price **$4.50** **Glycol Sales** **14,700** **Gallons** **Methane Gas Price (MG) =** **$ -**

		Escalation Year	0	1	2	3	4	5	6	7	8	9	10 Year
Assumptions		CalendarYear	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Gas Curve													
LFG Generation - Avg			1,101	1,170	1,237	1,302	1,364	1,423	1,479	1,533	1,584	1,632	
Lfg Recoverable Rate		75.0%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Landfill Gas Available			826	878	928	977	1,023	1,067	1,109	1,150	1,188	1,224	
Average MMBTU @ 50% Methane & 95% Utilization			208,631	221,706	234,402	246,719	258,467	269,647	280,259	290,491	300,155	309,251	
Gas Demand													
Average SCFM			1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	13.26547187
Average MMBTU @ 50% Methane			353	353	353	353	353	353	353	353	353	353	3,530
Glycol Sales Volume	gallons/yr		14,700	14,700	14,700	14,700	14,700	14,700	14,700	14,700	14,700	14,700	147,000
		Escalator											
Assumed Methane Gas Price		2%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Assumed Glycol Price		2%	$4.50	$ 4.59	$ 4.68	$ 4.78	$ 4.87	$ 4.97	$ 5.07	$ 5.17	$ 5.27	$ 5.38	
Income & Savings		Escalator											
MG Sales - Landfill Gas Production		2.0%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Glycol Sales		2.0%	$66,150	$67,473	$68,796	$70,266	$71,589	$73,059	$74,529	$75,999	$77,469	$79,086	$724,416
Avoided Cost of Glycol Disposal		2.0%	$35,000	$35,700	$37,142	$39,416	$42,665	$47,105	$53,048	$60,936	$71,396	$85,325	$507,733
Total Revenues			101,150	103,173	105,938	109,682	114,254	120,164	127,577	136,935	148,865	164,411	1,232,149
Costs of Sales													
Purchased Electricity - Blower/Compressor		2.0%	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975	54,749
Purchased Methane Gas	$ -	2.0%	-	-	-	-	-	-	-	-	-	-	-
Costs of Sales			5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975	54,749
Gross Profit			96,150	98,073	100,736	104,376	108,842	114,644	121,947	131,191	143,007	158,435	1,177,401
Expenses - Operations													
Distillation O&M		2.0%	53,803	54,879	55,977	57,096	58,238	59,403	60,591	61,803	63,039	64,300	589,128
Property Insur. - (% of value)	1.00%	2.0%	3,500	3,570	3,641	3,714	3,789	3,864	3,942	4,020	4,101	4,183	38,324
General Liability Insur. (% of revenue)	1.00%	2.0%	1,012	1,052	1,102	1,164	1,237	1,327	1,437	1,573	1,744	1,965	13,612
Administration		2.0%	6,000	6,120	6,242	6,367	6,495	6,624	6,757	6,892	7,030	7,171	65,698
Personal Property Tax - n/a - assume Pollution Control Exemp.			0	0	0	0	0	0	0	0	0	0	-
Interest			0	0	0	0	0	0	0	0	0	0	-
Total Expenses			64,315	65,621	66,963	68,342	69,758	71,218	72,726	74,288	75,914	77,618	706,762
Net Operating Profit			31,836	32,452	33,774	36,034	39,084	43,426	49,220	56,903	67,093	80,818	470,638
Less													
Depreciation/Amort Finance Fees (Pipeline Only)			50,000	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	350,000
Net Profit Before Tax			(18,165)	(17,548)	(16,226)	(13,966)	(10,916)	(6,574)	(780)	56,903	67,093	80,818	120,638
			-18.0%	-17.0%	-15.3%	-12.7%	-9.6%	-5.5%	-0.6%	41.6%	45.1%	49.2%	9.8%
MUSA Contributions													
Millage Rate on NBV of PPE	1.60%		5,600	4,800	4,000	3,200	2,400	1,600	800	-	-	-	22,400
Gross Revenue Rate	1.25%		1,264	1,290	1,324	1,371	1,428	1,502	1,595	1,712	1,861	2,055	15,402
Total Taxes			6,864	6,090	5,324	4,571	3,828	3,102	2,395	1,712	1,861	2,055	37,802
Net Income			(25,029)	(23,638)	(21,551)	(18,537)	(14,744)	(9,676)	(3,174)	55,192	65,232	78,762	82,836
			-24.7%	-22.9%	-20.3%	-16.9%	-12.9%	-8.1%	-2.5%	40.3%	43.8%	47.9%	6.7%

Anchorage Medium BTU Gas Project

Glycol Distillation **Annual Proforma**

Glycol Price **$4.50** **Glycol Sales** **14,700** **Gallons** **Methane Gas Price (MG) =** **$ -**

Cash Flow - Total Project	Construction 2005											
Capital Expenditures	(350,000)											
Loan	-											
Add Depreciation/Amort (Pipeline & Related Costs)		50,000	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	350,000
Less Principal Payment		0	0	0	0	0	0	0	0	0	0	0
Net After Tax Cash Flow	(350,000)	24,971	26,362	28,449	31,463	35,256	40,324	46,826	55,192	65,232	78,762	432,836
Cumulative After Tax Cash @	(350,000)	(325,029)	(298,667)	(270,218)	(238,755)	(203,499)	(163,175)	(116,350)	(61,158)	4,074	**82,836**	
Net Present Value (NPV)	**2.000%**										**$29,901**	
Bank Principal Balance (Yr End)	-	-	-	-	-	-	-	-	2,012	-		

Investment Analysis - Total Project	Const. Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 YEAR TOTAL
% Ownership 100.00%												
Capital Expenditures	(350,000)											(350,000)
Construction Interest												-
Bond	-											-
Cash Flow		24,971	26,362	28,449	31,463	35,256	40,324	46,826	55,192	65,232	78,762	432,836
												-
After Tax Cash Flow - Year	(350,000)	24,971	26,362	28,449	31,463	35,256	40,324	46,826	55,192	65,232	78,762	82,836
After Tax Cash Flow - Cum.	(350,000)	(325,029)	(298,667)	(270,218)	(238,755)	(203,499)	(163,175)	(116,350)	(61,158)	4,074	82,836	

Project IRR - on Cash Investment **3.35%**

NPV - After tax - Discount @	**2.00%**	**$29,901**	
	2.50%	**$18,303**	
	2.75%	**$12,725**	
Discount = to IRR	**3.00%**	**$7,290**	NPV and IRR reconcile

Return on Revenues	**Average**	**Minimum**
Pre Tax	**5.71%**	**-17.96%**
After Tax	**2.37%**	**-24.74%**

Anchorage Medium BTU Gas Project
Glycol Distillation
Capital Estimate Detail

April 19, 2004

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Description			Sub-Total	Total
Gas Collection System / Compressor Facility				
Wellfield based on $12,000 per acre asuming xx acres	$0			
Compressor	$0			
Glycol Distillation Equipment	$350,000			
Contingency	$0	Included in above		
			$350,000	
Pipeline and Related Costs				
Blower Upgrade	$0	Included in GCCS		
Pipeline 0 miles @ $60 per foot	$0			
D.O.T. Pipeline Safety Standards Design & Compliance	$0	Included in Pipeline estimate		
Air Compressor	$0	Included in Pipeline estimate		
Surveying	$0	Included in Pipeline estimate		
Geotechnical	$0	Included in Pipeline estimate		
Planning/Coordination/Legal	$0	Included in Pipeline estimate		
Construction Interest	$0	None assumed		
Right of Way Payment	$0	None assumed		
Wetlands Investigation	$0	Included in Pipeline estimate		
End User Upgrades	$0	Allowance		
Contingency - 10%	$0	Included in above		
			$0	
Project Total				**$350,000**

Anchorage Medium BTU Gas Project
Glycol Distillation

Depreciation & Amortization Schedules

April 19, 2004

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Depreciation Amounts		Amount
Gas Treatment and Processing System		350,000
Pipeline and Related Costs		-
Construction Interest		-
	Sub-Total	**350,000**

	Year	Depreciation
1	2006	$50,000
2	2007	$50,000
3	2008	$50,000
4	2009	$50,000
5	2010	$50,000
6	2011	$50,000
7	2012	$50,000
8	2013	$0
9	2014	$0
10	2015	$0
		$350,000