MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

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Bismarck, ND 58501
(701) 222-7900

February 7, 2013

Ms. Kate Whitney, Administrator
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620

Re: General Gas Rate Application
Docket No. D2012.9.100

Dear Ms. Whitney:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Public Service Commission data requests dated December 19, 2012, January 8, 2013, January 17, 2013 and January 21, 2013. Responses to the following requests are attached:

PSC-003	PSC-059	PSC-110	PSC-128 - Revised
PSC-051	PSC-060	PSC-113	PSC-129
PSC-053	PSC-061	PSC-116	PSC-131
PSC-054	PSC-062	PSC-117	PSC-139
PSC-055	PSC-063	PSC-120	PSC-142
PSC-057	PSC-064	PSC-121	PSC-143
PSC-058	PSC-065	PSC-122	PSC-145

This completes all outstanding data responses.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments
cc: Service List

Montana-Dakota Utilities Co.
Docket No. D2012.9.100
Service List

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MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-003

Regarding: Billings Landfill Project
(Project) Witness: Aberle/Morman

a. Please provide MDU's estimated output (in dkt) of the Billings Landfill Project over the next 10 years. Does MDU expect the Project to produce natural gas during all hours of the year?

b. Please explain why MDU classified the cost of the Billings Landfill Project as only energy-related in both cost of service studies.

c. Mr. Morman states that initial studies of the Billings Landfill Project indicated that natural gas could be developed for about $6 per dkt from the Project. Now that MDU has built the Project and it is in service, do the results of those studies seem accurate?

d. Please explain the method MDU used to apportion the costs of the Project among the different jurisdictions in its service territory.

e. Please explain how the royalty paid to the City of Billings is calculated.

Response:

a. Please see Attachment A for the estimated dk production.
b. The production facility was allocated on an energy factor and classified as an energy-related cost as it represents a commodity, gas supply. This is consistent with the manner the facility was allocated to each jurisdiction.
c. Currently the gas being developed is in excess of the original $6 per dk estimate. The investment and operation and maintenance costs of running the landfill are close to the original projections, however the amount of gas being withdrawn from the landfill is considerably less than the original study. The initial wells that are in phase 1 are producing very little gas as it appears the material has decomposed to a point where no methane gas is being produced. In the summer of 2012, Montana-Dakota installed horizontal pipes in a new area of the landfill and the results are very encouraging. This area of the landfill is currently accepting additional solid waste and as the fill is added to the top of the pipe more methane will be produced as the solid waste continues to decompose. Montana-Dakota plans to add additional horizontal pipe as the landfill continues to expand and this can be done inexpensively and, as stated above, the results are promising. While the initial production is less than

the initial study indicated, Montana-Dakota viewed this supply as a long term option. Montana-Dakota believes the production of the landfill methane will increase in the upcoming years and this will serve as a long term supply to meet customers' required energy requirements.

d. The Billings Landfill project costs were allocated to Montana using an allocation factor based on normalized gas sales volumes.

e. The calculation of the royalty to the City of Billings is based on 15 percent of the amount of energy produced and delivered to Montana-Dakota's distribution system (dk) at a price based on the First of the Month Index for the Rocky Mountain CIG transfer point. This is a point that Montana-Dakota utilizes to purchase natural gas supply and is representative of the cost of gas being produced in the Rocky Mountain region.

Billings Landfill

Year	Projected Annual Production (dkt)	
2011	129,216	actual
2012	88,535	actual
	130,000	full year production
2013	139,595	
2014	148,205	
2015	157,346	
2016	177,346	
2017	197,346	
2018	217,346	
2019	237,346	
2020	257,346	
2021	277,346	
2022	297,346	
2023	317,346	

Assumptions:
The Billings Landfill receives 250,000 tons of landfill per year.
Horizontal collectors are spaced approximately 200 feet apart.
Horizontal collectors have 60 foot vertical spacing.
Montana-Dakota receives permitting from the Montana DEQ and the City of Billings allows the installation of collectors.
Landfill is expected to run approximately 93% of the time, to allow for maintenance.
As additional cover is added to the landfill, production will increase more rapidly in future years.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC 051

Regarding: Contract Customers
Witness: Applicable Witness

a. Does MDU have any contract customers in MT?

b. Please identify each contract transportation customer, the annual volume transported for each and explain how (and at what estimated cost) each of these customers could have by passed MDU's system for gas deliveries.

c. Please provide a list of all current MDU contract customers and the maturity dates of those contracts.

Response:

a. Yes, Montana-Dakota requires all transportation service and interruptible sales customers to enter into a contract for service.

b. Montana-Dakota has not studied potential bypass scenarios for each of the interruptible sales and transportation service customers on its system. However, Montana-Dakota does have four transportation service customers with a contract for less than the maximum transportation rate and while specific bypass cost studies are not maintained due to the many variables affecting such studies (land acquisition costs, right of way costs, pipeline construction and associated piping) the Company is aware of each of those customers' relative location to other pipelines and/or other opportunities available for their energy requirements and reviews that information in determining the need for a flexible rate in order to provide a competitive rate and retain the customer on the system. Please see Statement Workpapers, Statement H page 26 for volumes by customer.

c. All interruptible sales and transportation contracts have an initial 12 month term and are extended unless either party provides written termination. Listed below are the maturity dates for the contracts at less than the maximum rate under Rate 82:

82-1 Initial term expired. Agreement continues until either party provides a 30-day notice of cancellation.

82-2 Initial term expired. Cancellation by either party requires 180 day written notice prior to anniversary date of April 1.

82-3 8/31/2013

82-4 Initial term expired. Agreement continues until either party provides a 30-day notice of cancellation.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-053

Regarding: Utility integration effort
Witness: Goodin, p. 8, Aberle

You testified that in seeking to control costs through opportunities that create efficiencies, MDU participated in a utility integration effort with other utilities in the MDU Resources Group, Inc.'s Utility Group to pursue best practices and streamline similar processes. Please discuss the extent to which this utility integration effort addressed cost of service and rate design methods, or whether it may address those topics in the future.

Response:

The integration efforts were not related to cost of service and rate design methods are not expected to change in the future.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-054

Regarding: Cost of service methods
Witness: Aberle

a. Is MDU required to submit marginal cost of service studies with its natural gas rate applications in any of its other regulatory jurisdictions? If so, please identify the jurisdiction and list the cost functions for which MDU is required to estimate marginal costs.

b. To the extent you know, please identify which, if any, of the three other utilities within the MDU Resources Group, Inc.'s Utility Group (see the testimony of D.L. Goodin, p. 8) are required by their regulatory commissions to submit marginal cost of service studies to support rate proposals.

c. Please provide the most recent class cost of service/cost allocation decisions issued by the North Dakota, South Dakota and Wyoming regulatory commissions regarding MDU's natural gas utility services in those jurisdictions in which findings were made regarding reasonable methods for classifying and allocating distribution mains-related costs.

Response:

a. No.
b. It is Ms. Aberle's understanding that the Oregon Public Utilities Commission requires long run incremental cost studies to be filed as part of a rate case.
c. No such references were found based on a review of Orders issued since 1993.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-055

Regarding: Marginal cost study
Witness: Aberle, Mormon

a. **Please confirm that in Ms. Aberle's Exhibit_(TAA-3), p. 27 of 28, the five year averages for Customer Accounts Expense, Customer Service & Informational Expense, and Sales Expenses are in 2014 dollars, not 2006 dollars. Otherwise, please explain.**

b. **In Order 6580a, Docket D2004.4.50, the Commission directed MDU to more thoroughly evaluate forward-looking gas costs as part of its marginal cost studies, including how Williston Basin Interstate Pipeline-related transportation costs are incurred and how those costs are allocated to rate classes. (Order 6580a, p. 81.) Please explain where MDU has addressed this issue in this case or, alternatively, if it has not been addressed in this case, please explain whether MDU has addressed the issue in a tracker proceeding and, if so, please identify the proceeding.**

c. **Mr. Mormon testified that that MDU's studies of the Billings Landfill project indicated that gas could be produced for about $6.00 per dkt and that production costs would decrease over time as the landfill grows and economies of scale are exploited. (See p. 5 of Mr. Mormon's prefiled testimony.) Please provide MDU's economic analysis of the Billings Landfill project and discuss whether that project's costs approximate the long-run marginal cost of gas supply.**

Response:

a. The expenses are in 2014 dollars.

b. The gas supply portfolio, including associated transportation and storage services, is addressed in the Annual Gas Cost Tracking Adjustment filing submitted in September of each year. All gas supply related costs, other than the proposed investment in the Billings landfill, are recovered through the monthly Gas Cost Tracking adjustments and are not part of the rate case process.

c. Please see Attachment A for the Final Report from Wenck Associates dated December 2007. Please see Attachment B for the analysis prepared during the 2008. Please see Attachment C for a Final Report from Wenck Associates dated January 2009. Please see Attachment D for analyses prepared in 2009. Please see Attachment E for an analysis completed in

October 2011. The Billings Landfill project does not approximate the long-run marginal cost of gas supply for Montana-Dakota.

Response No. PSC-055
Attachment A

Montana-Dakota Utilities Co.

City of Billings Regional Landfill Gas-to-Energy Feasibility Report

Final Report

Wenck File #1987-01

Prepared for:

MONTANA-DAKOTA UTILITIES CO.
400 North 4th Street
Bismarck, ND 58501

Prepared by:

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December 2007

Wenck

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Executive Summary

Montana-Dakota Utilities Co. (Montana-Dakota) has retained Wenck Associates, Inc. (Wenck) to complete a feasibility study evaluating the technical and economic aspects of installing a gas-to-energy system at the City of Billings Regional Landfill.

A landfill gas-to-energy system collects the gas generated by decomposing municipal solid waste (MSW). The gas is extracted out of vertical wells and into underground lateral piping by applying a negative pressure to the landfill via a compressor or blower unit. The gas, once compressed and cleaned to the necessary extent, can be used as a viable fuel source in different applications.

The City of Billings Regional Landfill is a MSW facility that has been receiving waste since 1968. Approximately 4 million tons of MSW have been placed over the years.

Theoretical landfill gas generation analyses indicate that landfill gas flow rates are high enough to feasibly install a gas-to-energy system at the Billings Landfill. Approximately 1,480 standard cubic feet per minute of landfill gas is currently available based on Wenck's revised landfill gas generation model. The specific type of gas-to-energy system is yet to be determined. Three potential gas-to-energy options have been identified and are as follows:

- Option 1 - Distributing gas directly to a Montana-Dakota-owned natural gas pipeline
- Option 2 - Piping gas directly to end user (third party)
- Option 3 - Electrical generation

Regardless of the gas-to-energy system implemented, an active gas system would need to be installed to collect the landfill gas. Wenck has provided budgetary capital and O & M costs associated with an active gas system and each gas-to-energy option. A summary of the costs and annual energy production is presented below.

Table 1
City of Billings Regional Landfill
Summary of Total Estimated Capital Costs and Annual Energy Production

Item	Option 1 Direct Use	Option 2 Third Party	Option 3 Electrical Generation
Landfill Active Gas System	$2,203,000	$2,203,000	$2,203,000
Capital Cost	$4,173,000	$2,210,000	$3,867,000
Total	**$6,376,000**	**$4,413,000**	**$6,070,000**
Energy Produced Per Year	**331,000 MMBtu**	**331,000 MMBtu**	**24,400,000 kWh**

* Assumed continuous flow rate of 1,400 scfm
** Assumed 3,000 kW of usable power at a load factor of 93%

Table 2
City of Billings Regional Landfill
Summary of Total Estimated O & M Costs

Item	Option 1 Direct Use	Option 2 Third Party	Option 3 Electrical Generation
Landfill Active Gas System	$110,000	$110,000	$110,000
Annual O & M	$485,000	$361,000	$370,000
Total*	**$595,000**	**$471,000**	**$480,000**

*Increase of 7% per year

1.0 Background and Purpose

In 2007, Montana-Dakota Utilities Co. (Montana-Dakota) contacted Wenck Associates, Inc. (Wenck) about the feasibility of landfill gas utilization from the City of Billings Regional Landfill. Discussions between Montana-Dakota and Wenck on landfill gas potential and different end-use options were held. Montana-Dakota has since requested that Wenck perform a feasibility study to evaluate the technical and economic aspects of such options. The three gas-to-energy options are:

- Direct use of landfill gas to a Montana-Dakota natural gas distribution pipeline
- Piping gas to end user (third party)
- Electrical generation

Purpose of Feasibility Study

The purpose of the feasibility study is to assess the technical and economic feasibility of implementing a gas-to-energy system at the City of Billings Regional Landfill. The key objectives of the feasibility study, as set forth in a letter dated May 3, 2007, are defined below:

- Re-develop the landfill model for gas generation to predict current and future gas generation
- Conceptual design of gas system
- Evaluate cost associated with system
- Develop O & M costs associated with alternatives
- Evaluate resulting issues and permits
- Develop capital cost for the above information
- Provide projected annual O & M costs

2.0 Landfill Gas Generation

Landfill Gas

Landfill gas is composed of a mixture of a variety of different gases. By volume, landfill gas typically contains 45% to 60% methane and 40% to 60% carbon dioxide. Landfill gas also includes small amounts of nitrogen, oxygen, ammonia, sulfides, hydrogen, carbon monoxide, and nonmethane organic compounds (NMOCs) such as trichloroethylene, benzene, and vinyl chloride.

Landfill gas is generated by the decomposition of organic waste (food, paper, etc.). The quality and quantity of the gas is a critical element in gas-to-energy systems. The quantity of landfill gas will determine the economic feasibility of many aspects of operating the system, including the distance the gas can be reasonably transported (piped) to an end user and still provide a reasonable payback period for capital expenditure.

The volume of gas a landfill can generate can be estimated through physical pump tests, in which a vacuum is applied to passive gas vents in order to draw the landfill gas to the surface. The vacuum pressure can be regulated to determine potential gas flow rates, and contents of the landfill gas can be monitored with a landfill multi gas meter. Based on the methane content, suction pressure applied to the vent, and duration of the test, a reasonable prediction of the sustainable landfill gas flow rate can be established.

The City of Billings Regional Landfill currently does not have any gas vents. Therefore, all landfill gas generation projections must be determined from theoretical modeling.

City of Billings Regional Landfill

The City of Billings Regional Landfill has been receiving waste since 1968. At that time, annual waste placement was around 19,000 tons. Approximately 241,000 tons of waste per year will have been placed by the end of 2007, with a projected annual waste placement increase of 1.25 %.

Approximately 200 acres are currently planned for waste placement, which, according to 2006 projections, would continue until approximately 2050. The landfill's 50-year plan projects a cumulative waste placement total of 16,232,000 tons from 2005 to 2054, for a total of 20,932,00 tons since 1968. Although a 200-acre footprint is planned for waste placement, the City owns a total of 842 acres of adjacent land. See Figure 1 for the City of Billings Regional Landfill existing conditions.

A breakdown of the landfill's incoming waste composition is shown below. All numbers are approximate.

- 67 % Municipal Solid Waste
- 24 % Construction & Demolition Debris, and Inert Waste
- 3 % Sludge
- 3 % Contaminated Soil
- 2% Composted Brush

2.1 THEORETICAL GAS MODELING

In 1996, EMCON conducted a landfill gas analysis of the Billings Landfill as part of the landfill gas management plan. EMCON developed a Landfill Gas Generation Model from the results of the analysis. The model estimates the quantity of landfill gas generated over time, and takes into consideration the following factors:

- Refuse acceptance rates
- Waste stream composition
- Kinematic factors (e.g. lag time, conversion time, methane yields)
- Moisture content history
- Operations protocol

Data was input into the model using available landfill data and best effort assumptions, and the resulting output was the theoretical landfill gas generation rate. The output data was classified in terms of three ranges of landfill gas generation: possible range, expected range, and recoverable

range. The possible range of landfill gas generation is the maximum and minimum values of landfill gas generation. The expected range consists of the high and low values, which are more site-specific, and the recoverable range factors in the efficiency of the site's landfill gas extraction system. The recoverable range applies a recovery factor directly to the expected range.

The 1996 EMCON model predicted a possible range between 1.9 and 3.4 cubic feet of landfill gas per pound of dry refuse. The expected range was between 2.3 and 2.9 cubic feet of gas per pound of dry refuse, while the predicted recovery factor was assumed to be 80%. The corresponding recoverable range is between 1.8 and 2.3 cubic feet per pound of dry refuse. These values can be applied to the waste placement and compaction data to formulate gas generation projections. The landfill gas generation model is a comprehensive projection of annual gas generation flow rates, from which a theoretical generation curve is developed.

2.2 REVISED GAS MODEL

Wenck completed a revised model of the landfill gas generation using an independent modeling program. More current data was available for Wenck's revised model, as refuse acceptance data was available through 2004. The results from Wenck's revised gas model show higher landfill gas generation potential. This is due primarily to an increase in the landfill's service area since the 1996 study. Figure 2 shows a comparison of the theoretical and revised landfill gas generation models for the Billings Landfill.

The primary input into the model is the landfill's refuse acceptance rate. The 1996 EMCON study made waste generation rate projections, based on best effort assumptions, until 2049. These projections ended up being conservative. For example, the quantity of 2004 landfilled waste, based on these projections, was 141,000 tons. The actual amount of waste landfilled in 2004 was 248,271 tons, or an increase of 76% over the projected amount. Because of these acceptance rate increases, the results of Wenck's model show higher landfill gas generation rates than the 1996 model. Both landfill gas generation models used a recovery factor of 80%. Table 4-1 shows a summary of each model's gas generation projections, as well as the equivalent MMBTU's per hour and year.

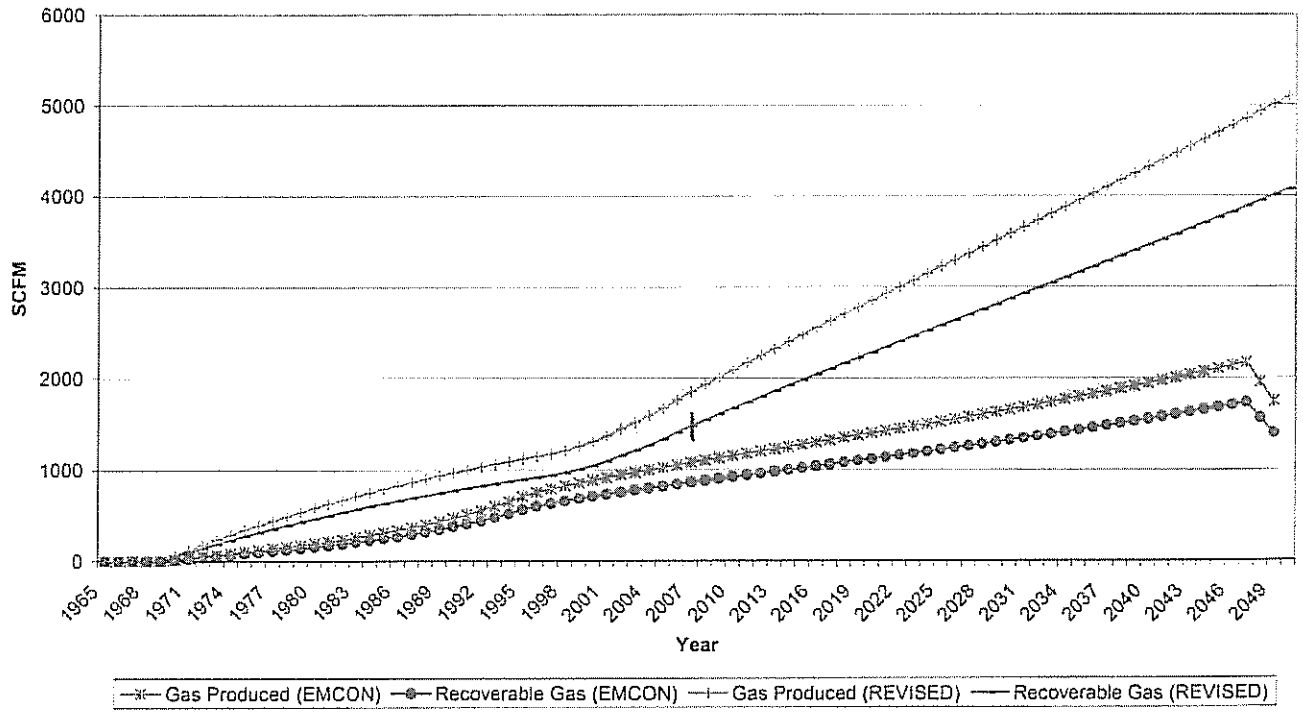
Table 2-1

Summary of Landfill Gas Generation Models

Recoverable Gas Generation Projections

	Model Entity					
Time	**EMCON (1996)**			**Wenck Revised (2007)**		
	SCFM	**MMBtu Per Hour**	**MMBtu Per Year**	**SCFM**	**MMBtu Per Hour**	**MMBtu Per Year**
Current (2007)	864	23.6	206,740	1,481	40.4	353,900
Peak (Year)	1,735 (2046)	47.3	414,350	4,078 (2050)	111.2	974,100

Figure 2
City of Billings Regional Landfill
Comparison of Landfill Gas Generation Curves



3.0 Landfill Active Gas System

Regardless of the gas-to-energy option implemented, an active gas system must be installed to collect the landfill gas. The active gas system would essentially be the same for all gas-to-energy options, with variations only in the necessity and sizing of the compressor. This section summarizes the components and workings of an active gas system.

3.1 CITY OF BILLINGS REGIONAL LANDFILL

There are currently no gas vents at the City of Billings Regional Landfill, meaning that wells, horizontal piping, and a collection system would need to be installed as part of an active gas system.

Components of an active gas system are described below and include:

- Gas wells
- Gas piping
- Condensate tanks
- Blower and Flare
- Compressor
- Gas treatment system

The active gas system would include either a blower or a compressor. The necessity of a blower or compressor is dependent on each gas-to-energy option. See Figure 3 for a preliminary active gas system layout of the Billings Landfill.

Gas Wells

A gas well is typically a 36-inch diameter borehole into the waste that has a 6-inch perforated riser pipe encased in coarse aggregate to collect the landfill gas. The gas well is sealed at the top (ground surface) to prevent gas escape. The gas well is connected to sub-header piping below the surface to transmit it through the collection system. A wellhead (valve) is placed at the top of the well, before the sub-header piping, to control the flow of gas being pulled from each individual well.

Gas Piping

From the well, the gas is transferred through a horizontal sub-header pipe that is sloped at a minimum of 3 percent grade away from the well, providing condensate drainage, to a main gas header pipe. A gas header is a larger diameter pipe that encircles the perimeter of the gas wells to collect gas from the sub-header pipes. The header pipe delivers the gas to the blower and/or compressor. The main gas header pipe is designed to be graded at a minimum of 3 percent when placed in waste and 0.5 percent when located out of the waste to facilitate the collection of condensate.

Based on Wenck's preliminary estimations of gas flows, it was determined that a 6-inch sub-header and an 18-inch header pipe would be needed. The size of the horizontal pipe system was designed to keep gas velocities below 20 feet per second in the gas header and to optimize the efficiency of the header pipe.

Condensate Tanks

A critical element of any gas collection system is the collection and treatment of condensate. Condensate forms when the moisture in gas travels from a vertical well to the horizontal piping and condenses (liquefies). If condensate is not removed, efficiency is lost because the available area within the pipe for gas flow is restricted. Condensate tanks are similar to leachate collection tanks and are placed at designed low points along the gas header pipe to collect the condensate. Condensate tanks can be used in conjunction with the landfill's leachate collection system. The preliminary design of the active gas system includes one proposed 2,000-gallon condensate tank.

As condensate accumulates in the condensate tank, periodic removal is required. Typically, condensate is sent to WWTP for disposal.

Blower and Flare

A landfill gas blower is necessary to produce a vacuum on the gas vents to pull the landfill gas from the wells to a flare. A flare is a unit that is utilized for igniting and burning the landfill gas. The flare burns off the majority of the organic constituents.

Due to safety concerns and noise reduction, an enclosed flare is recommended. An enclosed flare is proposed as part of this feasibility study. An enclosed flare has its flame entirely enclosed, rather than having an open flare. In addition, an enclosed flare does not require additional gas treatment other than a standard filter located before the blower. As part of the proposed flare system, a control panel and auto-dialer are included. The control panel would allow the flare to be operated if the compressor is out of operation, or if the end user is only utilizing a small portion of the landfill gas. In addition, the system would include a flow meter to measure gas flow, and a paperless chart recorder to record gas flows and temperature.

Maintenance on blower units is minimal, but includes changing oil and inspecting the belts on the system. The motor is required to be overhauled or replaced approximately every five years.

Compressor

A compressor is similar to a blower, but it is capable of increasing the pressure of the gas, allowing it to be sent through a pipeline to an end user. Thus, a compressor is only necessary if the required end-use pressure of the gas is higher than a blower can provide.

The necessity of a compressor is described for each option in Section 4. A skid-mounted oil-flooded screw compressor would be used when required.

Typical maintenance performed on an oil-filled screw compressor includes changing oil and filters, which includes the oil/gas separator membrane on a yearly basis. As with a blower, the compressor's motor needs to be replaced or overhauled approximately every five years.

A blower or compressor is required as part of the active gas system. However, since the blower or compressor requirements are specific to each end user, the costs will be included under each gas-to-energy option.

Moisture Removal / Gas Treatment

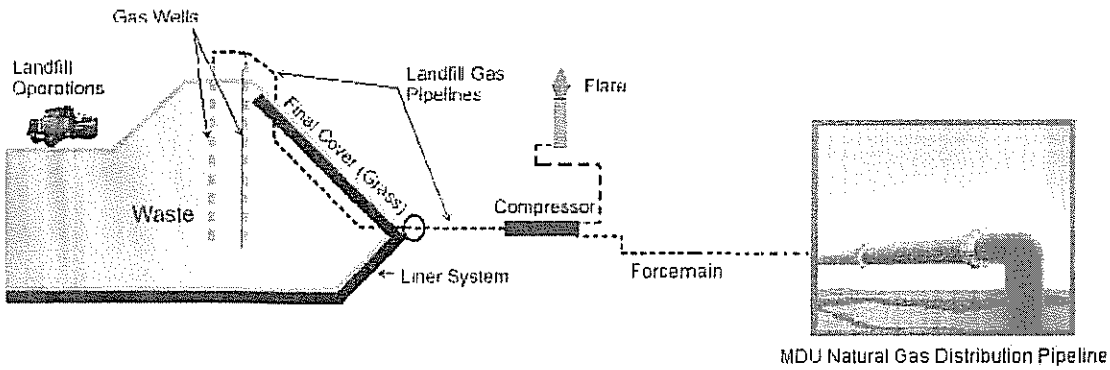
After the raw gas has been collected and passed through the compressor or blower, moisture is removed with a chiller unit. A chiller, or dehydration unit, cools down the gas to 40 degrees dew point. Cooling the landfill gas causes the moisture in the gas to condense in liquid form. When the condensate is removed, most of the VOCs (volatile organic compounds) other than methane are also removed from the gas. The dehydration unit would have to be inspected annually by a commercial refrigeration contractor. The coalescer filter is similar to a filter on an air compressor, in that it collects additional impurities or particulates that were not removed with the condensate. The coalescing filter has to be replaced every six to twelve months, depending on the pressure drop caused by the filter.

Specific gas treatment procedures will be required for each end use option. Sections 4 and 5 will include specific procedures and costs for each option.

4.0 Gas-To-Energy Options and Modifications

This section describes the gas-to-energy options and addresses specific modifications for each system. The gas collection system (i.e., the active gas system except for the blower/compressor) would remain the same for each option. However, the sizing of a blower/compressor, along with other modifications, depends on the specific gas-to-energy system implemented.

4.1 OPTION 1: MONTANA-DAKOTA DIRECT USE TO PIPELINE



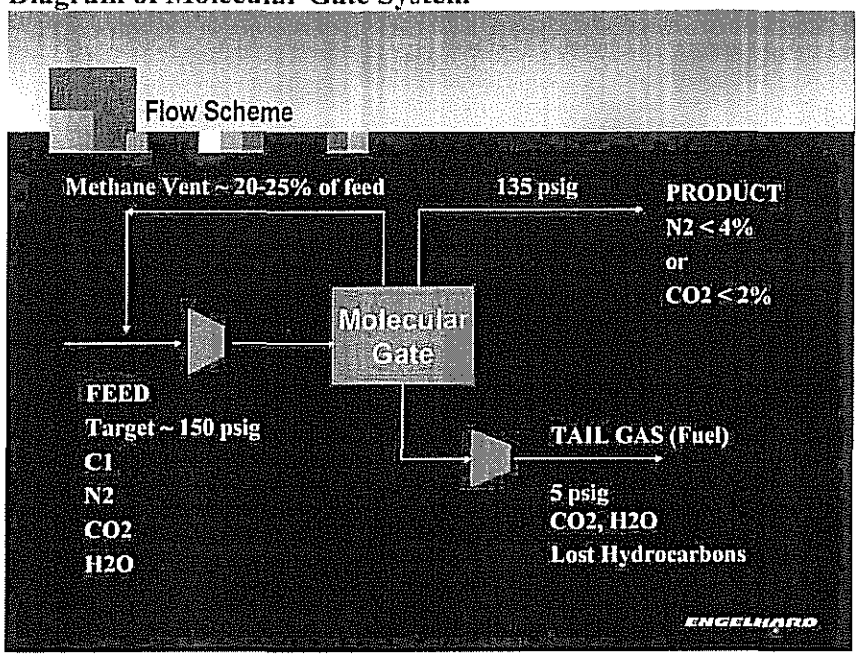
The first gas-to-energy option consists of cleaning the landfill gas and sending it directly to a Montana-Dakota-owned natural gas distribution pipeline. This option would use as much landfill gas as the compressor could supply. The following steps would be required in this process:

- Determine specific Montana-Dakota requirements (gas treatment, pressure requirements, etc.)
- Modify active gas system accordingly
- Construct pipeline to transport cleaned gas directly to Montana-Dakota distribution pipeline

Pipeline-quality gas requires special treatment prior to distribution. Inert substances, such as N_2 and CO_2, are unfavorable and need to be removed before the gas enters a high-Btu pipeline. A maximum inert specification of 2 to 4% is typically used for high-Btu pipelines.

A technology called Molecular Gate effectively removes N_2 and / or CO_2 from landfill gas. In this system, the compressed gas is fed at 150 psig through a fixed bed of solid adsorbent material. N_2, CO_2, and H_2O "cling to" the adsorbent, while methane passes through the bed. Several pressure vessels are used in this system, and the gas flow is diverted to another tank when the original becomes saturated. The original vessel is cleaned by decreasing the pressure, and is again brought online when the N_2, CO_2, and H_2O have been removed. The system is designed for unattended operation and can automatically adjust to variable flow rates, feed compositions, and purity requirements. Figure 4 shows a diagram of the Molecular Gate system.

Figure 4
Diagram of Molecular Gate System

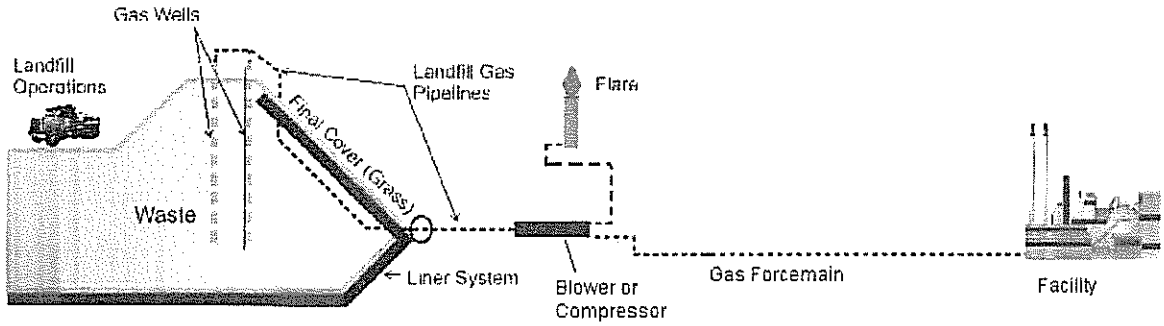


When the landfill gas has been cleaned to pipeline specifications, it is distributed through a forcemain to a natural gas distribution pipe. Through the Molecular Gate system, gas is discharged at a pressure of 135 psig, which is not adequate for a Montana-Dakota pipeline's

operational pressure of 750 psi. To be able attain 750 psi the gas would have to be compressed again after the molecular gate system before it is discharged into Montana-Dakota pipeline. Based on the results of Wenck's revised landfill gas generation model, the compressor and gas cleaning system were sized for a flow rate of 1,400 scfm.

Upgrading this gas-to-energy option is the least flexible of the three options, but it is possible. Expansion would require additional compressors as well as additional processing containers. Therefore, the system size must be carefully selected during the design stages.

4.2 OPTION 2: THIRD PARTY END USER (NO CLEANING)



The fundamental steps in a gas-to-energy system to a third party are as follows:

- Find an end user (24-hour facility) to utilize landfill gas as a fuel source
- Determine system requirements, special modifications, etc.
- Construct forcemain pipeline to facility and perform modifications

In this application, all landfill gas can be sent to the end user. Common end users of gas-to-energy systems include ethanol plants, refineries, and other 24-hour processing facilities. These facilities use the constant flow of landfill gas as a fuel source for their boilers. Boiler applications are generally less sensitive to landfill gas contaminants, and therefore require less cleanup than other alternative uses for landfill gas. Boilers have the lowest NO_x and carbon monoxide emissions of the combustion technologies.

Special Boiler Modifications

The equipment for retrofitting a boiler to burn landfill gas is commercially available, proven, and not overly complex. However, the decisions that must be made during engineering and design are site-specific and may be somewhat involved. For example, some installations have retained the original burner, but have modified it for landfill gas while maintaining the existing natural gas fuel train and gas ring to permit landfill gas/natural gas co-firing. Other installations have replaced the entire burner, controls, and fuel train with a dual-fuel burner and dual-fuel trains specifically designed to handle medium-Btu gas. In general, the decision to furnish all new equipment is made based on the owner's preference, or because the existing burner and controls are nearing the end of their useful lives. Additional analysis may be required to determine the amount of landfill gas compression provided versus the modifications needed for the burner and gas train. Because landfill gas is typically a wet gas, often containing trace corrosive compounds, the fuel train and possibly some burner "internals" should be replaced with corrosion-resistant materials. Stainless steel has typically been the material selected. The controls associated with fuel flow and combustion air flow need to be engineered to cope with the variable heat content of landfill gas. The complexity of the burner management system will depend upon whether the boiler is to be co-fired with natural gas or oil, and whether the boiler is to be co-fired at all times, or if there will be times when it will be fired with landfill gas only. Modern oxygen analyzers and flame sensors make it possible to fire landfill gas with the same level of safety that is characteristic of current natural gas systems.

Other Considerations

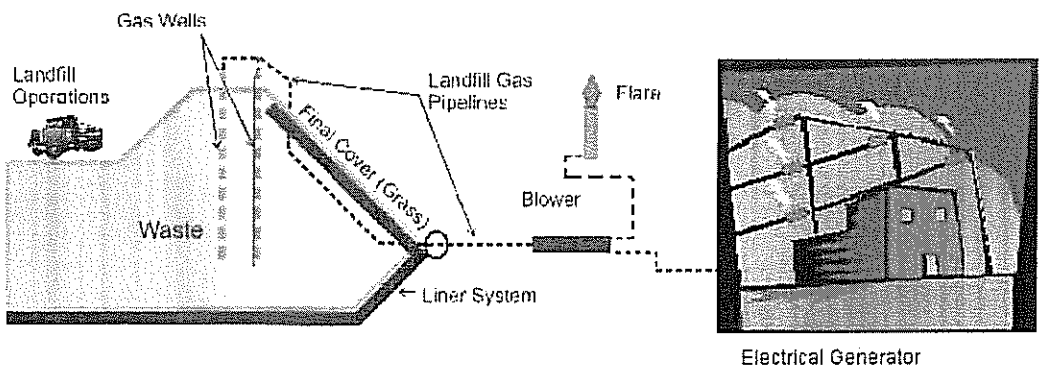
In designing and assessing the economic feasibility of projects utilizing landfill gas in boilers, several factors in addition to the boiler retrofit must be considered. For example, the quantity of landfill gas available must be considered and compared to the facility's steam needs and boiler capacities. Factors such as pipeline right-of-way issues and the distance between the landfill and the boiler will influence costs and the price at which landfill gas can be delivered and sold to the boiler owner. Because landfill gas is generally saturated with moisture, gas treatment is needed before it is introduced into the pipeline and subsequently the boiler, to avoid condensation and

corrosion. Additionally, condensate tanks along the pipeline are necessary as condensation in the main pipeline can cause blockages. Fortunately, the level of landfill gas clean-up required for boiler use is minimal, with only large particle and moisture removal needed. Other compounds in LFG, such as siloxanes, do not damage boilers or impair their function.

For the purpose of this study, Wenck assumed a potential end user is four miles from the landfill. The gas pressure requirement is assumed to be 18 psi and the flow rate is assumed to be 1,400 CFM (based on the 2007 landfill gas generation projection from Wenck's revised model). For the given length, pressure, and flow rate, a dual-staged blower and a dehydration unit would be needed as part of the active gas collection system. Section 5 includes budgetary capital and annual O & M costs associated with this gas-to-energy option. It is assumed that the end user would take care of any special modifications to the boiler and/or end-use facility.

Future expansion of this option would require additional compression (blowers). The forcemain pipe size should be designed to accommodate increasing gas flows in the future.

4.3 OPTION 3: ELECTRICAL GENERATION



Electrical generation consists of sending the landfill gas directly to a generator that uses it as a fuel source. This gas-to-energy option utilizes only as much landfill gas as the generators can take in. The basic steps involved in this process include:

- Cleaning landfill gas to appropriate levels

- Selecting a generator based on gas flow rates
- Utility agreement and connection
- Transmission of electricity

Since the landfill gas pressure requirements for electrical generation are relatively small (approximately 2 psig), a compressor would not be required as part of the active gas system for electrical generation. A dehydration unit would be required to condense the moisture and remove unwanted VOCs. Additional contaminants would be removed with a coalescer filter.

Generator selection is important in maximizing landfill gas utilization. For this study, two 550 scfm generators were selected. Although Wenck's revised model indicates that approximately 1,480 scfm may currently be recoverable, the installation of two units would be recommended in case gas generation is less than predicted. Each generator is rated at 1,600 kW, with approximatey 1,500 kW of usable power after losses.

This gas-to-energy option would be expanded incrementally by adding generators to the system. The proposed 3,500 square foot building that houses the generators would be large enough to accommodate two additional generators for future expansion. The interconnect point must be capable of handling increased capacity as additional generators are brought online.

An agreement with the utility provider would need to be established. Since Montana-Dakota does not provide electrical services in the immediate Billings region, an agreement would need to be established with one of the current providers - Northwestern Energy or Yellowstone Valley REA.

Transmitting electricity to the grid would be the final step in this gas-to-energy system. Montana-Dakota's in-house capabilities in electrical transmission would prove to be ideal for this.

5.0 Economic Evaluation

The active landfill gas collection system and blower/compressor are the key components for a gas-to-energy system. To help determine the feasibility of the system, an economic evaluation was completed to review the capital and operational and maintenance costs for each gas-to-energy option discussed in Section 4. The budgetary cost estimates were based on supportable, reasonably conservative assumptions, which shall result in conservative cost estimates. These cost estimates project the initial capital expenditure and the annual operation and maintenance costs.

Cost estimates are based on user knowledge of gas-to-energy systems construction and operation, experienced vendors, and construction and operation and maintenance costs at existing gas-to-energy systems. The major economic inputs that were developed for the estimate are the capital cost and operation and maintenance (O&M) costs. Included in the capital cost estimate were allowances for design, project management, construction management, insurance, and security during construction. For comparative purposes, building enclosures for each gas-to-energy option are assumed to be $150 per square foot. Estimated O&M costs include utilities, parts, supplies, condensate disposal, chemicals, and services by outside contractors (e.g., specialty maintenance).

5.1 ACTIVE GAS SYSTEM BUDGETARY COST ESTIMATES

Table 5-1 provides an estimated capital cost for City of Billings Regional Landfill to install an active gas system with an enclosed flare. The blower or compressor and enclosed building is not included in the cost estimate, as it is specific to the gas-to-energy option chosen.

5.1.1 Capital Cost

Table 5-1
City of Billings Regional Landfill
Active Gas System Capital Costs

Bid Item		Quantity		Unit Price	Extended Price
1	Field Engineering	1	LS	$15,000	$15,000
2	Mobilization	1	LS	$20,000	$20,000
3	[1]Health & Safety Plan	1	LS	$2,000	$2,000
4	Install Gas Wells	4,400	VLF*	$110	$484,000
5	Wellhead Assembly	39	EA	$1,500	$58,500
6	6-inch HDPE Subheader	8200	LF	$30	$246,000
7	18-inch HDPE Header	8550	LF	$70	$598,500
8	12-inch Valve	1	EA	$6,000	$6,000
9	Access Riser	1	EA	$1,000	$1,000
10	2,000 Gallon Condensate Tank	1	EA	$9,000	$9,000
11	Electrical	1	LS	$60,000	$60,000
12	Enclosed Flare	1	LS	$195,000	$195,000
				Total Capital Costs	**$1,695,000**
13	Legal, Administration, Permitting & Engineering (15%)	1	LS	$254,000	$254,000
14	Contingency (15%)	1	LS	$254,000	$254,000
				Active Gas System Total **	**$2,203,000**

* Vertical Lineal Foot

** Prices do not include blower/compressor or enclosed building.

[1] The health and safety plan is a document that addresses safety and health hazards associated with construction of an active gas collection system. (Plan is supplied by contractor)

Note: Additional costs would be associated with expansion of the active gas collection system. The capital costs to expand the gas system could be paid with the additional revenue generated by the sale of additional landfill gas.

5.1.2 Operation and Maintenance Costs

Table 5-2 provides estimated annual O & M costs for the Billings Landfill active gas system with an enclosed flare. Active gas system management typically consists of the day-to-day tasks associated with managing an active gas collection system (maintenance, adjustments to wellfield, blower etc.).

Table 5-2
City of Billings Regional Landfill
Active Gas System Annual O & M Costs

Bid Item		Quantity		Unit Price	Extended Price
1	Condensate Disposal	1	LS	$10,000	$10,000
2	Active Gas System Management	1	LS	$100,000	$100,000
				Active Gas System O & M Total*	**$110,000**
*Increase of 7% per year					

5.2 MONTANA-DAKOTA DIRECT USE BUDGETARY COST ESTIMATES

5.2.1 Capital Cost

Table 5-3 provides estimated capital costs for a compressor and gas treatment system to deliver landfill gas to a distribution pipeline. Items 2 through 5 are components of the Molecular Gate system described in the previous Section. The price estimate is for a 1,400 scfm system.

Table 5-3
City of Billings Regional Landfill
Montana-Dakota Direct Use Capital Costs

Bid Item		Quantity		Unit Price	Total Price
1	Oil Flooded Screw Compressor	1	LS	$450,000	$450,000
2	System Cost CO2 Removal	1	LS	$900,000	$900,000
3	System Cost N2 Removal	1	LS	$700,000	$700,000
4	H2S Removal	1	LS	$100,000	$100,000
5	Moisture Removal	1	LS	$120,000	$120,000
6	Equipment Installation	1	LS	$400,000	$400,000
7	Slab for Molecular Gate System	1	LS	$25,000	$25,000
8	Building Enclosure	700	SF	$150	$105,000
9	Forcemain to Distribution Pipeline	1	LS	$110,000	$110,000
10	Reciprocating Compressor (750 psi)	1	LS	$300,000	$300,000
				Total Capital Costs	**$3,210,000**
11	Legal, Administration, Permitting & Engineering (15%)	1	LS	$481,500	$481,500
12	Contingency (15%)	1	LS	$481,500	$481,500
				MDU Direct Use Total	**$4,173,000**

M-D EXPERTS

5.2.2 Operation and Maintenance Costs

Table 5-4 provides estimated annual O & M costs for a compressor and gas treatment system to deliver landfill gas to a distribution pipeline. The electrical consumption cost assumes the compressor runs continuously (no shut downs) at an electric rate of $0.08 cents per kWh.

Table 5-4
City of Billings Regional Landfill
Montana-Dakota Direct Use Annual O & M Costs

Bid Item		Quantity		Unit Price	Extended Price
1	Electrical Consumption	1	LS	$385,000	$385,000
2	Maintenance	1	LS	$150,000	$150,000
				MDU Direct Use O & M Total*	**$535,000**
*Increase of 7% per year					

5.3 THIRD PARTY END USER BUDGETARY COST ESTIMATES

5.3.1 Capital Cost

Table 5-5 provides estimated capital costs for a compressor and gas treatment system to deliver landfill gas as a fuel source via a 4-mile pipeline at 18 psi with a flow rate of 1,400 scfm.

Table 5-5
City of Billings Regional Landfill
Third Party End User Capital Costs

Bid Item		Quantity		Unit Price	Extended Price
1	Dual-Stage Blower	1	LS	$260,000	$260,000
2	Dehydration Unit	1	LS	$125,000	$125,000
3	Slab for Dehydration Unit	1	LS	$25,000	$25,000
4	Building Enclosure	600	SF	$150	$90,000
5	Forcemain Pipeline (4-miles) (Estimated)	1	LS	1200000	$1,200,000
				Total Capital Costs	**$1,700,000**
6	Legal, Administration, Permitting & Engineering (15%)	1	LS	$255,000	$255,000
7	Contingency (15%)	1	LS	$255,000	$255,000
				Compressor & Gas Treatment System Total	**$2,210,000**

5.3.2 Operation and Maintenance Costs

Table 5-6 provides estimated annual O & M costs for a compressor and gas treatment system to deliver landfill gas as a fuel source via a 4-mile pipeline at 18 psi. The electrical consumption cost assumes the blower and dehydration unit run continuously (no shut downs) at an electric rate of $0.08 cents per kWh.

Table 5-6
City of Billings Regional Landfill
Third Party End User Annual O & M Costs

Bid Item		Quantity		Unit Price	Extended Price
1	Electrical Consumption (Blower)	1	LS	$280,000	$280,000
2	Electrical Consumption (Dehydration Unit)	1	LS	$21,000	$21,000
3	Blower Equipment Maintenance	1	LS	$30,000	$30,000
4	Dehydration Unit Equipment Maintenance	1	LS	$30,000	$30,000
	Compressor & Gas Treatment O & M Total*				**$361,000**
*Increase of 7% per year					

5.4 ELECTRICAL GENERATION BUDGETARY COST ESTIMATES

5.4.1 Capital Cost

The total cost to install two 1.6 MW electrical generators would be approximately $4,515,000. This price includes an all-inclusive masonry building with sufficient room for four generators. Thus, two additional generators could be installed as needed, with equipment being the only additional cost. A building that is smaller or constructed with different material would reduce the capital cost.

Table 5-7
City of Billings Regional Landfill
Electrical Generation Capital Costs

	Bid Item	Quantity		Unit Price	Extended Price
1	Cat 3520C Electrical Generator (1.6 MW)	2	EA	$750,000	$1,500,000
2	Fuel Gas Booster (2,400 scfm)*	1	EA	$250,000	$250,000
3	Step up Transformer to 12.47 KV	1	EA	$60,000	$60,000
4	Switchgear	1	EA	$300,000	$300,000
5	Gas Chromatograph	1	EA	$80,000	$80,000
6	Building Enclosure	3,500	SF	$150	$525,000
7	Interconnect Cost (assumed 2 miles)	1	EA	$260,000	$260,000
				Total Capital Costs	**$2,975,000**
8	Legal, Administration, Permitting & Engineering (15%)	1	LS	$446,000	$446,000
9	Contingency (15%)	1	LS	$446,000	$446,000
				Electrical Generation System Total	**$3,867,000**

* Includes fuel conditioning to meet Caterpillar specifications

5.4.2 Operation and Maintenance Costs

Table 5-8 provides estimated annual O & M costs for electrical generation with two 1.6 MW generators.

Table 5-8
City of Billings Regional Landfill
Electrical Generation Annual O & M Costs

	Bid Item	Quantity		Unit Price	Extended Price
1	Generator Maintenance	2	EA	$185,000	$370,000
				Electrical Generation O & M Total	**$370,000**

* Assumes 93% on-line, with O & M cost of 1.5 cents per kW (generally accepted values)

5.5 SUMMARY OF TOTAL COSTS

The total estimated capital and O & M costs for the active gas system and each of the three options are listed in Tables 5-9 and 5-10 below. A summary of the annual energy production for each option is included for comparison purposes.

Table 5-9
City of Billings Regional Landfill
Summary of Total Estimated Capital Costs and Annual Energy Production

Item	Option 1 Direct Use	Option 2 Third Party	Option 3 Electrical Generation
Landfill Active Gas System	$2,203,000	$2,203,000	$2,203,000
Capital Cost	$4,173,000	$2,210,000	$3,867,000
Total	**$6,376,000**	**$4,413,000**	**$6,070,000**
Energy Produced Per Year	**331,000 MMBtu**	**331,000 MMBtu**	**24,400,000 kWh**

* Assumed continuous flow rate of 1,400 scfm
** Assumed 3,000 kW of usable power at a load factor of 93%

Table 5-10
City of Billings Regional Landfill
Summary of Total Estimated O & M Costs

Item	Option 1 Direct Use	Option 2 Third Party	Option 3 Electrical Generation
Landfill Active Gas System	$110,000	$110,000	$110,000
Annual O & M	$485,000	$361,000	$370,000
Total*	**$595,000**	**$471,000**	**$480,000**

*Increase of 7% per year

6.0 Recommendations

Based on the feasibility study, Wenck believes that all three proposed options are technically feasible and Wenck would recommend Montana-Dakota move forward with evaluating and developing a gas-to-energy system at the landfill. Wenck would recommend Montana-Dakota move forward in the following steps:

1. Montana-Dakota prepare a financial model to determine economic feasibility of each option
2. Install a minimum of three gas wells to be tested over a duration to predict more accurate gas generation
3. Negotiate an agreement with the City of Billings to purchase the gas

Based on the results of this feasibility study, the items identified above appear to provide a sequence of steps that could be undertaken by Montana-Dakota. If chosen, their implementation should provide a foundation for a successful gas-to-energy project.

Response No. PSC-055
Attachment B

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Assumptions:

- MDU would own the landfill gas system when it goes on line.
- Renewable Energy Credits (RECs) or green tags are available but not part of modeled revenue
- Tax rate – 40%
- 50% / 50% ratio with a debt cost of 7.0%
- Tax depreciation - 15 Year MACRS
- Capitalization is based on net plant book value less future tax liability (DITs)
- Assumes minor capital expenditures
- Assumes an after-tax equity return of 10% (pre-tax 16.67%)
- There is a possibility for a property tax credit for new or expanding project

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Operating Revenues										
Annual Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Operating Expenses										
O&M	787,241	818,421	842,067	866,353	895,582	922,358	952,054	987,824	1,024,434	1,065,035
Depreciation 1/	236,321	236,321	236,321	236,321	236,321	236,321	236,321	238,821	241,321	241,321
Taxes Other Than Incor	65,607	63,925	62,242	60,560	58,878	57,196	55,513	54,525	53,519	51,801
Total Exp.	1,089,168	1,118,666	1,140,630	1,163,234	1,190,781	1,215,875	1,243,888	1,281,170	1,319,274	1,358,157
Income before Taxes	(1,089,168)	(1,118,666)	(1,140,630)	(1,163,234)	(1,190,781)	(1,215,875)	(1,243,888)	(1,281,170)	(1,319,274)	(1,358,157)
Interest Expense	263,169	248,715	235,298	222,813	211,167	200,277	189,745	181,996	174,095	163,268
Taxable income	(1,352,337)	(1,367,381)	(1,375,928)	(1,386,047)	(1,401,948)	(1,416,152)	(1,433,633)	(1,463,166)	(1,493,369)	(1,521,425)
Income Taxes	(540,935)	(546,953)	(550,371)	(554,419)	(560,779)	(566,461)	(573,453)	(585,266)	(597,348)	(608,570)
Tax Credit										
Operating Income	($548,233)	($571,713)	($590,259)	($608,815)	($630,002)	($649,414)	($670,435)	($695,904)	($721,926)	($749,587)
Rate Base	$9,121,978	$8,620,978	$8,155,899	$7,723,149	$7,319,475	$6,942,005	$6,576,937	$6,308,369	$6,034,500	$5,659,212
Rate of Return	-6.01%	-6.63%	-7.24%	-7.88%	-8.61%	-9.35%	-10.19%	-11.03%	-11.96%	-13.25%
Revenue Requirement	$2,206,762	$2,174,879	$2,139,863	$2,109,448	$2,087,538	$2,066,385	$2,049,672	$2,054,052	$2,058,601	$2,051,505
dk Production	281,350	297,350	313,350	329,350	345,350	361,350	377,350	393,350	409,350	425,350
Cost per Dk	$7.843	$7.314	$6.829	$6.405	$6.045	$5.719	$5.432	$5.222	$5.029	$4.823
Average Rev. Req.	$2,375,246	30 years								
Avg. Dk	513,350									
Avg. $/Dk	$4.627									
Rate Base										
Plant in Service										
Investment	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,552,827	$9,652,827
Additional Facilities								100,000	100,000	
	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,452,827	$9,552,827	$9,652,827	$9,652,827
Accumulated Reserve 1/										
InvestmeReserve & DIT	330,849	831,849	1,296,928	1,729,678	2,133,352	2,510,822	2,875,890	3,244,458	3,618,327	3,993,615
Rate base	$9,121,978	$8,620,978	$8,155,899	$7,723,149	$7,319,475	$6,942,005	$6,576,937	$6,308,369	$6,034,500	$5,659,212

REVENU

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
Operating Revenues								
Annual Fee		$0	$0	$0	$0		$0	$0
Operating Expenses								
O&M	1,104,044	1,144,620	1,185,435	1,227,902	1,270,595	1,315,027	1,360,484	1,406,985
Depreciation 1/	241,321	241,321	241,321	243,821	246,321	246,321	246,321	246,321
Taxes Other Than Incor	50,084	48,366	46,648	45,624	44,583	42,829	41,076	39,322
Total Exp.	1,395,448	1,434,307	1,473,404	1,517,347	1,561,498	1,604,177	1,647,880	1,692,629
Income before Taxes	(1,395,448)	(1,434,307)	(1,473,404)	(1,517,347)	(1,561,498)	(1,604,177)	(1,647,880)	(1,692,629)
Interest Expense	152,462	141,675	130,904	122,929	114,805	106,978	102,390	97,821
Taxable income	(1,547,910)	(1,575,982)	(1,604,308)	(1,640,276)	(1,676,303)	(1,711,155)	(1,750,270)	(1,790,450)
Income Taxes	(619,164)	(630,393)	(641,723)	(656,110)	(670,521)	(684,462)	(700,108)	(716,180)
Tax Credit								
Operating Income	($776,284)	($803,914)	($831,681)	($861,237)	($890,977)	($919,715)	($947,772)	($976,449)
Rate Base	$5,284,646	$4,910,729	$4,537,398	$4,260,974	$3,979,382	$3,708,065	$3,549,050	$3,390,685
Rate of Return	-14.69%	-16.37%	-18.33%	-20.21%	-22.39%	-24.80%	-26.70%	-28.80%
Revenue Requirement	$2,042,905	$2,035,952	$2,029,311	$2,039,388	$2,049,040	$2,058,477	$2,082,699	$2,108,044
dk Production	441,350	457,350	473,350	489,350	505,350	521,350	537,350	553,350
Cost per Dk	$4.629	$4.452	$4.287	$4.168	$4.055	$3.948	$3.876	$3.810
Average Rev. Req.								
Avg. Dk								
Avg. $/Dk								
Rate Base								
Plant in Service								
Investment	$9,652,827	$9,652,827	$9,652,827	$9,652,827	$9,752,827	$9,852,827	$9,852,827	$9,852,827
Additional Facilities				100,000	100,000			
	$9,652,827	$9,652,827	$9,652,827	$9,752,827	$9,852,827	$9,852,827	$9,852,827	$9,852,827
Accumulated Reserve 1/								
InvestmeReserve & DIT	4,368,181	4,742,098	5,115,429	5,491,853	5,873,445	6,144,762	6,303,777	6,462,142
Rate base	$5,284,646	$4,910,729	$4,537,398	$4,260,974	$3,979,382	$3,708,065	$3,549,050	$3,390,685

REVENU

	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
Operating Revenues								
Annual Fee	$0	$0		$0	$0	$0	$0	
Operating Expenses								
O&M	1,453,699	1,502,331	1,552,083	1,603,035	1,655,216	1,708,656	1,763,387	1,819,442
Depreciation 1/	246,321	248,821	251,321	376,321	376,321	376,321	376,321	378,821
Taxes Other Than Incor	37,569	36,510	35,432	68,346	65,667	62,988	60,309	58,325
Total Exp.	1,737,589	1,787,661	1,838,836	2,047,701	2,097,203	2,147,965	2,200,017	2,256,587
Income before Taxes	(1,737,589)	(1,787,661)	(1,838,836)	(2,047,701)	(2,097,203)	(2,147,965)	(2,200,017)	(2,256,587)
Interest Expense	93,269	91,513	89,608	223,978	211,556	199,770	188,528	180,525
Taxable income	(1,830,858)	(1,879,174)	(1,928,444)	(2,271,679)	(2,308,759)	(2,347,735)	(2,388,545)	(2,437,112)
Income Taxes	(732,343)	(751,670)	(771,378)	(908,672)	(923,504)	(939,094)	(955,418)	(974,845)
Tax Credit								
Operating Income	($1,005,246)	($1,035,991)	($1,067,458)	($1,139,029)	($1,173,699)	($1,208,871)	($1,244,599)	($1,281,742)
Rate Base	$3,232,905	$3,172,034	$3,105,993	$7,763,533	$7,332,976	$6,924,431	$6,534,751	$6,257,359
Rate of Return	-31.09%	-32.66%	-34.37%	-14.67%	-16.01%	-17.46%	-19.05%	-20.48%
Revenue Requirement	$2,133,674	$2,176,288	$2,219,372	$2,998,863	$2,995,615	$2,996,323	$3,000,633	$3,023,217
dk Production	569,350	585,350	601,350	617,350	633,350	649,350	665,350	681,350
Cost per Dk	$3.748	$3.718	$3.691	$4.858	$4.730	$4.614	$4.510	$4.437
Average Rev. Req.								
Avg. Dk								
Avg. $/Dk								
Rate Base								
Plant in Service								
Investment	$9,852,827	$9,852,827	$9,952,827	$10,052,827	$15,052,827	$15,052,827	$15,052,827	$15,052,827
Additional Facilities		100,000	100,000	5,000,000				100,000
	$9,852,827	$9,952,827	$10,052,827	$15,052,827	$15,052,827	$15,052,827	$15,052,827	$15,152,827
Accumulated Reserve 1/								
InvestmeReserve & DIT	6,619,922	6,780,793	6,946,834	7,289,294	7,719,851	8,128,396	8,518,076	8,895,468
Rate base	$3,232,905	$3,172,034	$3,105,993	$7,763,533	$7,332,976	$6,924,431	$6,534,751	$6,257,359

REVENU

	Year 27	Year 28	Year 29	Year 30
Operating Revenues				
Annual Fee	$0	$0	$0	$0
Operating Expenses				
O&M	1,876,852	1,935,653	1,995,878	2,057,563
Depreciation 1/	381,321	381,321	381,321	381,321
Taxes Other Than Incor	56,322	53,608	50,893	48,179
Total Exp.	2,314,495	2,370,581	2,428,091	2,487,062
Income before Taxes	(2,314,495)	(2,370,581)	(2,428,091)	(2,487,062)
Interest Expense	172,773	162,284	151,850	141,503
Taxable income	(2,487,268)	(2,532,865)	(2,579,941)	(2,628,565)
Income Taxes	(994,907)	(1,013,146)	(1,031,977)	(1,051,426)
Tax Credit				
Operating Income	($1,319,588)	($1,357,435)	($1,396,114)	($1,435,636)
Rate Base	$5,988,659	$5,625,098	$5,263,442	$4,904,796
Rate of Return	-22.03%	-24.13%	-26.52%	-29.27%
Revenue Requirement	$3,048,206	$3,059,749	$3,072,950	$3,087,982
dk Production	697,350	713,350	729,350	745,350
Cost per Dk	$4.371	$4.289	$4.213	$4.143
Average Rev. Req.				
Avg. Dk				
Avg. $/Dk				
Rate Base				
Plant in Service				
Investment	$15,152,827	$15,252,827	$15,252,827	$15,252,827
Additional Facilities	100,000			0
	$15,252,827	$15,252,827	$15,252,827	$15,252,827
Accumulated Reserve 1/				
InvestmeReserve & DIT	9,264,168	9,627,729	9,989,385	10,348,031
Rate base	$5,988,659	$5,625,098	$5,263,442	$4,904,796

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

CAPITALIZATION
DEBT AND EQUITY
(000)

	INITIAL INVESTMENT	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
TOTAL (Incl. DIT	9,452,827	9,121,978	8,620,978	8,155,899	7,723,149	7,319,475	6,942,005	6,576,937	6,308,369	6,034,500	5,659,212	5,284,646
DEBT	4,726,414	4,560,989	4,310,489	4,077,950	3,861,574	3,659,738	3,471,002	3,288,468	3,154,184	3,017,250	2,829,606	2,642,323
EQUITY	4,726,414	4,560,989	4,310,489	4,077,950	3,861,574	3,659,738	3,471,002	3,288,468	3,154,184	3,017,250	2,829,606	2,642,323

Long-Term Debt Cost **7%**

6

	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
TOTAL (Incl. DIT	4,910,729	4,537,398	4,260,974	3,979,382	3,708,065	3,549,050	3,390,685	3,232,905	3,172,034	3,105,993	7,763,533	7,332,976	6,924,431
DEBT	2,455,365	2,268,699	2,130,487	1,989,691	1,854,032	1,774,525	1,695,343	1,616,453	1,586,017	1,552,997	3,881,766	3,666,488	3,462,215
EQUITY	2,455,365	2,268,699	2,130,487	1,989,691	1,854,032	1,774,525	1,695,343	1,616,453	1,586,017	1,552,997	3,881,766	3,666,488	3,462,215

Lon

	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
TOTAL (Incl. DIT	6,534,751	6,257,359	5,988,659	5,625,098	5,263,442	4,904,796
DEBT	3,267,375	3,128,680	2,994,329	2,812,549	2,631,721	2,452,398
EQUITY	3,267,375	3,128,680	2,994,329	2,812,549	2,631,721	2,452,398

Long

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Depreciation Schedule

(000)

40 Year Life - Plant

Depreciation Schedule ($000)

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
BOOK DEPRECIATION	Cost											
Existing Assets (net of Accum. Dep.	9,452,827											
Depr. on Adjusted Fixed Assets		236,321	236,321	236,321	236,321	236,321	236,321	236,321	238,821	241,321	241,321	241,321
Total Book Depreciation		**236,321**	**236,321**	**236,321**	**236,321**	**236,321**	**236,321**	**236,321**	**238,821**	**241,321**	**241,321**	**241,321**
	YEAR #	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Year												
Turbines		236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	100,000	-	-	-	-	-	-	-	2,500	2,500	2,500	2,500
9	100,000	-	-	-	-	-	-	-	-	2,500	2,500	2,500
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	100,000	-	-	-	-	-	-	-	-	-	-	-
15	100,000	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	100,000	-	-	-	-	-	-	-	-	-	-	-
21	100,000	-	-	-	-	-	-	-	-	-	-	-
22	5,000,000	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-	-	-	-	-
26	100,000	-	-	-	-	-	-	-	-	-	-	-
27	100,000	-	-	-	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-	-	-	-	-
29	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-
Total Book Depreciation		**236,321**	**236,321**	**236,321**	**236,321**	**236,321**	**236,321**	**236,321**	**238,821**	**241,321**	**241,321**	**241,321**
Book Value	$9,452,827	9,216,506	8,980,186	8,743,865	8,507,544	8,271,224	8,034,903	7,798,582	7,659,762	7,518,441	7,277,120	7,035,800
Property Taxes												
Property Tax Rate	**0.7%**	**65,607**	**63,925**	**62,242**	**60,560**	**58,878**	**57,196**	**55,513**	**54,525**	**53,519**	**51,801**	**50,084**
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Enter MACRS rate (below in yellow)	4											
3 **MACRS**	**20 Year**	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%	5.2850%	4.8880%	4.5220%	4.4620%	4.4610%	4.4620%

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Depreciation Schedule

(000)

40 Year Life - Plant

Depreciation Schedule

($000)

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
4	MACRS	15 Year	5.0000%	9.5000%	8.5500%	7.6950%	6.9260%	6.2330%	5.9050%	5.9050%	5.9050%	5.9050%	5.9050%
5	MACRS	10 Year	10.0000%	18.0000%	14.4000%	11.5200%	9.2200%	7.3700%	6.5500%	6.5500%	6.5600%	6.5500%	3.2800%
6	MACRS	7 Year	14.2900%	24.4900%	17.4900%	12.4900%	8.9300%	8.9200%	8.9300%	4.4600%			
7	MACRS	5 Year	20.0000%	32.0000%	19.2000%	11.5200%	11.5200%	5.7600%					
8	MACRS	3 Year	33.3300%	44.4500%	14.8100%	7.4100%							

TAX DEPRECIATION

	Estimated											
Construction Property/Turbines	9,452,827	472,641	898,019	808,217	727,395	654,703	589,195	558,189	563,189	572,689	576,239	574,434
Total Tax Depreciation\Amortization		472,641	898,019	808,217	727,395	654,703	589,195	558,189	563,189	572,689	576,239	574,434
Balance Sheet DITs - Current Year		(94,528)	(264,679)	(228,758)	(196,430)	(167,353)	(141,150)	(128,748)	(129,748)	(132,548)	(133,968)	(133,246)
Balance Sheet DITs - Accumulated		(94,528)	(359,207)	(587,966)	(784,396)	(951,748)	(1,092,898)	(1,221,646)	(1,351,393)	(1,483,941)	(1,617,908)	(1,751,154)

		YEAR #	1	2	3	4	5	6	7	8	9	10	11
Year	Amount												
Existing	9,452,827	15 Year	472,641	898,019	808,217	727,395	654,703	589,195	558,189	558,189	558,189	558,189	558,189
1	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
4	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
5	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
7	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
8	100,000	15 Year	-	-	-	-	-	-	-	5,000	9,500	8,550	7,695
9	100,000	15 Year	-	-	-	-	-	-	-	-	5,000	9,500	8,550
10	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
11	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
13	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
14	100,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
15	100,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
16	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
19	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
20	100,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
21	100,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
22	5,000,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
25	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
26	100,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
27	100,000	15 Year	-	-	-	-	-	-	-	-	-	-	-
28	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			472,641	898,019	808,217	727,395	654,703	589,195	558,189	563,189	572,689	576,239	574,434

40 Year Life - Plant

		Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23
BOOK DEPRECIATION													
Existing Assets (net of Accum. Dep													
Depr. on Adjusted Fixed Assets		241,321	241,321	243,821	246,321	246,321	246,321	246,321	246,321	248,821	251,321	376,321	376,321
Total Book Depreciation		241,321	241,321	243,821	246,321	246,321	246,321	246,321	246,321	248,821	251,321	376,321	376,321
		12	13	14	15	16	17	18	19	20	21	22	23
Year													
Turbines		236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321	236,321
1	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-
8	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
9	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
10	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	100,000	-	-	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
15	100,000	-	-	-	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-	-
20	100,000	-	-	-	-	-	-	-	-	2,500	2,500	2,500	2,500
21	100,000	-	-	-	-	-	-	-	-	-	2,500	2,500	2,500
22	5,000,000	-	-	-	-	-	-	-	-	-	-	125,000	125,000
23	-	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-	-	-	-	-	-
26	100,000	-	-	-	-	-	-	-	-	-	-	-	-
27	100,000	-	-	-	-	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-	-	-	-	-	-
29	-	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Book Depreciation		241,321	241,321	243,821	246,321	246,321	246,321	246,321	246,321	248,821	251,321	376,321	376,321
Book Value		6,794,479	6,553,158	6,409,338	6,263,017	6,016,696	5,770,376	5,524,055	5,277,734	5,128,914	4,977,593	9,601,272	9,224,951
Property Taxes													
Property Tax Rate		48,366	46,648	45,624	44,583	42,829	41,076	39,322	37,569	36,510	35,432	68,346	65,667
		12	13	14	15	16	17	18	19	20	21	22	23
Enter MACRS rate (below in yellow)													
3	**MACRS**	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	2.2310%		

40 Year Life - Plant

	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23
4 MACRS	5.9050%	5.9050%	5.9050%	5.9050%	2.9510%							
5 MACRS												
6 MACRS												
7 MACRS												
8 MACRS												

TAX DEPRECIATION

Construction Property/Turbines	572,810	571,348	575,327	584,499	308,813	28,055	26,431	24,969	28,948	38,120	291,670	511,911
Total Tax Depreciation\Amortizat	572,810	571,348	575,327	584,499	308,813	28,055	26,431	24,969	28,948	38,120	291,670	511,911
Balance Sheet DITs - Current Year	(132,596)	(132,011)	(132,603)	(135,272)	(24,997)	87,306	87,956	88,541	87,949	85,280	33,860	(54,236)
Balance Sheet DITs - Accumulated	(1,883,749)	(2,015,761)	(2,148,363)	(2,283,635)	(2,308,632)	(2,221,325)	(2,133,370)	(2,044,829)	(1,956,880)	(1,871,600)	(1,837,739)	(1,891,975)

Year	Amount	12	13	14	15	16	17	18	19	20	21	22	23
Existing	9,452,827	558,189	558,189	558,189	558,189	278,953	-	-	-	-	-	-	-
1	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-
8	100,000	6,926	6,233	5,905	5,905	5,905	5,905	5,905	5,905	5,905	5,905	5,905	2,951
9	100,000	7,695	6,926	6,233	5,905	5,905	5,905	5,905	5,905	5,905	5,905	5,905	5,905
10	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	100,000	-	-	5,000	9,500	8,550	7,695	6,926	6,233	5,905	5,905	5,905	5,905
15	100,000	-	-	-	5,000	9,500	8,550	7,695	6,926	6,233	5,905	5,905	5,905
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-	-
20	100,000	-	-	-	-	-	-	-	-	5,000	9,500	8,550	7,695
21	100,000	-	-	-	-	-	-	-	-	-	5,000	9,500	8,550
22	5,000,000	-	-	-	-	-	-	-	-	-	-	250,000	475,000
23	-	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-	-	-	-	-	-
26	100,000	-	-	-	-	-	-	-	-	-	-	-	-
27	100,000	-	-	-	-	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-	-	-	-	-	-
29	-	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Tax Depreciation		**572,810**	**571,348**	**575,327**	**584,499**	**308,813**	**28,055**	**26,431**	**24,969**	**28,948**	**38,120**	**291,670**	**511,911**

12

40 Year Life - Plant

		Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
BOOK DEPRECIATION								
Existing Assets (net of Accum. Dep								
Depr. on Adjusted Fixed Assets		376,321	376,321	378,821	381,321	381,321	381,321	381,321
Total Book Depreciation		**376,321**	**376,321**	**378,821**	**381,321**	**381,321**	**381,321**	**381,321**
		24	25	26	27	28	29	30
Year								
Turbines		236,321	236,321	236,321	236,321	236,321	236,321	236,321
1	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-
8	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500
9	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500
10	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-
14	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500
15	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500
16	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-
20	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500
21	100,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500
22	5,000,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	100,000	-	-	2,500	2,500	2,500	2,500	2,500
27	100,000	-	-	-	2,500	2,500	2,500	2,500
28	-	-	-	-	-	-	-	-
29	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-
Total Book Depreciation		**376,321**	**376,321**	**378,821**	**381,321**	**381,321**	**381,321**	**381,321**
Book Value		8,848,631	8,472,310	8,193,489	7,912,169	7,530,848	7,149,527	6,768,207
Property Taxes								
Property Tax Rate		**62,988**	**60,309**	**58,325**	**56,322**	**53,608**	**50,893**	**48,179**
		24	25	26	27	28	29	30

Enter MACRS rate (below in yellow)

3 **MACRS**

40 Year Life - Plant

	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
4 MACRS							
5 MACRS							
6 MACRS							
7 MACRS							
8 MACRS							

TAX DEPRECIATION

Construction Property/Turbines	456,882	409,719	375,248	349,770	336,920	332,161	324,632
Total Tax Depreciation\Amortizat	456,882	409,719	375,248	349,770	336,920	332,161	324,632
Balance Sheet DITs - Current Year	(32,225)	(13,359)	1,429	12,620	17,760	19,664	22,675
Balance Sheet DITs - Accumulated	(1,924,200)	(1,937,559)	(1,936,130)	(1,923,510)	(1,905,750)	(1,886,086)	(1,863,410)

Year	Amount	24	25	26	27	28	29	30
Existing	9,452,827	-	-	-	-	-	-	-
1	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-
8	100,000	-	-	-	-	-	-	-
9	100,000	2,951	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-
14	100,000	5,905	5,905	5,905	5,905	5,905	2,951	-
15	100,000	5,905	5,905	5,905	5,905	5,905	5,905	2,951
16	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-
20	100,000	6,926	6,233	5,905	5,905	5,905	5,905	5,905
21	100,000	7,695	6,926	6,233	5,905	5,905	5,905	5,905
22	5,000,000	427,500	384,750	346,300	311,650	295,250	295,250	295,250
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	100,000	-	-	5,000	9,500	8,550	7,695	6,926
27	100,000	-	-	-	5,000	9,500	8,550	7,695
28	-	-	-	-	-	-	-	-
29	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-
Total Tax Depreciation		**456,882**	**409,719**	**375,248**	**349,770**	**336,920**	**332,161**	**324,632**

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Revenue Requirement	$2,206,762	$2,174,879	$2,139,863	$2,109,448	$2,087,538	$2,066,385	$2,049,672	$2,054,052	$2,058,601	$2,051,505
dk Production	281,350	297,350	313,350	329,350	345,350	361,350	377,350	393,350	409,350	425,350
Cost per Dk	$7.843	$7.314	$6.829	$6.405	$6.045	$5.719	$5.432	$5.222	$5.029	$4.823
System Dk Sales 1/	35,425,000	35,591,919	35,761,803	35,904,850	36,048,469	36,192,663	36,337,434	36,482,784	36,628,715	36,775,230
	0.04%	0.47%	0.48%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk	$0.062	$0.061	$0.060	$0.059	$0.058	$0.057	$0.056	$0.056	$0.056	$0.056

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Response No. PSC-055
Attachment C

Montana-Dakota Utilities Co.

City of Billings Regional Landfill Gas-to-Energy Confirmation Report

Final Report

Wenck File #1987-04

Prepared for:

MONTANA-DAKOTA UTILITIES CO.
400 North 4th Street
Bismarck, ND 58501

Prepared by:

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(701) 297-9600

January 2009

Wenck

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FIGURES

1 Record Test Well Locations
2 Comparison of Landfill Gas Generation Curves
3 Preliminary Active Gas System Layout

Appendix

A Well Drilling Photographs and Well Logs
B Pump Test Readings
C Landfill Gas Analysis

1.0 Background and Purpose

In 2007, Montana-Dakota Utilities Co. (Montana-Dakota) contacted Wenck Associates, Inc. (Wenck) about the feasibility of landfill gas utilization from the City of Billings Regional Landfill. Montana-Dakota requested that Wenck perform a feasibility study to evaluate the technical and economic aspects the following three gas-to-energy options:

- Natural gas pipeline distribution (Pipeline Distribution)
- Piping gas to end user (third party)
- Electrical generation

Since the feasibility study was completed, Montana-Dakota and Wenck have had several meetings to discuss the best gas utilization option and the revised landfill gas generation curve. Montana-Dakota determined that direct use of landfill gas to their natural gas distribution pipeline was the best gas utilization option for them. To determine if the validity of the revised gas generation curve, Montana-Dakota retained Wenck to drill three test wells in various locations of the landfill, perform pump tests on the wells and collect and analyze landfill gas samples.

Purpose of Confirmation Study

The purpose of the confirmation study is to assess the technical and economical feasibility of implementing a gas-to-energy system at the City of Billings Regional Landfill. The key objectives of the confirmation study are defined below:

- Construct three (3) gas wells to an individual depth of approximately 120 feet
- Evaluate waste cuttings
- Pump test wells
- Collect and analyze three (6) landfill gas samples
- Re-evaluate gas generation curve
- Preliminary design of gas treatment system based on revised generation curve
- Re-evaluate cost estimates based on revised gas generation curve

2.0 Gas Wells

During the week of November 3, 2008, three gas wells were installed to a an individual depth of 107 (Well 1), 121 (Well 2) and 118 (Well 3) feet that assisted in the landfill gas generation study. The gas wells were placed in areas with older waste and newer waste to get a good representation of waste type and gas composition. The final location of the wells can be found in Figure 1. During the drilling of the wells, Wenck analyzed waste cuttings to determine waste composition, moisture content and decomposition of waste. Then Wenck installed three (3) landfill gas wellheads on the wells to provide a mean to collect landfill gas sample and perform pump tests on the wells. The gas wells were designed and constructed to standards that will allow the wells to be utilized in the gas collection system.

2.1 GAS WELL INSTALLATION

During the drilling of the 36-inch diameter borehole Wenck analyzed the waste cuttings for composition, moisture and decomposition. The waste was primarily was composed of household wastes, yard wastes (favorable wastes for gas generation) and some demolition debris. Moisture content of the waste was primarily dry with some damp and wet regions, which is not optimal for gas generation, but is not the only factor in determining favorable conditions for gas generation. As the well drilling extended around 100 feet, the waste decomposition increased to where it was turning black. With the waste oxidized (black), Wenck would recommend terminating drilling at that point since we believe the waste will produce marginal gas compared to the cost of drilling.

Photographs and well logs from each of the wells can be found in appendix A.

2.2 PUMP TESTS

Once the well installation was complete, Wenck installed 2-inch vertical Landtec Wellheads to aid in pump tests and to collect gas samples. With the wellhead installed the well was connected to a 1 or 1.5 horsepower vacuum pump via 2-inch kanaflex hose that vented the landfill gas to the atmosphere with the approval from the Montana Department of Environmental Quality to vent to the atmosphere. With the vacuum applied to the well, Wenck utilized Landtec Landfill Gas Meter to obtain gas composition for the following parameters:

- Barometric Pressure
- Gas Temperature
- Methane (CH_4)
- Carbon Dioxide (CO_2)
- Oxygen (O_2)
- Balance Gas (Nitrogen)
- Static Pressure ((+) indicates positive pressure at wellhead; build up of landfill gas coming out of well without any assistance from vacuum (-) indicates vacuum applied at wellhead)
- Differential Pressure
- Gas Flow

The objective of the pump tests was to maximize gas flow out of each well while maintaining a minimum of 50 percent methane and oxygen content less than 1 percent. All of the wells performed as expected based on the revised gas generation curve developed by Wenck as part of the feasibility study. All of the wells stabilized or was close to stabilizing before the tests were terminated.

The pump tests were operated for approximately 9 days (well 3), 7 days (well 1) and 6 days (well 2). Well readings were taken three (3) times a day during landfill operations. A summary of the well readings can be found in Appendix B.

2.3 LANDFILL GAS ANALYSIS

During the pump tests, Wenck collected six (6) landfill gas samples from the three wells. Two (2) gas samples were collected from each well, via silicon lined summa canister and analyzed for the following parameters:

- Methane, CO_2, Nitrogen and Oxygen
- NMOCs
- Chlorinated Compounds
- Siloxanes
- Sulfur Compounds
- Moisture Content

The gas analysis indicated that gas quality in two of the three wells (wells 1 and 2) looks good with methane concentrations greater than 50 percent and no big issues with either sulfur or VOC's. The oxygen and nitrogen levels in the gas samples were a result of sampling techniques and not induced stress on the wells from over pulling on them. However the gas analysis from well 3 (Samples Well 3-A and Well 3-B) shows more CO_2 than methane which suggest less than optimum methanogenic production. The VOC levels in the samples imply a younger waste that may not be at a steady state methanogenesis yet. Conversations with landfill personal indicated waste in Well 3 area was only a few years old which corresponds to the gas analysis.

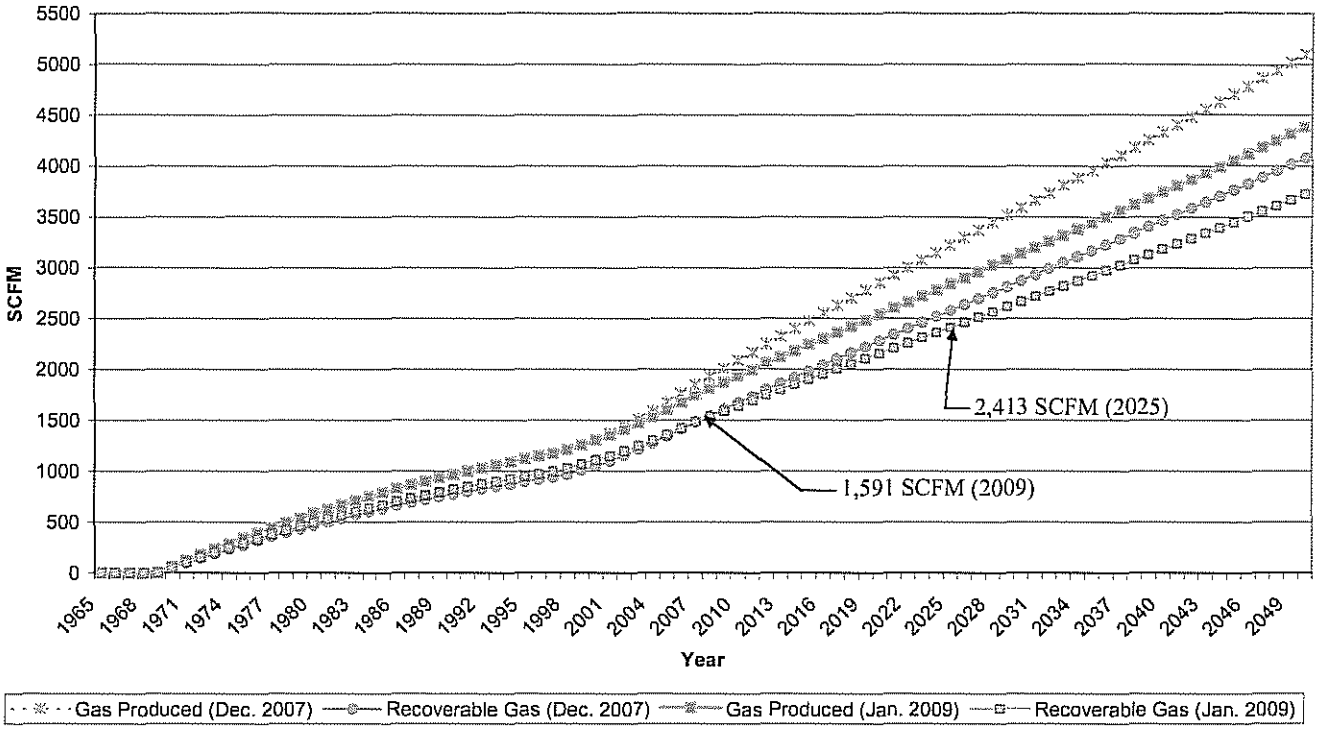
With the dilution factor utilized by the lab, Wenck does not give much credibility into the siloxane levels. Additionally the detection level for siloxane is in the PPB, which is low enough not to be a major concern.

Overall, the gas results look like typical landfill. Landfill gas analysis can be found in Appendix C. Note that Gas Sample Well 2-A was not analyzed due to oxygen intrusion during sample collection.

3.0 Gas Generation

Based on the information obtained from the well drilling, pump tests, gas analysis and site information, Wenck revised the gas generation curve utilizing actual field data rather than the theoretical data utilized as part of the initial generation curve. The revised generation curve was similar to the initial curve but varied slightly. The current recoverable gas generation rate slightly increased to 1,591 SCFM and the max generation rate decreased to 3,722 SCFM from 4,078 SCFM. The max generation rate decreased due to the amount of inorganic waste being disposed at the landfill. See Figure 2 below for the revised generation curve.

Figure 2
City of Billings Regional Landfill
Comparison of Landfill Gas Generation Curves



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Based on the revised generation curve above the Billings Regional Landfill will currently generate approximately **340,685 MMBtu's** in 2010 with the gas treatment system (Molecular Gate System) running 93% of the time. A summary of future sellable MMBtu's can be found in Table 3-1 below.

Table 3-1
City of Billings Regional Landfill
Sellable Annual MMBTU's

Year	Landfill Gas Generation Rate	Sellable Gas Per Year
	SCFM	*MMBTU's
2010	1,644	340,685
2015	1,905	394,771
2020	2,160	447,615
2025	2,413	500,044
2030	2,667	552,680
2035	2,922	605,523
2040	3,182	659,403
2045	3,448	714,526
2050	3,722	771,307

*Assumes 93% Runtime

4.0 Economic Evaluation

Based on the revised site knowledge, gas analysis, gas generation curve and larger system Wenck revised the capital and O&M Costs for the pipeline distribution option. The budgetary cost estimates were based on supportable, reasonably conservative assumptions, which shall result in conservative cost estimates. These cost estimates project the initial capital expenditure and the annual operation and maintenance costs.

Cost estimates are based on user knowledge of gas-to-energy systems construction and operation, experienced vendors, and construction and operation and maintenance costs at existing gas-to-energy systems. The major economic inputs that were developed for the estimate are the capital cost and operation and maintenance (O&M) costs. Included in the capital cost estimate were allowances for design, project management, construction management, insurance, and security during construction. Estimated O&M costs include utilities, parts, supplies, condensate disposal, chemicals, and services by outside contractors (e.g., specialty maintenance).

4.1 ACTIVE GAS SYSTEM BUDGETARY COST ESTIMATES

Table 4-1 provides an estimated capital cost for City of Billings Regional Landfill to install an active gas system. The compressors, enclosed flare, gas cleaning equipment and enclosed building are not included in the cost estimate.

4.1.1 Capital Cost

Table 4-1
City of Billings Regional Landfill
Active Gas System Capital Costs

Bid Item		Quantity		Unit Price	Extended Price
1	Field Engineering	1	LS	$15,000	$15,000
2	Mobilization	1	LS	$20,000	$20,000
3	[1]Health & Safety Plan	1	LS	$2,000	$2,000
4	Install Gas Wells	5,400	VLF*	$100	$540,000
5	Wellhead Assembly	54	EA	$1,300	$70,200
6	Wellbore Seals	54	EA	$500	$27,000
7	6-inch HDPE Subheader	8,800	LF	$30	$264,000
8	12-inch HDPE Subheader	4,100	LF	$45	$184,500
9	24-inch HDPE Header	9,400	LF	$75	$705,000
10	6-inch Drain line	1,000	LF	$25	$25,000
11	Road Crossings	5	EA	$5,000	$25,000
12	6-inch Valve	5	EA	$2,000	$10,000
13	12-inch Valve	6	EA	$4,000	$24,000
14	24-inch Valve	8	EA	$8,000	$64,000
15	Access Riser	14	EA	$5,000	$70,000
16	1,000 Gallon Condensate Tank	4	EA	$18,000	$72,000
17	Electrical	1	LS	$120,000	$120,000
18	Site Restoration	1	LS	$75,000	$75,000
				Total Capital Costs	**$2,312,700**
19	Legal, Administration, Permitting & Engineering (15%)	1	LS	$347,000	$347,000
20	Contingency (15%)	1	LS	$347,000	$347,000
				Active Gas System Total **	**$3,006,700**

* Vertical Lineal Foot

** Prices do not include compressor, gas cleaning system, enclosed flare and enclosed building.

[1] The health and safety plan is a document that addresses safety and health hazards associated with construction of an active gas collection system. (Plan is supplied by contractor)

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The total estimated active gas system capital costs increased approximately $800,000 from the initial feasibility study in December 2007 primarily due to additional information gained about the Billings Regional Landfill. Based on the information gained the well field was expanded in area from the initial preliminary layout to maximize landfill gas extraction, which increased the well drilling, horizontal piping, valves and condensate tank quantities. Along with the well field expansion, an item was added for site restoration of the final closed landfill area to meet specifications.

4.1.2 Operation and Maintenance Costs

Table 4-2 provides estimated annual O & M costs for the Billings Landfill active gas system with gas utilization equipment. Active gas system management typically consists of the day-to-day tasks associated with managing an active gas collection system (maintenance, adjustments to wellfield, compressor etc.). Management will require a full-time employee to manage the system.

Table 4-2
City of Billings Regional Landfill
Active Gas System Annual O & M Costs

Item		Quantity		Unit Price	Extended Price
1	Condensate Disposal	1	LS	$10,000	$10,000
2	Active Gas System Management	1	LS	$100,000	$100,000
				Active Gas System O & M Total	**$110,000**

4.2 MONTANA-DAKOTA PIPELINE DISTRIBUTION BUDGETARY COST ESTIMATES

4.2.1 Capital Cost

Table 4-3 provides estimated capital costs for a compressor and gas treatment system to deliver landfill gas to a distribution pipeline and generators and enclosed flare to burn off tail gas. The

price estimate is for a 2,400 scfm system, which should have enough capacity until year 2025 when the landfill is projected to go above 2,400 scfm.

As a result of cleaning the landfill gas to pipeline quality, two tail gases are generated. Tail gas #1 is comprised of approximately 88% CO_2 and 11 to 12% CH_4 which is flared off in the enclosed flare. Tail gas #2 is composition consists of approximately 60% CH_4, 30% Nitrogen, 7% CO_2, and 2% oxygen. The reason the methane (CH_4) concentrations are so high is that the nitrogen molecules and the methane molecules are approximately the same size and it is very difficult and costly to separate them out. With the methane concentration above 50%, tail gas #2 can either be sent to the enclosed flare or sent to a generator to generate electricity for the landfill gas equipment. Based on the max power consumption of the equipment at approximately 1,050 to 1,100 kW and the relatively clean gas readily available, two (2) 250 kW generators were added to project to utilize the tail gas #2 and offset operating costs.

Power to start-up the equipment would all come from the grid, but then once the equipment is up and running the electricity generated by the generators would displace the grid.

Table 4-3
City of Billings Regional Landfill
Montana-Dakota Pipeline Distribution Capital Costs

Case 2 Feed Flow				2,400 SCFM	
Bid Item		**Quantity**		**Unit Price**	**Total Price**
1	Oil Flooded Screw Compressor	1	LS	$550,000	$550,000
2	System Cost CO2 Removal	1	LS	$1,550,000	$1,550,000
3	System Cost N2 Removal	1	LS	$1,205,000	$1,205,000
4	Recycle Compressor	1	LS	$80,000	$80,000
5	Equipment Installation	1	LS	$700,000	$700,000
6	Tail gas flare for CO2 & N2 Stream	1	LS	$165,000	$165,000
7	Slab for Molecular Gate System	1	LS	$40,000	$40,000
8	Building Enclosure	3,000	SF	$50	$150,000
9	Forcemain to Distribution Pipeline w/ Odorizer	1	LS	$450,000	$450,000
10	250 kW Generator	2	EA	$250,000	$500,000
				Total Capital Costs	**$5,390,000**
11	Legal, Administration, Permitting & Engineering (15%)	1	LS	$808,500	$808,500
12	*Contingency (5.7%)	1	LS	$308,500	$308,500
				MDU Pipeline Distribution Total	**$6,507,000**

*The total contingency percentage was lowered due to better costs from suppliers and more data available from the test wells.

4.2.2 Operation and Maintenance Costs

Table 4-4 provides estimated annual O & M costs for a compressor and gas treatment system to deliver landfill gas to a distribution pipeline. The electrical consumption cost assumes the compressor runs 93% of the time at an electric rate of $0.07 cents per kWh.

Table 4-4
City of Billings Regional Landfill
Montana-Dakota Gas Pipeline Distribution Annual O & M Costs

Item		Quantity		Unit Price	Extended Price
1	*Electrical Consumption ($0.07/kW)	1	LS	$315,000	$315,000
2	Maintenance	1	LS	$90,000	$90,000
3	*Generator O&M	1	LS	$65,000	$65,000
	MDU Gas Pipeline Distribution O & M Total				**$470,000**
*Assumes 93% operational time					

4.3 SUMMARY OF TOTAL COSTS

The total estimated capital and O & M costs for the active gas system and Gas Pipeline Distribution are summarized in Table 4-5 comparing December 2007 totals to January 2009 totals.

Table 4-5
City of Billings Regional Landfill
Summary of Total Estimated Capital Costs and Annual O&M Costs

Item	Capital Costs		Annual O&M Costs	
	Dec. 2007	**Jan. 2009**	**Dec. 2007**	**Jan. 2009**
Landfill Active Gas System	$2,203,000	$3,006,700	$110,000	$110,000
Gas Pipeline Distribution	$6,214,000	$6,507,000	$535,000	$470,000
Total	**$8,417,000**	**$9,513,700**	**$645,000**	**$580,000**

In summary, costs went up in capital due to landfill information from the City of Billings. The increase in size of the molecular gate system and oil flooded screw compressor to 2,400 scfm increased the electrical and maintenance on the O&M totals.

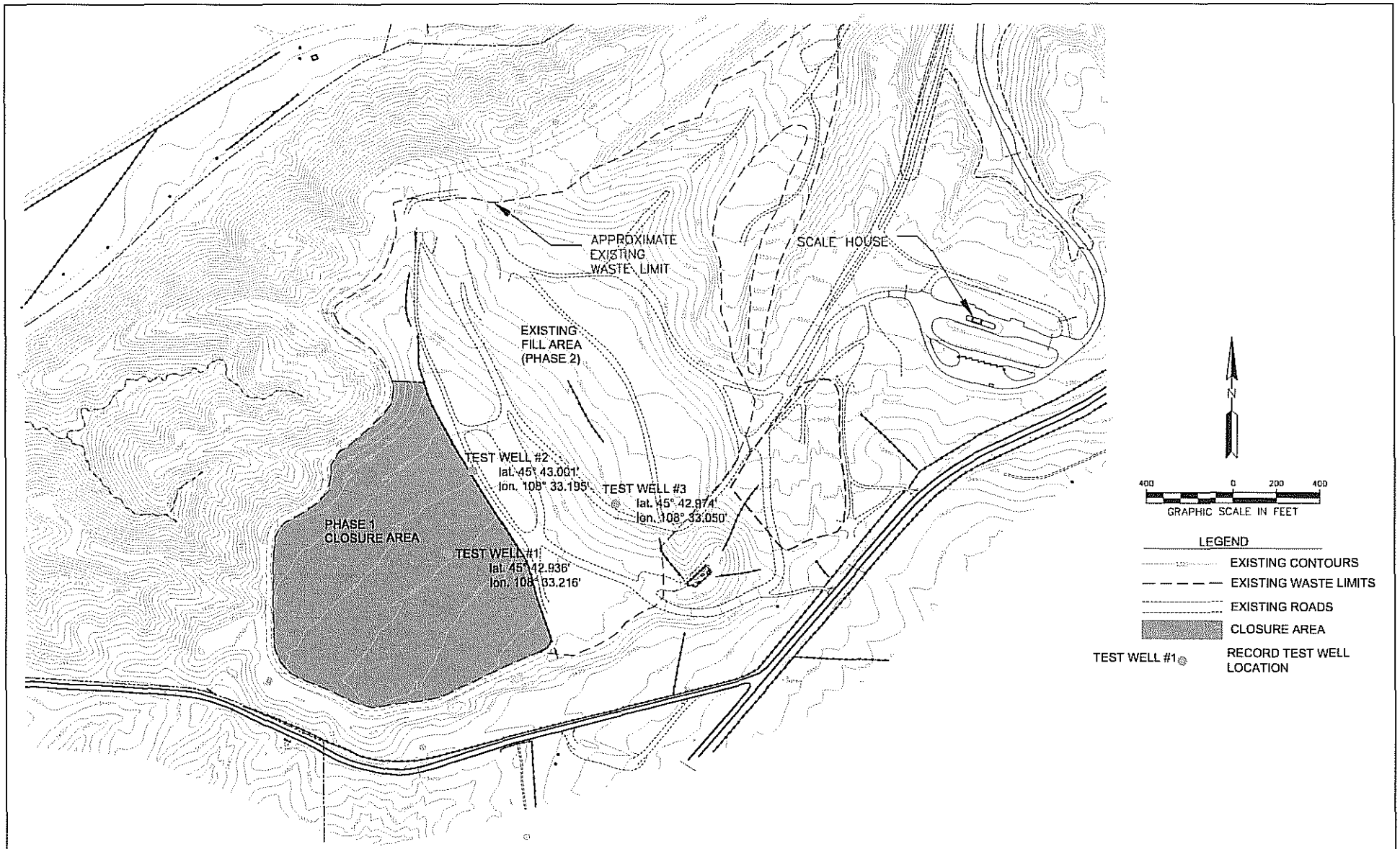
5.0 Recommendations

Based on the confirmation study, Wenck believes the waste cuttings, pump tests and gas analysis indicate that the Billings Regional Landfill is a good candidate for a gas-to-energy project. Wenck would recommend Montana-Dakota re-evaluate the economic modeled based on the revised capital costs, O&M costs and gas generation curve.

Figures

Figure 2:

Record Test Well Locations



RECORD TEST WELL LOCATIONS

City of Billings Regional Landfill

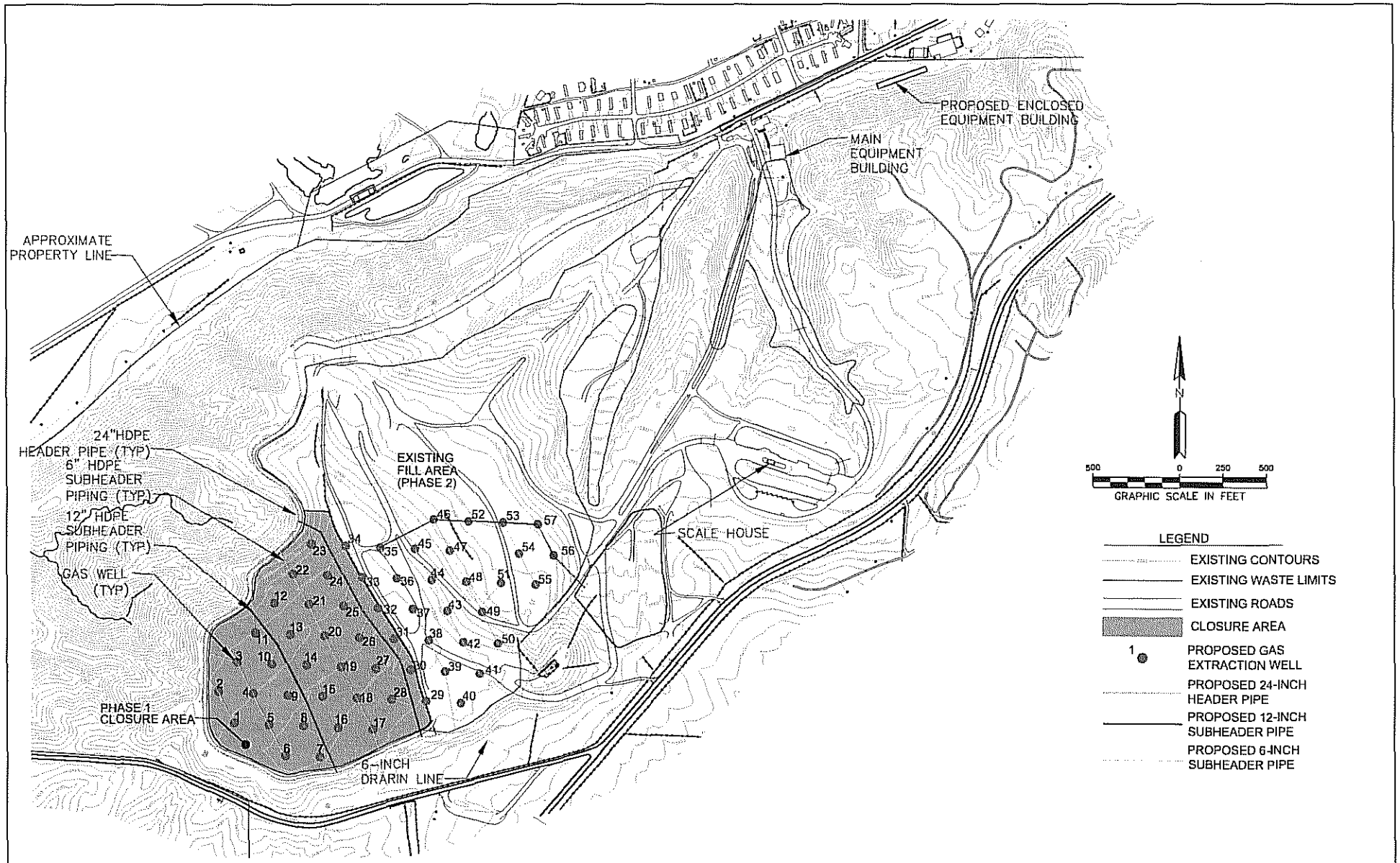
Wenck Associates, Inc.
Environmental Engineers
1800 Pioneer Creek Center
Maple Plain, MN 55359

Dec. 2008

Figure 2

Figure 3:

Preliminary Active Gas System Layout



PRELIMINARY ACTIVE GAS SYSTEM LAYOUT

City of Billings Regional Landfill

Wenck Associates, Inc. Environmental Engineers — Wenck — 1800 Pioneer Creek Center, Maple Plain, MN 55339

JAN. 09

Figure 3

Appendix A

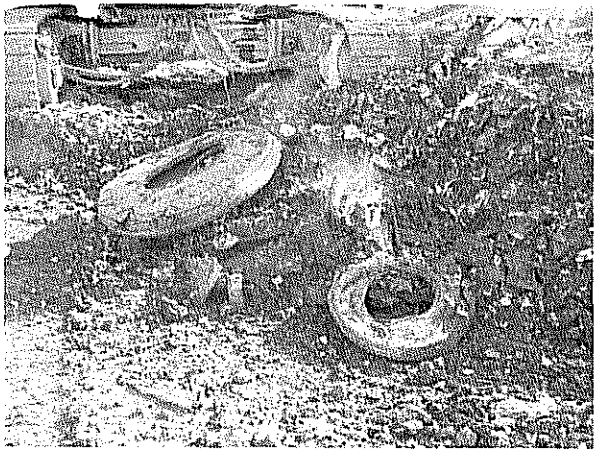
Well Drilling Photographs and Well Logs

Well #1

- Material in pic 1 shows representative material in upper areas of well.
- Dark material in pic 2 at lower level of well suggest oxidized material and well drilling should be terminated at this depth.

Well #2

- Picture 1 shows high wood and yard waste.
- Picture 2 shows oxidized organic material and tires below 100 feet and well drilling should be terminated at this point.



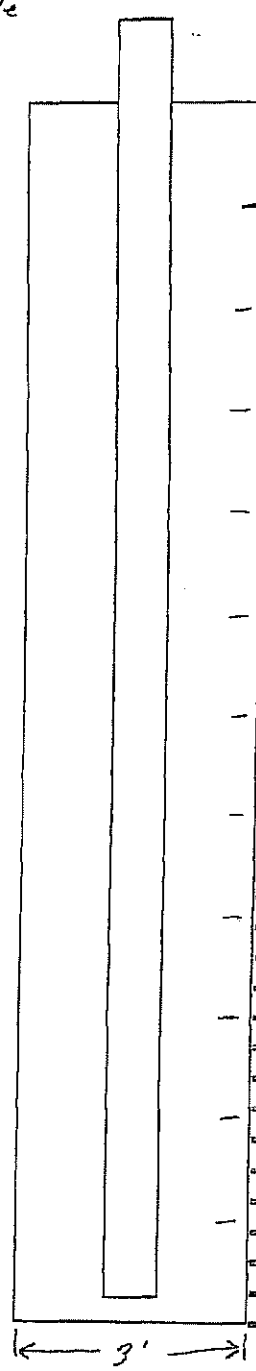
Well #3

- Pic 1 shows typical solid waste in well.
- Pic 2 is beginning to turn dark and well drilling should be terminated at this time.

11-5-08

Project: City of Billings
Well #: 1
Well depth:
~~Slot depth~~:
Bore Hole

Provide indication of soil, liquids, plastic, C/D, yard waste, solid waste, paper, other (specify). Strong/medium/weak gas odor Level or depth from surface, note level at change in waste charac.



	Level	Material
Dry	10'	Yard waste, paper
		Strong gas odor
Damp	20'	Yard waste
		Strong gas odor
Damp	30'	Yard Waste, Wood
		Strong Gas odor
Wet	50'	Yard Waste
		Strong gas odor
Wet	60'	Yard Waste
		Strong gas odor
Wet	70'	Yard waste
		Strong gas odor
Wet	80'	Yard Waste, Metal
		Strong gas odor
Wet	90'	Yard Waste, Tires
	100'	
	110'	
	120'	

The deeper the refuge is, the more it has decomposed.

soil/tires/ox City of Billings
Well #: 2
Well depth: 120
Slot depth: Per drawing

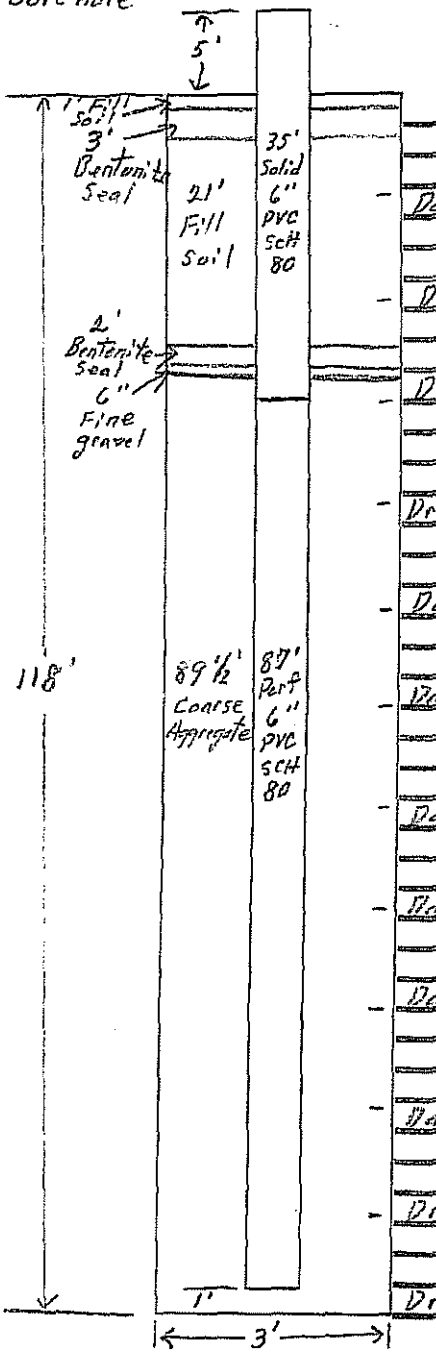
Provide indication of soil, liquids, plastic, C/D, yard waste, solid waste, paper, other (specify). Strong/medium/weak gas odor Level or depth from surface, note level at change in waste charac.

	Level	Material
dry	0-5	cover material - mixed
dry	10	mixed solid & yard waste
damp	20	paper/wood/plastic bags
damp	27	green yard clips/household was
damp	50	wood/mixed
dry	60	increasing soil/mixed waste
dry	65	soil/mixed msw
dry	72	yard waste/wood
damp	82	yard waste/soil
damp	93	yard waste/soil/wood/paper
damp	100	material turning dark
		moisture increasing
very damp	114	soil/tires/oxidized material
very damp	121	black/packed tires

11-5-08 - 11-6-08 Revised

Project: City of Billings
Well #: 3
Well depth: 122
~~Slot length~~: 118'
Bore Hole

Provide indication of soil, liquids, plastic, C/D, yard waste, solid waste, paper, other (specify). Strong/medium/weak gas odor Level or depth from surface, note level at change in waste charac.



	Level	Material
Damp	10'	Yard waste, Paper
Dry	20'	Strong gas odor Yard waste, paper, Tires
Dry	30'	Strong Gas odor Yard waste, paper
Dry	40'	Strong gas odor Yard Waste, Paper, Tires
Damp	50'	Strong gas odor Yard waste, paper, Phone book
Damp	60'	Strong gas odor Yard waste, paper, Wood
Damp	70'	Strong gas odor Yard waste, paper
Damp	80'	Strong gas odor Yard Waste, paper
Damp	90'	Strong gas odor Yard waste, paper, Wood
Damp	100'	Strong gas odor Yard waste paper
Dry	110'	Strong gas odor Dirt
Dry	118'	Strong gas odor Dirt

Refuge has not decomposed very much. About the same from top to bottom of bore hole.

Appendix B

Pump Test Readings

Montana-Dakota Utilities Co.
Gas-to-Energy Project - Phase I
City of Billings Regional Landfill

Well 1

Date	Time	Barametric Pressure	Temperature	Gas Flow	CH4	CO2	O2	Balance (Nitrogen)	Static Pressure	Differential Pressure
		inches of HG	°F	SCFM	%	%	%	%	%	%
*11/8/08	12:20	26.34	50	36	54.9	36.8	2.4	5.9		
11/8/08	13:14	26.43	51	86	39.0	27.1	7.2	26.7		
11/8/08	15:58	26.27	60	64	56.5	43.4	0.0	00.1		
11/9/08	8:25	26.12	97	64	50.5	36.1	2.7	9.7		
11/9/08	8:33	26.12	97	65	56.7	43.1	0.1	0.1		
11/9/08	12:12	26.1	100	65	54.9	38.9	1.9	4.3		
11/9/08	16:45	26.05	102	64	55.9	44	0	0.1		
11/10/08	8:52	26.15	104	36	57.1	41.7	0.7	0.1	0.007	0.346
11/10/08	12:04	26.15	105	40	57.1	42.6	0.1	0.2	-0.0007	0.383
11/10/08	16:09	26.15	105	45	56.5	43.1	0.3	0.1	1.3	0.473
11/11/08	8:31	26.33	106	37	56.8	43.1	0.3	0.1	1.3	0.473
11/11/08	12:15	26.25	107	54	56.6	43.3	0	0.1	1.3	0.702
11/11/08	16:22	26.13	107	59	55.9	44	0	0.1	0.008	0.8
11/12/08	9:06	26.12	107	55	55.9	44	0	0.1	-1.2	0.703
11/12/08	12:30	26.01	108	52	56.1	43.8	0	0.1	-0.6	0.636
11/12/08	16:26	25.97	108	53	56	43.9	0	0.1	-0.7	0.651
**11/13/08	9:45	26	112	75	57.3	42.6	0	0.1		
11/14/08	12:13	26.58	103	73	57.1	42.2	0.6	0.1		

*Vent passively venting - no vacuum applied

**Restarted Generator for Vacuum Pump

Montana-Dakota Utilities Co.
Gas-to-Energy Project - Phase I
City of Billings Regional Landfill

Well 2

Date	Time	Barametric Pressure	Temperature	Gas Flow	CH4	CO2	O2	Balance (Nitrogen)	Static Pressure	Differential Pressure
		inches of HG	°F	SCFM	%	%	%	%	%	%
*11/9/08	15:58	26.07	53	13	55.4	44.5	0	0.1		
11/9/08	16:52	26.07	53	53	54.8	45.1	0	0.1		
11/10/08	8:29	26.13	84	64	54.5	45.3	0	0.2	2.1	0.92
11/10/08	12:31	26.15	90	63	54.7	45.2	0	0.1	1.7	0.956
11/10/08	16:20	26.15	90	63	54.4	45.5	0	0.1	2.6	0.955
11/11/08	8:20	26.33	97	57	55.4	44.3	0.2	0.1	2.6	0.809
11/11/08	12:00	26.27	98	62	54.5	45.5	0	0	2.2	0.872
11/11/08	16:04	26.15	99	63	54	45.9	0	0.1	1.6	0.954
11/12/08	8:30	26.12	101	60	54	45.9	0	0.1	1.7	0.884
11/12/08	12:53	26.02	102	62	54.3	45.6	0	0.1	-1.4	0.906
11/12/08	16:15	25.98	102	61	54.2	45.7	0	0.1	-1.4	0.886
11/13/08	9:32	26.01	101	81	54.0	45.9	0	0.1		
11/13/08	14:39	26.08	108	81	55	44.5	0.3	0.2		
11/14/08	11:59	26.58	97	77	56.8	43	0	0.2		

*Vent passively venting - no vacuum applied

Montana-Dakota Utilities Co.
Gas-to-Energy Project - Phase I
City of Billings Regional Landfill

Well 3

Date	Time	Barametric Pressure	Temperature	Gas Flow	CH4	CO2	O2	Balance (Nitrogen)	Static Pressure	Differential Pressure
		inches of HG	°F	SCFM	%	%	%	%	%	%
11/6/08	16:50		62	152	59.4	39.4	1	0.2		
11/7/08	8:50	26.43	69	92	54	44.5	0.6	0.9		
11/7/08	10:50	26.68	70	58	51.1	48.2	0.6	0.1		
11/7/08	15:05	26.44	72	178	23.6	20.3	12	44.1		
11/7/08	15:43	26.45	71	58	34.8	30.3	8.0	26.9		
11/7/08	16:49	26.48	66	66	50.2	49	0.7	0.1		
11/8/08	8:28	26.38	74	65	52.3	46	1.6	0.1		
*11/8/08	13:29	26.31	76	45	25.5	17.8	11.7	45		
11/8/08	13:39	26.31	76	34	50.8	33.9	3.8	11.6		
11/8/08	16:20	26.26	76	49	57.6	42.3	0	0.1		
11/9/08	8:11	26.12	77	51	56.9	41	1.5	0.6		
11/9/08	12:23	26.09	78	50	57.1	41.9	0.8	0.2		
11/9/08	16:37	26.06	77	46	50	36.4	3.8	9.8		
11/9/08	16:42	26.05	77	44	53.5	38.1	2.7	5.7		
11/10/08	9:10	26.13	77	40	58.6	41	41.3	0.1	0.3	-0.122
11/10/08	12:44	26.14	78	40	58.5	41.4	0	0.1	0.7	0.352
11/10/08	15:56	26.15	78	42	55.7	43.5	0.6	0.2	0.9	0.402
11/11/08	7:49	26.15	78	33	50.1	49	0.8	0.1	-1.2	0.26
11/11/08	11:39	26.28	79	34	50.4	49.1	0.4	0.1	-0.8	0.288
11/11/08	15:51	26.15	79	51	51	48.6	0.3	0.1	-0.7	0.594
11/12/08	8:09	26.11	79	47	50.4	49.3	0.2	0.9	-0.9	0.534
11/12/08	12:17	26.02	79	45	50.8	49	0.1	0.1	-1	0.488
11/12/08	16:04	25.98	79	50	50.5	49.2	0.1	0.2	-1.1	0.588
11/13/08	9:24	26.02	79	72	49	50.7	0.2	0.1		
11/13/08	14:08	26.01	79	71	48.9	45.3	3.1	2.7		
**11/14/08	11:40	26.58	78	62	28.6	29.8	12.2	29.4		

*Vacuum Pump Down Approximately 3 Hours

**Air Leak in Connections

Appendix C

Landfill Gas Analysis

AirTECHNOLOGY Laboratories, Inc.

December 3, 2008

FL Cert #E87847/LA Cert #04140
EPA Method TO14A/TO15
EPA Method TO3
RSK-175
EPA Method 25C/3C

Wenck Associates
ATTN: Marlon Mackowick
1111 Westrac Dr., Suite 108
Fargo, ND 58103

LABORATORY TEST RESULTS

Project Reference: MDU-Billings; 1987-04
Lab Number: A8111705-01/06

Enclosed are results for sample(s) received 11/17/08 by Air Technology Laboratories. Analyses were performed according to specifications on the chain of custody provided with the sample(s).

Report Narrative:

- Sample analyses were performed within method performance criteria and meet all requirements of the NELAC Standards.
- All results are reported without qualifications.

Results were e-mailed to Marlon Mackowick on 12/03/08.

ATL appreciates the opportunity to provide testing services to your company. If you have any questions regarding these results, please call me at (626) 964-4032.

Sincerely,

Mark Johnson
Operations Manager
MJohnson@AirTechLabs.com

Enclosures

Note: The cover letter is an integral part of this analytical report.

CHAIN OF CUSTODY RECORD

Pg 1 of 1

AirTECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130
City of Industry, CA 91748
626-964-4032 • Fax: 626-964-5832

Project Name: MDU - Billings
Project #: 1987-04
P.O. #:

FOR LABORATORY USE ONLY

Method of Transport: Walk-in ☐ Courier ☐ UPS ☐ FedEx ☒ ATL ☐

Sample Condition Upon Receipt: 1. CHILLED Y☐ N☐ 4. SEALED Y☐ N☐ 2. HEADSPACE (VOA) Y☐ N☐ 5. # OF SPLS MATCH COC Y☐ N☐ 3. CONTAINER INTACT Y☐ N☐ 6. PRESERVED Y☐ N☐

Company: Wenck Associates
Contact: Marlon Mackowick
Address: 1111 Westrac Dr. Ste 108
City Fargo State ND Zip Code 58103
TEL: (701) 297-9600
FAX: (701) 297-9601

Sampled/Relinquished by: (Signature and Printed Name)	Date:	Time:	Received by: (Signature and Printed Name)	Date:	Time:
Matt Anderson	11-13-08	1745	fedex		
Relinquished by: (Signature and Printed Name) fedex	11/17/08	0850	Received by: (Signature and Printed Name) Jason Chien	11/17/08	0850.
Relinquished by: (Signature and Printed Name)	Date:	Time:	Received by: (Signature and Printed Name)	Date:	Time:

I hereby authorize ATL to perform the work indicated below:
Matt Anderson 11-13-08
Project Mgr./Submitter (Print Name) Date
Signature

Send Report To:
Attn: Rod Ambrosio
Co: Wenck
Address 1111 Westrac Dr. Ste 108
City Fargo State ND Zip 58103

Bill To:
Attn: Melissa Wuebbelter
Co: Wenck
Address 1800 Pioneer Creek Center
City Maple Plain State MN Zip 55359

Special Instructions/Comments:
call Marlon Mackowick w/ questions
ASTM 4888
701-297-9600

Unless otherwise requested, all samples will be disposed 14 days after reporting or at Lab's discretion.

Sample Archive/Disposal:
☒ Laboratory Standard
☐ Other
☐ Return To:
* $10.00 FEE PER HAZARDOUS SAMPLE DISPOSAL.

Circle or Add Analysis(es) Requested — CIRCLE APPROPRIATE MATRIX

LAB USE ONLY Lab No.	Sample Description: Sample I.D.	Date	Time	T03 Gas / BTEX / MTBE	T03 Hexane	T03 Carbon Chain	TO14A VOCs	TO15 VOCs Std or Low Level	15/16 Sulfur Comp Std/Low Level	15/16 H2S Std or Low Level	Fixed Gas D1946 or 3C	25C/3C TNMOC	25.1 TGNMHC	D1945 Natural Gas	RSK 175 Dissolved Gas	Siloxanes ASTM 5136 (modified)	TICs	AIR • VAPOR	INDOOR AIR	LANDFILL GAS	WATER	SOLID • SOIL	OIL • SOLVENT • LIQUID	OTHER	TAT	Container(s) #	Container(s) Type	PRESERVATION	REMARKS
AR111705-01	well 3-A	11-13-08	1229				X	X			X				X	X	X			X					E	1	1C	N	Flow
-02	well 3-B (HOLD)*	11-13-08	1333																	X						1			controller needle
-03	well 2-A	11-13-08	1450														X			X						1			is very
-04	well 2-B (HOLD)*	11-13-08	1521																	X						1			sticky & easy
-05	well 1-A	11-13-08	1609														X			X						1			to manipulate
-06	well 1-B (HOLD)*	11-13-08	1634																	X						1			
	* Hold for back-up per M. Mackowick 11/18/08																												

LAST LINE

DELIVERABLES: EDD ☐ LEVEL III ☐ LEVEL IV ☐

• TAT starts 8 a.m. following day if samples received after 5 p.m.

TAT: A= Overnight ≤ 24 hr B= Emergency Next workday C= Critical 2 Workdays D= Urgent 3 Workdays E= Routine 7 Workdays

Container Types: B=Tedlar Bag C=Canister V=VOA O= Other

Preservatives: H=Hcl N=None

DISTRIBUTION: **White** with report, **Yellow** to folder, **Pink** to submitter.

34

Client: Wenck Associates
Attn: Marlon Mackowick

Project Name: MDU - Billings
Project Number: 1987-04
Date Received: 11/17/2008
Matrix: Vapor

TNMOC by EPA METHOD 25C
Fixed Gases by EPA METHOD 3C

Lab Number:			A8111705-01		A8111705-02		A8111705-04		A8111705-05		A8111705-06	
Client Sample ID:			Well 3-A		Well 3-B		Well 2-B		Well 1-A		Well 1-B	
Date Collected:			11/13/2008		11/13/2008		11/13/2008		11/13/2008		11/13/2008	
Date Analyzed:			11/19/2008		11/21/2008		11/21/2008		11/21/2008		11/19/2008	
Analyst Initials:			VM		VM		VM		VM		VM	
QC Batch:			081119GC8A1		081121GC8A1		081121GC8A1		081121GC8A1		081119GC8A1	
Dilution Factor:			2.8		2.8		2.8		2.7		2.7	
ANALYTE	Units	PQL	Result	RL	Result	RL	Result	RL	Result	RL	Result	RL
TNMOC	ppmv C	10	3,700	28	3,500	28	1,500	28	1,100	27	1,300	27
TNMOC uncorr*	ppmv C	10	3,200	28	2,600	28	1,300	28	860	27	1,000	27
Nitrogen	% v/v	1.0	7.3	2.8	17	2.8	7.0	2.8	12	2.7	12	2.7
Oxygen	% v/v	0.50	ND	1.4	4.2	1.4	1.9	1.4	3.4	1.4	3.2	1.4
Carbon Dioxide	% v/v	0.010	48	0.028	41	0.028	42	0.028	37	0.027	37	0.027
Methane	% v/v	0.0010	46	0.0028	39	0.0028	54	0.0028	51	0.0027	52	0.0027

ND = Not detected at or above reporting limit.
PQL = Practical Quantitation Limit.
TNMOC = Total Non-Methane Organic Carbon.
TNMOC uncorr* = TNMOC concentration in sample without nitrogen/moisture correction.
NA = Nitrogen/moisture correction causes division by zero.

Reviewed/Approved By: _____ Date: 12/2/08
Mark Johnson
Operations Manager

The cover letter is an integral part of this analytical report.

Client: Wenck Associates
Attn: Marlon Mackowick

Client's Project: MDU-Billings, 1987-04
Date Received: 11/17/08
Matrix: Air
Units: ppbv

EPA Method TO15

Lab No:		A8111705-01		A8111705-02		A8111705-04		A8111705-05		A8111705-06	
Client Sample I.D.:		Well 3-A		Well 3-B		Well 2-B		Well 1-A		Well 1-B	
Date Sampled:		11/13/08		11/13/08		11/13/08		11/13/08		11/13/08	
Date Analyzed:		11/20/08		11/20/08		11/21/08		11/21/08		11/20/08	
QC Batch No:		081120MS2A1		081120MS2A1		081121MS2A1		081121MS2A1		081120MS2A1	
Analyst Initials:		VM		VM		VM		VM		VM	
Dilution Factor:		110		84		110		82		68	
ANALYTE	PQL	Result	RL	Result	RL	Result	RL	Result	RL	Result	RL
Dichlorodifluoromethane (12)	1.0	2,600	110	2,400	84	1,500	110	1,400	82	1,400	68
Chloromethane	2.0	ND	220	320	170	420	220	330	160	330	140
1,2-Cl-1,1,2,2-F ethane (114)	1.0	420	110	660	84	150	110	150	82	160	68
Vinyl Chloride	1.0	760	110	710	84	160	110	270	82	290	68
Bromomethane	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Chloroethane	1.0	660	110	640	84	ND	110	ND	82	ND	68
Trichlorofluoromethane (11)	1.0	1,800	110	1,600	84	ND	110	ND	82	ND	68
1,1-Dichloroethene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Carbon Disulfide	5.0	620	560	590	420	ND	560	ND	410	ND	340
1,1,2-Cl 1,2,2-F ethane (113)	1.0	180	110	170	84	ND	110	ND	82	ND	68
Acetone	5.0	7,900	560	6,100	420	14,000	560	16,000	410	17,000	340
Methylene Chloride	1.0	9,400	110	8,800	84	750	110	560	82	590	68
t-1,2-Dichloroethene	1.0	150	110	140	84	ND	110	ND	82	ND	68
1,1-Dichloroethane	1.0	430	110	390	84	140	110	86	82	92	68
Vinyl Acetate	5.0	ND	560	ND	420	ND	560	ND	410	ND	340
c-1,2-Dichloroethene	1.0	510	110	470	84	1,300	110	930	82	1,000	68
2-Butanone	1.0	10,000	110	9,100	84	17,000	110	13,000	82	15,000	68
t-Butyl Methyl Ether	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Chloroform	1.0	ND	110	86	84	ND	110	ND	82	ND	68
1,1,1-Trichloroethane	1.0	440	110	410	84	ND	110	ND	82	ND	68
Carbon Tetrachloride	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Benzene	1.0	940	110	1,100	84	1,300	110	750	82	860	68
1,2-Dichloroethane	1.0	170	110	160	84	ND	110	ND	82	ND	68
Trichloroethene	1.0	570	110	550	84	570	110	440	82	550	68
1,2-Dichloropropane	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Bromodichloromethane	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
c-1,3-Dichloropropene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
4-Methyl-2-Pentanone	1.0	ND	110	ND	84	4,400	110	2,000	82	2,300	68
Toluene	1.0	14,000	110	13,000	84	17,000	110	7,000	82	9,900	68
t-1,3-Dichloropropene	1.0	220	110	220	84	ND	110	110	82	ND	68
1,1,2-Trichloroethane	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Tetrachloroethene	1.0	760	110	770	84	850	110	330	82	430	68
2-Hexanone	1.0	ND	110	ND	84	120	110	ND	82	82	68
Dibromochloromethane	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
1,2-Dibromoethane	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
Chlorobenzene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68

AirTECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130 ♦ City of Industry, CA 91748 ♦ Ph: (626) 964-4032 ♦ Fx: (626) 964-5832

Client: Wenck Associates
Attn: Marlon Mackowick

Client's Project: MDU-Billings, 1987-04
Date Received: 11/17/08
Matrix: Air
Units: ppbv

EPA Method TO15

Lab No:		A8111705-01		A8111705-02		A8111705-04		A8111705-05		A8111705-06	
Client Sample I.D.:		Well 3-A		Well 3-B		Well 2-B		Well 1-A		Well 1-B	
Date Sampled:		11/13/08		11/13/08		11/13/08		11/13/08		11/13/08	
Date Analyzed:		11/20/08		11/20/08		11/21/08		11/21/08		11/20/08	
QC Batch No:		081120MS2A1		081120MS2A1		081121MS2A1		081121MS2A1		081120MS2A1	
Analyst Initials:		VM		VM		VM		VM		VM	
Dilution Factor:		110		84		110		82		68	
ANALYTE	PQL	Result	RL	Result	RL	Result	RL	Result	RL	Result	RL
Ethylbenzene	1.0	1,900	110	1,900	84	1,300	110	500	82	1,100	68
p,&m-Xylene	1.0	3,100	110	3,000	84	1,700	110	590	82	1,500	68
o-Xylene	1.0	850	110	830	84	420	110	130	82	360	68
Styrene	1.0	120	110	87	84	ND	110	ND	82	ND	68
Bromoform	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
1,1,2,2-Tetrachloroethane	2.0	ND	220	ND	170	ND	220	ND	160	ND	140
Benzyl Chloride	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
4-Ethyl Toluene	1.0	ND	110	120	84	ND	110	ND	82	ND	68
1,3,5-Trimethylbenzene	2.0	ND	220	ND	170	ND	220	ND	160	ND	140
1,2,4-Trimethylbenzene	2.0	ND	220	ND	170	ND	220	ND	160	ND	140
1,3-Dichlorobenzene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
1,4-Dichlorobenzene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
1,2-Dichlorobenzene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68
1,2,4-Trichlorobenzene	2.0	ND	220	ND	170	ND	220	ND	160	ND	140
Hexachlorobutadiene	1.0	ND	110	ND	84	ND	110	ND	82	ND	68

PQL = Practical Quantitation Limit
ND= Not Detected (below RL)
RL = PQL X Dilution Factor

Reviewed/Approved By: _____ Date 12/2/08
Mark Johnson
Operations Manager

The cover letter is an integral part of this analytical report

AirTECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130 ♦ City of Industry, CA 91748 ♦ Ph: (626) 964-4032 ♦ Fx: (626) 964-5832

LCS/LCSD Recovery and RPD Summary Report

QC Batch #: 081120MS2A1

Matrix: Air

EPA Method TO-14/TO-15

Lab No:	Method Blank		LCS		LCSD						
Date Analyzed:	11/20/08		11/20/08		11/20/08						
Data File ID:	20NOV005.D		20NOV003.D		20NOV004.D						
Analyst Initials:	VM		VM		VM						
Dilution Factor:	0.2		1.0		1.0			Limits			
ANALYTE	Result ppbv	Spike Amount	Result ppbv	% Rec	Result ppbv	% Rec	RPD	Low %Rec	High %Rec	Max. RPD	Pass/ Fail
1,1-Dichloroethene	0.0	10.0	10.5	105	10.2	102	2.2	70	130	30	Pass
Methylene Chloride	0.0	10.0	11.0	110	10.6	106	3.2	70	130	30	Pass
Trichloroethene	0.0	10.0	9.7	97	9.4	94	3.1	70	130	30	Pass
Toluene	0.0	10.0	10.1	101	9.5	95	6.0	70	130	30	Pass
1,1,2,2-Tetrachloroethane	0.0	10.0	9.1	91	9.1	91	0.6	70	130	30	Pass

RPD = Relative Percent Difference

Reviewed/Approved By: _____ Date: 12/2/08

Mark Johnson
Operations Manager

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LCS/LCSD Recovery and RPD Summary Report

QC Batch #: 081121MS2A1

Matrix: Air

EPA Method TO-14/TO-15

Lab No:	Method Blank		LCS		LCSD						
Date Analyzed:	11/21/08		11/21/08		11/21/08						
Data File ID:	21NOV008.D		21NOV003.D		21NOV004.D						
Analyst Initials:	VM		VM		VM						
Dilution Factor:	0.2		1.0		1.0			Limits			
ANALYTE	Result ppbv	Spike Amount	Result ppbv	% Rec	Result ppbv	% Rec	RPD	Low %Rec	High %Rec	Max. RPD	Pass/ Fail
1,1-Dichloroethene	0.0	10.0	10.4	104	10.6	106	1.9	70	130	30	Pass
Methylene Chloride	0.0	10.0	11.3	113	11.0	110	2.9	70	130	30	Pass
Trichloroethene	0.0	10.0	9.5	95	9.5	95	0.1	70	130	30	Pass
Toluene	0.0	10.0	10.0	100	10.2	102	1.6	70	130	30	Pass
1,1,2,2-Tetrachloroethane	0.0	10.0	9.1	91	9.2	92	1.1	70	130	30	Pass

RPD = Relative Percent Difference

Reviewed/Approved By: _____ Date: 12/2/08

Mark Johnson
Operations Manager

The cover letter is an integral part of this analytical report

Client:	Wenck Associates
Attn:	Marlon Mackowick
Client's Project:	MDU-Billings, 1987-04
Date Received:	11/17/08
Matrix:	Air
Units:	ppbv

EPA Method TO15 Tentatively Identified Compounds (Library Search)

Lab No:	A8111705-01
Client Sample I.D.:	Well 3-A
Date Sampled:	11/13/08
Date Analyzed:	11/20/08
QC Batch No:	081120MS2A1
Analyst Initials:	VM
Dilution Factor:	110

Tentative Identification	Estimated Result (ppbv)
Isobutane	24,000
Butane	16,000
2-Methyl-Butane	58,000
Ethanol	17,000
Pentane	17,000
2-Methyl-Pentane	13,000
Hexane	10,000
Ethyl Acetate	7,900
3-Methyl-Hexane	9,200

Reviewed/Approved By: 12/2/08
Mark Johnson
Operations Manager

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Client:	Wenck Associates
Attn:	Marlon Mackowick
Client's Project:	MDU-Billings, 1987-04
Date Received:	11/17/08
Matrix:	Air
Units:	ppbv

EPA Method TO15 Tentatively Identified Compounds (Library Search)

Lab No:	A8111705-02
Client Sample I.D.:	Well 3-B
Date Sampled:	11/13/08
Date Analyzed:	11/20/08
QC Batch No:	081120MS2A1
Analyst Initials:	VM
Dilution Factor:	84

Tentative Identification	Estimated Result (ppbv)
Isobutane	20,000
Butane	13,000
2-Methyl-Butane	47,000
Ethanol	14,000
Pentane	14,000
2-Methyl-Pentane	11,000
Hexane	8,500
Ethyl Acetate	6,700
2-Methyl-Hexane	4,600
3-Methyl-Hexane	7,500

Reviewed/Approved By: 12/2/08
Mark Johnson
Operations Manager

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Client:	Wenck Associates
Attn:	Marlon Mackowick
Client's Project:	MDU-Billings, 1987-04
Date Received:	11/17/08
Matrix:	Air
Units:	ppbv

EPA Method TO15 Tentatively Identified Compounds (Library Search)

Lab No:	A8111705-04
Client Sample I.D.:	Well 2-B
Date Sampled:	11/13/08
Date Analyzed:	11/21/08
QC Batch No:	081121MS2A1
Analyst Initials:	VM
Dilution Factor:	110
Tentative Identification	**Estimated Result (ppbv)**
Isobutane	5,200
Ethanol	4,200
Isopropyl Alcohol	6,900
Dimethyl Sulfide	3,600
2-Butanol	8,900
2-Butanone	6,200
Ethyl Acetate	4,700
Tetrahydrofuran	3,000
Methyl cyclohexane	4,000
1R-.alpha.-Pinene	3,200

Reviewed/Approved By: 12/2/08
Mark Johnson
Operations Manager

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Client:	Wenck Associates
Attn:	Marlon Mackowick
Client's Project:	MDU-Billings, 1987-04
Date Received:	11/17/08
Matrix:	Air
Units:	ppbv

EPA Method TO15 Tentatively Identified Compounds (Library Search)

Lab No:	A8111705-05
Client Sample I.D.:	Well 1-A
Date Sampled:	11/13/08
Date Analyzed:	11/21/08
QC Batch No:	081121MS2A1
Analyst Initials:	VM
Dilution Factor:	82

Tentative Identification	Estimated Result (ppbv)
Isobutane	5,200
Ethanol	8,300
Isopropyl Alcohol	4,600
1-Propanol	3,800
2-Butanol	5,100
2-Butanone	6,900
Ethyl Acetate	5,600
Tetrahydrofuran	2,300
3-Methyl-Hexane	3,000
Methyl cyclohexane	2,900

Reviewed/Approved By: 12/2/08
Mark Johnson
Operations Manager

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Client:	Wenck Associates
Attn:	Marlon Mackowick
Client's Project:	MDU-Billings, 1987-04
Date Received:	11/17/08
Matrix:	Air
Units:	ppbv

EPA Method TO15 Tentatively Identified Compounds (Library Search)

Lab No:	A8111705-06
Client Sample I.D.:	Well 1-B
Date Sampled:	11/13/08
Date Analyzed:	11/20/08
QC Batch No:	081120MS2A1
Analyst Initials:	VM
Dilution Factor:	68
Tentative Identification	**Estimated Result (ppbv)**
Isobutane	5,500
Ethanol	9,400
Isopropyl Alcohol	4,600
1-Propanol	4,700
2-Butanol	6,700
2-Butanone	8,200
Ethyl Acetate	6,400
Tetrahydrofuran	2,500
3-Methyl-Hexane	2,800
Cyclohexane	2,600

Reviewed/Approved By: _____ 12/2/08
Mark Johnson
Operations Manager

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Client: Wenck Associates
Attn: Marlon Mackowick

Client's Project: MDU-Billings, 1987-04
Date Received: 11/17/08
Matrix: Air
Units: ppbv

EPA Method TO15 (Siloxanes)

Lab No:		A8111705-01		A8111705-02		A8111705-04		A8111705-05		A8111705-06	
Client Sample I.D.:		Well 3-A		Well 3-B		Well 2-B		Well 1-A		Well 1-B	
Date Sampled:		11/13/08		11/13/08		11/13/08		11/13/08		11/13/08	
Date Analyzed:		11/20/08		11/20/08		11/21/08		11/21/08		11/20/08	
QC Batch No:		081120MS2A1		081120MS2A1		081121MS2A1		081121MS2A1		081120MS2A1	
Analyst Initials:		VM		VM		VM		VM		VM	
Dilution Factor:		110		84		110		82		68	
ANALYTE	PQL	Result	RL	Result	RL	Result	RL	Result	RL	Result	RL
Hexamethyldisiloxane	10	ND	1,100	ND	840	ND	1,100	ND	820	ND	680
Hexamethylcyclotrisiloxane	10	ND	1,100	ND	840	ND	1,100	ND	820	ND	680
Octamethyltrisiloxane	10	ND	1,100	ND	840	ND	1,100	ND	820	ND	680
Octamethylcyclotetrasiloxane	10	ND	1,100	ND	840	ND	1,100	ND	820	ND	680
Decamethyltetrasiloxane	10	ND	1,100	ND	840	ND	1,100	ND	820	ND	680
Decamethylcyclopentasiloxane	50	ND	5,600	ND	4,200	ND	5,600	ND	4,100	ND	3,400
Dodecamethylpentasiloxane	200	ND	22,000	ND	17,000	ND	22,000	ND	16,000	ND	14,000

PQL = Practical Quantitation Limit
ND= Not Detected (below RL)
RL = PQL X Dilution Factor

Reviewed/Approved By: _____ Date 12/2/08
Mark Johnson
Operations Manager

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AirTECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130 ♦ City of Industry, CA 91748 ♦ Ph: (626) 964-4032 ♦ Fx: (626) 964-5832

Client: Wenck Associates
Attn: Marlon Mackowick

Client's Project: MDU-Billings 1987-04
Date Received: 11/17/08
Matrix: Air
Units: ppmv

EPA 15/16 (Sulfur Compounds in Air)

Lab No.:		A8111705-01		A8111705-02		A8111705-04		A8111705-05		A8111705-06	
Client Sample I.D.:		Well 3-A		Well 3-B		Well 2-B		Well 1-A		Well 1-B	
Date Sampled:		11/13/08		11/13/08		11/13/08		11/13/08		11/13/08	
Date Analyzed:		11/17/08		11/17/08		11/17/08		11/17/08		11/17/08	
Analyst Initials:		VM		VM		VM		VM		VM	
QC Batch:		081117GC3A1		081117GC3A1		081117GC3A1		081117GC3A1		081117GC3A1	
Dilution Factor:		2.8		2.8		2.8		2.7		2.7	
ANALYTE	PQL	RL	Results	RL	Results	RL	Results	RL	Results	RL	Results
Hydrogen Sulfide	0.20	5.6	36	5.6	34	5.6	52	0.55	ND	0.55	20
Carbonyl Sulfide	0.20	0.56	ND	0.56	ND	0.56	ND	0.55	ND	0.55	ND
Methyl Mercaptan	0.20	0.56	1.3	0.56	1.1	0.56	2.4	0.55	ND	0.55	1.3
Ethyl Mercaptan	0.20	0.56	ND	0.56	ND	0.56	ND	0.55	ND	0.55	ND
Dimethyl Sulfide	0.20	0.56	3.6	0.56	3.0	0.56	7.0	0.55	2.3	0.55	2.5
Carbon Disulfide	0.20	0.56	0.87	0.56	0.71	0.56	ND	0.55	ND	0.55	ND
Dimethyl Disulfide	0.20	0.56	ND	0.56	ND	0.56	ND	0.55	ND	0.55	ND

PQL = Practical Quantitation Limit
ND = Not Detected (Below RL)
RL = Reporting Limit = PQL X Dilution Factor

Reviewed/Approved By: _____ Date: 12/2/08
Mark J. Johnson
Operations Manager

The cover letter is an integral part of this analytical report.

Response No. PSC-055
Attachment D

Billings Landfill Project
Project Details

Cost Breakdown & Budget

Item Description		Total Cost	Notes
Gas Processing equipment Cost	$	6,442,304	Mole Gates for CO2 and N2, compressors, buildings, & Distribution system constructions
Active Gas System	$	2,108,787	Landfill Installaitin and Well Field
Permiting, Design, Construction Mgmt	$	600,000	Includes committed and not committed task orders
Total Cost before ES&GA and AFUDC	$	**9,151,091**	

		Raw		w ES&GS, AFUDC	
2009 Reforecast Budget	$	896,000	$	1,428,000	
2010 Proposed Budget	$	8,255,000	$	8,550,775	Estimated at financial model assumptions
Totals	$	9,151,000	$	9,978,775	

Notes

Oringal 2008 budget was $8,460,101 so project cost have increase by approximately $600,000 which is due increase from 2007 Wenck Study to Final Study completed in Jan 2009

Financial Model Summary

	1st Year Rev. Requirement	1st year of gas cost savings	Cost per dk	Gas (Cost) Savings 1st Ten Years	Year of Cumu-lative Savings	Produced DK Cost Year 1 (2010)	Procudced dk Cost 2015
Scenario III - Complete and operating in 2010	2,326,267.00	Year 6	0.066	(56,343.00)	Year 11	$ 6.832	$ 5.777

Assumptions:

Natural Gas CIG Cost project Year 1(2010) at $5.25 increasing to $6.25 by 2015
MDU would own the landfill gas system when it goes on line.
Complete and in service 2010
Renewable Energy Credits (RECs) or green tags are available but not part of modeled revenue
Tax rate – 39%
50% / 50% ratio with a debt cost of 7.0% for financial
2008 average capital structure for revenue requirement
Tax depreciation - 15 Year MACRS
Capitalization is based on net plant book value less future tax liability (DITs)
Assumes minor capital expenditures with major investemnt in Year 16
Assumes an after-tax equity return of 10% (pre-tax 16.67%)
There is a possibility for a property tax credit for new or expanding project (production tax or 30% of capital costs)
15% ES and GA overheads on first $1.0 million of investment
AFUDC rate of 7.2% annually

Rate Recover of regulated project

Desired rate recovery of cost would be through a general rate case if timing would be advantagous. Possible recovery of cost plus return through PGA but still would require commission action.

Projected value of Tax Credits and Green Credits not included in model

Tax Credits at 30% of capital cost			$	2,993,633
Green Credits Yr 1 (increasing with production)	$	2.00	$	15,134
	$	4.00	$	30,268
	$	6.00	$	45,402
	$	10.00	$	75,670
	$	15.00	$	113,505
	$	20.00	$	151,340

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF BILLINGS LANDFILL OPTIONS

	1st Year Rev. Requirement	1st year of gas cost savings	Cost per dk	Gas (Cost) Savings 1st Ten Years	Year of Cumulative Savings
Scenario I - Complete and operating in 2009	$2,322,721	Year 6	$0.066	($26,963)	Year 11
Scenario II - Complete and operating in 2009, final payment in 2010	2,317,837	Year 6	0.066	14,023	Year 10
Scenario III - Complete and operating in 2010	2,326,267	Year 6	0.066	(56,343)	Year 11
With production @ 90%					
Scenario I - Complete and operating in 2009	$2,295,893	Year 7	$0.065	(1,954,861)	Year 15
Scenario II - Complete and operating in 2009, final payment in 2010	2,291,009	Year 7	0.065	(1,914,664)	Year 15
Scenario III - Complete and operating in 2010	2,299,439	Year 7	0.065	(1,984,611)	Year 15

2

BILLINGS, MT LANDFILL GAS PROJECT - OWNED BY MDU

Assumptions:

- MDU would own the landfill gas system when it goes on line.
- Complete and in service at the end of 2009
- Renewable Energy Credits (RECs) or green tags are available but not part of modeled revenue
- Tax rate - 39%
- 50% / 50% ratio with a debt cost of 7.0% for financial
- 2008 average capital structure for revenue requirement
- Tax depreciation - 15 Year MACRS
- Capitalization is based on net plant book value less future tax liability (DITs)
- Assumes minor capital expenditures with major investment in Year 16
- Assumes an after-tax equity return of 10% (pre-tax 16.67%)
- There is a possibility for a property tax credit for new or expanding project
- 15% ES and GA overheads on first $1.0 million of investment
- AFUDC rate of 7.2% annually

Scenario I - Complete in 2009

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Operating Revenues										
Annual Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Operating Expenses										
O&M	848,289	891,241	929,604	953,174	972,187	1,042,477	1,070,050	1,090,827	1,112,227	1,141,819
Depreciation 1/	248,871	248,871	248,871	255,121	255,121	255,121	261,371	261,371	261,371	267,621
Taxes Other Than Incon	69,091	67,319	65,548	65,511	63,695	61,879	61,798	59,938	58,077	57,952
Total Exp.	1,166,251	1,207,431	1,244,023	1,273,806	1,291,003	1,359,477	1,393,219	1,412,136	1,431,675	1,467,392
Income before Taxes	(1,166,251)	(1,207,431)	(1,244,023)	(1,273,806)	(1,291,003)	(1,359,477)	(1,393,219)	(1,412,136)	(1,431,675)	(1,467,392)
Interest Expense	290,093	274,375	259,770	253,453	240,357	228,102	223,541	211,323	199,153	194,303
Taxable income	(1,456,344)	(1,481,806)	(1,503,793)	(1,527,259)	(1,531,360)	(1,587,579)	(1,616,760)	(1,623,459)	(1,630,828)	(1,661,695)
Income Taxes	(567,974)	(577,904)	(586,479)	(595,631)	(597,231)	(619,156)	(630,537)	(633,149)	(636,023)	(648,061)
Tax Credit										
Operating Income	($598,277)	($629,527)	($657,544)	($678,175)	($693,772)	($740,321)	($762,682)	($778,987)	($795,652)	($819,331)
Rate Base	$9,608,909	$9,088,271	$8,604,516	$8,395,267	$7,961,487	$7,555,537	$7,404,469	$6,999,762	$6,596,657	$6,436,018
Rate of Return	-6.23%	-6.93%	-7.64%	-8.08%	-8.71%	-9.80%	-10.30%	-11.13%	-12.06%	-12.73%
Revenue Requirement	$2,322,721	$2,301,241	$2,279,611	$2,284,210	$2,249,199	$2,268,816	$2,284,375	$2,254,584	$2,225,609	$2,241,992
dk Production	340,685	340,685	340,685	340,685	340,685	394,771	394,771	394,771	394,771	394,771
Cost per Dk	$6.818	$6.755	$6.691	$6.705	$6.602	$5.747	$5.787	$5.711	$5.638	$5.679
Average Rev. Req.	$2,639,984	30 years								
Avg. Dk	473,553									
Avg. $/Dk	$5.575									
Rate Base										
Plant in Service										
Investment	$9,954,840	$9,954,840	$9,954,840	$9,954,840	$10,204,840	$10,204,840	$10,204,840	$10,454,840	$10,454,840	$10,454,840
Additional Facilities	0	0	0	250,000	0	0	250,000	0	0	250,000
	$9,954,840	$9,954,840	$9,954,840	$10,204,840	$10,204,840	$10,204,840	$10,454,840	$10,454,840	$10,454,840	$10,704,840
Accumulated Reserve 1/										
Acc. Reserve	248,871	497,742	746,613	1,001,734	1,256,855	1,511,976	1,773,347	2,034,718	2,296,089	2,563,710
DIT	97,060	368,827	603,711	807,839	986,498	1,137,327	1,277,024	1,420,360	1,562,094	1,705,112
	345,931	866,569	1,350,324	1,809,573	2,243,353	2,649,303	3,050,371	3,455,078	3,858,183	4,268,822
Rate base	$9,608,909	$9,088,271	$8,604,516	$8,395,267	$7,961,487	$7,555,537	$7,404,469	$6,999,762	$6,596,657	$6,436,018

Scenario I - Complete in 2009

REVENU

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Operating Revenues									
Annual Fee		$0	$0	$0	$0		$0	$0	$0
Operating Expenses									
O&M	1,216,064	1,239,448	1,272,266	1,297,074	1,322,627	1,411,057	1,438,166	1,466,088	1,504,996
Depreciation 1/	267,621	267,621	273,871	273,871	273,871	405,121	405,121	405,121	411,371
Taxes Other Than Incon	56,047	54,142	53,972	52,022	50,073	84,561	81,677	78,793	77,644
Total Exp.	1,539,732	1,561,211	1,600,109	1,622,967	1,646,571	1,900,739	1,924,964	1,950,002	1,994,011
Income before Taxes	(1,539,732)	(1,561,211)	(1,600,109)	(1,622,967)	(1,646,571)	(1,900,739)	(1,924,964)	(1,950,002)	(1,994,011)
Interest Expense	181,796	169,338	164,199	151,403	138,656	282,395	268,337	254,886	249,346
Taxable income	(1,721,528)	(1,730,549)	(1,764,308)	(1,774,370)	(1,785,227)	(2,183,134)	(2,193,301)	(2,204,888)	(2,243,357)
Income Taxes	(671,396)	(674,914)	(688,080)	(692,004)	(696,238)	(851,422)	(855,387)	(859,906)	(874,909)
Tax Credit									
Operating Income	($868,336)	($886,297)	($912,029)	($930,963)	($950,333)	($1,049,317)	($1,069,577)	($1,090,096)	($1,119,102)
Rate Base	$6,021,742	$5,609,067	$5,438,859	$5,015,012	$4,592,768	$9,353,925	$8,888,264	$8,442,729	$8,259,213
Rate of Return	-14.42%	-15.80%	-16.77%	-18.56%	-20.69%	-11.22%	-12.03%	-12.91%	-13.55%
Revenue Requirement	$2,264,472	$2,236,284	$2,254,697	$2,226,545	$2,199,329	$3,026,520	$2,994,702	$2,966,118	$2,988,040
dk Production	447,615	447,615	447,615	447,615	447,615	500,044	500,044	500,044	500,044
Cost per Dk	$5.059	$4.996	$5.037	$4.974	$4.913	$6.053	$5.989	$5.932	$5.976
Average Rev. Req.									
Avg. Dk									
Avg. $/Dk									
Rate Base									
Plant in Service									
Investment	$10,704,840	$10,704,840	$10,704,840	$10,954,840	$10,954,840	$10,954,840	$16,204,840	$16,204,840	$16,204,840
Additional Facilities	0	0	250,000	0	0	5,250,000	0	0	250,000
	$10,704,840	$10,704,840	$10,954,840	$10,954,840	$10,954,840	$16,204,840	$16,204,840	$16,204,840	$16,454,840
Accumulated Reserve 1/									
Acc. Reserve	2,831,331	3,098,952	3,372,823	3,646,694	3,920,565	4,325,686	4,730,807	5,135,928	5,547,299
DIT	1,851,767	1,996,821	2,143,158	2,293,134	2,441,507	2,525,229	2,585,769	2,626,183	2,648,328
	4,683,098	5,095,773	5,515,981	5,939,828	6,362,072	6,850,915	7,316,576	7,762,111	8,195,627
Rate base	$6,021,742	$5,609,067	$5,438,859	$5,015,012	$4,592,768	$9,353,925	$8,888,264	$8,442,729	$8,259,213

Scenario I - Complete in 2009

REVENU

	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Operating Revenues								
Annual Fee	$0		$0	$0	$0	$0		$0
Operating Expenses								
O&M	1,534,618	1,619,612	1,662,479	1,694,848	1,728,188	1,774,198	1,866,475	1,902,907
Depreciation 1/	411,371	411,371	417,621	417,621	417,621	423,871	423,871	423,871
Taxes Other Than Incon	74,716	71,788	70,594	67,622	64,649	63,411	60,394	57,377
Total Exp.	2,020,705	2,102,771	2,150,694	2,180,091	2,210,458	2,261,480	2,350,740	2,384,155
Income before Taxes	(2,020,705)	(2,102,771)	(2,150,694)	(2,180,091)	(2,210,458)	(2,261,480)	(2,350,740)	(2,384,155)
Interest Expense	236,688	224,486	219,884	207,712	195,588	190,872	178,584	166,345
Taxable income	(2,257,393)	(2,327,257)	(2,370,578)	(2,387,803)	(2,406,046)	(2,452,352)	(2,529,324)	(2,550,500)
Income Taxes	(880,383)	(907,630)	(924,526)	(931,243)	(938,358)	(956,417)	(986,436)	(994,695)
Tax Credit								
Operating Income	($1,140,322)	($1,195,141)	($1,226,168)	($1,248,848)	($1,272,100)	($1,305,063)	($1,364,304)	($1,389,460)
Rate Base	$7,839,933	$7,435,767	$7,283,344	$6,880,160	$6,478,578	$6,322,343	$5,915,346	$5,509,952
Rate of Return	-14.55%	-16.07%	-16.84%	-18.15%	-19.64%	-20.64%	-23.06%	-25.22%
Revenue Requirement	$2,964,272	$2,997,695	$3,027,273	$3,008,145	$2,990,180	$3,022,399	$3,062,676	$3,047,299
dk Production	500,044	552,680	552,680	552,680	552,680	552,680	605,523	605,523
Cost per Dk	$5.928	$5.424	$5.477	$5.443	$5.410	$5.469	$5.058	$5.033
Average Rev. Req.								
Avg. Dk								
Avg. $/Dk								
Rate Base								
Plant in Service								
Investment	$16,454,840	$16,454,840	$16,454,840	$16,704,840	$16,704,840	$16,704,840	$16,954,840	$16,954,840
Additional Facilities	0	0	250,000	0	0	250,000	0	0
	$16,454,840	$16,454,840	$16,704,840	$16,704,840	$16,704,840	$16,954,840	$16,954,840	$16,954,840
Accumulated Reserve 1/								
Acc. Reserve	5,958,670	6,370,041	6,787,662	7,205,283	7,622,904	8,046,775	8,470,646	8,894,517
DIT	2,656,237	2,649,032	2,633,834	2,619,397	2,603,358	2,585,722	2,568,848	2,550,371
	8,614,907	9,019,073	9,421,496	9,824,680	10,226,262	10,632,497	11,039,494	11,444,888
Rate base	$7,839,933	$7,435,767	$7,283,344	$6,880,160	$6,478,578	$6,322,343	$5,915,346	$5,509,952

Scenario I - Complete in 2009

REVENU

	Year 28	Year 29	Year 30
Operating Revenues			
Annual Fee	$0	$0	$0
Operating Expenses			
O&M	1,953,474	1,992,124	2,031,934
Depreciation 1/	430,121	430,121	430,121
Taxes Other Than Incon	56,094	53,033	49,971
Total Exp.	2,439,689	2,475,278	2,512,026
Income before Taxes	(2,439,689)	(2,475,278)	(2,512,026)
Interest Expense	161,514	149,111	136,757
Taxable income	(2,601,203)	(2,624,389)	(2,648,783)
Income Taxes	(1,014,469)	(1,023,512)	(1,033,025)
Tax Credit			
Operating Income	($1,425,220)	($1,451,766)	($1,479,001)
Rate Base	$5,349,904	$4,939,095	$4,529,888
Rate of Return	-26.64%	-29.39%	-32.65%
Revenue Requirement	$3,083,572	$3,069,717	$3,057,216
dk Production	605,523	605,523	605,523
Cost per Dk	$5.092	$5.070	$5.049
Average Rev. Req.			
Avg. Dk			
Avg. $/Dk			
Rate Base			
Plant in Service			
Investment	$16,954,840	$17,204,840	$17,204,840
Additional Facilities	250,000	0	0
	$17,204,840	$17,204,840	$17,204,840
Accumulated Reserve 1/			
Acc. Reserve	9,324,638	9,754,759	10,184,880
DIT	2,530,298	2,510,986	2,490,072
	11,854,936	12,265,745	12,674,952
Rate base	$5,349,904	$4,939,095	$4,529,888

Scenario I

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU
CAPITALIZATION
DEBT AND EQUITY
(000)

	INITIAL INVESTMENT	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
TOTAL (Incl. DITs)	9,954,840	9,608,909	9,088,271	8,604,516	8,395,267	7,961,487	7,555,537	7,404,469	6,999,762	6,596,657	6,436,018	6,021,742
DEBT	4,977,420	4,804,455	4,544,136	4,302,258	4,197,634	3,980,743	3,777,769	3,702,234	3,499,881	3,298,329	3,218,009	3,010,871
EQUITY	4,977,420	4,804,455	4,544,136	4,302,258	4,197,634	3,980,743	3,777,769	3,702,234	3,499,881	3,298,329	3,218,009	3,010,871

Long-Term Debt Cost **7%**

Scenario I

	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22
TOTAL (Incl. DITs)	5,609,067	5,438,859	5,015,012	4,592,768	9,353,925	8,888,264	8,442,729	8,259,213	7,839,933	7,435,767	7,283,344
DEBT	2,804,534	2,719,429	2,507,506	2,296,384	4,676,962	4,444,132	4,221,365	4,129,607	3,919,966	3,717,884	3,641,672
EQUITY	2,804,534	2,719,429	2,507,506	2,296,384	4,676,962	4,444,132	4,221,365	4,129,607	3,919,966	3,717,884	3,641,672

Lon;

Scenario I

	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33
TOTAL (Incl. DITs)	6,880,160	6,478,578	6,322,343	5,915,346	5,509,952	5,349,904	4,939,095	4,529,888	4,182,318	3,895,919	3,610,196
DEBT	3,440,080	3,239,289	3,161,171	2,957,673	2,754,976	2,674,952	2,469,547	2,264,944	2,091,159	1,947,959	1,805,098
EQUITY	3,440,080	3,239,289	3,161,171	2,957,673	2,754,976	2,674,952	2,469,547	2,264,944	2,091,159	1,947,959	1,805,098

Lon;

Scenario I

	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
TOTAL (Incl. DITs)	3,327,673	3,048,027	2,768,381	2,491,615	2,217,726	1,943,838	1,672,829
DEBT	1,663,836	1,524,013	1,384,190	1,245,808	1,108,863	971,919	836,415
EQUITY	1,663,836	1,524,013	1,384,190	1,245,808	1,108,863	971,919	836,415

Lon

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Scenario I - Complete in 2009

Depreciation Schedule
(000)

1.1230637

40 Year Life - Plant

Depreciation Schedule
($000)

	Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
BOOK DEPRECIATION											
Existing Assets (net of Accun	9,954,840										
Depr. on Adjusted Fixed Assets		248,871	248,871	248,871	255,121	255,121	255,121	261,371	261,371	261,371	267,621
Total Book Depreciation		**248,871**	**248,871**	**248,871**	**255,121**	**255,121**	**255,121**	**261,371**	**261,371**	**261,371**	**267,621**

		YEAR #	1	2	3	4	5	6	7	8	9	10
	Year Landfill		248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871
2010	1	-	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	-	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	-	-	-	-	-	-	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	-	-	-	-	-	-	-	-	-	6,250
2020	11	-	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	-	-	-	-	-	-	-	-
2023	14	-	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	-	-	-	-	-	-	-	-	-	-
2026	17	-	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	-	-
2029	20	-	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-	-

Scenario I - Complete in 2009		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Total Book Depreciation		248,871	248,871	248,871	255,121	255,121	255,121	261,371	261,371	261,371	267,621
Book Value	$9,954,840	9,705,969	9,457,098	9,208,227	9,203,106	8,947,985	8,692,864	8,681,493	8,420,122	8,158,751	8,141,130
Property Taxes											
Property Tax Rate	0.7%	69,091	67,319	65,548	65,511	63,695	61,879	61,798	59,938	58,077	57,952

			1	2	3	4	5	6	7	8	9	10
Enter MACRS rate (below in y		4										
3	**MACRS**	**20 Year**	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%	5.2850%	4.8880%	4.5220%	4.4620%	4.4610%
4	**MACRS**	**15 Year**	5.0000%	9.5000%	8.5500%	7.6950%	6.9260%	6.2330%	5.9050%	5.9050%	5.9050%	5.9050%
5	**MACRS**	**10 Year**	10.0000%	18.0000%	14.4000%	11.5200%	9.2200%	7.3700%	6.5500%	6.5500%	6.5600%	6.5500%
6	**MACRS**	**7 Year**	14.2900%	24.4900%	17.4900%	12.4900%	8.9300%	8.9200%	8.9300%	4.4600%		
7	**MACRS**	**5 Year**	20.0000%	32.0000%	19.2000%	11.5200%	11.5200%	5.7600%				
8	**MACRS**	**3 Year**	33.3300%	44.4500%	14.8100%	7.4100%						

TAX DEPRECIATION

	Estimated										
Construction Property/Turbin	9,954,840	497,742	945,710	851,139	778,525	713,222	641,860	619,571	628,898	624,791	634,333
Total Tax Depreciation\Amortization		497,742	945,710	851,139	778,525	713,222	641,860	619,571	628,898	624,791	634,333
Balance Sheet DITs - Current Year		(97,060)	(271,767)	(234,884)	(204,128)	(178,659)	(150,828)	(139,698)	(143,336)	(141,734)	(143,018)
Balance Sheet DITs - Accumulated		(97,060)	(368,827)	(603,711)	(807,839)	(986,498)	(1,137,327)	(1,277,024)	(1,420,360)	(1,562,094)	(1,705,112)

Year	Amount	YEAR #	1	2	3	4	5	6	7	8	9	10
Existing	9,954,840	**15 Year**	497,742	945,710	851,139	766,025	689,472	620,485	587,833	587,833	587,833	587,833
1	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	-	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
5	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	-	-	-	-	-	-	12,500	23,750	21,375	19,238
8	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	-	-	-	-	-	-	-	-	-	12,500
11	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	-	-	-	-	-	-	-	-	-	-
14	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-	-

Scenario I - Complete in 2009

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
16	5,250,000	15 Year	-	-	-	-	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**497,742**	**945,710**	**851,139**	**778,525**	**713,222**	**641,860**	**619,571**	**628,898**	**624,791**	**634,333**

Scenario 1 - Complete in 2009

40 Year Life - Plant

BOOK DEPRECIATION	**Cost**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**
Existing Assets (net of Accun	9,954,840									
Depr. on Adjusted Fixed Assets		267,621	267,621	273,871	273,871	273,871	405,121	405,121	405,121	411,371
Total Book Depreciation		**267,621**	**267,621**	**273,871**	**273,871**	**273,871**	**405,121**	**405,121**	**405,121**	**411,371**

		YEAR #	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**
	Year										
	Landfill		248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	-	-	-	-	-	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Scenario I - Complete in 2009										
Total Book Depreciation		267,621	267,621	273,871	273,871	273,871	405,121	405,121	405,121	411,371
Book Value	$9,954,840	7,873,509	7,605,888	7,582,017	7,308,146	7,034,275	11,879,154	11,474,033	11,068,912	10,907,541
Property Taxes										
Property Tax Rate	0.7%	56,047	54,142	53,972	52,022	50,073	84,561	81,677	78,793	77,644

		11	12	13	14	15	16	17	18	19
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%
4 **MACRS**	**15 Year**	5.9050%	5.9050%	5.9050%	5.9050%	5.9050%	2.9510%			
5 **MACRS**	**10 Year**	3.2800%								
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,954,840	643,661	639,553	649,096	658,423	654,316	619,792	560,353	508,745	468,153
Total Tax Depreciation\Amortization		643,661	639,553	649,096	658,423	654,316	619,792	560,353	508,745	468,153
Balance Sheet DITs - Current Year		(146,656)	(145,054)	(146,338)	(149,975)	(148,373)	(83,722)	(60,540)	(40,413)	(22,145)
Balance Sheet DITs - Accumulated		(1,851,767)	(1,996,821)	(2,143,158)	(2,293,134)	(2,441,507)	(2,525,229)	(2,585,769)	(2,626,183)	(2,648,328)

Year	Amount	YEAR #	11	12	13	14	15	16	17	18	19
Existing	9,954,840	**15 Year**	587,833	587,833	587,833	587,833	587,833	293,767	-	-	-
1	-	**15 Year**	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
5	-	**15 Year**	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
8	-	**15 Year**	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
11	-	**15 Year**	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
14	-	**15 Year**	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-

Scenario I - Complete in 2009

			Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
16	5,250,000	15 Year	-	-	-	-	-	262,500	498,750	448,875	403,988
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**643,661**	**639,553**	**649,096**	**658,423**	**654,316**	**619,792**	**560,353**	**508,745**	**468,153**

Scenario I - Complete in 2009

40 Year Life - Plant

			Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
BOOK DEPRECIATION		**Cost**									
Existing Assets (net of Accun		9,954,840									
Depr. on Adjusted Fixed Assets			411,371	411,371	417,621	417,621	417,621	423,871	423,871	423,871	430,121
Total Book Depreciation			**411,371**	**411,371**	**417,621**	**417,621**	**417,621**	**423,871**	**423,871**	**423,871**	**430,121**
		YEAR #	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
	Year										
	Landfill		248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	6,250	6,250	6,250	6,250
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	6,250
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

		Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
Scenario I - Complete in 2009										
Total Book Depreciation		411,371	411,371	417,621	417,621	417,621	423,871	423,871	423,871	430,121
Book Value	$9,954,840	10,496,170	10,084,799	9,917,178	9,499,557	9,081,936	8,908,065	8,484,194	8,060,323	7,880,202
Property Taxes										
Property Tax Rate	0.7%	74,716	71,788	70,594	67,622	64,649	63,411	60,394	57,377	56,094

		20	21	22	23	24	25	26	27	28
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4610%	2.2310%							
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,954,840	431,653	392,895	378,653	380,603	376,495	378,653	380,603	376,495	378,653
Total Tax Depreciation\Amortization		431,653	392,895	378,653	380,603	376,495	378,653	380,603	376,495	378,653
Balance Sheet DITs - Current Year		(7,910)	7,206	15,198	14,437	16,039	17,635	16,875	18,477	20,073
Balance Sheet DITs - Accumulated		(2,656,237)	(2,649,032)	(2,633,834)	(2,619,397)	(2,603,358)	(2,585,722)	(2,568,848)	(2,550,371)	(2,530,298)

Year	Amount	YEAR #	20	21	22	23	24	25	26	27	28
Existing	9,954,840	**15 Year**	-	-	-	-	-	-	-	-	-
1	-	**15 Year**	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	-	-	-	-	-	-	-	-	-
5	-	**15 Year**	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	14,763	14,763	7,378	-	-	-	-	-	-
8	-	**15 Year**	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
11	-	**15 Year**	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
14	-	**15 Year**	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-

Scenario I - Complete in 2009

			Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
16	5,250,000	15 Year	363,615	327,233	310,013	310,013	310,013	310,013	310,013	310,013	310,013
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	12,500	23,750	21,375	19,238
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**431,653**	**392,895**	**378,653**	**380,603**	**376,495**	**378,653**	**380,603**	**376,495**	**378,653**

Scenario I - Complete in 2009

40 Year Life - Plant

			Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
BOOK DEPRECIATION		**Cost**									
Existing Assets (net of Accun		9,954,840									
Depr. on Adjusted Fixed Assets			430,121	430,121	430,121	430,121	430,121	430,121	430,121	430,121	430,121
Total Book Depreciation			**430,121**	**430,121**	**430,121**	**430,121**	**430,121**	**430,121**	**430,121**	**430,121**	**430,121**
		YEAR #	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**
	Year Landfill		248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871	248,871
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

		Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
Scenario I - Complete in 2009										
Total Book Depreciation		430,121	430,121	430,121	430,121	430,121	430,121	430,121	430,121	430,121
Book Value	$9,954,840	7,450,081	7,019,960	6,589,839	6,159,718	5,729,597	5,299,476	4,869,355	4,439,234	4,009,113
Property Taxes										
Property Tax Rate	0.7%	53,033	49,971	46,909	43,847	40,786	37,724	34,662	31,600	28,538

		29	30	31	32	33	34	35	36	37
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**									
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,954,840	380,603	376,495	218,453	61,603	59,870	51,665	44,288	44,288	36,903
Total Tax Depreciation\Amortization		380,603	376,495	218,453	61,603	59,870	51,665	44,288	44,288	36,903
Balance Sheet DITs - Current Year		19,312	20,914	82,551	143,722	144,398	147,598	150,475	150,475	153,355
Balance Sheet DITs - Accumulated		(2,510,986)	(2,490,072)	(2,407,521)	(2,263,799)	(2,119,401)	(1,971,803)	(1,821,328)	(1,670,853)	(1,517,498)

Year	Amount	YEAR #	29	30	31	32	33	34	35	36	37
Existing	9,954,840	15 Year	-	-	-	-	-	-	-	-	-
1	-	15 Year	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	-	-	-	-	-	-	-	-	-
5	-	15 Year	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	-	-	-	-	-	-	-	-	-
8	-	15 Year	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	-	-	-	-	-	-	-	-	-
11	-	15 Year	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	-	-	-	-	-	-	-	-	-
14	-	15 Year	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-

Scenario I - Complete in 2009

			Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
16	5,250,000	15 Year	310,013	310,013	154,928	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**380,603**	**376,495**	**218,453**	**61,603**	**59,870**	**51,665**	**44,288**	**44,288**	**36,903**

Scenario I - Complete in 2009

40 Year Life - Plant

			Year 38	Year 39	Year 40
BOOK DEPRECIATION		Cost			
Existing Assets (net of Accun		9,954,840			
Depr. on Adjusted Fixed Assets			430,121	430,121	430,121
Total Book Depreciation			**430,121**	**430,121**	**430,121**

			YEAR #	38	39	40
	Year					
	Landfill			248,871	248,871	248,871
2010	1	-		-	-	-
2011	2	-		-	-	-
2012	3	-		-	-	-
2013	4	250,000		6,250	6,250	6,250
2014	5	-		-	-	-
2015	6	-		-	-	-
2016	7	250,000		6,250	6,250	6,250
2017	8	-		-	-	-
2018	9	-		-	-	-
2019	10	250,000		6,250	6,250	6,250
2020	11	-		-	-	-
2021	12	-		-	-	-
2022	13	250,000		6,250	6,250	6,250
2023	14	-		-	-	-
2024	15	-		-	-	-
2025	16	5,250,000		131,250	131,250	131,250
2026	17	-		-	-	-
2027	18	-		-	-	-
2028	19	250,000		6,250	6,250	6,250
2029	20	-		-	-	-
2030	21	-		-	-	-
2031	22	250,000		6,250	6,250	6,250
2032	23	-		-	-	-
2033	24	-		-	-	-
2034	25	250,000		6,250	6,250	6,250
2035	26	-		-	-	-
2036	27	-		-	-	-
2037	28	250,000		6,250	6,250	6,250
2038	29	-		-	-	-
2039	30	-		-	-	-

		Year 38	Year 39	Year 40
Scenario I - Complete in 2009				
Total Book Depreciation		430,121	430,121	430,121
Book Value	$9,954,840	3,578,992	3,148,871	2,718,750
Property Taxes				
Property Tax Rate	0.7%	25,477	22,415	19,353

		38	39	40
Enter MACRS rate (below in y	4			
3 **MACRS**	**20 Year**			
4 **MACRS**	**15 Year**			
5 **MACRS**	**10 Year**			
6 **MACRS**	**7 Year**			
7 **MACRS**	**5 Year**			
8 **MACRS**	**3 Year**			

TAX DEPRECIATION

	Estimated			
Construction Property/Turbin	9,954,840	29,525	29,525	22,140
Total Tax Depreciation\Amortization		29,525	29,525	22,140
Balance Sheet DITs - Current Year		156,232	156,232	159,113
Balance Sheet DITs - Accumulated		(1,361,266)	(1,205,033)	(1,045,921)

		YEAR #	38	39	40
Year	Amount				
Existing	9,954,840	15 Year	-	-	-
1	-	15 Year	-	-	-
2	-	15 Year	-	-	-
3	-	15 Year	-	-	-
4	250,000	15 Year	-	-	-
5	-	15 Year	-	-	-
6	-	15 Year	-	-	-
7	250,000	15 Year	-	-	-
8	-	15 Year	-	-	-
9	-	15 Year	-	-	-
10	250,000	15 Year	-	-	-
11	-	15 Year	-	-	-
12	-	15 Year	-	-	-
13	250,000	15 Year	-	-	-
14	-	15 Year	-	-	-
15	-	15 Year	-	-	-

Scenario I - Complete in 2009

			Year 38	Year 39	Year 40
16	5,250,000	15 Year	-	-	-
17	-	15 Year	-	-	-
18	-	15 Year	-	-	-
19	250,000	15 Year	-	-	-
20	-	15 Year	-	-	-
21	-	15 Year	-	-	-
22	250,000	15 Year	-	-	-
23	-	15 Year	-	-	-
24	-	15 Year	-	-	-
25	250,000	15 Year	14,763	14,763	7,378
26	-	15 Year	-	-	-
27	-	15 Year	-	-	-
28	250,000	15 Year	14,763	14,763	14,763
29	-	15 Year	-	-	-
30	-	15 Year	-	-	-
Total Tax Depreciation			**29,525**	**29,525**	**22,140**

Scenario I - Complete in 2009

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Revenue Requirement		$2,322,721	$2,301,241	$2,279,611	$2,284,210	$2,249,199	$2,268,816	$2,284,375	$2,254,584	$2,225,609	$2,241,992
dk Production	100%	340,685	340,685	340,685	340,685	340,685	394,771	394,771	394,771	394,771	394,771
Cost per Dk		$6.818	$6.755	$6.691	$6.705	$6.602	$5.747	$5.787	$5.711	$5.638	$5.679
System Dk Sales 1/		35,200,000	35,530,000	36,013,000	36,199,000	36,343,796	36,489,171	36,635,128	36,781,669	36,928,796	37,076,511
		0.69%	0.94%	1.36%	0.52%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk		$0.066	$0.065	$0.063	$0.063	$0.062	$0.062	$0.062	$0.061	$0.060	$0.060

Scenario I - Complete in 2009

REVENU

		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
Revenue Requirement		$2,264,472	$2,236,284	$2,254,697	$2,226,545	$2,199,329	$3,026,520	$2,994,702	$2,966,118
dk Production	100%	447,615	447,615	447,615	447,615	447,615	500,044	500,044	500,044
Cost per Dk		$5.059	$4.996	$5.037	$4.974	$4.913	$6.053	$5.989	$5.932
System Dk Sales 1/		37,224,817	37,373,716	37,523,211	37,673,304	37,823,997	37,975,293	38,127,194	38,279,703
		0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk		$0.061	$0.060	$0.060	$0.059	$0.058	$0.080	$0.079	$0.077

BILLINGS, MT LANDFILL GAS PROJECT - OWNED BY MDU

Assumptions:

- MDU would own the landfill gas system when it goes on line.
- Complete and in service at the end of 2009, final payment in January 2010
- Renewable Energy Credits (RECs) or green tags are available but not part of modeled revenue
- Tax rate - 39%
- 50% / 50% ratio with a debt cost of 7.0% for financial
- 2008 average capital structure for revenue requirement
- Tax depreciation - 15 Year MACRS
- Capitalization is based on net plant book value less future tax liability (DITs)
- Assumes minor capital expenditures with major investment in Year 16
- Assumes an after-tax equity return of 10% (pre-tax 16.67%)
- There is a possibility for a property tax credit for new or expanding project
- 15% ES and GA overheads on first $1.0 million of investment
- AFUDC rate of 7.2% annually

Scenario II - Final Payment in Jan 2010

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Operating Revenues										
Annual Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Operating Expenses										
O&M	848,289	891,241	929,604	953,174	972,187	1,042,477	1,070,050	1,090,827	1,112,227	1,141,819
Depreciation 1/	248,047	248,047	248,047	254,297	254,297	254,297	260,547	260,547	260,547	266,797
Taxes Other Than Incon	68,862	67,096	65,331	65,300	63,490	61,680	61,605	59,750	57,895	57,776
Total Exp.	1,165,198	1,206,384	1,242,981	1,272,771	1,289,974	1,358,453	1,392,201	1,411,124	1,430,669	1,466,391
Income before Taxes	(1,165,198)	(1,206,384)	(1,242,981)	(1,272,771)	(1,289,974)	(1,358,453)	(1,392,201)	(1,411,124)	(1,430,669)	(1,466,391)
Interest Expense	289,132	273,466	258,910	252,638	239,584	227,368	222,845	210,665	198,533	193,722
Taxable income	(1,454,330)	(1,479,850)	(1,501,891)	(1,525,409)	(1,529,558)	(1,585,821)	(1,615,046)	(1,621,789)	(1,629,202)	(1,660,113)
Income Taxes	(567,189)	(577,142)	(585,738)	(594,909)	(596,527)	(618,470)	(629,868)	(632,498)	(635,389)	(647,444)
Tax Credit										
Operating Income	($598,009)	($629,242)	($657,243)	($677,862)	($693,447)	($739,983)	($762,333)	($778,626)	($795,280)	($818,947)
Rate Base	$9,577,083	$9,058,169	$8,576,016	$8,368,260	$7,935,873	$7,531,228	$7,381,421	$6,977,977	$6,576,134	$6,416,758
Rate of Return	-6.24%	-6.95%	-7.66%	-8.10%	-8.74%	-9.83%	-10.33%	-11.16%	-12.09%	-12.76%
Revenue Requirement	$2,317,837	$2,296,570	$2,275,138	$2,279,924	$2,245,088	$2,264,867	$2,280,585	$2,250,950	$2,222,133	$2,238,674
dk Production	340,685	340,685	340,685	340,685	340,685	394,771	394,771	394,771	394,771	394,771
Cost per Dk	$6.803	$6.741	$6.678	$6.692	$6.590	$5.737	$5.777	$5.702	$5.629	$5.671
Average Rev. Req.	$2,637,180	30 years								
Avg. Dk	473,553									
Avg. $/Dk	$5.569									
Rate Base										
Plant in Service										
Investment	$9,921,868	$9,921,868	$9,921,868	$9,921,868	$10,171,868	$10,171,868	$10,171,868	$10,421,868	$10,421,868	$10,421,868
Additional Facilities	0	0	0	250,000	0	0	250,000	0	0	250,000
	$9,921,868	$9,921,868	$9,921,868	$10,171,868	$10,171,868	$10,171,868	$10,421,868	$10,421,868	$10,421,868	$10,671,868
Accumulated Reserve 1/										
Acc. Reserve	248,047	496,093	744,140	998,437	1,252,734	1,507,030	1,767,577	2,028,124	2,288,670	2,555,467
DIT	96,738	367,605	601,712	805,171	983,262	1,133,610	1,272,870	1,415,768	1,557,064	1,699,643
	344,785	863,699	1,345,852	1,803,608	2,235,995	2,640,640	3,040,447	3,443,891	3,845,734	4,255,110
Rate base	$9,577,083	$9,058,169	$8,576,016	$8,368,260	$7,935,873	$7,531,228	$7,381,421	$6,977,977	$6,576,134	$6,416,758

Scenario II - Final Payment in Jan 2010

REVENU

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Operating Revenues									
Annual Fee		$0	$0	$0	$0		$0	$0	$0
Operating Expenses									
O&M	1,216,064	1,239,448	1,272,266	1,297,074	1,322,627	1,411,057	1,438,166	1,466,088	1,504,996
Depreciation 1/	266,797	266,797	273,047	273,047	273,047	404,297	404,297	404,297	410,547
Taxes Other Than Incon	55,877	53,977	53,813	51,870	49,926	84,420	81,542	78,664	77,521
Total Exp.	1,538,737	1,560,222	1,599,126	1,621,990	1,645,600	1,899,773	1,924,004	1,949,049	1,993,064
Income before Taxes	(1,538,737)	(1,560,222)	(1,599,126)	(1,621,990)	(1,645,600)	(1,899,773)	(1,924,004)	(1,949,049)	(1,993,064)
Interest Expense	181,253	168,832	163,732	150,974	138,265	282,031	267,988	254,552	249,027
Taxable income	(1,719,990)	(1,729,054)	(1,762,858)	(1,772,964)	(1,783,865)	(2,181,804)	(2,191,992)	(2,203,601)	(2,242,091)
Income Taxes	(670,796)	(674,331)	(687,515)	(691,456)	(695,707)	(850,904)	(854,877)	(859,404)	(874,415)
Tax Credit									
Operating Income	($867,941)	($885,891)	($911,611)	($930,534)	($949,893)	($1,048,869)	($1,069,127)	($1,089,645)	($1,118,649)
Rate Base	$6,003,743	$5,592,331	$5,423,384	$5,000,800	$4,579,818	$9,341,857	$8,876,699	$8,431,667	$8,248,654
Rate of Return	-14.46%	-15.84%	-16.81%	-18.61%	-20.74%	-11.23%	-12.04%	-12.92%	-13.56%
Revenue Requirement	$2,261,312	$2,233,282	$2,251,851	$2,223,857	$2,196,799	$3,024,102	$2,992,350	$2,963,833	$2,985,822
dk Production	447,615	447,615	447,615	447,615	447,615	500,044	500,044	500,044	500,044
Cost per Dk	$5.052	$4.989	$5.031	$4.968	$4.908	$6.048	$5.984	$5.927	$5.971
Average Rev. Req.									
Avg. Dk									
Avg. $/Dk									
Rate Base									
Plant in Service									
Investment	$10,671,868	$10,671,868	$10,671,868	$10,921,868	$10,921,868	$10,921,868	$16,171,868	$16,171,868	$16,171,868
Additional Facilities	0	0	250,000	0	0	5,250,000	0	0	250,000
	$10,671,868	$10,671,868	$10,921,868	$10,921,868	$10,921,868	$16,171,868	$16,171,868	$16,171,868	$16,421,868
Accumulated Reserve 1/									
Acc. Reserve	2,822,264	3,089,060	3,362,107	3,635,154	3,908,201	4,312,497	4,716,794	5,121,091	5,531,637
DIT	1,845,861	1,990,477	2,136,377	2,285,914	2,433,850	2,517,514	2,578,375	2,619,110	2,641,577
31	4,668,125	5,079,537	5,498,484	5,921,068	6,342,050	6,830,011	7,295,169	7,740,201	8,173,214
Rate base	$6,003,743	$5,592,331	$5,423,384	$5,000,800	$4,579,818	$9,341,857	$8,876,699	$8,431,667	$8,248,654

Scenario II - Final Payment in Jan 2010

REVENU

	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Operating Revenues								
Annual Fee	$0		$0	$0	$0	$0		$0
Operating Expenses								
O&M	1,534,618	1,619,612	1,662,479	1,694,848	1,728,188	1,774,198	1,866,475	1,902,907
Depreciation 1/	410,547	410,547	416,797	416,797	416,797	423,047	423,047	423,047
Taxes Other Than Incon	74,599	71,676	70,489	67,522	64,555	63,323	60,312	57,300
Total Exp.	2,019,763	2,101,835	2,149,765	2,179,167	2,209,540	2,260,568	2,349,833	2,383,254
Income before Taxes	(2,019,763)	(2,101,835)	(2,149,765)	(2,179,167)	(2,209,540)	(2,260,568)	(2,349,833)	(2,383,254)
Interest Expense	236,384	224,197	219,611	207,454	195,345	190,644	178,372	166,148
Taxable income	(2,256,147)	(2,326,032)	(2,369,376)	(2,386,621)	(2,404,885)	(2,451,212)	(2,528,205)	(2,549,402)
Income Taxes	(879,897)	(907,152)	(924,056)	(930,782)	(937,905)	(955,973)	(986,000)	(994,267)
Tax Credit								
Operating Income	($1,139,866)	($1,194,683)	($1,225,709)	($1,248,385)	($1,271,635)	($1,304,595)	($1,363,833)	($1,388,987)
Rate Base	$7,829,876	$7,426,214	$7,274,293	$6,871,612	$6,470,533	$6,314,800	$5,908,307	$5,503,415
Rate of Return	-14.56%	-16.09%	-16.85%	-18.17%	-19.65%	-20.66%	-23.08%	-25.24%
Revenue Requirement	$2,962,120	$2,995,610	$3,025,255	$3,006,192	$2,988,294	$3,020,578	$3,060,921	$3,045,611
dk Production	500,044	552,680	552,680	552,680	552,680	552,680	605,523	605,523
Cost per Dk	$5.924	$5.420	$5.474	$5.439	$5.407	$5.465	$5.055	$5.030
Average Rev. Req.								
Avg. Dk								
Avg. $/Dk								
Rate Base								
Plant in Service								
Investment	$16,421,868	$16,421,868	$16,421,868	$16,671,868	$16,671,868	$16,671,868	$16,921,868	$16,921,868
Additional Facilities	0	0	250,000	0	0	250,000	0	0
	$16,421,868	$16,421,868	$16,671,868	$16,671,868	$16,671,868	$16,921,868	$16,921,868	$16,921,868
Accumulated Reserve 1/								
Acc. Reserve	5,942,184	6,352,731	6,769,527	7,186,324	7,603,121	8,026,168	8,449,214	8,872,261
DIT	2,649,808	2,642,924	2,628,047	2,613,932	2,598,214	2,580,900	2,564,347	2,546,192
	8,591,992	8,995,654	9,397,575	9,800,256	10,201,335	10,607,068	11,013,561	11,418,453
Rate base	$7,829,876	$7,426,214	$7,274,293	$6,871,612	$6,470,533	$6,314,800	$5,908,307	$5,503,415

Scenario II - Final Payment in Jan 2010

REVENU

	Year 28	Year 29	Year 30
Operating Revenues			
Annual Fee	$0	$0	$0
Operating Expenses			
O&M	1,953,474	1,992,124	2,031,934
Depreciation 1/	429,297	429,297	429,297
Taxes Other Than Incon	56,024	52,968	49,912
Total Exp.	2,438,795	2,474,389	2,511,143
Income before Taxes	(2,438,795)	(2,474,389)	(2,511,143)
Interest Expense	161,331	148,944	136,606
Taxable income	(2,600,126)	(2,623,333)	(2,647,749)
Income Taxes	(1,014,049)	(1,023,100)	(1,032,622)
Tax Credit			
Operating Income	($1,424,746)	($1,451,289)	($1,478,521)
Rate Base	$5,343,870	$4,933,564	$4,524,860
Rate of Return	-26.66%	-29.42%	-32.68%
Revenue Requirement	$3,081,951	$3,068,162	$3,055,727
dk Production	605,523	605,523	605,523
Cost per Dk	$5.090	$5.067	$5.046
Average Rev. Req.			
Avg. Dk			
Avg. $/Dk			
Rate Base			
Plant in Service			
Investment	$16,921,868	$17,171,868	$17,171,868
Additional Facilities	250,000	0	0
	$17,171,868	$17,171,868	$17,171,868
Accumulated Reserve 1/			
Acc. Reserve	9,301,558	9,730,854	10,160,151
DIT	2,526,441	2,507,450	2,486,857
	11,827,998	12,238,304	12,647,008
Rate base	$5,343,870	$4,933,564	$4,524,860

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Scenario II

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU
CAPITALIZATION
DEBT AND EQUITY
(000)

	INITIAL INVESTMENT	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
TOTAL (Incl. DITs)	9,921,868	9,577,083	9,058,169	8,576,016	8,368,260	7,935,873	7,531,228	7,381,421	6,977,977	6,576,134	6,416,758	6,003,743
DEBT	4,960,934	4,788,542	4,529,085	4,288,008	4,184,130	3,967,936	3,765,614	3,690,711	3,488,988	3,288,067	3,208,379	3,001,872
EQUITY	4,960,934	4,788,542	4,529,085	4,288,008	4,184,130	3,967,936	3,765,614	3,690,711	3,488,988	3,288,067	3,208,379	3,001,872

Long-Term Debt Cost **7%**

Scenario II

I	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22
TOTAL (Incl. DITs)	5,592,331	5,423,384	5,000,800	4,579,818	9,341,857	8,876,699	8,431,667	8,248,654	7,829,876	7,426,214	7,274,293
DEBT	2,796,165	2,711,692	2,500,400	2,289,909	4,670,929	4,438,349	4,215,834	4,124,327	3,914,938	3,713,107	3,637,147
EQUITY	2,796,165	2,711,692	2,500,400	2,289,909	4,670,929	4,438,349	4,215,834	4,124,327	3,914,938	3,713,107	3,637,147

Long-T

Scenario II

I	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33
TOTAL (Incl. DITs)	6,871,612	6,470,533	6,314,800	5,908,307	5,503,415	5,343,870	4,933,564	4,524,860	4,177,792	3,891,896	3,606,676
DEBT	3,435,806	3,235,267	3,157,400	2,954,153	2,751,708	2,671,935	2,466,782	2,262,430	2,088,896	1,945,948	1,803,338
EQUITY	3,435,806	3,235,267	3,157,400	2,954,153	2,751,708	2,671,935	2,466,782	2,262,430	2,088,896	1,945,948	1,803,338

Long-T

Scenario II

I	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
TOTAL (Incl. DITs)	3,324,656	3,045,513	2,766,369	2,490,107	2,216,721	1,943,335	1,672,829
DEBT	1,662,328	1,522,756	1,383,185	1,245,053	1,108,360	971,668	836,415
EQUITY	1,662,328	1,522,756	1,383,185	1,245,053	1,108,360	971,668	836,415

Long-T

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Scenario II - Final payment in January 2010

Depreciation Schedule
(000)

1.1230637

40 Year Life - Plant

Depreciation Schedule
($000)

	Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
BOOK DEPRECIATION											
Existing Assets (net of Accun	9,921,868										
Depr. on Adjusted Fixed Assets		248,047	248,047	248,047	254,297	254,297	254,297	260,547	260,547	260,547	266,797
Total Book Depreciation		**248,047**	**248,047**	**248,047**	**254,297**	**254,297**	**254,297**	**260,547**	**260,547**	**260,547**	**266,797**

	Year	YEAR #	1	2	3	4	5	6	7	8	9	10
	Landfill		248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047
2010	1	-	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	-	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	-	-	-	-	-	-	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	-	-	-	-	-	-	-	-	-	6,250
2020	11	-	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	-	-	-	-	-	-	-	-
2023	14	-	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	-	-	-	-	-	-	-	-	-	-
2026	17	-	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	-	-
2029	20	-	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-	-

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Scenario II - Final payment in January 2010											
Total Book Depreciation		248,047	248,047	248,047	254,297	254,297	254,297	260,547	260,547	260,547	266,797
Book Value	$9,921,868	9,673,821	9,425,775	9,177,728	9,173,431	8,919,135	8,664,838	8,654,291	8,393,744	8,133,198	8,116,401
Property Taxes											
Property Tax Rate	0.7%	68,862	67,096	65,331	65,300	63,490	61,680	61,605	59,750	57,895	57,776

			1	2	3	4	5	6	7	8	9	10
Enter MACRS rate (below in y		4										
3	**MACRS**	**20 Year**	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%	5.2850%	4.8880%	4.5220%	4.4620%	4.4610%
4	**MACRS**	**15 Year**	5.0000%	9.5000%	8.5500%	7.6950%	6.9260%	6.2330%	5.9050%	5.9050%	5.9050%	5.9050%
5	**MACRS**	**10 Year**	10.0000%	18.0000%	14.4000%	11.5200%	9.2200%	7.3700%	6.5500%	6.5500%	6.5600%	6.5500%
6	**MACRS**	**7 Year**	14.2900%	24.4900%	17.4900%	12.4900%	8.9300%	8.9200%	8.9300%	4.4600%		
7	**MACRS**	**5 Year**	20.0000%	32.0000%	19.2000%	11.5200%	11.5200%	5.7600%				
8	**MACRS**	**3 Year**	33.3300%	44.4500%	14.8100%	7.4100%						

TAX DEPRECIATION

	Estimated										
Construction Property/Turbin	9,921,868	496,093	942,577	848,320	775,988	710,939	639,805	617,624	626,951	622,844	632,386
Total Tax Depreciation\Amortization		496,093	942,577	848,320	775,988	710,939	639,805	617,624	626,951	622,844	632,386
Balance Sheet DITs - Current Year		(96,738)	(270,867)	(234,106)	(203,460)	(178,090)	(150,348)	(139,260)	(142,898)	(141,296)	(142,580)
Balance Sheet DITs - Accumulated		(96,738)	(367,605)	(601,712)	(805,171)	(983,262)	(1,133,610)	(1,272,870)	(1,415,768)	(1,557,064)	(1,699,643)

		YEAR #	1	2	3	4	5	6	7	8	9	10
Year	Amount											
Existing	9,921,868	**15 Year**	496,093	942,577	848,320	763,488	687,189	618,430	585,886	585,886	585,886	585,886
1	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	-	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
5	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	-	-	-	-	-	-	12,500	23,750	21,375	19,238
8	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	-	-	-	-	-	-	-	-	-	12,500
11	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	-	-	-	-	-	-	-	-	-	-
14	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-	-

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Scenario II - Final payment in January 2010

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
16	5,250,000	15 Year	-	-	-	-	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**496,093**	**942,577**	**848,320**	**775,988**	**710,939**	**639,805**	**617,624**	**626,951**	**622,844**	**632,386**

Scenario II - Final payment in January 2010

40 Year Life - Plant

BOOK DEPRECIATION	Cost	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Existing Assets (net of Accun	9,921,868									
Depr. on Adjusted Fixed Assets		266,797	266,797	273,047	273,047	273,047	404,297	404,297	404,297	410,547
Total Book Depreciation		**266,797**	**266,797**	**273,047**	**273,047**	**273,047**	**404,297**	**404,297**	**404,297**	**410,547**

			YEAR #	11	12	13	14	15	16	17	18	19
	Year											
	Landfill			248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047
2010	1	-		-	-	-	-	-	-	-	-	-
2011	2	-		-	-	-	-	-	-	-	-	-
2012	3	-		-	-	-	-	-	-	-	-	-
2013	4	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-		-	-	-	-	-	-	-	-	-
2015	6	-		-	-	-	-	-	-	-	-	-
2016	7	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-		-	-	-	-	-	-	-	-	-
2018	9	-		-	-	-	-	-	-	-	-	-
2019	10	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-		-	-	-	-	-	-	-	-	-
2021	12	-		-	-	-	-	-	-	-	-	-
2022	13	250,000		-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-		-	-	-	-	-	-	-	-	-
2024	15	-		-	-	-	-	-	-	-	-	-
2025	16	5,250,000		-	-	-	-	-	131,250	131,250	131,250	131,250
2026	17	-		-	-	-	-	-	-	-	-	-
2027	18	-		-	-	-	-	-	-	-	-	-
2028	19	250,000		-	-	-	-	-	-	-	-	6,250
2029	20	-		-	-	-	-	-	-	-	-	-
2030	21	-		-	-	-	-	-	-	-	-	-
2031	22	250,000		-	-	-	-	-	-	-	-	-
2032	23	-		-	-	-	-	-	-	-	-	-
2033	24	-		-	-	-	-	-	-	-	-	-
2034	25	250,000		-	-	-	-	-	-	-	-	-
2035	26	-		-	-	-	-	-	-	-	-	-
2036	27	-		-	-	-	-	-	-	-	-	-
2037	28	250,000		-	-	-	-	-	-	-	-	-
2038	29	-		-	-	-	-	-	-	-	-	-
2039	30	-		-	-	-	-	-	-	-	-	-

Scenario II - Final payment in January 2010

		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Total Book Depreciation		266,797	266,797	273,047	273,047	273,047	404,297	404,297	404,297	410,547
Book Value	$9,921,868	7,849,604	7,582,808	7,559,761	7,286,714	7,013,668	11,859,371	11,455,074	11,050,777	10,890,231
Property Taxes										
Property Tax Rate	0.7%	55,877	53,977	53,813	51,870	49,926	84,420	81,542	78,664	77,521

		11	12	13	14	15	16	17	18	19
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%
4 **MACRS**	**15 Year**	5.9050%	5.9050%	5.9050%	5.9050%	5.9050%	2.9510%			
5 **MACRS**	**10 Year**	3.2800%								
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,921,868	641,714	637,606	647,149	656,476	652,369	618,819	560,353	508,745	468,153
Total Tax Depreciation\Amortization		641,714	637,606	647,149	656,476	652,369	618,819	560,353	508,745	468,153
Balance Sheet DITs - Current Year		(146,218)	(144,616)	(145,900)	(149,538)	(147,936)	(83,664)	(60,862)	(40,735)	(22,466)
Balance Sheet DITs - Accumulated		(1,845,861)	(1,990,477)	(2,136,377)	(2,285,914)	(2,433,850)	(2,517,514)	(2,578,375)	(2,619,110)	(2,641,577)

Year	Amount	YEAR #	11	12	13	14	15	16	17	18	19
Existing	9,921,868	15 Year	585,886	585,886	585,886	585,886	585,886	292,794	-	-	-
1	-	15 Year	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
5	-	15 Year	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
8	-	15 Year	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
11	-	15 Year	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
14	-	15 Year	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-

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Scenario II - Final payment in January 2010

			Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
16	5,250,000	15 Year	-	-	-	-	-	262,500	498,750	448,875	403,988
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**641,714**	**637,606**	**647,149**	**656,476**	**652,369**	**618,819**	**560,353**	**508,745**	**468,153**

Scenario II - Final payment in January 2010

40 Year Life - Plant

		Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
BOOK DEPRECIATION	**Cost**									
Existing Assets (net of Accun	9,921,868									
Depr. on Adjusted Fixed Assets		410,547	410,547	416,797	416,797	416,797	423,047	423,047	423,047	429,297
Total Book Depreciation		**410,547**	**410,547**	**416,797**	**416,797**	**416,797**	**423,047**	**423,047**	**423,047**	**429,297**

			YEAR #	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
	Year											
	Landfill			248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047
2010	1	-		-	-	-	-	-	-	-	-	-
2011	2	-		-	-	-	-	-	-	-	-	-
2012	3	-		-	-	-	-	-	-	-	-	-
2013	4	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-		-	-	-	-	-	-	-	-	-
2015	6	-		-	-	-	-	-	-	-	-	-
2016	7	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-		-	-	-	-	-	-	-	-	-
2018	9	-		-	-	-	-	-	-	-	-	-
2019	10	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-		-	-	-	-	-	-	-	-	-
2021	12	-		-	-	-	-	-	-	-	-	-
2022	13	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-		-	-	-	-	-	-	-	-	-
2024	15	-		-	-	-	-	-	-	-	-	-
2025	16	5,250,000		131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250
2026	17	-		-	-	-	-	-	-	-	-	-
2027	18	-		-	-	-	-	-	-	-	-	-
2028	19	250,000		6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-		-	-	-	-	-	-	-	-	-
2030	21	-		-	-	-	-	-	-	-	-	-
2031	22	250,000		-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-		-	-	-	-	-	-	-	-	-
2033	24	-		-	-	-	-	-	-	-	-	-
2034	25	250,000		-	-	-	-	-	6,250	6,250	6,250	6,250
2035	26	-		-	-	-	-	-	-	-	-	-
2036	27	-		-	-	-	-	-	-	-	-	-
2037	28	250,000		-	-	-	-	-	-	-	-	6,250
2038	29	-		-	-	-	-	-	-	-	-	-
2039	30	-		-	-	-	-	-	-	-	-	-

Scenario II - Final payment in January 2010

		Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
Total Book Depreciation		410,547	410,547	416,797	416,797	416,797	423,047	423,047	423,047	429,297
Book Value	$9,921,868	10,479,684	10,069,137	9,902,341	9,485,544	9,068,747	8,895,701	8,472,654	8,049,607	7,870,310
Property Taxes										
Property Tax Rate	0.7%	74,599	71,676	70,489	67,522	64,555	63,323	60,312	57,300	56,024

		20	21	22	23	24	25	26	27	28
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4610%	2.2310%							
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,921,868	431,653	392,895	378,653	380,603	376,495	378,653	380,603	376,495	378,653
Total Tax Depreciation\Amortization		431,653	392,895	378,653	380,603	376,495	378,653	380,603	376,495	378,653
Balance Sheet DITs - Current Year		(8,231)	6,884	14,876	14,116	15,718	17,314	16,553	18,155	19,751
Balance Sheet DITs - Accumulated		(2,649,808)	(2,642,924)	(2,628,047)	(2,613,932)	(2,598,214)	(2,580,900)	(2,564,347)	(2,546,192)	(2,526,441)

Year	Amount	YEAR #	20	21	22	23	24	25	26	27	28
Existing	9,921,868	**15 Year**	-	-	-	-	-	-	-	-	-
1	-	**15 Year**	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	-	-	-	-	-	-	-	-	-
5	-	**15 Year**	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	14,763	14,763	7,378	-	-	-	-	-	-
8	-	**15 Year**	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
11	-	**15 Year**	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
14	-	**15 Year**	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-

Scenario II - Final payment in January 2010

			Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
16	5,250,000	15 Year	363,615	327,233	310,013	310,013	310,013	310,013	310,013	310,013	310,013
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	12,500	23,750	21,375	19,238
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**431,653**	**392,895**	**378,653**	**380,603**	**376,495**	**378,653**	**380,603**	**376,495**	**378,653**

Scenario II - Final payment in January 2010

40 Year Life - Plant

			Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
BOOK DEPRECIATION		**Cost**									
Existing Assets (net of Accun		9,921,868									
Depr. on Adjusted Fixed Assets			429,297	429,297	429,297	429,297	429,297	429,297	429,297	429,297	429,297
Total Book Depreciation			**429,297**	**429,297**	**429,297**	**429,297**	**429,297**	**429,297**	**429,297**	**429,297**	**429,297**
		YEAR #	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**
	Year Landfill		248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047	248,047
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

Scenario II - Final payment in January 2010

		Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
Total Book Depreciation		429,297	429,297	429,297	429,297	429,297	429,297	429,297	429,297	429,297
Book Value	$9,921,868	7,441,014	7,011,717	6,582,420	6,153,124	5,723,827	5,294,530	4,865,234	4,435,937	4,006,640
Property Taxes										
Property Tax Rate	0.7%	52,968	49,912	46,856	43,800	40,744	37,689	34,633	31,577	28,521

		29	30	31	32	33	34	35	36	37
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**									
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,921,868	380,603	376,495	218,453	61,603	59,870	51,665	44,288	44,288	36,903
Total Tax Depreciation\Amortization		380,603	376,495	218,453	61,603	59,870	51,665	44,288	44,288	36,903
Balance Sheet DITs - Current Year		18,991	20,593	82,229	143,401	144,076	147,276	150,154	150,154	153,034
Balance Sheet DITs - Accumulated		(2,507,450)	(2,486,857)	(2,404,628)	(2,261,227)	(2,117,151)	(1,969,874)	(1,819,721)	(1,669,567)	(1,516,534)

Year	Amount	YEAR #	29	30	31	32	33	34	35	36	37
Existing	9,921,868	15 Year	-	-	-	-	-	-	-	-	-
1	-	15 Year	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	-	-	-	-	-	-	-	-	-
5	-	15 Year	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	-	-	-	-	-	-	-	-	-
8	-	15 Year	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	-	-	-	-	-	-	-	-	-
11	-	15 Year	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	-	-	-	-	-	-	-	-	-
14	-	15 Year	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-

Scenario II - Final payment in January 2010

			Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
16	5,250,000	15 Year	310,013	310,013	154,928	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**380,603**	**376,495**	**218,453**	**61,603**	**59,870**	**51,665**	**44,288**	**44,288**	**36,903**

Scenario II - Final payment in January 2010

40 Year Life - Plant

			Year 38	Year 39	Year 40
BOOK DEPRECIATION		**Cost**			
Existing Assets (net of Accun		9,921,868			
Depr. on Adjusted Fixed Assets			429,297	429,297	429,297
Total Book Depreciation			**429,297**	**429,297**	**429,297**

			YEAR #	**38**	**39**	**40**
	Year					
	Landfill			248,047	248,047	248,047
2010	1	-		-	-	-
2011	2	-		-	-	-
2012	3	-		-	-	-
2013	4	250,000		6,250	6,250	6,250
2014	5	-		-	-	-
2015	6	-		-	-	-
2016	7	250,000		6,250	6,250	6,250
2017	8	-		-	-	-
2018	9	-		-	-	-
2019	10	250,000		6,250	6,250	6,250
2020	11	-		-	-	-
2021	12	-		-	-	-
2022	13	250,000		6,250	6,250	6,250
2023	14	-		-	-	-
2024	15	-		-	-	-
2025	16	5,250,000		131,250	131,250	131,250
2026	17	-		-	-	-
2027	18	-		-	-	-
2028	19	250,000		6,250	6,250	6,250
2029	20	-		-	-	-
2030	21	-		-	-	-
2031	22	250,000		6,250	6,250	6,250
2032	23	-		-	-	-
2033	24	-		-	-	-
2034	25	250,000		6,250	6,250	6,250
2035	26	-		-	-	-
2036	27	-		-	-	-
2037	28	250,000		6,250	6,250	6,250
2038	29	-		-	-	-
2039	30	-		-	-	-

Scenario II - Final payment in January 2010

		Year 38	Year 39	Year 40
Total Book Depreciation		429,297	429,297	429,297
Book Value	$9,921,868	3,577,343	3,148,047	2,718,750
Property Taxes				
Property Tax Rate	0.7%	25,465	22,409	19,353

		38	39	40
Enter MACRS rate (below in y	4			
3 **MACRS**	**20 Year**			
4 **MACRS**	**15 Year**			
5 **MACRS**	**10 Year**			
6 **MACRS**	**7 Year**			
7 **MACRS**	**5 Year**			
8 **MACRS**	**3 Year**			

TAX DEPRECIATION

	Estimated			
Construction Property/Turbin	9,921,868	29,525	29,525	22,140
Total Tax Depreciation\Amortization		29,525	29,525	22,140
Balance Sheet DITs - Current Year		155,911	155,911	158,791
Balance Sheet DITs - Accumulated		(1,360,623)	(1,204,712)	(1,045,921)

Year	Amount	YEAR #	38	39	40
Existing	9,921,868	15 Year	-	-	-
1	-	15 Year	-	-	-
2	-	15 Year	-	-	-
3	-	15 Year	-	-	-
4	250,000	15 Year	-	-	-
5	-	15 Year	-	-	-
6	-	15 Year	-	-	-
7	250,000	15 Year	-	-	-
8	-	15 Year	-	-	-
9	-	15 Year	-	-	-
10	250,000	15 Year	-	-	-
11	-	15 Year	-	-	-
12	-	15 Year	-	-	-
13	250,000	15 Year	-	-	-
14	-	15 Year	-	-	-
15	-	15 Year	-	-	-

Scenario II - Final payment in January 2010

			Year 38	Year 39	Year 40
16	5,250,000	15 Year	-	-	-
17	-	15 Year	-	-	-
18	-	15 Year	-	-	-
19	250,000	15 Year	-	-	-
20	-	15 Year	-	-	-
21	-	15 Year	-	-	-
22	250,000	15 Year	-	-	-
23	-	15 Year	-	-	-
24	-	15 Year	-	-	-
25	250,000	15 Year	14,763	14,763	7,378
26	-	15 Year	-	-	-
27	-	15 Year	-	-	-
28	250,000	15 Year	14,763	14,763	14,763
29	-	15 Year	-	-	-
30	-	15 Year	-	-	-
Total Tax Depreciation			**29,525**	**29,525**	**22,140**

Scenario II - Final Payment Jan 2010

2009 Final	2008 a-Oct	2008 a-Nov	2008 a-Dec	2008 Year	2009 Jan	2009 Feb	2009 Mar	2009 Apr	2009 May	2009 Jun	2009 Jul
J159744 DEVELOP GAS PROD-BLGS LANDFILL											
Budget											
Construction Expenditures					1,625	277	277	262	200	1,785	1,785
Removal											
Closings											
Ending CWIP	28	29	29	29	1,659	1,948	2,238	2,515	2,732	4,540	6,359
AFUDC - Borrowed		0	0	0	2	5	6	6	7	10	14
AFUDC - Other Funds					3	7	8	9	10	13	20
Total AFUDC		0	0	0	5	11	13	15	17	23	35
% of total	0.00%	0.00%	0.00%	0.00%	19.81%	3.38%	3.38%	3.19%	2.44%	21.77%	21.77%
AFUDC Rate					0.32%	0.59%	0.59%	0.60%	0.61%	0.51%	0.54%
Updated Amount											
Expenditure				112,097			1,851,861	524,654	194,849	1,738,466	1,738,466
ES & GA				12,409			137,591				
Balance				124,506	124,506	124,506	2,113,958	2,638,612	2,833,461	4,571,927	6,310,393
AFUDC						747	12,684	15,832	17,001	27,432	37,862
Total	8,097,700										
	7,985,603										
Total Amount	9,513,700										
ES & GA	150,000										
AFUDC	258,168										
	9,921,868										

Scenario II - Final Payment Jan 2010

2009 Final	2009 Aug	2009 Sep	2009 Oct	2009 Nov	2009 Dec	2009 Year	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 Year
J159744 DEVELOP GAS F											
Budget											
Construction Expenditures		1,785	205			8,201					
Removal											
Closings			8,489			8,489					
Ending CWIP	6,400	8,231									
AFUDC - Borrowed	17	19	22			108					
AFUDC - Other Funds	24	27	31			151					
Total AFUDC	40	46	53			259					
% of total	0.00%	21.76%	2.50%			100.00%					
AFUDC Rate	0.63%	0.56%									
Updated Amount											
Expenditure		1,737,667	199,640			7,985,603	1,416,000				1,416,000
ES & GA	137,591					275,182					
Balance	6,447,984	8,185,651	8,385,291	8,385,291	8,385,291	8,385,291	9,801,291				
AFUDC	38,688	49,114	50,312			249,672	8,496				8,496
Total											
Total Amount											
ES & GA											
AFUDC											

Scenario I - Complete in 2009

2009 Final	2008 a-Oct	2008 a-Nov	2008 a-Dec	2008 Year	2009 Jan	2009 Feb	2009 Mar	2009 Apr	2009 May	2009 Jun	2009 Jul
J159744 DEVELOP GAS PROD-BLGS LANDFILL											
Budget											
Construction Expenditures					1,625	277	277	262	200	1,785	1,785
Removal											
Closings											
Ending CWIP	28	29	29	29	1,659	1,948	2,238	2,515	2,732	4,540	6,359
AFUDC - Borrowed		0	0	0	2	5	6	6	7	10	14
AFUDC - Other Funds					3	7	8	9	10	13	20
Total AFUDC		0	0	0	5	11	13	15	17	23	35
% of total	0.00%	0.00%	0.00%	0.00%	19.81%	3.38%	3.38%	3.19%	2.44%	21.77%	21.77%
AFUDC Rate					0.32%	0.59%	0.59%	0.60%	0.61%	0.51%	0.54%
Updated Amount											
Expenditure				112,097			2,180,232	617,685	229,399	2,046,729	2,046,729
ES & GA				12,409			137,591				
Balance				124,506	124,506	124,506	2,442,329	3,060,014	3,289,413	5,336,142	7,382,871
AFUDC						747	14,654	18,360	19,736	32,017	44,297
Total	9,513,700										
	9,401,603										

Total Amount	9,513,700
ES & GA	150,000
AFUDC	291,140
	9,954,840

Scenario I - Complete in 2009

2009 Final	2009 Aug	2009 Sep	2009 Oct	2009 Nov	2009 Dec	2009 Year	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 Year
J159744 DEVELOP GAS F											
Budget											
Construction Expenditures		1,785	205			8,201					
Removal											
Closings			8,489			8,489					
Ending CWIP	6,400	8,231									
AFUDC - Borrowed	17	19	22			108					
AFUDC - Other Funds	24	27	31			151					
Total AFUDC	40	46	53			259					
% of total	0.00%	21.76%	2.50%			100.00%					
AFUDC Rate	0.63%	0.56%									
Updated Amount											
Expenditure		2,045,789	235,040			9,401,603					
ES & GA	137,591					275,182					
Balance	7,520,462	9,566,251	9,801,291	9,801,291	9,801,291	9,801,291					
AFUDC	45,123	57,398	58,808			291,140					
Total											
Total Amount											
ES & GA											
AFUDC											

Scenario II - Final Payment in Jan 2010

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Revenue Requirement		$2,317,837	$2,296,570	$2,275,138	$2,279,924	$2,245,088	$2,264,867	$2,280,585	$2,250,950	$2,222,133	$2,238,674
dk Production	100%	340,685	340,685	340,685	340,685	340,685	394,771	394,771	394,771	394,771	394,771
Cost per Dk		$6.803	$6.741	$6.678	$6.692	$6.590	$5.737	$5.777	$5.702	$5.629	$5.671
System Dk Sales 1/		35,200,000	35,530,000	36,013,000	36,199,000	36,343,796	36,489,171	36,635,128	36,781,669	36,928,796	37,076,511
		0.69%	0.94%	1.36%	0.52%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk		$0.066	$0.065	$0.063	$0.063	$0.062	$0.062	$0.062	$0.061	$0.060	$0.060

Scenario II - Final Payment in Jan 2010

REVENU

		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
Revenue Requirement		$2,261,312	$2,233,282	$2,251,851	$2,223,857	$2,196,799	$3,024,102
dk Production	100%	447,615	447,615	447,615	447,615	447,615	500,044
Cost per Dk		$5.052	$4.989	$5.031	$4.968	$4.908	$6.048
System Dk Sales 1/		37,224,817	37,373,716	37,523,211	37,673,304	37,823,997	37,975,293
		0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk		$0.061	$0.060	$0.060	$0.059	$0.058	$0.080

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Assumptions:

- MDU would own the landfill gas system when it goes on line.
- Complete and in service 2010
- Renewable Energy Credits (RECs) or green tags are available but not part of modeled reve
- Tax rate - 39%
- 50% / 50% ratio with a debt cost of 7.0% for financial
- 2008 average capital structure for revenue requirement
- Tax depreciation - 15 Year MACRS
- Capitalization is based on net plant book value less future tax liability (DITs)
- Assumes minor capital expenditures with major investemnt in Year 16
- Assumes an after-tax equity return of 10% (pre-tax 16.67%)
- There is a possibility for a property tax credit for new or expanding project
- 15% ES and GA overheads on first $1.0 million of investment
- AFUDC rate of 7.2% annually

Scenario III - Completed in 2010

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Operating Revenues										
Annual Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Operating Expenses										
O&M	848,289	891,241	929,604	953,174	972,187	1,042,477	1,070,050	1,090,827	1,112,227	1,141,819
Depreciation 1/	249,469	249,469	249,469	255,719	255,719	255,719	261,969	261,969	261,969	268,219
Taxes Other Than Incon	69,257	67,481	65,705	65,665	63,844	62,024	61,939	60,074	58,209	58,080
Total Exp.	1,167,015	1,208,192	1,244,779	1,274,558	1,291,751	1,360,220	1,393,958	1,412,870	1,432,406	1,468,118
Income before Taxes	(1,167,015)	(1,208,192)	(1,244,779)	(1,274,558)	(1,291,751)	(1,360,220)	(1,393,958)	(1,412,870)	(1,432,406)	(1,468,118)
Interest Expense	290,790	275,035	260,395	254,045	240,919	228,634	224,046	211,800	199,603	194,726
Taxable income	(1,457,805)	(1,483,227)	(1,505,174)	(1,528,603)	(1,532,670)	(1,588,854)	(1,618,004)	(1,624,670)	(1,632,009)	(1,662,844)
Income Taxes	(568,544)	(578,458)	(587,018)	(596,155)	(597,741)	(619,653)	(631,022)	(633,621)	(636,483)	(648,509)
Tax Credit										
Operating Income	($598,471)	($629,734)	($657,761)	($678,403)	($694,010)	($740,567)	($762,936)	($779,249)	($795,923)	($819,609)
Rate Base	$9,632,013	$9,110,123	$8,625,204	$8,414,872	$7,980,080	$7,573,184	$7,421,199	$7,015,576	$6,611,555	$6,450,000
Rate of Return	-6.21%	-6.91%	-7.63%	-8.06%	-8.70%	-9.78%	-10.28%	-11.11%	-12.04%	-12.71%
Revenue Requirement	$2,326,267	$2,304,631	$2,282,856	$2,287,321	$2,252,185	$2,271,684	$2,287,128	$2,257,224	$2,228,133	$2,244,401
dk Production - 100%	340,685	340,685	340,685	340,685	340,685	394,771	394,771	394,771	394,771	394,771
Cost per Dk	$6.828	$6.765	$6.701	$6.714	$6.611	$5.754	$5.794	$5.718	$5.644	$5.685
Average Rev. Req.	$2,642,019	30 years								
Avg. Dk	473,553									
Avg. $/Dk	$5.579									
Rate Base										
Plant in Service										
Investment	$9,978,775	$9,978,775	$9,978,775	$9,978,775	$10,228,775	$10,228,775	$10,228,775	$10,478,775	$10,478,775	$10,478,775
Additional Facilities	0	0	0	250,000	0	0	250,000	0	0	250,000
	$9,978,775	$9,978,775	$9,978,775	$10,228,775	$10,228,775	$10,228,775	$10,478,775	$10,478,775	$10,478,775	$10,728,775
Accumulated Reserve 1/										
Acc. Reserve	249,469	498,939	748,408	1,004,128	1,259,847	1,515,566	1,777,536	2,039,505	2,301,474	2,569,694
DIT	97,293	369,714	605,163	809,775	988,848	1,140,025	1,280,040	1,423,694	1,565,745	1,709,081
	346,762	868,652	1,353,571	1,813,903	2,248,695	2,655,591	3,057,576	3,463,199	3,867,220	4,278,775
Rate base	$9,632,013	$9,110,123	$8,625,204	$8,414,872	$7,980,080	$7,573,184	$7,421,199	$7,015,576	$6,611,555	$6,450,000

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Scenario III - Completed in 2010

REVENU

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Operating Revenues									
Annual Fee		$0	$0	$0	$0		$0	$0	$0
Operating Expenses									
O&M	1,216,064	1,239,448	1,272,266	1,297,074	1,322,627	1,411,057	1,438,166	1,466,088	1,504,996
Depreciation 1/	268,219	268,219	274,469	274,469	274,469	405,719	405,719	405,719	411,969
Taxes Other Than Incon	56,170	54,261	54,087	52,133	50,179	84,663	81,775	78,887	77,734
Total Exp.	1,540,454	1,561,928	1,600,822	1,623,676	1,647,276	1,901,439	1,925,660	1,950,694	1,994,699
Income before Taxes	(1,540,454)	(1,561,928)	(1,600,822)	(1,623,676)	(1,647,276)	(1,901,439)	(1,925,660)	(1,950,694)	(1,994,699)
Interest Expense	182,191	169,705	164,538	151,715	138,939	282,659	268,590	255,128	249,577
Taxable income	(1,722,645)	(1,731,633)	(1,765,360)	(1,775,391)	(1,786,215)	(2,184,098)	(2,194,250)	(2,205,822)	(2,244,276)
Income Taxes	(671,831)	(675,337)	(688,490)	(692,403)	(696,624)	(851,798)	(855,758)	(860,271)	(875,268)
Tax Credit									
Operating Income	($868,623)	($886,591)	($912,332)	($931,273)	($950,652)	($1,049,641)	($1,069,902)	($1,090,423)	($1,119,431)
Rate Base	$6,034,807	$5,621,217	$5,450,092	$5,025,329	$4,602,168	$9,362,685	$8,896,659	$8,450,759	$8,266,879
Rate of Return	-14.39%	-15.77%	-16.74%	-18.53%	-20.66%	-11.21%	-12.03%	-12.90%	-13.54%
Revenue Requirement	$2,266,767	$2,238,464	$2,256,763	$2,228,494	$2,201,165	$3,028,276	$2,996,407	$2,967,776	$2,989,650
dk Production - 100%	447,615	447,615	447,615	447,615	447,615	500,044	500,044	500,044	500,044
Cost per Dk	$5.064	$5.001	$5.042	$4.979	$4.918	$6.056	$5.992	$5.935	$5.979
Average Rev. Req.									
Avg. Dk									
Avg. $/Dk									
Rate Base									
Plant in Service									
Investment	$10,728,775	$10,728,775	$10,728,775	$10,978,775	$10,978,775	$10,978,775	$16,228,775	$16,228,775	$16,228,775
Additional Facilities	0	0	250,000	0	0	5,250,000	0	0	250,000
	$10,728,775	$10,728,775	$10,978,775	$10,978,775	$10,978,775	$16,228,775	$16,228,775	$16,228,775	$16,478,775
Accumulated Reserve 1/									
Acc. Reserve	2,837,913	3,106,133	3,380,602	3,655,071	3,929,541	4,335,260	4,740,979	5,146,699	5,558,668
DIT	1,856,054	2,001,426	2,148,081	2,298,375	2,447,066	2,530,830	2,591,137	2,631,317	2,653,228
	4,693,968	5,107,558	5,528,683	5,953,446	6,376,607	6,866,090	7,332,116	7,778,016	8,211,896
Rate base	$6,034,807	$5,621,217	$5,450,092	$5,025,329	$4,602,168	$9,362,685	$8,896,659	$8,450,759	$8,266,879

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Scenario III - Completed in 2010

REVENU

	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Operating Revenues								
Annual Fee	$0		$0	$0	$0	$0		$0
Operating Expenses								
O&M	1,534,618	1,619,612	1,662,479	1,694,848	1,728,188	1,774,198	1,866,475	1,902,907
Depreciation 1/	411,969	411,969	418,219	418,219	418,219	424,469	424,469	424,469
Taxes Other Than Incon	74,801	71,869	70,671	67,694	64,717	63,475	60,454	57,432
Total Exp.	2,021,389	2,103,450	2,151,369	2,180,761	2,211,124	2,262,142	2,351,398	2,384,808
Income before Taxes	(2,021,389)	(2,103,450)	(2,151,369)	(2,180,761)	(2,211,124)	(2,262,142)	(2,351,398)	(2,384,808)
Interest Expense	236,908	224,695	220,083	207,899	195,765	191,037	178,739	166,489
Taxable income	(2,258,297)	(2,328,145)	(2,371,452)	(2,388,660)	(2,406,889)	(2,453,179)	(2,530,137)	(2,551,297)
Income Taxes	(880,736)	(907,977)	(924,866)	(931,578)	(938,687)	(956,740)	(986,753)	(995,006)
Tax Credit								
Operating Income	($1,140,653)	($1,195,473)	($1,226,503)	($1,249,183)	($1,272,437)	($1,305,402)	($1,364,645)	($1,389,802)
Rate Base	$7,847,233	$7,442,702	$7,289,914	$6,886,365	$6,484,419	$6,327,818	$5,920,456	$5,514,697
Rate of Return	-14.54%	-16.06%	-16.82%	-18.14%	-19.62%	-20.63%	-23.05%	-25.20%
Revenue Requirement	$2,965,833	$2,999,208	$3,028,740	$3,009,562	$2,991,549	$3,023,720	$3,063,948	$3,048,524
dk Production - 100%	500,044	552,680	552,680	552,680	552,680	552,680	605,523	605,523
Cost per Dk	$5.931	$5.427	$5.480	$5.445	$5.413	$5.471	$5.060	$5.035
Average Rev. Req.								
Avg. Dk								
Avg. $/Dk								
Rate Base								
Plant in Service								
Investment	$16,478,775	$16,478,775	$16,478,775	$16,728,775	$16,728,775	$16,728,775	$16,978,775	$16,978,775
Additional Facilities	0	0	250,000	0	0	250,000	0	0
	$16,478,775	$16,478,775	$16,728,775	$16,728,775	$16,728,775	$16,978,775	$16,978,775	$16,978,775
Accumulated Reserve 1/								
Acc. Reserve	5,970,638	6,382,607	6,800,826	7,219,046	7,637,265	8,061,734	8,486,204	8,910,673
DIT	2,660,905	2,653,466	2,638,035	2,623,364	2,607,092	2,589,223	2,572,115	2,553,405
	8,631,542	9,036,073	9,438,861	9,842,410	10,244,357	10,650,957	11,058,319	11,464,078
Rate base	$7,847,233	$7,442,702	$7,289,914	$6,886,365	$6,484,419	$6,327,818	$5,920,456	$5,514,697

Scenario III - Completed in 2010

REVENU

	Year 28	Year 29	Year 30
Operating Revenues			
Annual Fee	$0	$0	$0
Operating Expenses			
O&M	1,953,474	1,992,124	2,031,934
Depreciation 1/	430,719	430,719	430,719
Taxes Other Than Incon	56,146	53,080	50,013
Total Exp.	2,440,339	2,475,923	2,512,667
Income before Taxes	(2,440,339)	(2,475,923)	(2,512,667)
Interest Expense	161,646	149,232	136,868
Taxable income	(2,601,985)	(2,625,155)	(2,649,535)
Income Taxes	(1,014,774)	(1,023,810)	(1,033,319)
Tax Credit			
Operating Income	($1,425,565)	($1,452,113)	($1,479,348)
Rate Base	$5,354,284	$4,943,110	$4,533,538
Rate of Return	-26.62%	-29.38%	-32.63%
Revenue Requirement	$3,084,748	$3,070,847	$3,058,295
dk Production · 100%	605,523	605,523	605,523
Cost per Dk	$5.094	$5.071	$5.051
Average Rev. Req.			
Avg. Dk			
Avg. $/Dk			
Rate Base			
Plant in Service			
Investment	$16,978,775	$17,228,775	$17,228,775
Additional Facilities	250,000	0	0
	$17,228,775	$17,228,775	$17,228,775
Accumulated Reserve 1/			
Acc. Reserve	9,341,393	9,772,112	10,202,831
DIT	2,533,099	2,513,553	2,492,406
	11,874,491	12,285,665	12,695,237
Rate base	$5,354,284	$4,943,110	$4,533,538

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Scenario III

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU
CAPITALIZATION
DEBT AND EQUITY
(000)

	INITIAL INVESTMENT	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
TOTAL (Incl. DITs)	9,978,775	9,632,013	9,110,123	8,625,204	8,414,872	7,980,080	7,573,184	7,421,199	7,015,576	6,611,555	6,450,000	6,034,807
DEBT	4,989,388	4,816,006	4,555,061	4,312,602	4,207,436	3,990,040	3,786,592	3,710,599	3,507,788	3,305,778	3,225,000	3,017,404
EQUITY	4,989,388	4,816,006	4,555,061	4,312,602	4,207,436	3,990,040	3,786,592	3,710,599	3,507,788	3,305,778	3,225,000	3,017,404

Long-Term Debt Cost **7%**

Scenario III

	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
TOTAL (Incl. DITs)	5,621,217	5,450,092	5,025,329	4,602,168	9,362,685	8,896,659	8,450,759	8,266,879	7,847,233	7,442,702
DEBT	2,810,608	2,725,046	2,512,665	2,301,084	4,681,343	4,448,329	4,225,380	4,133,439	3,923,616	3,721,351
EQUITY	2,810,608	2,725,046	2,512,665	2,301,084	4,681,343	4,448,329	4,225,380	4,133,439	3,923,616	3,721,351

Long-

Scenario III

	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31
TOTAL (Incl. DITs)	7,289,914	6,886,365	6,484,419	6,327,818	5,920,456	5,514,697	5,354,284	4,943,110	4,533,538	4,185,603
DEBT	3,644,957	3,443,183	3,242,209	3,163,909	2,960,228	2,757,349	2,677,142	2,471,555	2,266,769	2,092,801
EQUITY	3,644,957	3,443,183	3,242,209	3,163,909	2,960,228	2,757,349	2,677,142	2,471,555	2,266,769	2,092,801

Long-

Scenario III

	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
TOTAL (Incl. DITs)	3,898,839	3,612,751	3,329,863	3,049,852	2,769,841	2,492,710	2,218,456	1,944,203	1,672,829
DEBT	1,949,420	1,806,375	1,664,931	1,524,926	1,384,920	1,246,355	1,109,228	972,101	836,415
EQUITY	1,949,420	1,806,375	1,664,931	1,524,926	1,384,920	1,246,355	1,109,228	972,101	836,415

Long-

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Scenario III - Completed in 2010

Depreciation Schedule
(000)

1.1230637

40 Year Life - Plant

Depreciation Schedule
($000)

	Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
BOOK DEPRECIATION											
Existing Assets (net of Accun	9,978,775										
Depr. on Adjusted Fixed Assets		249,469	249,469	249,469	255,719	255,719	255,719	261,969	261,969	261,969	268,219
Total Book Depreciation		**249,469**	**249,469**	**249,469**	**255,719**	**255,719**	**255,719**	**261,969**	**261,969**	**261,969**	**268,219**

		YEAR #	1	2	3	4	5	6	7	8	9	10
	Year Landfill		249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469
2010	1	-	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	-	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	-	-	-	-	-	-	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	-	-	-	-	-	-	-	-	-	6,250
2020	11	-	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	-	-	-	-	-	-	-	-
2023	14	-	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	-	-	-	-	-	-	-	-	-	-
2026	17	-	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	-	-
2029	20	-	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Total Book Depreciation		249,469	249,469	249,469	255,719	255,719	255,719	261,969	261,969	261,969	268,219
Book Value	$9,978,775	9,729,306	9,479,836	9,230,367	9,224,648	8,968,928	8,713,209	8,701,239	8,439,270	8,177,301	8,159,081
Property Taxes											
Property Tax Rate	0.7%	69,257	67,481	65,705	65,665	63,844	62,024	61,939	60,074	58,209	58,080

			1	2	3	4	5	6	7	8	9	10
Enter MACRS rate (below in y	4											
3	**MACRS**	**20 Year**	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%	5.2850%	4.8880%	4.5220%	4.4620%	4.4610%
4	**MACRS**	**15 Year**	5.0000%	9.5000%	8.5500%	7.6950%	6.9260%	6.2330%	5.9050%	5.9050%	5.9050%	5.9050%
5	**MACRS**	**10 Year**	10.0000%	18.0000%	14.4000%	11.5200%	9.2200%	7.3700%	6.5500%	6.5500%	6.5600%	6.5500%
6	**MACRS**	**7 Year**	14.2900%	24.4900%	17.4900%	12.4900%	8.9300%	8.9200%	8.9300%	4.4600%		
7	**MACRS**	**5 Year**	20.0000%	32.0000%	19.2000%	11.5200%	11.5200%	5.7600%				
8	**MACRS**	**3 Year**	33.3300%	44.4500%	14.8100%	7.4100%						

TAX DEPRECIATION

	Estimated										
Construction Property/Turbin	9,978,775	498,939	947,984	853,185	780,367	714,880	643,352	620,984	630,312	626,204	635,747
Total Tax Depreciation\Amortization		498,939	947,984	853,185	780,367	714,880	643,352	620,984	630,312	626,204	635,747
Balance Sheet DITs - Current Year		(97,293)	(272,421)	(235,449)	(204,612)	(179,073)	(151,177)	(140,016)	(143,653)	(142,052)	(143,336)
Balance Sheet DITs - Accumulated		(97,293)	(369,714)	(605,163)	(809,775)	(988,848)	(1,140,025)	(1,280,040)	(1,423,694)	(1,565,745)	(1,709,081)

		YEAR #	1	2	3	4	5	6	7	8	9	10
Year	Amount											
Existing	9,978,775	**15 Year**	498,939	947,984	853,185	767,867	691,130	621,977	589,247	589,247	589,247	589,247
1	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	-	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
5	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	-	-	-	-	-	-	12,500	23,750	21,375	19,238
8	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	-	-	-	-	-	-	-	-	-	12,500
11	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	-	-	-	-	-	-	-	-	-	-
14	-	**15 Year**	-	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
16	5,250,000	15 Year	-	-	-	-	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**498,939**	**947,984**	**853,185**	**780,367**	**714,880**	**643,352**	**620,984**	**630,312**	**626,204**	**635,747**

Scenario III - Completed in 2010

40 Year Life - Plant

			Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
BOOK DEPRECIATION		**Cost**									
Existing Assets (net of Accun		9,978,775									
Depr. on Adjusted Fixed Assets			268,219	268,219	274,469	274,469	274,469	405,719	405,719	405,719	411,969
Total Book Depreciation			**268,219**	**268,219**	**274,469**	**274,469**	**274,469**	**405,719**	**405,719**	**405,719**	**411,969**
		YEAR #	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**
	Year Landfill		249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	-	-	-	-	-	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Total Book Depreciation		268,219	268,219	274,469	274,469	274,469	405,719	405,719	405,719	411,969
Book Value	$9,978,775	7,890,862	7,622,643	7,598,173	7,323,704	7,049,234	11,893,515	11,487,796	11,082,076	10,920,107
Property Taxes										
Property Tax Rate	0.7%	56,170	54,261	54,087	52,133	50,179	84,663	81,775	78,887	77,734

			11	12	13	14	15	16	17	18	19
Enter MACRS rate (below in y		4									
3	**MACRS**	**20 Year**	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%
4	**MACRS**	**15 Year**	5.9050%	5.9050%	5.9050%	5.9050%	5.9050%	2.9510%			
5	**MACRS**	**10 Year**	3.2800%								
6	**MACRS**	**7 Year**									
7	**MACRS**	**5 Year**									
8	**MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,978,775	645,074	640,967	650,509	659,837	655,729	620,499	560,353	508,745	468,153
Total Tax Depreciation\Amortization		645,074	640,967	650,509	659,837	655,729	620,499	560,353	508,745	468,153
Balance Sheet DITs - Current Year		(146,973)	(145,371)	(146,656)	(150,293)	(148,691)	(83,764)	(60,307)	(40,180)	(21,911)
Balance Sheet DITs - Accumulated		(1,856,054)	(2,001,426)	(2,148,081)	(2,298,375)	(2,447,066)	(2,530,830)	(2,591,137)	(2,631,317)	(2,653,228)

Year	Amount	YEAR #	11	12	13	14	15	16	17	18	19
Existing	9,978,775	15 Year	589,247	589,247	589,247	589,247	589,247	294,474	-	-	-
1	-	15 Year	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
5	-	15 Year	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
8	-	15 Year	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
11	-	15 Year	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
14	-	15 Year	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
16	5,250,000	15 Year	-	-	-	-	-	262,500	498,750	448,875	403,988
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**645,074**	**640,967**	**650,509**	**659,837**	**655,729**	**620,499**	**560,353**	**508,745**	**468,153**

Scenario III - Completed in 2010

40 Year Life - Plant

			Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
BOOK DEPRECIATION		**Cost**									
Existing Assets (net of Accun		9,978,775									
Depr. on Adjusted Fixed Assets			411,969	411,969	418,219	418,219	418,219	424,469	424,469	424,469	430,719
Total Book Depreciation			**411,969**	**411,969**	**418,219**	**418,219**	**418,219**	**424,469**	**424,469**	**424,469**	**430,719**
		YEAR #	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
	Year Landfill		249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	6,250	6,250	6,250	6,250
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	6,250
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

		Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
Scenario III - Completed in 2010										
Total Book Depreciation		411,969	411,969	418,219	418,219	418,219	424,469	424,469	424,469	430,719
Book Value	$9,978,775	10,508,138	10,096,168	9,927,949	9,509,729	9,091,510	8,917,041	8,492,571	8,068,102	7,887,383
Property Taxes										
Property Tax Rate	0.7%	74,801	71,869	70,671	67,694	64,717	63,475	60,454	57,432	56,146

		20	21	22	23	24	25	26	27	28
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4610%	2.2310%							
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,978,775	431,653	392,895	378,653	380,603	376,495	378,653	380,603	376,495	378,653
Total Tax Depreciation\Amortization		431,653	392,895	378,653	380,603	376,495	378,653	380,603	376,495	378,653
Balance Sheet DITs - Current Year		(7,676)	7,439	15,431	14,671	16,273	17,869	17,108	18,710	20,306
Balance Sheet DITs - Accumulated		(2,660,905)	(2,653,466)	(2,638,035)	(2,623,364)	(2,607,092)	(2,589,223)	(2,572,115)	(2,553,405)	(2,533,099)

Year	Amount	YEAR #	20	21	22	23	24	25	26	27	28
Existing	9,978,775	15 Year	-	-	-	-	-	-	-	-	-
1	-	15 Year	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	-	-	-	-	-	-	-	-	-
5	-	15 Year	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	14,763	14,763	7,378	-	-	-	-	-	-
8	-	15 Year	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
11	-	15 Year	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
14	-	15 Year	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
16	5,250,000	15 Year	363,615	327,233	310,013	310,013	310,013	310,013	310,013	310,013	310,013
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	12,500	23,750	21,375	19,238
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**431,653**	**392,895**	**378,653**	**380,603**	**376,495**	**378,653**	**380,603**	**376,495**	**378,653**

Scenario III - Completed in 2010

40 Year Life - Plant

			Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
BOOK DEPRECIATION		**Cost**									
Existing Assets (net of Accun		9,978,775									
Depr. on Adjusted Fixed Assets			430,719	430,719	430,719	430,719	430,719	430,719	430,719	430,719	430,719
Total Book Depreciation			**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**
		YEAR #	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**
	Year										
	Landfill		249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469	249,469
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	5,250,000	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250	131,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010		Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
Total Book Depreciation		**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**	**430,719**
Book Value	$9,978,775	7,456,663	7,025,944	6,595,224	6,164,505	5,733,786	5,303,066	4,872,347	4,441,628	4,010,908
Property Taxes										
Property Tax Rate	**0.7%**	**53,080**	**50,013**	**46,947**	**43,881**	**40,815**	**37,749**	**34,683**	**31,617**	**28,551**

		29	30	31	32	33	34	35	36	37
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**									
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	9,978,775	380,603	376,495	218,453	61,603	59,870	51,665	44,288	44,288	36,903
Total Tax Depreciation\Amortization		380,603	376,495	218,453	61,603	59,870	51,665	44,288	44,288	36,903
Balance Sheet DITs - Current Year		19,546	21,148	82,784	143,956	144,631	147,831	150,708	150,708	153,589
Balance Sheet DITs - Accumulated		(2,513,553)	(2,492,406)	(2,409,622)	(2,265,666)	(2,121,035)	(1,973,204)	(1,822,495)	(1,671,787)	(1,518,198)

Year	Amount	YEAR #	29	30	31	32	33	34	35	36	37
Existing	9,978,775	15 Year	-	-	-	-	-	-	-	-	-
1	-	15 Year	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	-	-	-	-	-	-	-	-	-
5	-	15 Year	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	-	-	-	-	-	-	-	-	-
8	-	15 Year	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	-	-	-	-	-	-	-	-	-
11	-	15 Year	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	-	-	-	-	-	-	-	-	-
14	-	15 Year	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37
16	5,250,000	15 Year	310,013	310,013	154,928	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**380,603**	**376,495**	**218,453**	**61,603**	**59,870**	**51,665**	**44,288**	**44,288**	**36,903**

Scenario III - Completed in 2010

40 Year Life - Plant

			Year 38	Year 39	Year 40
BOOK DEPRECIATION		Cost			
Existing Assets (net of Accun		9,978,775			
Depr. on Adjusted Fixed Assets			430,719	430,719	430,719
Total Book Depreciation			**430,719**	**430,719**	**430,719**

			YEAR #	38	39	40
	Year					
	Landfill			249,469	249,469	249,469
2010	1	-		-	-	-
2011	2	-		-	-	-
2012	3	-		-	-	-
2013	4	250,000		6,250	6,250	6,250
2014	5	-		-	-	-
2015	6	-		-	-	-
2016	7	250,000		6,250	6,250	6,250
2017	8	-		-	-	-
2018	9	-		-	-	-
2019	10	250,000		6,250	6,250	6,250
2020	11	-		-	-	-
2021	12	-		-	-	-
2022	13	250,000		6,250	6,250	6,250
2023	14	-		-	-	-
2024	15	-		-	-	-
2025	16	5,250,000		131,250	131,250	131,250
2026	17	-		-	-	-
2027	18	-		-	-	-
2028	19	250,000		6,250	6,250	6,250
2029	20	-		-	-	-
2030	21	-		-	-	-
2031	22	250,000		6,250	6,250	6,250
2032	23	-		-	-	-
2033	24	-		-	-	-
2034	25	250,000		6,250	6,250	6,250
2035	26	-		-	-	-
2036	27	-		-	-	-
2037	28	250,000		6,250	6,250	6,250
2038	29	-		-	-	-
2039	30	-		-	-	-

		Year 38	Year 39	Year 40
Scenario III - Completed in 2010				
Total Book Depreciation		430,719	430,719	430,719
Book Value	$9,978,775	3,580,189	3,149,469	2,718,750
Property Taxes				
Property Tax Rate	0.7%	25,485	22,419	19,353

		38	39	40
Enter MACRS rate (below in y	4			
3 **MACRS**	**20 Year**			
4 **MACRS**	**15 Year**			
5 **MACRS**	**10 Year**			
6 **MACRS**	**7 Year**			
7 **MACRS**	**5 Year**			
8 **MACRS**	**3 Year**			

TAX DEPRECIATION

	Estimated			
Construction Property/Turbin	9,978,775	29,525	29,525	22,140
Total Tax Depreciation\Amortization		29,525	29,525	22,140
Balance Sheet DITs - Current Year		156,466	156,466	159,346
Balance Sheet DITs - Accumulated		(1,361,732)	(1,205,266)	(1,045,921)

		YEAR #	38	39	40
Year	Amount				
Existing	9,978,775	15 Year	-	-	-
1	-	15 Year	-	-	-
2	-	15 Year	-	-	-
3	-	15 Year	-	-	-
4	250,000	15 Year	-	-	-
5	-	15 Year	-	-	-
6	-	15 Year	-	-	-
7	250,000	15 Year	-	-	-
8	-	15 Year	-	-	-
9	-	15 Year	-	-	-
10	250,000	15 Year	-	-	-
11	-	15 Year	-	-	-
12	-	15 Year	-	-	-
13	250,000	15 Year	-	-	-
14	-	15 Year	-	-	-
15	-	15 Year	-	-	-

Scenario III - Completed in 2010

			Year 38	Year 39	Year 40
16	5,250,000	15 Year	-	-	-
17	-	15 Year	-	-	-
18	-	15 Year	-	-	-
19	250,000	15 Year	-	-	-
20	-	15 Year	-	-	-
21	-	15 Year	-	-	-
22	250,000	15 Year	-	-	-
23	-	15 Year	-	-	-
24	-	15 Year	-	-	-
25	250,000	15 Year	14,763	14,763	7,378
26	-	15 Year	-	-	-
27	-	15 Year	-	-	-
28	250,000	15 Year	14,763	14,763	14,763
29	-	15 Year	-	-	-
30	-	15 Year	-	-	-
Total Tax Depreciation			**29,525**	**29,525**	**22,140**

Scenario III - Completed in 2010

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Revenue Requirement		$2,326,267	$2,304,631	$2,282,856	$2,287,321	$2,252,185	$2,271,684	$2,287,128	$2,257,224	$2,228,133	$2,244,401
dk Production	100%	340,685	340,685	340,685	340,685	340,685	394,771	394,771	394,771	394,771	394,771
Cost per Dk		$6.828	$6.765	$6.701	$6.714	$6.611	$5.754	$5.794	$5.718	$5.644	$5.685
System Dk Sales 1/		35,200,000	35,530,000	36,013,000	36,199,000	36,343,796	36,489,171	36,635,128	36,781,669	36,928,796	37,076,511
		0.69%	0.94%	1.36%	0.52%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk		$0.066	$0.065	$0.063	$0.063	$0.062	$0.062	$0.062	$0.061	$0.060	$0.061

Scenario III - Completed in 2010

REVENU

		Year 11	Year 12	Year 13	Year 14	Year 15
Revenue Requirement		$2,266,767	$2,238,464	$2,256,763	$2,228,494	$2,201,165
dk Production	100%	447,615	447,615	447,615	447,615	447,615
Cost per Dk		$5.064	$5.001	$5.042	$4.979	$4.918
System Dk Sales 1/		37,224,817	37,373,716	37,523,211	37,673,304	37,823,997
		0.40%	0.40%	0.40%	0.40%	0.40%
Increase per dk		$0.061	$0.060	$0.060	$0.059	$0.058

Billings Landfill Proposed Phased Installation

	Capital Costs	Phase 1 (2009)	Phase 2 (2010)	Inflation
Drill wells and installation of field lines	$ 3,006,700	$ 3,006,700		3.00%
Compressor	$ 550,000		$ 566,500	
CO2 removal	$ 1,550,000		$ 1,596,500	
N2 removal	$ 1,205,000		$ 1,241,150	
Recycle compressor	$ 80,000		$ 82,400	
Equipment installation	$ 700,000		$ 721,000	
Gas flare for CO2 and N2	$ 165,000	$ 165,000		
Slab for molecular gate	$ 40,000	$ 40,000		
Building	$ 150,000		$ 154,500	
Main to distribution system	$ 450,000	$ 450,000		
Generators	$ 500,000		$ 515,000	
Legal, engineering, premitting, etc.	$ 808,500	$ 808,500		
Contingency	$ 308,500		$ 317,755	
	$ 9,513,700	**$ 4,470,200**		
Phase 2 with 3.00% inflation			**$ 5,194,805**	
Total capital costs with 3.00% inflation for phase 2			**$ 9,665,005**	

Phase 1 should include drilling of wells, burying of all pipe, pouring of concrete, any ground work, etc.

Phase 2 would be installation of purchased equipment.

Response No. PSC-055
Attachment E

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Assumptions:

- MDU owns the landfill gas system
- Complete and in service 2010 - year 1 is 2011
- Renewable Energy Credits (RECs) or green tags are part of model
- Tax rate - 39%
- 50% / 50% ratio with a debt cost of 7.0% for financial
- 2010 average capital structure for revenue requirement
- Tax depreciation - 15 Year MACRS
- Capitalization is based on net plant book value less future tax liability (DITs)
- Assumes minor capital expenditures with major investemnt in Year 16
- Assumes an after-tax equity return of 10% (pre-tax 16.67%)

October 2011 Update

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Operating Revenues										
Annual Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Operating Expenses										
Cost of gas	69,749	74,964	83,414	89,221	91,903	134,555	138,586	142,754	147,030	151,443
O&M	580,000	634,114	653,137	672,731	692,913	713,700	735,111	757,164	779,879	803,275
Carbon Credit	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Depreciation 1/	271,587	271,587	271,587	277,837	277,837	277,837	284,087	284,087	284,087	290,337
Taxes Other Than Incon	242,060	242,060	242,060	242,060	242,060	242,060	242,060	242,060	242,060	242,060
Total Exp.	1,063,396	1,122,725	1,150,198	1,181,849	1,204,713	1,268,152	1,299,844	1,326,065	1,353,056	1,387,115
Income before Taxes	(1,063,396)	(1,122,725)	(1,150,198)	(1,181,849)	(1,204,713)	(1,268,152)	(1,299,844)	(1,326,065)	(1,353,056)	(1,387,115)
Interest Expense	310,594	293,766	278,129	270,713	256,727	243,638	238,133	225,115	212,145	206,357
Taxable income	(1,373,990)	(1,416,491)	(1,428,327)	(1,452,562)	(1,461,440)	(1,511,790)	(1,537,977)	(1,551,180)	(1,565,201)	(1,593,472)
Income Taxes	(535,856)	(552,431)	(557,047)	(566,499)	(569,962)	(589,598)	(599,811)	(604,960)	(610,428)	(621,454)
Tax Credit										
Operating Income	($527,540)	($570,294)	($593,151)	($615,350)	($634,751)	($678,554)	($700,033)	($721,105)	($742,628)	($765,661)
Rate Base	$10,485,970	$9,917,810	$9,389,900	$9,139,526	$8,667,345	$8,225,451	$8,039,600	$7,600,112	$7,162,225	$6,966,804
Rate of Return	-5.03%	-5.75%	-6.32%	-6.73%	-7.32%	-8.25%	-8.71%	-9.49%	-10.37%	-10.99%
Revenue Requirement	$2,401,272	$2,388,111	$2,348,230	$2,347,936	$2,310,554	$2,317,614	$2,325,594	$2,295,742	$2,266,865	$2,275,990
dk Production - 100%	127,500	127,750	127,750	127,750	127,750	181,586	181,586	181,586	181,586	181,586
Cost per Dk	$18.834	$18.694	$18.381	$18.379	$18.087	$12.763	$12.807	$12.643	$12.484	$12.534
Average Rev. Req.	$2,431,881	30 years								
Avg. Dk	260,401									
Avg. $/Dk	$9.339									
Rate Base										
Plant in Service										
Investment	$10,863,476	$10,863,476	$10,863,476	$10,863,476	$11,113,476	$11,113,476	$11,113,476	$11,363,476	$11,363,476	$11,363,476
Additional Facilities	0	0	0	250,000	0	0	250,000	0	0	250,000
	$10,863,476	$10,863,476	$10,863,476	$11,113,476	$11,113,476	$11,113,476	$11,363,476	$11,363,476	$11,363,476	$11,613,476
Accumulated Reserve 1/										
Acc. Reserve	271,587	543,174	814,761	1,092,598	1,370,435	1,648,271	1,932,358	2,216,445	2,500,532	2,790,869
DIT	105,919	402,492	658,816	881,352	1,075,696	1,239,753	1,391,517	1,546,919	1,700,719	1,855,803
	377,506	945,666	1,473,576	1,973,950	2,446,131	2,888,025	3,323,876	3,763,364	4,201,251	4,646,672
Rate base	$10,485,970	$9,917,810	$9,389,900	$9,139,526	$8,667,345	$8,225,451	$8,039,600	$7,600,112	$7,162,225	$6,966,804

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October 2011 Update

REVENU

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Operating Revenues									
Annual Fee		$0	$0	$0	$0		$0	$0	$0
Operating Expenses									
Cost of gas	201,387	207,435	213,660	220,059	226,670	285,669	294,231	303,052	312,131
O&M	827,373	852,194	877,760	904,093	931,216	959,152	987,927	1,017,565	1,048,092
Carbon Credit	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Depreciation 1/	290,337	290,337	296,587	296,587	296,587	302,837	302,837	302,837	309,087
Taxes Other Than Incon	242,060	242,060	242,060	242,060	242,060	242,060	242,060	242,060	242,060
Total Exp.	1,461,157	1,492,026	1,530,067	1,562,799	1,596,533	1,689,718	1,727,055	1,765,514	1,811,370
Income before Taxes	(1,461,157)	(1,492,026)	(1,530,067)	(1,562,799)	(1,596,533)	(1,689,718)	(1,727,055)	(1,765,514)	(1,811,370)
Interest Expense	193,056	179,802	173,730	160,146	146,608	143,960	137,502	131,092	131,949
Taxable income	(1,654,213)	(1,671,828)	(1,703,797)	(1,722,945)	(1,743,141)	(1,833,678)	(1,864,557)	(1,896,606)	(1,943,319)
Income Taxes	(645,143)	(652,013)	(664,481)	(671,949)	(679,825)	(715,134)	(727,177)	(739,676)	(757,894)
Tax Credit									
Operating Income	($816,014)	($840,013)	($865,586)	($890,850)	($916,708)	($974,584)	($999,878)	($1,025,838)	($1,053,476)
Rate Base	$6,517,745	$6,070,288	$5,865,298	$5,406,669	$4,949,643	$4,860,236	$4,642,218	$4,425,802	$4,454,732
Rate of Return	-12.52%	-13.84%	-14.76%	-16.48%	-18.52%	-20.05%	-21.54%	-23.18%	-23.65%
Revenue Requirement	$2,292,738	$2,266,517	$2,278,404	$2,252,620	$2,228,044	$2,309,823	$2,319,343	$2,330,190	$2,379,737
dk Production - 100%	234,430	234,430	234,430	234,430	234,430	286,859	286,859	286,859	286,859
Cost per Dk	$9.780	$9.668	$9.719	$9.609	$9.504	$8.052	$8.085	$8.123	$8.296
Average Rev. Req.									
Avg. Dk									
Avg. $/Dk									
Rate Base									
Plant in Service									
Investment	$11,613,476	$11,613,476	$11,613,476	$11,863,476	$11,863,476	$11,863,476	$12,113,476	$12,113,476	$12,113,476
Additional Facilities	0	0	250,000	0	0	250,000	0	0	250,000
	$11,613,476	$11,613,476	$11,863,476	$11,863,476	$11,863,476	$12,113,476	$12,113,476	$12,113,476	$12,363,476
Accumulated Reserve 1/									
Acc. Reserve	3,081,206	3,371,543	3,668,130	3,964,717	4,261,304	4,564,140	4,866,977	5,169,814	5,478,901
DIT	2,014,525	2,171,645	2,330,049	2,492,090	2,652,530	2,689,100	2,604,281	2,517,860	2,429,843
	5,095,731	5,543,188	5,998,178	6,456,807	6,913,833	7,253,240	7,471,258	7,687,674	7,908,744
Rate base	$6,517,745	$6,070,288	$5,865,298	$5,406,669	$4,949,643	$4,860,236	$4,642,218	$4,425,802	$4,454,732

October 2011 Update

REVENU

	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Operating Revenues								
Annual Fee	$0		$0	$0	$0	$0		$0
Operating Expenses								
Cost of gas	321,512	391,913	403,677	415,797	428,273	441,106	525,066	540,838
O&M	1,079,535	1,111,921	1,145,279	1,179,637	1,215,026	1,251,477	1,289,021	1,327,692
Carbon Credit	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Depreciation 1/	309,087	309,087	315,337	315,337	315,337	321,587	321,587	321,587
Taxes Other Than Incon	242,060	242,060	242,060	242,060	242,060	242,060	242,060	242,060
Total Exp.	1,852,194	1,954,981	2,006,353	2,052,831	2,100,696	2,156,230	2,277,734	2,332,177
Income before Taxes	(1,852,194)	(1,954,981)	(2,006,353)	(2,052,831)	(2,100,696)	(2,156,230)	(2,277,734)	(2,332,177)
Interest Expense	125,379	118,855	119,599	112,916	106,280	106,911	100,114	93,365
Taxable income	(1,977,573)	(2,073,836)	(2,125,952)	(2,165,747)	(2,206,976)	(2,263,141)	(2,377,848)	(2,425,542)
Income Taxes	(771,253)	(808,796)	(829,121)	(844,641)	(860,721)	(882,625)	(927,361)	(945,961)
Tax Credit								
Operating Income	($1,080,941)	($1,146,185)	($1,177,232)	($1,208,190)	($1,239,975)	($1,273,605)	($1,350,373)	($1,386,216)
Rate Base	$4,232,901	$4,012,673	$4,037,790	$3,812,147	$3,588,106	$3,609,411	$3,379,956	$3,152,102
Rate of Return	-25.54%	-28.56%	-29.16%	-31.69%	-34.56%	-35.29%	-39.95%	-43.98%
Revenue Requirement	$2,392,258	$2,466,947	$2,521,524	$2,539,212	$2,558,492	$2,616,744	$2,708,973	$2,734,346
dk Production · 100%	286,859	339,495	339,495	339,495	339,495	339,495	392,338	392,338
Cost per Dk	$8.339	$7.267	$7.427	$7.479	$7.536	$7.708	$6.905	$6.969
Average Rev. Req.								
Avg. Dk								
Avg. $/Dk								
Rate Base								
Plant in Service								
Investment	$12,363,476	$12,363,476	$12,363,476	$12,613,476	$12,613,476	$12,613,476	$12,863,476	$12,863,476
Additional Facilities	0	0	250,000	0	0	250,000	0	0
	$12,363,476	$12,363,476	$12,613,476	$12,613,476	$12,613,476	$12,863,476	$12,863,476	$12,863,476
Accumulated Reserve 1/								
Acc. Reserve	5,787,988	6,097,075	6,412,412	6,727,749	7,043,086	7,364,673	7,686,259	8,007,846
DIT	2,342,587	2,253,729	2,163,274	2,073,580	1,982,284	1,889,392	1,797,261	1,703,528
	8,130,575	8,350,803	8,575,686	8,801,329	9,025,370	9,254,065	9,483,520	9,711,374
Rate base	$4,232,901	$4,012,673	$4,037,790	$3,812,147	$3,588,106	$3,609,411	$3,379,956	$3,152,102

October 2011 Update

REVENU

	Year 28	Year 29	Year 30
Operating Revenues			
Annual Fee	$0	$0	$0
Operating Expenses			
Cost of gas	557,081	573,794	591,038
O&M	1,367,523	1,408,549	1,450,805
Carbon Credit	(100,000)	(100,000)	(100,000)
Depreciation 1/	327,837	327,837	327,837
Taxes Other Than Incon	242,060	242,060	242,060
Total Exp.	2,394,501	2,452,240	2,511,740
Income before Taxes	(2,394,501)	(2,452,240)	(2,511,740)
Interest Expense	93,883	86,974	80,112
Taxable income	(2,488,384)	(2,539,214)	(2,591,852)
Income Taxes	(970,470)	(990,293)	(1,010,822)
Tax Credit			
Operating Income	($1,424,031)	($1,461,947)	($1,500,918)
Rate Base	$3,169,595	$2,936,327	$2,704,660
Rate of Return	-44.93%	-49.79%	-55.49%
Revenue Requirement	$2,798,900	$2,826,878	$2,856,820
dk Production · 100%	392,338	392,338	392,338
Cost per Dk	$7.134	$7.205	$7.282
Average Rev. Req.			0.648
Avg. Dk			
Avg. $/Dk			
Rate Base			
Plant in Service			
Investment	$12,863,476	$13,113,476	$13,113,476
Additional Facilities	250,000	0	0
	$13,113,476	$13,113,476	$13,113,476
Accumulated Reserve 1/			
Acc. Reserve	8,335,683	8,663,520	8,991,357
DIT	1,608,198	1,513,629	1,417,459
	9,943,881	10,177,149	10,408,816
Rate base	$3,169,595	$2,936,327	$2,704,660

Scenario III

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU
CAPITALIZATION
DEBT AND EQUITY
(000)

	INITIAL INVESTMENT	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
TOTAL (Incl. DITs)	10,863,476	10,485,970	9,917,810	9,389,900	9,139,526	8,667,345	8,225,451	8,039,600	7,600,112	7,162,225	6,966,804
DEBT	5,431,738	5,242,985	4,958,905	4,694,950	4,569,763	4,333,673	4,112,726	4,019,800	3,800,056	3,581,112	3,483,402
EQUITY	5,431,738	5,242,985	4,958,905	4,694,950	4,569,763	4,333,673	4,112,726	4,019,800	3,800,056	3,581,112	3,483,402

Long-Term Debt Cost **7%**

Scenario III

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
TOTAL (Incl. DITs)	6,517,745	6,070,288	5,865,298	5,406,669	4,949,643	4,860,236	4,642,218	4,425,802	4,454,732	4,232,901
DEBT	3,258,873	3,035,144	2,932,649	2,703,335	2,474,821	2,430,118	2,321,109	2,212,901	2,227,366	2,116,451
EQUITY	3,258,873	3,035,144	2,932,649	2,703,335	2,474,821	2,430,118	2,321,109	2,212,901	2,227,366	2,116,451

Long-

Scenario III

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
TOTAL (Incl. DITs)	4,012,673	4,037,790	3,812,147	3,588,106	3,609,411	3,379,956	3,152,102	3,169,595	2,936,327	2,704,660
DEBT	2,006,336	2,018,895	1,906,074	1,794,053	1,804,706	1,689,978	1,576,051	1,584,797	1,468,163	1,352,330
EQUITY	2,006,336	2,018,895	1,906,074	1,794,053	1,804,706	1,689,978	1,576,051	1,584,797	1,468,163	1,352,330

Long-

Billings, MT LANDFILL GAS PROJECT - OWNED BY MDU

Scenario III - Completed in 2010

Depreciation Schedule
(000)

1.1230637

40 Year Life - Plant

Depreciation Schedule
($000)

	Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
BOOK DEPRECIATION											
Existing Assets (net of Accun	10,863,476										
Depr. on Adjusted Fixed Assets		271,587	271,587	271,587	277,837	277,837	277,837	284,087	284,087	284,087	290,337
Total Book Depreciation		**271,587**	**271,587**	**271,587**	**277,837**	**277,837**	**277,837**	**284,087**	**284,087**	**284,087**	**290,337**

	Year	YEAR #	1	2	3	4	5	6	7	8	9	10
	Landfill		271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587
2010	1	-	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	-	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	-	-	-	-	-	-	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	-	-	-	-	-	-	-	-	-	6,250
2020	11	-	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	-	-	-	-	-	-	-	-
2023	14	-	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-	-
2025	16	250,000	-	-	-	-	-	-	-	-	-	-
2026	17	-	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	-	-
2029	20	-	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Total Book Depreciation		271,587	271,587	271,587	277,837	277,837	277,837	284,087	284,087	284,087	290,337
Book Value	##########	10,591,889	10,320,302	10,048,715	10,020,878	9,743,042	9,465,205	9,431,118	9,147,031	8,862,944	8,822,607
Property Taxes											
Property Tax Rate	0.7%	75,397	73,464	71,531	71,333	69,355	67,377	67,134	65,112	63,090	62,803

			1	2	3	4	5	6	7	8	9	10
Enter MACRS rate (below in y		4										
3	**MACRS**	**20 Year**	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%	5.2850%	4.8880%	4.5220%	4.4620%	4.4610%
4	**MACRS**	**15 Year**	5.0000%	9.5000%	8.5500%	7.6950%	6.9260%	6.2330%	5.9050%	5.9050%	5.9050%	5.9050%
5	**MACRS**	**10 Year**	10.0000%	18.0000%	14.4000%	11.5200%	9.2200%	7.3700%	6.5500%	6.5500%	6.5600%	6.5500%
6	**MACRS**	**7 Year**	14.2900%	24.4900%	17.4900%	12.4900%	8.9300%	8.9200%	8.9300%	4.4600%		
7	**MACRS**	**5 Year**	20.0000%	32.0000%	19.2000%	11.5200%	11.5200%	5.7600%				
8	**MACRS**	**3 Year**	33.3300%	44.4500%	14.8100%	7.4100%						

TAX DEPRECIATION

	Estimated										
Construction Property/Turbin	10,863,476	543,174	1,032,030	928,827	848,444	776,154	698,495	673,226	682,553	678,446	687,988
Total Tax Depreciation\Amortization		543,174	1,032,030	928,827	848,444	776,154	698,495	673,226	682,553	678,446	687,988
Balance Sheet DITs - Current Year		(105,919)	(296,573)	(256,324)	(222,537)	(194,344)	(164,057)	(151,764)	(155,402)	(153,800)	(155,084)
Balance Sheet DITs - Accumulated		(105,919)	(402,492)	(658,816)	(881,352)	(1,075,696)	(1,239,753)	(1,391,517)	(1,546,919)	(1,700,719)	(1,855,803)

Year	Amount	YEAR #	1	2	3	4	5	6	7	8	9	10
Existing	10,863,476	15 Year	543,174	1,032,030	928,827	835,944	752,404	677,120	641,488	641,488	641,488	641,488
1	-	15 Year	-	-	-	-	-	-	-	-	-	-
2	-	15 Year	-	-	-	-	-	-	-	-	-	-
3	-	15 Year	-	-	-	-	-	-	-	-	-	-
4	250,000	15 Year	-	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
5	-	15 Year	-	-	-	-	-	-	-	-	-	-
6	-	15 Year	-	-	-	-	-	-	-	-	-	-
7	250,000	15 Year	-	-	-	-	-	-	12,500	23,750	21,375	19,238
8	-	15 Year	-	-	-	-	-	-	-	-	-	-
9	-	15 Year	-	-	-	-	-	-	-	-	-	-
10	250,000	15 Year	-	-	-	-	-	-	-	-	-	12,500
11	-	15 Year	-	-	-	-	-	-	-	-	-	-
12	-	15 Year	-	-	-	-	-	-	-	-	-	-
13	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
14	-	15 Year	-	-	-	-	-	-	-	-	-	-
15	-	15 Year	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
16	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
17	-	15 Year	-	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
20	-	15 Year	-	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**543,174**	**1,032,030**	**928,827**	**848,444**	**776,154**	**698,495**	**673,226**	**682,553**	**678,446**	**687,988**

Bonus Tax Depreciation												
MACRS		15 Year	5.0000%	9.5000%	8.5500%	7.6950%	6.9260%	6.2330%	5.9050%	5.9050%	5.9050%	5.9050%

Scenario III - Completed in 2010

40 Year Life - Plant

BOOK DEPRECIATION	**Cost**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**
Existing Assets (net of Accun	10,863,476									
Depr. on Adjusted Fixed Assets		290,337	290,337	296,587	296,587	296,587	302,837	302,837	302,837	309,087
Total Book Depreciation		**290,337**	**290,337**	**296,587**	**296,587**	**296,587**	**302,837**	**302,837**	**302,837**	**309,087**

		YEAR #	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**
	Year										
	Landfill		271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	250,000	-	-	-	-	-	6,250	6,250	6,250	6,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	-	-	-	-	-	-	-	-	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	-	-	-	-	-	-	-
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	-	-	-	-
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	-
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
Total Book Depreciation		290,337	290,337	296,587	296,587	296,587	302,837	302,837	302,837	309,087
Book Value	##########	8,532,270	8,241,933	8,195,346	7,898,759	7,602,173	7,549,336	7,246,499	6,943,662	6,884,575
Property Taxes										
Property Tax Rate	0.7%	60,736	58,669	58,338	56,227	54,115	53,739	51,583	49,428	49,007

		11	12	13	14	15	16	17	18	19
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%	4.4610%	4.4620%
4 **MACRS**	**15 Year**	5.9050%	5.9050%	5.9050%	5.9050%	5.9050%	2.9510%			
5 **MACRS**	**10 Year**	3.2800%								
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	10,863,476	697,316	693,208	702,751	712,078	707,971	396,606	85,353	81,245	83,403
Total Tax Depreciation\Amortization		697,316	693,208	702,751	712,078	707,971	396,606	85,353	81,245	83,403
Balance Sheet DITs - Current Year		(158,722)	(157,120)	(158,404)	(162,042)	(160,440)	(36,570)	84,819	86,421	88,017
Balance Sheet DITs - Accumulated		(2,014,525)	(2,171,645)	(2,330,049)	(2,492,090)	(2,652,530)	(2,689,100)	(2,604,281)	(2,517,860)	(2,429,843)

Year	Amount	YEAR #	11	12	13	14	15	16	17	18	19
Existing	10,863,476	**15 Year**	641,488	641,488	641,488	641,488	641,488	320,581	-	-	-
1	-	**15 Year**	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
5	-	**15 Year**	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
8	-	**15 Year**	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
11	-	**15 Year**	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
14	-	**15 Year**	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
16	250,000	15 Year	-	-	-	-	-	12,500	23,750	21,375	19,238
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	-	-	-	-	-	-	-
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	-	-	-	-
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	-
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**697,316**	**693,208**	**702,751**	**712,078**	**707,971**	**396,606**	**85,353**	**81,245**	**83,403**

Bonus Tax Depreciation

MACRS	15 Year	5.9050%	5.9050%	5.9050%	5.9050%	5.9050%	2.9510%

Scenario III - Completed in 2010

40 Year Life - Plant

BOOK DEPRECIATION	**Cost**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**	**Year 28**
Existing Assets (net of Accun	10,863,476									
Depr. on Adjusted Fixed Assets		309,087	309,087	315,337	315,337	315,337	321,587	321,587	321,587	327,837
Total Book Depreciation		**309,087**	**309,087**	**315,337**	**315,337**	**315,337**	**321,587**	**321,587**	**321,587**	**327,837**

		YEAR #	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
	Year										
	Landfill		271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587	271,587
2010	1	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-
2013	4	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2014	5	-	-	-	-	-	-	-	-	-	-
2015	6	-	-	-	-	-	-	-	-	-	-
2016	7	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2017	8	-	-	-	-	-	-	-	-	-	-
2018	9	-	-	-	-	-	-	-	-	-	-
2019	10	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2020	11	-	-	-	-	-	-	-	-	-	-
2021	12	-	-	-	-	-	-	-	-	-	-
2022	13	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2023	14	-	-	-	-	-	-	-	-	-	-
2024	15	-	-	-	-	-	-	-	-	-	-
2025	16	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2026	17	-	-	-	-	-	-	-	-	-	-
2027	18	-	-	-	-	-	-	-	-	-	-
2028	19	250,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2029	20	-	-	-	-	-	-	-	-	-	-
2030	21	-	-	-	-	-	-	-	-	-	-
2031	22	250,000	-	-	6,250	6,250	6,250	6,250	6,250	6,250	6,250
2032	23	-	-	-	-	-	-	-	-	-	-
2033	24	-	-	-	-	-	-	-	-	-	-
2034	25	250,000	-	-	-	-	-	6,250	6,250	6,250	6,250
2035	26	-	-	-	-	-	-	-	-	-	-
2036	27	-	-	-	-	-	-	-	-	-	-
2037	28	250,000	-	-	-	-	-	-	-	-	6,250
2038	29	-	-	-	-	-	-	-	-	-	-
2039	30	-	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010		Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
Total Book Depreciation		309,087	309,087	315,337	315,337	315,337	321,587	321,587	321,587	327,837
Book Value	##########	6,575,488	6,266,401	6,201,064	5,885,727	5,570,390	5,498,804	5,177,217	4,855,630	4,777,793
Property Taxes										
Property Tax Rate	0.7%	46,807	44,607	44,142	41,897	39,652	39,143	36,853	34,564	34,010

		20	21	22	23	24	25	26	27	28
Enter MACRS rate (below in y	4									
3 **MACRS**	**20 Year**	4.4610%	2.2310%							
4 **MACRS**	**15 Year**									
5 **MACRS**	**10 Year**									
6 **MACRS**	**7 Year**									
7 **MACRS**	**5 Year**									
8 **MACRS**	**3 Year**									

TAX DEPRECIATION

	Estimated									
Construction Property/Turbin	10,863,476	85,353	81,245	83,403	85,353	81,245	83,403	85,353	81,245	83,403
Total Tax Depreciation\Amortization		85,353	81,245	83,403	85,353	81,245	83,403	85,353	81,245	83,403
Balance Sheet DITs - Current Year		87,256	88,858	90,454	89,694	91,296	92,892	92,131	93,733	95,329
Balance Sheet DITs - Accumulated		(2,342,587)	(2,253,729)	(2,163,274)	(2,073,580)	(1,982,284)	(1,889,392)	(1,797,261)	(1,703,528)	(1,608,198)

Year	Amount	YEAR #	20	21	22	23	24	25	26	27	28
Existing	10,863,476	**15 Year**	-	-	-	-	-	-	-	-	-
1	-	**15 Year**	-	-	-	-	-	-	-	-	-
2	-	**15 Year**	-	-	-	-	-	-	-	-	-
3	-	**15 Year**	-	-	-	-	-	-	-	-	-
4	250,000	**15 Year**	-	-	-	-	-	-	-	-	-
5	-	**15 Year**	-	-	-	-	-	-	-	-	-
6	-	**15 Year**	-	-	-	-	-	-	-	-	-
7	250,000	**15 Year**	14,763	14,763	7,378	-	-	-	-	-	-
8	-	**15 Year**	-	-	-	-	-	-	-	-	-
9	-	**15 Year**	-	-	-	-	-	-	-	-	-
10	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	7,378	-	-	-
11	-	**15 Year**	-	-	-	-	-	-	-	-	-
12	-	**15 Year**	-	-	-	-	-	-	-	-	-
13	250,000	**15 Year**	14,763	14,763	14,763	14,763	14,763	14,763	14,763	14,763	7,378
14	-	**15 Year**	-	-	-	-	-	-	-	-	-
15	-	**15 Year**	-	-	-	-	-	-	-	-	-

Scenario III - Completed in 2010

			Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
16	250,000	15 Year	17,315	15,583	14,763	14,763	14,763	14,763	14,763	14,763	14,763
17	-	15 Year	-	-	-	-	-	-	-	-	-
18	-	15 Year	-	-	-	-	-	-	-	-	-
19	250,000	15 Year	23,750	21,375	19,238	17,315	15,583	14,763	14,763	14,763	14,763
20	-	15 Year	-	-	-	-	-	-	-	-	-
21	-	15 Year	-	-	-	-	-	-	-	-	-
22	250,000	15 Year	-	-	12,500	23,750	21,375	19,238	17,315	15,583	14,763
23	-	15 Year	-	-	-	-	-	-	-	-	-
24	-	15 Year	-	-	-	-	-	-	-	-	-
25	250,000	15 Year	-	-	-	-	-	12,500	23,750	21,375	19,238
26	-	15 Year	-	-	-	-	-	-	-	-	-
27	-	15 Year	-	-	-	-	-	-	-	-	-
28	250,000	15 Year	-	-	-	-	-	-	-	-	12,500
29	-	15 Year	-	-	-	-	-	-	-	-	-
30	-	15 Year	-	-	-	-	-	-	-	-	-
Total Tax Depreciation			**85,353**	**81,245**	**83,403**	**85,353**	**81,245**	**83,403**	**85,353**	**81,245**	**83,403**

0.25%

Bonus Tax Depreciation

MACRS 15 Year

Scenario III - Completed in 2010

40 Year Life - Plant

		Year 29	Year 30
BOOK DEPRECIATION	**Cost**		
Existing Assets (net of Accun	10,863,476		
Depr. on Adjusted Fixed Assets		327,837	327,837
Total Book Depreciation		**327,837**	**327,837**

	Year		YEAR #	29	30
	Landfill			271,587	271,587
2010	1	-		-	-
2011	2	-		-	-
2012	3	-		-	-
2013	4	250,000		6,250	6,250
2014	5	-		-	-
2015	6	-		-	-
2016	7	250,000		6,250	6,250
2017	8	-		-	-
2018	9	-		-	-
2019	10	250,000		6,250	6,250
2020	11	-		-	-
2021	12	-		-	-
2022	13	250,000		6,250	6,250
2023	14	-		-	-
2024	15	-		-	-
2025	16	250,000		6,250	6,250
2026	17	-		-	-
2027	18	-		-	-
2028	19	250,000		6,250	6,250
2029	20	-		-	-
2030	21	-		-	-
2031	22	250,000		6,250	6,250
2032	23	-		-	-
2033	24	-		-	-
2034	25	250,000		6,250	6,250
2035	26	-		-	-
2036	27	-		-	-
2037	28	250,000		6,250	6,250
2038	29	-		-	-
2039	30	-		-	-

		Year 29	Year 30
Scenario III - Completed in 2010			
Total Book Depreciation		327,837	327,837
Book Value	##########	4,449,956	4,122,119
Property Taxes			
Property Tax Rate	0.7%	31,677	29,343

		29	30
Enter MACRS rate (below in y	4		
3 **MACRS**	**20 Year**		
4 **MACRS**	**15 Year**		
5 **MACRS**	**10 Year**		
6 **MACRS**	**7 Year**		
7 **MACRS**	**5 Year**		
8 **MACRS**	**3 Year**		

TAX DEPRECIATION

	Estimated		
Construction Property/Turbin	10,863,476	85,353	81,245
Total Tax Depreciation\Amortization		85,353	81,245
Balance Sheet DITs - Current Year		94,569	96,171
Balance Sheet DITs - Accumulated		(1,513,629)	(1,417,459)

Year	Amount	YEAR #	29	30
Existing	10,863,476	**15 Year**	-	-
1	-	**15 Year**	-	-
2	-	**15 Year**	-	-
3	-	**15 Year**	-	-
4	250,000	**15 Year**	-	-
5	-	**15 Year**	-	-
6	-	**15 Year**	-	-
7	250,000	**15 Year**	-	-
8	-	**15 Year**	-	-
9	-	**15 Year**	-	-
10	250,000	**15 Year**	-	-
11	-	**15 Year**	-	-
12	-	**15 Year**	-	-
13	250,000	**15 Year**	-	-
14	-	**15 Year**	-	-
15	-	**15 Year**	-	-

Scenario III - Completed in 2010

			Year 29	Year 30
16	250,000	15 Year	14,763	14,763
17	-	15 Year	-	-
18	-	15 Year	-	-
19	250,000	15 Year	14,763	14,763
20	-	15 Year	-	-
21	-	15 Year	-	-
22	250,000	15 Year	14,763	14,763
23	-	15 Year	-	-
24	-	15 Year	-	-
25	250,000	15 Year	17,315	15,583
26	-	15 Year	-	-
27	-	15 Year	-	-
28	250,000	15 Year	23,750	21,375
29	-	15 Year	-	-
30	-	15 Year	-	-
Total Tax Depreciation			**85,353**	**81,245**

Bonus Tax Depreciation

MACRS	15 Year

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT - BILLINGS LANDFILL OWNERSHIP

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Revenue Requirement	$2,401,272	$2,388,111	$2,348,230	$2,347,936	$2,310,554	$2,317,614	$2,325,594	$2,295,742	$2,266,865	$2,275,990
dk Production 100%	127,500	127,750	127,750	127,750	127,750	181,586	181,586	181,586	181,586	181,586
Cost per Dk	$18.834	$18.694	$18.381	$18.379	$18.087	$12.763	$12.807	$12.643	$12.484	$12.534
System Dk Sales 1/	35,115,744	36,197,246	36,389,685	36,533,555	35,569,717	36,762,207	36,909,256	37,056,893	37,205,121	37,353,941
Increase per dk	$0.068	$0.066	$0.065	$0.064	$0.065	$0.063	$0.063	$0.062	$0.061	$0.061

October 2011 Update

REVENU

		Year 11	Year 12	Year 13	Year 14	Year 15
Revenue Requirement		$2,292,738	$2,266,517	$2,278,404	$2,252,620	$2,228,044
dk Production	100%	234,430	234,430	234,430	234,430	234,430
Cost per Dk		$9.780	$9.668	$9.719	$9.609	$9.504
System Dk Sales 1/		37,503,357	37,653,370	37,803,983	37,955,199	38,107,020
Increase per dk		$0.061	$0.060	$0.060	$0.059	$0.058

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-057

Regarding: Embedded cost of service study
Witness: Aberle

a. **Please explain what is included in "Rent from Gas Property" on line 117, of the "Embedded CCOS-Details" tab in the Statement L spreadsheet and the rationale for the allocation factor applied to that revenue.**

b. **Please explain what is included in "Ad Valorem Taxes – Other" on line 202 of the "Embedded CCOS-Details" tab in the Statement L spreadsheet and the rationale for the allocation factor applied to those taxes.**

c. **Please explain what is included in "Other Income Tax Charges" on line 215 of the "Embedded CCOS-Details" tab in the Statement L spreadsheet and the rationale for the allocation factor applied to those charges.**

d. **Please clarify whether you consider the term "gas send out" to mean the same thing as "gas throughput."**

e. **Please explain what prevented you from being able to directly assign costs for services, meters, and regulators to customer classes in the embedded cost of service study and whether you envision being able to do that in the future.**

Response:

a. Rent from Gas Property includes rental income received for rent of gas property. The rental income was allocated on Net Plant in Service to match how the investment associated with the rental income was allocated.

b. Ad Valorem Taxes-Other includes the ad valorem taxes associated with distribution, general and common plant as shown on Statement K page 1 of 1. Allocation Factor 15 Distribution Plant was used to allocate the plant related taxes as the dollars associated with distribution plant was the largest cost contributor.

c. The "Other Income Tax Charges" in the embedded cost study represents the total M-1 deductions less the M-1 deduction associated with the Unrecovered Purchased Gas Cost Account that is allocated separately as shown on Statement J page 7. The Net Plant in Service allocator was used as this factor best represents the overall cost of service associated with the system.

d. Yes, the term gas sendout has been used in the data responses to refer to sales and transportation volumes or total throughput.

e. Services, meters and regulators are not accounted for by rate class and therefore were not directly assigned. Montana-Dakota does not envision tracking such investments by customer class in the future.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-058

Regarding: Embedded cost study
Witness: Aberle

a. **On p. 6 of your prefiled direct testimony you state that distribution plant accounts are allocated based on the cause for the investments and that distribution mains are classified as demand-related and allocated to rate classes based on their share of system peak demand. Does this approach imply that system peak demand is the underlying cause of investment in distribution mains? If not, please explain.**

b. **Do your proposed rates recover distribution mains-related costs based on customers' demands at the time of the system peak or demands in those months in which MDU is statistically most likely to experience peak demand?**

c. **To the extent system peak demand is the cause of distribution mains-related investments would it be just and reasonable to recover the associated costs solely from customer demand in those months in which MDU is statistically most likely to experience peak demand? If not, please explain why.**

d. **If MDU were to price its distribution service so that the price at the system peak reflected all the mains-related costs, and the price during all other times did not reflect any mains-related costs, would it be reasonable to assume that demand on the defined peak day would decline, other things equal? If not, please explain.**

Response:

a. No. System peak demand affects the investment in main but is not the underlying cause for investment in main. The need to serve customers is the primary driver for the need for distribution main investment.

b. The cost of distribution mains is recovered through the volumetric distribution delivery charge under the current and proposed rates.

c. No. As noted above, peak demand is not the sole cause for distribution main. As the costs are in fixed in nature and the primary driver for the need is customers, a fixed monthly charge would be most appropriate for recovery of all non-gas related costs.

d. The commodity cost of gas represents approximately 70% of a typical residential customer's bill and as a variable cost provides a meaningful price

signal to customers to reduce requirements in order to lower their natural gas bill. The collection of distribution costs associated with mains only in the winter months would only serve to exacerbate the issue of customers dealing with high winter bills and not necessarily result in a reduction in peak demand.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-059

Regarding: MDU responses to data requests MCC-098 and MCC-105
Witness: Aberle

a. **Data request MCC-098 asked MDU to provide the dates and hours during which small and large interruptible customers have been interrupted in the past three years. With regard to Attachment A of MDU's response, please explain the reasons for the interruptions that occurred in April and May 2009.**

b. **Please explain the method MDU uses to calculate the Dk curtailed.**

c. **Please explain the method MDU uses to determine which customer or customers to curtail.**

d. **According to MDU's response to data request MCC-105, MDU's peak days were December 14 and January 31 in 2009 and 2011, respectively. However, Attachment A to data request MCC-098 shows that customers were curtailed on December 11, 2009, and February 24, 2011, but not on the peak days in these years. Please explain why MDU did not need to curtail customers on the peak days in these years but curtailed customers on other days in relative close proximity to the peak day.**

e. **Please provide heating degree data for the curtailments shown in Attachment A to MDU's response to data request MCC-098 and for the peak days shown in response to MCC-105. In addition, please provide the Dk consumption of each of the customers identified in Attachment A to data request MCC-098 on the day they were curtailed and their consumption on the peak day listed in MDU's response to MCC-105.**

Response:

a. The curtailments were a result of the gas from the customer's shipper being allocated by the upstream pipeline, in this case WBI Energy, and were not a result of constraints on Montana-Dakota's distribution system. If the shipper is unable to supply the gas to Montana-Dakota's border station for the customer downstream of Montana-Dakota's border station, the customer is informed of the curtailment by Montana-Dakota.

b. The amount of the curtailment is equal to the amount that was cut by the upstream pipeline.

c. If the curtailment is due to a shipper constraint and that shipper is providing natural gas to a single customer downstream of Montana-Dakota's border station, the customer is curtailed by the amount cut by the pipeline. If the shipper is providing natural gas to multiple customers downstream of Montana-Dakota's border station, the shipper is required to provide Montana-Dakota the priority of which the customers are to be curtailed. The shipper determines the curtailment priority. If the curtailment is called by Montana-Dakota, the priority of service specified in Montana-Dakota's Conditions of Service Rate 100 section V. ¶10 is used to determine which customers will be curtailed if more than one customer is required to be curtailed.

d. As noted in Response a. above, the reported curtailments were caused by the upstream pipeline curtailment of the shipper's gas and were not curtailments initiated by Montana-Dakota.

e. Please see Attachment A, page 1 for the Dk curtailed and used by the interruptible customers curtailed during the 2009-2011 heating seasons. The heating degree days for the days with curtailments are also provided on page 1. Please see Attachment A, page 2 for the sales and transportation volumes used by the curtailed customers for the peak days shown in response MCC-105. Please see Response No. PSC-011d for the degree days applicable to the peak days.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
SMALL AND LARGE INTERRUPTIBLE
CUSTOMERS CURTAILMENTS
2009-2011 HEATING SEASONS

Date of Curtailment	Rate	Customer Number	DK Curtailed	DK Consumed	Heating Degree Days
4/11/2009	81	267	13	7	11
4/11/2009	81	270	27	114	7
4/11/2009 Total		2	40	121	
5/31/2009	81	141	41	41	0
2/24/2011	81	253	150	64	67
2/24/2011	81	254	150	69	61
2/24/2011	81	245	100	-	67
2/24/2011 Total		3	400	133	
1/1/2009	81	44	125	114	52
2/2/2009	81	219	30	37	61
12/11/2009	82	2	76	4,696	38

Peak Day TRANSPORTED Volume

Customer No.	2/17/2006	1/11/2007	12/15/2008	12/14/2009	1/7/2010	1/31/2011
2	7,855	3,415	7,580	4,287	9,164	
44	117	126		123	127	134
141			7			
219	43	38		45	40	44
245	54	55		7	39	44
253	89	88	69	117	70	79
254	81	64	91	50	39	
267	46	40		9	42	45
270	476	475	101	514	234	514

Peak Day SALES Volume

Customer No.	2/17/2006	1/11/2007	12/15/2008	12/14/2009	1/7/2010	1/31/2011
2						
44			181			
141	16	17	30	12	12	
219			54			
245				35		
253					16	
254					91	
267				39		
270					83	

Peak Day INTERRUPTED Volume

Customer No.	2/17/2006	1/11/2007	12/15/2008	12/14/2009	1/7/2010	1/31/2011
2						
44						
141						
219						
245			50			
253						
254						
267			2			
270			246			

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-060

Regarding: MDU's response to data request MCC-113
Witness: Aberle

a. **Attachment A to MDU's response to data request MCC-113 shows several projects where 6 in main was installed as part of a plan to loop the west end of Billings to address pressure issues. Please provide information detailing the pressure issues in the west end of Billings and any economic analyses of alternative ways of addressing the issues, including why looping is the best option.**

b. **It appears there is a considerable amount of variation in the cost per additional Mcfd of capacity when comparing the average cost of the nine distribution plant additions provided by MDU. For example, as restated in 1/1/14 dollars, the cost for project #4 is approximately $73.54 per additional Mcfd of capacity while project #8 is approximately $16.58 per additional Mcfd of capacity. Please discuss why this type of variation is present in these projects, including what the main drivers of cost are in expanding MDU's distribution system to provide additional capacity.**

c. **Was any portion of the costs of these projects not directly related to an expansion of capacity on MDU's distribution system, such as maintenance/repair to existing lines that did not necessarily increase capacity on the system?**

Response:

a. Distribution system pressures are monitored on an ongoing basis and addressed as necessary. There are basically 4 ways to increase capacity. 1) Increase the pressure (unless the system is at maximum capacity) 2) Install larger diameter pipe at same pressure 3) Add a border station; and 4) Loop the system to provide two feeds into a given system. Montana-Dakota employs the looping option as often as possible because it is the most economical option and enhances the reliability of the system.

b. The costs used in Exhibit No.___(TAA-3), page 7 incorrectly included the total project cost and not the incremental cost associated with the incremental capacity provided for projects 1 through 6. In addition, the incremental Mcfd provided under Projects 4, 5, 6 and 8 has been modified to reflect a more consistent pressure drop per foot of main. Please see Attachment A for revised Exhibit No. ___(TAA-3) pages affected by this correction. Variations in the cost per additional Mcfd still exist because of the variations in construction costs

dependent upon the terrain, weather, location, etc. The incremental capacity is also an estimate which will cause variations in the cost per Mcfd. The revised workpapers are provided in Attachment B.

c. No.

Revised TAA-3
Page 7

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

MARGINAL DEMAND-RELATED DISTRIBUTION INVESTMENT

Montana Demand-Related
Distribution Plant Additions

Project Number	Project Year	Incremental Capacity (Mcfd)	Investment in Gas Distribution System	Restated in 1/1/14 Dollars 1/
(1)	(2)	(3)	(4)	(5)
1	2011	415	$1,317	$1,343
2	2011	638	4,806	4,903
3	2011	800	2,373	2,421
4	2011	1,416	13,735	14,011
5	2011	2,189	12,396	12,645
6	2011	662	4,932	5,031
7	2011	2,998	145,000	147,912
8	2011	2,305	65,000	66,305
9	2011	12,000	64,000	65,285
	Total	23,008	$312,242	$318,513

Demand-Related Distribution Investment
per Additional Mcfd of Distribution Capacity: $13.84

1/ Plant additions in Column (4) are restated in 1/1/14 dollars in Column (5) using the Producer Price Index for Metals and Metal Products (weighted 50%) and the Producer Price Index for Unit Labor Costs - Non Farm (weighted 50%).

Revised TAA-3
Page 1

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

Marginal Cost	Total	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
(1)	(2)	(3)	(3)	(4)	(5)	(6)
I - Marginal Cost-Based Revenues						
Marginal Costs						
Commodity Cost ($/Dk) 1/		$3.917	$3.917	$3.917	$2.938	$2.938
Demand Cost ($/MCFD) 2/						
Distribution Level Service 2/		$208.54	$140.47	$24.47	$6.52	$2.48
Customer Cost ($/Month) 2/		$15.26	$22.97	$69.50	$230.08	$418.60
Billing Determinants 3/						
Dk Sales	10,129,873	6,097,461	1,119,203	2,694,623	218,586	0
Dk Transportation	4,884,226	0	0	0	686,293	4,197,933
Total Dk Throughput	15,014,099	6,097,461	1,119,203	2,694,623	904,879	4,197,933
Dk Throughput at Distribution	12,268,927	6,012,077	1,097,011	2,633,666	732,540	1,793,633
Peak Demand at Dist. (Mcfd)	85,504	48,225	10,068	20,290	2,007	4,914
Average No. of Customers	78,910	70,161	6,547	2,153	44	5
Average No. of Bills	946,920	841,932	78,564	25,836	528	60
Marginal Cost-Based Revenues						
Commodity (Sales Gas)	39,464,717	23,883,755	4,383,918	10,554,838	642,206	0
Demand (Distribution Level)	11,992,863	10,056,842	1,414,252	496,496	13,086	12,187
Customer	16,594,697	12,847,882	1,804,615	1,795,602	121,482	25,116
Total	$68,052,277	$46,788,479	$7,602,785	$12,846,936	$776,774	$37,303
II - Final Proposed Revenue Requirement 4/	$62,794,604					
III - Adjustment Factor	0.92274067					
IV - Revenue Requirements						
Proportioned to classes	$62,794,604	$43,173,633	$7,015,399	$11,854,390	$716,761	$34,421
Less Miscellaneous Revenue 5/	$416,112	$280,482	$37,585	$81,820	$7,553	$8,672
Net Revenue Requirement	$62,378,492	$42,893,151	$6,977,814	$11,772,570	$709,208	$25,749
V - Operating Revenue Before Increase 5/	$58,923,014	$35,729,916	$6,648,114	$14,608,669	$1,387,511	$548,804
VI - Required Increase	$3,455,478	$7,163,235	$329,700	($2,836,099)	($678,303)	($523,055)
VII- Percentage Increase	5.86%	20.05%	4.96%	-19.41%	-48.89%	-95.31%

1/ Exhibit No. __(TAA-3) page 2
2/ Exhibit No. __(TAA-3) pages 6-12.
3/ Rule 38.5.164, Statement H, page 3.
4/ Rule 38.5.175, page 7.
5/ Rule 38.5.176, Schedule L-1, page 4

Revised TAA-3
Page 2

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

SUMMARY OF MARGINAL COSTS BY CUSTOMER CLASS

	Customer Class				
Marginal Cost	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
(1)	(2)	(3)	(4)	(5)	(6)
Commodity Cost ($/Dk) 1/	$3.917	$3.917	$3.917	$2.938	$2.938
Demand Cost ($/MCFD) 2/ Distribution Level Service	$208.54	$140.47	$24.47	$6.52	$2.48
Customer Cost ($/Customer/Month) 3/	$15.26	$22.97	$69.50	$230.08	$418.60

1/ Exhibit No. __ (TAA-3), page 3.
2/ Exhibit No. __ (TAA-3), page 6.
3/ Exhibit No. __ (TAA-3), pages 8-12.

Revised TAA-3
Page 6

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF DISTRIBUTION DEMAND-RELATED MARGINAL COSTS

Line No.	Description	Rate 60	Rate 70 < 500 cu ft	Rate 70 > 500 cu ft	Rates 71/81	Rates 85/82
1	Distribution Demand-Related Marginal Cost ($/Mcfd) 1/	$1,552.86	$1,046.01	$182.27	$48.64	$18.48
2	General and Common Plant Allocation (Line 1 x 27.26%) 2/	423.31	285.14	49.69	13.26	5.04
3	Marginal Cost Including General Plant	1,976.17	1,331.15	231.96	61.90	23.52
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	8.655%	8.655%	8.655%	8.655%	8.655%
5	Annual Levelized Amount (Line 3 x Line 4)	171.04	115.21	20.08	5.36	2.04
6	Demand-Related Operation & Maintenance Expense (Line 3 x .78%) 4/	15.41	10.38	1.81	0.48	0.18
7	Demand-Related Administrative & General Allocation (Line 3 x 0.41%) 5/	8.10	5.46	0.95	0.25	0.10
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	194.55	131.05	22.84	6.09	2.32
	Taxes Other Than Income Taxes (Excl. Revenue-Related)					
9	Property Taxes (Line 3 x 0.60%) 6/	11.86	7.99	1.39	0.37	0.14
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	0.98	0.66	0.11	0.03	0.01
11	Sub-Total Taxes Other	12.84	8.65	1.50	0.40	0.15
	Working Capital Requirement					
12	Materials and Supplies (Line 3 x .14%) 2/	2.77	1.86	0.32	0.09	0.03
13	Prepayments (Line 3 x 0.01%) 2/	0.20	0.13	0.02	0.01	0
14	Total Working Capital	2.97	1.99	0.34	0.10	0.03
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.36	0.24	0.04	0.01	0
17	Sub-Total (Line 8 + Line 11 + Line 16)	207.75	139.94	24.38	6.50	2.47
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.79	0.53	0.09	0.02	0.01
19	Total Demand-Related Marginal Cost of Distribution	$208.54	$140.47	$24.47	$6.52	$2.48

1/ Exhibit No. __(TAA-3), page 7 and page 13.
2/ Exhibit No. __(TAA-3), page 14.
3/ Exhibit No. __(TAA-3), page 16.
4/ Exhibit No. __(TAA-3), page 17.
5/ Exhibit No. __(TAA-3), page 24.
6/ Exhibit No. __(TAA-3), page 26.
7/ Exhibit No. __(TAA-3), page 15.

Project #	Description	Actual Cost	Cost if installed 2" (satisfying only immediate needs)	Cost increase due to larger pipe size in portion	Gain in MCFD due to larger pipe size	$ /MCFD (due to increase in pipe size)
1	TWIN COULEE SUBDVISION 740' OF 4" MAIN	$ 15,861.00	$ 14,544.00	$ 1,317.00	415	$ 3.17
2	HILLBROOK SUBDIVISION 2700' OF 4" MAIN	$ 13,158.00	$ 8,352.00	$ 4,806.00	638	$ 7.53
3	GRANITE PARK SUBDIVISION 1333' of 4" MAIN	$ 19,619.00	$ 17,246.00	$ 2,373.00	800	$ 2.97
4	PIONEER ESTATES SUBDIVISION 2795' OF 4" & 2000' OF 6"	$ 70,088.00	$ 56,353.00	$ 13,735.00	1416	$ 9.70
5	COPPER RIDGE SUBDIVISION 4100' OF 6" MAIN	$ 26,344.00	$ 13,948.00	$ 12,396.00	2189	$ 5.66
6	GREENSLEEVES SUBDIVISION 3760' OF 4" MAIN	$ 27,976.00	$ 23,044.00	$ 4,932.00	662	$ 7.45
7	WEST END REINFORCEMENT	$ 145,115.00	-		2988	$ 48.57
8	SHILOH ROAD MAIN EXTENSION	$ 64,850.00			2305	$ 28.13

#4

Pipe Flow Calculation: Pioneer Estates Subdvision - REVISED

Calculation Data...

Pipe Size/Type: 2P-S11
Length: 4796 Feet
Efficiency: 0.95 Decimal
Flow: 145 Mcfd

Inside Diameter: 1.917 Inches

1561 MCFD (AVG. OF 4" & 6") − 145 MCFD (2") = 1416 MCFD

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55.00 Psi	51 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 4.00 Psi ← Previous Pdrop assumption of 2 psi too low.
Average Pressure: 53.02 Psi
Average Compressibility: 1.000000
Calculation Method: None
Line Volume At Average Pressure: 0.5 Mcf
Average Flow Velocity: 17 Feet/sec

Gas Properties...

Base Pressure: 13.10 Psi
Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.#156204
For this subdivision, 2" main would have adequate supply for immediate need. We installed some 4" and 6" in order to continue with our plan to loop the west end for alleviate pressure drops.

GASCalc 4.0 Revision: 030 - December 19, 2001
Date: 2/6/2013

#4

Pipe Flow Calculation: Pioneer Estates Subdvision - REVISED

Calculation Data...

Pipe Size/Type: 4P-S11.5
Length: 4796 Feet
Efficiency: 0.95 Decimal
Flow: 820 Mcfd

Inside Diameter: 3.670 Inches

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55.00 Psi	51 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 4.00 Psi
Average Pressure: 53.02 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 1.8 Mcf
Average Flow Velocity: 26 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.#156204
For this subdivision, 2" main would have adequate supply for immediate need. We installed some 4" and 6" in order to continue with our plan to loop the west end for alleviate pressure drops.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

#4

Pipe Flow Calculation: Pioneer Estates Subdvision - REVISED

Calculation Data...

Pipe Size/Type: 6P-11.5
Length: 4796 Feet
Efficiency: 0.95 Decimal
Flow: 2302 Mcfd

Inside Diameter: 5.403 Inches

2302 MCFD + 820 MCFD = 3122 MCFD
FLOW IF 6" FLOW IF 4"
AVG = 1561 MCFD

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55.00 Psi	51 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 4.00 Psi
Average Pressure: 53.02 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 3.9 Mcf
Average Flow Velocity: 33 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.#156204
For this subdivision, 2" main would have adequate supply for immediate need. We installed some 4" and 6" in order to continue with our plan to loop the west end for alleviate pressure drops.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

#5

Pipe Flow Calculation: Copper Ridge Subdivision

Calculation Data...

Pipe Size/Type: 2P-S11
Length: 4100 Feet
Efficiency: 0.95 Decimal
Flow: 147 Mcfd

Inside Diameter: 1.917 Inches

FLOW OF 6" MAIN – FLOW OF 2" MAIN = CAPACITY INCREASE
2336 MCFD – 147 MCFD = 2189 MCFD

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55 Psi	51.5 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 3.50 Psi
Average Pressure: 53.27 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 0.4 Mcf
Average Flow Velocity: 17 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.#153821
For this subdivision, 2" would adequately supply it for immediate need. We installed 67" in order t o continue with our plan to loope the west end for pressure issues and to provide for adequate fut ure needs.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

#5

Pipe Flow Calculation: Copper Ridge Subdivision

Calculation Data...

Pipe Size/Type: 6P-11.5
Length: 4100 Feet
Efficiency: 0.95 Decimal
Flow: 2336 Mcfd

Inside Diameter: 5.403 Inches

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55 Psi	51.5 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 3.50 Psi
Average Pressure: 53.27 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 3.3 Mcf
Average Flow Velocity: 33 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.#153821
For this subdivision, 2" would adequately supply it for immediate need. We installed 67" in order t o continue with our plan to loope the west end for pressure issues and to provide for adequate fut ure needs.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

#6

Pipe Flow Calculation: Greensleeves Subdivision

Calculation Data...

Pipe Size/Type: 2P-S11
Length: 3760 Feet
Efficiency: 0.95 Decimal
Flow: 142 Mcfd

Inside Diameter: 1.917 Inches

FLOW OF 4" MAIN – FLOW OF 2" MAIN = INCREASE IN CAPACITY
804 MCFD – 142 MCFD = 662 MCFD

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55.00 Psi	52 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 3.00 Psi
Average Pressure: 53.51 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 0.4 Mcf
Average Flow Velocity: 16 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.# 56221
For this subdivision, 2" main would adequately supply it for the immediate need. Had we not insta lled 4" along the main grid, as map shows, we would not be able to utilize this for future customers further out. This allows us to continue with our plan to loop the system with larger pipe along a gri d to satisfy future needs.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

#6

Pipe Flow Calculation: Greensleeves Subdivision

Calculation Data...

Pipe Size/Type: 4P-S11.5
Length: 3760 Feet
Efficiency: 0.95 Decimal
Flow: 804 Mcfd

Inside Diameter: 3.670 Inches

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55.00 Psi	52 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 3.00 Psi
Average Pressure: 53.51 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 1.4 Mcf
Average Flow Velocity: 25 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O.# 56221
For this subdivision, 2" main would adequately supply it for the immediate need. Had we not insta lled 4" along the main grid, as map shows, we would not be able to utilize this for future customers further out. This allows us to continue with our plan to loop the system with larger pipe along a gri d to satisfy future needs.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

#8

Pipe Flow Calculation: Shiloh Road Main Extension

Calculation Data...

Pipe Size/Type: 6P-11.5
Length: 4200 Feet
Efficiency: 0.95 Decimal
Flow: 2305 Mcfd

Inside Diameter: 5.403 Inches

Flow Equation: IGT-Improved

	Inlet (Upstream) Values...	Outlet (Downstream) Values...
Pressure:	55.00 Psi	51.5 Psi
Elevation:	3000 Feet	3000 Feet
Temperature:	60.0 Fahrenheit	60.0 Fahrenheit

No Fittings Are Attached

Heat Loss Or Gain Calculation Method: None

Linear Pressure Drop: 3.50 Psi
Average Pressure: 53.27 Psi
Average Compressibility: 1.000000
Line Volume At Average Pressure: 3.4 Mcf
Average Flow Velocity: 33 Feet/sec

Calculation Method: None

Gas Properties...

Base Pressure: 13.10 Psi

Base Temperature: 60.0 Fahrenheit

Viscosity: 0.0000070 Lbm/ft-sec
Specific Gravity: 0.600
Ratio Of Specific Heats: 1.30

Assigned Gas Properties File: None

Calculation Notes...

These calculations are only valid within the applicability of the selected flow equation.

The Flow value was calculated.

References:
Flow Equation - Gas Age Magazine, May 1967, Gas Behavior In Distribution Systems
Compressibility - No Reference Available.

Notes:
W.O. #174030
This area is experiencing considerable growth in commerical business. Extending 6" is prudent fo r future load.

GASCalc 4.0 Revision: 030 - December 19, 2001

Date: 2/6/2013

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-061

Regarding: Interruptible rates 71, 80, 81, 82, and 85
Witness: Aberle

a. **Please explain the method used to derive the minimum and maximum distribution delivery charge contained in MDU's proposed interruptible rates.**

b. **Please explain how the actual distribution delivery charge that is paid by the MDU customer is determined. If the rate is determined through contract negotiation, please explain what factors are considered when determining the actual distribution delivery charge for these customers.**

Response:

a. The maximum distribution delivery charge is based on the revenues required to be collected under the rate schedule after the collection of base rate revenues. The variable costs associated with serving the rate classes is considered in developing the proposed minimum charges. In this Docket no changes were proposed for the minimum prices effective under each schedule as the current prices are above the variable costs identified in the embedded cost of service study and a decrease in the charges was determined not to be necessary.

b. The distribution delivery charge applicable under each of the flexible rate schedules is determined through contract negotiation. Please refer to Response No. PSC-51 for the number of contracts on a negotiated rate and the basis for the rates charged.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-062

Regarding: Customer attributes
Witness: Aberle

a. **Please provide a description of the type of customer that typically takes service under each of MDU's rate options. For example, under which rate would a hospital, oil refinery, or large retail store most likely take natural gas service?**

b. **Over the last 10 years, when a new customer came on to MDU's distribution system, what percentage of those customers required the installation of a new service line, meter, or regulator in order to begin receiving service? Please provide the information per rate class and broken down by service lines, meters or regulators.**

c. **Please provide, year-by-year and by each rate schedule, the total number of customers that took natural gas service under each of MDU's rate schedules for the last 10 years.**

Response:

a. The application of rates is prescribed in Montana-Dakota's Conditions of Service Rate 100 Section V. ¶3 (set forth below). The Nonresidential service would be served under Rate 70 if natural gas service is provided on a firm basis and under one of the interruptible services (Rates 71, 85, 81 or 82 if interruptible service). As further noted in Conditions of Service Rate 100 III. ¶3, all new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, must consult with the Company to determine if the load may be served under Firm General Service Rate 70 or if the load will be served on an interruptible basis only. This determination would apply to a hospital, oil refinery or large retail store. The distinction between small and large interruptible sales or transportation service is based on annual volume requirements where the small interruptible rate schedules (71 or 81) are applicable to customers with annual interruptible requirements of 100,000 dk or less and the large interruptible rate schedules (85 or 82) are applicable to customers with annual interruptible requirements greater than 100,000 dk.

a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family with separate cooking facilities. Typical service would include the following: single private residences, single apartments, mobile homes

with separate meters and auxiliary buildings on the same premise when used for residential purposes by the residential customer. This is not an all-inclusive list.

b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, sorority and fraternity houses, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site. This is not an all-inclusive list.

b. Montana-Dakota does not track customer information in the manner requested.

c. Please see Attachment A.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
CUSTOMER COUNTS BY RATE 2002-2011

Rate	2002 Customers	2003 Customers	2004 Customers	2005 Customers	2006 Customers	2007 Customers	2008 Customers	2009 Customers	2010 Customers	2011 Customers
60	63,475	64,311	65,164	66,259	67,116	67,989	68,737	69,300	69,878	70,460
70 (Meters <500 CF/hr)	5,985	6,076	6,121	6,190	6,251	6,329	6,368	6,434	6,499	6,540
70 (Meters >500 CF/hr)	1,723	1,749	1,783	1,832	1,874	1,932	1,971	2,001	2,058	2,098
71	4	4	3	3	3	4	6	7	7	13
72	4	4	5	4	5	6	6	6	6	5
85	0	0	0	0	0	0	0	0	0	0
93	2	2	2	2	2	2	2	2	2	2
Natural Gas Total	71,193	72,146	73,078	74,290	75,251	76,262	77,090	77,750	78,450	79,118
80	3	3	3	3	3	3	0	0	0	0
81	34	34	35	36	39	37	39	37	36	31
82	5	5	5	5	5	5	5	5	5	5
Natural Gas Transport Total	42	42	43	44	47	45	44	42	41	36
Overall Total	71,235	72,188	73,121	74,334	75,298	76,307	77,134	77,792	78,491	79,154

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
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PSC-063

Regarding: Embedded cost of service study
Witness: Aberle

a. **Please explain the reasoning for allocating the cost of service lines using an allocation factor that is in part based on the average cost of a meter (allocation factor 10).**

b. **Has MDU provided adequate information in its embedded cost of service study that would allow a third party to calculate an allocation of costs based on both the average and excess demand method, as well as the peak and average demand method? If not, please provide the information that would allow a third party to make those calculations.**

c. **Please discuss why it is or why it is not appropriate to allocate the costs of mains to customers using either the average and excess demand method or the peak and average demand method.**

Response:

a. Weighted meter costs were used as a proxy for weighted service line costs in this case. A differentiation between meters and services would have been more appropriate however; the weightings will tend to be the same for the residential and firm general service classes while the service line costs to the large firm general and interruptible service classes will be overstated based on weighted meter costs.

b. Non-coincident peak day use is not available by customer class, which is needed in order to calculate an average and excess demand allocator.

c. Please see Response No. PSC-005c.

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PSC-064

Regarding: Marginal cost of service study
Witness: Aberle

a. **Ms. Aberle stated she used the pro forma cost of gas level for calendar year 2011 in her marginal cost of service study, and testified that "use of this cost of gas amount is representative of the long-run marginal cost of gas...." Please explain why the pro forma cost of gas for calendar year 2011 is considered to be representative of the long-run marginal cost of gas.**

b. **In MDU's last natural gas rate case (Docket No. D2004.4.50), MDU proposed a marginal distribution capacity cost of $10.65/mcfd. In this docket, MDU is proposing a marginal distribution capacity cost of $209.06/dk. Please explain why there is such a large difference in these two cost estimates. If there has been a change in MDU's methodology to estimate the marginal cost of distribution capacity, please describe how and why it has changed.**

Response:

a. Given uncertainties in the gas markets and the fact that the cost of gas does not affect the distribution revenue requirement, the matter of this rate case, the 2011 pro forma cost is an appropriate proxy to use for long-run marginal costs.

b. The increase is caused by the addition of the total mains investment per peak day in the demand component rather than classifying the mains investment as customer related.

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PSC-065

Regarding: Service lines
Witness: Aberle/Skabo

a. **What are the primary drivers of the cost of installing a new service line?**

b. **Of the 1,040 miles of service lines that MDU operates, how many of those miles are dedicated to residential customers? Please break down the 1,040 miles of service line usage by each of MDU's rate classes.**

c. **What is the average length of service line that is used to serve each of MDU's rate classes?**

d. **For each rate class on your system, please provide the length of the longest service line installed to serve a customer.**

e. **Please confirm that, by definition, a service line serves only one customer, and a line that serves more than one customer is considered a main line. If this is not true, please clarify. If there are additional factors that define a service line or main line, such as diameter, please explain.**

Response:

a. Labor, materials and equipment are the primary costs associated with an installed service line. Those costs are affected by items such as service line length, soil conditions, and location of the service line i.e., new development or established area where other utilities already exist.

b. Based on information obtained from the Company's GIS system, the following is a breakdown of the total service line lengths by rate class. The Other category represents vacant premises or service line points not identified by a rate code.

Rate	Percent of Total Service Line Miles
60	82.6%
70	12.0%
71/81	0.1%
Other	5.3%

c. Based on information obtained from the GIS system, the following are the average service line lengths by rate code:

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Rate	Service Line Avg Length (ft)
60	90
70 (small meter)	98
70 (large meter)	148
71	329
81	75

d. Based on the information obtained from the GIS system, the following are the maximum service line lengths by rate code. The customers served directly off the mainline or transmission level customers typically require long service lines as evidenced by the following.

Rate	Service Line Max Length (ft)
60	8,207
70	10,243
71/81	1,194

e. In general, the service line is a line that provides service to one customer service point.

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MONTANA PUBLIC SERVICE COMMISSION
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DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-110

RE: Rate case expense
Witness: Unknown

Does MDU agree with the proposition that a rate case is simultaneously an act undertaken as an ordinary and necessary measure of doing the business of a regulated utility, and also an act of advocacy beneficial to the regulated utility's owners? Please explain your view.

Response:

Montana-Dakota views a rate case as the process imposed and provided under the law to allow a utility the opportunity to collect revenues necessary for the Company to pay the costs of providing safe and reliable service and receive a reasonable return on the capital invested to provide such safe and reliable service. Montana-Dakota makes rate case filings because it cannot lawfully change any of its prices, up or down, without making a rate filing with the Commission.

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MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-113

RE: FTE Employees
Witness: Unknown

For the test year and the preceding three calendar years, please provide (on a total company basis), a summary table (using the categories and format shown below) that includes the number of FTE (exclude FTE created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company ❶ FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Response:

Please see Attachment A for the FTE employees and compensation. The Total Company FTE is as of December 31 of each year. The compensation includes compensation for the entire year. For example, summer temporary employees would not be included in the FTE column, but their compensation is included in the total compensation amount. The table includes employees in the Utilities Group who are Montana-Dakota employees that perform functions for all four utilities. For example the customer service center employees perform functions for all four utilities and their compensation is allocated among the four utilities as appropriate.

Year: 2011		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	6	1,343,994.10	-	870,138.59	2,214,132.69
Exempt	331	27,621,509.73	493,508.83	3,352,890.63	31,467,909.19
Nonexempt	284	7,867,181.52	274,343.71	503,596.21	8,645,121.44
Union	355	23,975,675.81	4,783,295.22	1,833,197.52	30,592,168.55
Total	976	60,808,361.16	5,551,147.76	6,559,822.95	72,919,331.87

Year: 2010		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	6	1,343,852.82	-	855,659.21	2,199,512.03
Exempt	314	24,102,937.35	253,285.65	2,750,683.90	27,106,906.90
Nonexempt	256	9,695,353.00	465,026.84	725,829.02	10,886,208.86
Union	347	23,500,670.38	4,108,589.53	1,892,847.50	29,502,107.41
Total	923	58,642,813.55	4,826,902.02	6,225,019.63	69,694,735.20

Year: 2009		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	6	1,498,986.49	-	810,451.39	2,309,437.88
Exempt	298	23,940,899.83	141,804.49	3,715,689.07	27,798,393.39
Nonexempt	224	7,816,382.93	425,783.11	1,091,642.11	9,333,808.15
Union	357	25,255,811.18	3,681,056.43	1,736,074.77	30,672,942.38
Total	885	58,512,080.43	4,248,644.03	7,353,857.34	70,114,581.80

Year: 2008		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	7	1,584,358.73	-	1,201,436.92	2,785,795.65
Exempt	299	22,036,593.41	171,189.01	2,643,774.09	24,851,556.51
Nonexempt	196	7,948,368.33	428,623.40	757,772.66	9,134,764.39
Union	417	25,411,840.86	4,173,908.47	1,918,511.40	31,504,260.73
Total	919	56,981,161.33	4,773,720.88	6,521,495.07	68,276,377.28

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-116

RE: Employee Compensation
Witness: Unknown

a. **Please provide any salary studies performed by MDU that pertain to the test period or any of the three preceding years.**

b. **Please show the results of the salary study and narrative explanations for how MDU uses the salary study information.**

c. **Please provide MDU policy information for how the salary studies have been applied in past years and how they have impacted the Company's decision to increase or decrease wages or incentives as a result of the study.**

Response:

a. Montana-Dakota does not complete independent salary studies but relies on proprietary and copyrighted studies from recognized firms that publish salary data. This data is used in the annual salary structure review process and for establishing incentive compensation target percentages.

b. The requested information is the proprietary information of a third party which Montana-Dakota is only allowed to use on a subscription basis. Montana-Dakota cannot, consistent with its legal obligations as a subscriber, provide the requested information.

   Montana-Dakota shares a common salary structure with MDU Resources and other corporate business units but retains flexibility in how employee compensation is administered within the salary structure. Annually, the business units of MDU Resources identify benchmark jobs to review and study salary data from published surveys. Many jobs that are reviewed are the same from year-to-year; these jobs are considered benchmark jobs and represent a diverse cross-section of jobs throughout the Company. Upon completion of the analysis of the results of the study, recommendations for Montana-Dakota positions are made to Montana-Dakota's President for approval.

   The salary study/structure review process has two purposes. (1) Jobs are reviewed and determinations made if a job is unchanged or if it should move to a higher or lower pay class/grade. Generally, market data is relatively stable so it is very unusual for a job to move to a different classification unless there is a significant shift in responsibilities or skills are in short supply in the

Response No. PSC-116 continued.

labor market. Market data would have to indicate a rate of pay that is 10 percent to 15 percent higher or lower than market for several consecutive years before Montana-Dakota would re-classify a job. (2) The second purpose of the salary structure review process is to determine how much the salary range (minimum midpoint and maximum) should be increased to maintain competitive with the prevailing wage in the labor market.

c. The Company has no formal policy for application of salary studies except the total rewards strategy provided in Response No. PSC-125. As a result of these salary studies, salary ranges have increased on average between 0-2 percent per year. Based on the salary review guidelines, provided as Attachment A, the actual adjustment to employee wages varies based on a number of factors outlined in Attachment A. Similar guidelines are issued every year.

In 2009 Montana-Dakota conducted a review of the prevalence of incentive compensation plans and confirmed through a study by Watson Wyatt that bonus plans were a common component of total rewards in the utility industry. The data was analyzed to develop a new employee incentive compensation plan.

INTERNAL CORRESPONDENCE

LOCATION: General Office
DATE: November 15, 2010
WRITER: Dave Goodin
SUBJECT: 2011 Compensation Review

Dennis Haider
Mike Gardner
Jay Skabo
Andrea Stomberg
Garret Senger
Anne Jones

2011 MERIT INCREASE GUIDELINES

The budget for 2011 merit pay increases for non-bargained employees of MDU Utilities Group has been approved. Worksheets for 2011 pay recommendations will be distributed to managers by your Human Resources Department this week.

It is very important you understand that merit increase budgets across all MDU Resources Companies continue to reflect our current economic environment, with some business units again freezing base salaries in 2011. Employees in the utility group continue taking on additional work and making significant efforts to reduce our O&M costs, keeping our companies financially strong. **I have approved a salary increase budget of 2.5%.** This is in line with other utilities across the United States.

The 2.5% budget authorized for our salary review process was calculated from current non-bargained employee salaries. The amount budgeted is by VP Rollup, not necessarily per person. Managers are expected to allocate any merit pay increases based on employee performance (merit) and equity (internal and external).

Employees that are above the salary range maximum are considered "red-circled" and are not eligible for a base pay increase in 2011. You will also be provided a listing of employees that are not eligible for a salary review in December because of a recent promotion, pay adjustment or hire date. In addition, employees receiving Marginal or Unacceptable Performance Review scores are not eligible for a pay increase.

I expect each of you to work with your managers to stay within an overall 2.5% budget by VP rollup. Managers will be given information on their salary worksheets that provides guidance to help them stay within the budget. You will be authorized additional dollars, beyond your approved salary budget, to bring any employee that is below the salary range up to the salary range minimum.

In addition, for 2011, another .5% is budgeted to be used at Vice President and Human Resources discretion in order to differentiate exceptional performers, expedite equity, address positions that are difficult to fill, and address compression issues. Managers should discuss the request for additional funds with their Vice President, and provide supporting documentation.

To help you with the process, promote consistency and ultimately stay within budget, I suggest you reference the following guidelines prepared by Human Resources.

GUIDELINE FOR ALLOCATING 2011 MERIT INCREASE BUDGET

Performance Rating Description	Compa Ratio 80 - 92 %	Compa Ratio 93-106%	Compa Ratio 107-120%
Performance rating reserved for outstanding performers in the company.	3.0 – 3.5%	2.50 – 3.0%	2.0 – 2.5%
Performance rating indicating employee performance meets or frequently exceeds expectations.	2.25 – 2.75%	1.5 – 2.0%	1.0% *In very limited special circumstances for pay equity purposes- consider lump sum in lieu of base pay increase.*
Employee performance that is below expectations or unsatisfactory.	0% - *Employees are not eligible for an increase in base pay.*		

Compa ratio = employee base pay/salary range midpoint. The above table has been prepared as a guideline, assuming the job is paid competitively when employee pay is in the middle one-third of the salary range (93-106% compa ratio).
It is recognized some jobs must be paid closer to the salary range maximum (120% compa ratio) to maintain competitive pay.

If you have any questions contact Amanda Ross or Jim Kaiser. Review and email your group's completed worksheets to Amanda Ross no later than **5PM on Wednesday, December 1, 2010.**

2011 PAY STRUCTURE

Below is the 2011 MDU Utility Group pay structure. The structure is common to MDU Resources and their business units. It is reviewed and updated annually based on salary market studies. The overall average structure increase for 2011 is 1.8%. The individual salary class changes vary from 1% to 2.8%.

2011 Pay Grade Structure

Grade	Minimum	Midpoint	Maximum
29	$20,000	$25,000	$30,000
30	$22,400	$28,000	$33,600
31	$25,520	$31,900	$38,280
32	$29,600	$37,000	$44,400
33	$34,600	$43,250	$51,900
34	$40,400	$50,500	$60,600
35	$46,240	$57,800	$69,360
36	$53,600	$67,000	$80,400
37	$61,600	$77,000	$92,400
38	$70,800	$88,500	$106,200
39	$80,800	$101,000	$121,200
40	$90,400	$113,000	$135,600
41	$101,000	$126,250	$151,500
42	$114,400	$143,000	$171,600

SALARY REVIEW PROCESS STEPS FOR MANAGERS AND SUPERVISORS

1. **Review Demographics**
   - Worksheets are based upon classification and pay level effective the first pay period in November.
   - Ensure all employees are listed; job titles, pay grades, performance ratings, and pay levels are accurate. Work with Amanda Ross regarding any changes or updates to this information.
2. **Merit Increases**
   - Recommend a pay adjustment by inputting a percentage in the Proposed Increase % column. The Salary Increase $ Value, New 2011 Salary, Compa, and total dollars spent cells will automatically calculate and update.
   - Exceptions to guidelines should be infrequent and will require additional supporting documentation.
3. **Lump Sum Bonuses**
   - Employees paid substantially above the prevailing labor market wage rate (typically mid-point) may be considered for a lump sum bonus in lieu of an increase to annual salary. However, these bonuses will be considered part of the budget dollars spent.
   - Lump sum bonuses do not increase base salary. They normally are used to improve equity issues between employees in the same classification.
   - Lump sum bonuses will be paid in a separate check dated December 18, 2010 and will be included in the employee's 2010 wages.
4. **Submit Spreadsheets**
   - Discuss salary recommendations with your Vice President and email completed spreadsheets to Amanda Ross. Your help in returning recommendations no later than **5PM on Wednesday, December 1,** is greatly appreciated.

SALARY REVIEW TIMELINE

- **November 17** – Salary worksheets and guidelines distributed
- **December 1** – All salary recommendations reviewed by Vice Presidents and emailed to Amanda Ross
- **December 8** – Final approval of recommendations by Dave Goodin
- **December 15** – Supervisors communicate salary increase information to employees

Effective Date of 2011 Increases (Corresponds with the Company's 2011 Pay Period Schedule)

- **December 19** –IGC employees
- **December 20** –MDU employees
- **December 23** –CNG employees

Pay Date Reflecting New 2011 Wage

- **January 7** – IGC
- **January 11** – CNG
- **January 14** – MDU

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-117

RE: Employee Compensation
Witness: Unknown

a. **Please demonstrate whether the wages and salaries in the test period or the preceding calendar years are above or below market compensation.**

b. **Please provide the information relied upon to demonstrate the Company's assertion of whether wages and salaries are above or below market levels.**

Response:

a-b. Bargaining Unit Positions – Montana-Dakota has one collective bargaining unit agreement for all positions represented by IBEW System Council U-13. This agreement establishes the wage paid to positions located in Montana, North Dakota, South Dakota and Wyoming. The last two contracts have been four year agreements with the most recent contract in 2011. The proposed wage increases in the 2011 labor agreement were established to keep Montana-Dakota's wages close to the median of its competitive labor market and maintain appropriate equity relationships between classifications within the Company.

Non-bargaining Positions – Each non-bargaining position is assigned to a salary classification that contains a minimum, midpoint and maximum salary range. Please see Response No. PSC-116 for a description of the process of adjusting salary ranges. The salary range midpoint (Zone 2) is assumed to be the median of the labor market for most positions.

The salary range begins at 80 percent of the determined midpoint and has a maximum of 120 percent of the midpoint. The table below breaks down the full range into zones, each making up one-third of the range.

	2011	2010	2009	2008
Zone 1	32%	34%	24%	23%
Zone 2	40%	35%	41%	51%
Zone 3	28%	31%	35%	26%

- Zone 1, or entry level, is typically comprised of those new to a position, with little experience. Low performers will also fall in this zone.
- Zone 2 reflects more seasoned employees with greater experience and solid job performance.

Response No. PSC-117 continued.

- Zone 3 is comprised of high performers, those who have been in the same position within the Company for an extensive amount of time, or when prevailing labor market wages require the Company to compensate at this level to attract and retain qualified individuals.

MONTANA-DAKOTA UTILITIES CO.
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PSC-120

RE: Discount rate calculation for cap-ex
Witness: Applicable Witness

The Commission is interested in learning more about how MDU makes capital-expenditure decisions.

a. Please describe how the Company establishes a discount rate or rates for analyzing new investments in (a) transmission, (b) storage, (c) distribution, (d) producing gas reserves, and (e) other investments.

b. Please explain any methodological differences in determining the discount rate(s) between these investment categories.

c. For each discount rate used since January 1 of the third year preceding the test year and calculated using factors also used by MDU or its consultants in calculating MDU's cost of capital, please provide the value of each factor used and the source from or method by which it was obtained.

Response:

Many factors go into the decision making process for capital expenditures at Montana-Dakota. First and foremost, capital expenditures will be considered on the basis of ensuring safe and reliable service to customers. In addition, capital expenditures will be required to service growth needs and existing or new regulatory and environmental requirements.

a. Montana-Dakota does not have any transmission, storage or producing gas reserves. The Company does not establish a discount rate for analyzing investment decision in regard to its utility business. Instead, the Company's practice in analyzing capital expenditure decisions is to use a composite authorized return on rate base from the most recent rate case filings in its four state jurisdictions. Projects are prioritized based on the most critical need. When capital expenditures are required in order to meet customer growth or are the result of regulatory or environmental requirements, these projects are evaluated in the same manner using the above mentioned average composite return on rate base with the assumption that such projects will be included in future rate base.

b. Not applicable.

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c. Montana-Dakota's composite authorized return on rate base for the 3 years preceding the test year were:

January - April 2008	9.90%
May 2008 - April 2009	9.51%
May 2009 – April 2010	9.41%
May 2010 – June 2011	9.31%

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PSC-121

RE: Landlord Agreement
Witness: Unknown

a. **Does MDU have an agreement in place allowing landlords to assume payment of a bill on behalf of a non-paying tenant?**

b. **If so, please provide that agreement.**

c. **Would MDU be opposed to creating a tariff governing this agreement?**

Response:

a. Montana-Dakota offers an optional agreement, at no charge, to landlords and property owners with rental properties referred to as a Continuous Service Agreement (CSA). The CSA provides the option to have utility service transferred to the account of the landlord or property owner in the event service to the tenant is discontinued. The agreement allows continuous utility service to the premise to avoid property damage. The landlord/property owner is only responsible for payment of service rendered from the time the account is transferred the landlord's name similar to any other account. The CSA also provides the option for the landlord or property owner to only request that service transfer to its name if the tenant voluntarily disconnects service at the premise. Since the landlord is effectively agreeing to be the new customer at the location, and pay for the services which will be received, the landlord must execute the Continuous Service Agreement to receive its benefits.
b. Please see Attachment A.
c. Yes. The CSA is not a schedule of a rate, toll or charge or a rule affecting such a rate, tool or charge to be filed as a tariff as provided in Section 69-3-301. The CSA is an agreement between Montana-Dakota and the landlord to be voluntarily executed by the landlord.

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

CONTINUOUS SERVICE AGREEMENT

Scan and return via:
- **E-mail:** customerservice@mdu.com
- **Fax:** 1-701-323-3104 or
- **Mail:** Montana-Dakota Utilities Co., Attn: Customer Support, PO Box 7608, Boise, ID 83707-1608

1. **RECITATION.** The Undersigned (hereinafter referred to as "Customer") is the Financially Responsible Party (i.e. owner, manager, or otherwise financially responsible for the maintenance of the real properties described on Exhibit A hereto (hereinafter referred to as "Properties") which may be occupied by others (hereinafter referred to as "Tenants") from time to time. **Montana-Dakota Utilities Co.** (hereinafter referred to as the "Utility") provides Natural Gas and/or Electric services (hereinafter referred to as "Energy Services") to the location of the Properties in accordance with the terms of tariffs filed with the state regulatory agency of the jurisdiction in which the Properties are located. The Agreement is intended to assure continuous Energy Services to the Properties during periods in which a Tenant has not arranged for or has failed to maintain energy services.

2. **TERM.** This Agreement between the Utility and the Customer is effective as of the date (hereinafter referred to as the "Effective Date") that it is processed by the Utility. For electronic communication purposes, the Customer must provide an active e-mail address prior to processing. Utility will provide e-mail notification that the Agreement has been processed. This Agreement will continue in effect until cancelled by either party upon five (5) days prior written notice sent in accordance with Paragraph 5 below. Properties subject to this Agreement must have energy services activated prior to or on the Effective Date. Termination of this Agreement does not relieve the Customer from its obligation to pay for any Energy Service charges incurred under this Agreement prior to the effective date of termination. In the event the Customer cancels this Agreement with respect to one or more Properties listed on Exhibit A, the Customer will not be eligible to enter another Continuous Service Agreement for a period of 12 months with respect to those Properties that were cancelled. Failure on the part of the Customer to pay their bills promptly when due shall constitute sufficient grounds for termination of this Agreement by the Utility.

3. **RESPONSIBILITY.** The Utility agrees to provide Energy Services at the Properties specified by the Customer between occupancy by tenants, regardless of the time of year, until this Agreement is terminated with respect to the properties. The Customer assumes liability for Energy Service charges incurred during periods in which a Tenant has not assumed responsibility for payment of Energy Services to the Properties.

   The Utility reserves the right to deny service or disconnect Energy Services pursuant to the rules and regulations of the applicable regulatory agency. If a Tenant is denied Energy Service, or Energy Services to the Tenant have been disconnected, the Customer may request that the Energy Services to the applicable Property be disconnected without affecting this Agreement. A disconnection of Energy Services to the Properties at the request of the Customer for any other reason will terminate the Agreement.

   In the event of a dispute regarding any sums due, the date of discontinuance, or the effective date of Energy Services, the Utility's records will be presumed correct unless the Customer presents information showing the Utility's records are incorrect in which event the presumption shall no longer apply.

4. **DISCONNECTION.** In addition to the above terms of service, if a Tenant account at such a Property is discontinued for **Nonpayment of Services,** ☐ **I DO** ☐ **I DO NOT** request the Utility to continue Energy Services at the Property and bill me for such Energy Services until a new Tenant account is opened or I request termination of the Agreement with respect to the Property. These instructions will apply even if the Tenant remains in the Property.

5. **CHANGES AND DELETIONS.** The Customer agrees to provide **PRIOR WRITTEN NOTICE** to the Utility of any changes in telephone number, mailing address, e-mail address or additions and deletions to Exhibit A, Service Property Locations.
   By signing this Agreement as the Customer, it is understood that the Customer is authorized to start or stop Energy Services, make additions or deletions of Properties to this Agreement and to enter into this Agreement. Other persons authorized to act on behalf of the Customer under this Agreement are shown on Exhibit B which may be amended by Customer upon receipt of written notice by the Utility.

6. **MISCELLANEOUS.** This Agreement constitutes the entire Agreement between the parties and supersedes all prior Agreements and understandings relating to continuation of Energy Services to any of Customer's properties prior to the effective date of this Agreement. The Utility has no further responsibility or liability to the Customer, expressed or implied, for continuation of Energy Services to Customer's properties except as set forth herein.

7. **LIABILITY LIMITATION.** THE LIABILITY OF THE UTILITY UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES OF CUSTOMER NOT TO EXCEED $500 AND NEITHER PARTY SHALL BE RESPONSIBLE FOR SPECIAL, INCIDENTAL, EXEMPLARY, OR CONSEQUENTIAL DAMAGES OR ANY COMMERCIAL LOSS OF ANY KIND (INCLUDING LOSS OF BUSINESS OR PROFIT). THIS LIMITATION APPLIES TO ALL CLAIMS WHETHER BASED ON BREACH OF EXPRESS OR IMPLIED WARRANTY, INDEMNITY, BREACH OF CONTRACT, NEGLIGENCE, STRICT LIABILITY IN TORT, OR OTHER LEGAL THEORY.

8. **SIGNATURE.** This Agreement must be signed by the Customer. If property management services are used and a Property Manager signs this Agreement, the Property Manager assumes financial responsibility for Energy Services pursuant to this Agreement.

BILLING INFORMATION

(* An asterisk indicates that the information is required for processing.)

Please Print

E-mail Address: _____
(Enter an active e-mail address for electronic communication purposes)

*Social Security Number: _____

*Business Tax ID Number: _____

Spouse/Partner Name: _____

*Emergency Contact Name: _____

*Billing Address: _____

*Address: _____

*City: _____ *State: _____ *Zip: _____

*City: _____ *State: _____ *Zip: _____

*Primary Contact Phone: (____) _____ – _____

*Emergency Phone Number: (____) _____ – _____

Cell Phone: (____) _____ – _____

Employer Name: _____

Fax Number: (____) _____ – _____

Work Phone: (____) _____ – _____

Customer Printed Name: _____

Signature: _____ Date: _____

FOR OFFICE USE ONLY

CSA ID #: _____ Processed By: _____ Date: _____

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

EXHIBIT A
SERVICE LOCATIONS

Scan and return via:
- **E-mail:** customerservice@mdu.com
- **Fax:** 1-701-323-3104 or
- **Mail:** Montana-Dakota Utilities Co., Attn: Customer Support, PO Box 7608, Boise, ID 83707-1608

IDENTIFICATION NUMBER (OFFICE USE ONLY)	COMPLETE STREET ADDRESS	APT. NO.	CITY, STATE
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
12.			
13.			
14.			
15.			
16.			
17.			
18.			
19.			
20.			

Customer Printed Name: _____

Signature: _____ Date: _____

FOR OFFICE USE ONLY

CSA ID #: _____ Processed By: _____ Date: _____

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

EXHIBIT B
CONTINUOUS SERVICE AGREEMENT AUTHORIZATION

Scan and return via:
- **E-mail:** customerservice@mdu.com
- **Fax:** 1-701-323-3104 or
- **Mail:** Montana-Dakota Utilities Co., Attn: Customer Support, PO Box 7608, Boise, ID 83707-1608

The Undersigned authorizes the agent designated below to act as personal representative, on their behalf, with regard to a Continuous Service Agreement entered into between the Customer and the Utility.

The Undersigned authorizes the persons or entities identified below: (1) To be party to information regarding the Agreement and account information pertaining to real properties described on Exhibit A, Properties. (2) To provide PRIOR WRITTEN NOTICE to the Utility of any changes to telephone number, mailing address, e-mail address or additions and deletions to Exhibit A. (3) To start and stop Energy Services for real properties described on Exhibit A.

(* An asterisk indicates that the information is required for processing.)

*Name of Authorized Property Management Company *(Complete if applicable)*:			
*Name of Authorized Person(s):			
*Social Security Number:		*Business Tax ID Number:	
*Address:			
*City:	*State:	*Zip:	
*Primary Contact Phone:	Cell Phone:	Fax Number:	E-mail Address:

I hereby affirm that I am the Financially Responsible Party (i.e. owner, manager, or otherwise financially responsible) for the real properties described on Exhibit A and authorize the aforementioned person or entities to act on my behalf regarding all aspects of the Continuous Service Agreement.

Customer Printed Name: _____

Signature: _____ Date: _____

FOR OFFICE USE ONLY

CSA ID #: _____ Processed By: _____ Date: _____

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
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PSC-122

RE: Establishment of pay stations and associated savings
Witness: Jay Skabo

What is the amount of savings associated with the changes described on p. 6, lines 20-23 of your testimony?

Response:

Pay stations were established in conjunction with the integration efforts discussed by Mr. Goodin in his testimony on pages 8-9. Approximately 29 Customer Service Representatives (CSR) and Credit Representative positions were eliminated when this change went into effect; of which 15 were located in Montana. The annual salaries and benefits for the 29 employees were approximately $1.2 million annually with the 15 Montana employees amount approximately $473,000. There was a one-time cost of severance of approximately $399,400 total Company and $122,000 for the Montana employees. The functions of these positions were replaced by the centralized customer service center, the centralized credit center and the pay stations.

The average annual cost of the Western Union Pay Stations is $139,000 for total Company with $41,900 of annual cost related to Montana.

The net savings are reflected in the revenue requirement in this case.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
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DATED JANUARY 21, 2013
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PSC-128

RE: Billings Landfill
Witness: Robert Morman

The direct testimony of Robert Morman filed with MDU's initial application states on page 2 that MDU was approached by Wenck Engineering (Wenck) to determine interest in partnering with the engineering firm to develop a project for capturing methane gas from the Billings landfill.

a. **Both in the prefiled testimony and in Mr. Morman's answers asked during an onsite audit, Mr. Morman indicated that MDU was approached by Wenck. Feasibility studies from 2007 and 2009 reviewed during the onsite audit indicate MDU approached Wenck about the project. Please explain the contradiction in answers.**

b. **Please indicate if there is a similar contradiction for MDU approaching the city of Billings. Indicate specifically if MDU approached the city first.**

Response:

a. Wenck Engineering approached Montana-Dakota first regarding the Billings Landfill as stated by Mr. Morman during the on-site audit and in Mr. Morman's testimony. Montana-Dakota then approached the City of Billings to determine their interest in capturing the methane gas from the Billings Landfill as described in Mr. Morman's testimony.

c. Please see Response No. PSC-128a.

Response No. PSC-128a correction:

Montana-Dakota misstated that Wenck Engineering approached Montana-Dakota on page 2, line 11 of Mr. Morman's testimony and during the on-site audit. Montana-Dakota approached Wenck Engineering in 2007 about the feasibility of landfill gas utilization from the City of Billings Regional Landfill. Montana-Dakota then approached the City of Billings to determine their interest in capturing the methane gas from the Billings Landfill as described in Mr. Morman's testimony.

MONTANA-DAKOTA UTILITIES CO.
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DATED JANUARY 21, 2013
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PSC-129

RE: Billings Landfill
Witness: Robert Morman

Provide documentation as to the experience mentioned on page 3 of Mr. Morman's testimony to attest to the fact Wenck had experience in development of methane gas. Indicate specific projects past and current.

Response:

Please see Attachment A for Wenck Associates, Inc. landfill projects.

Summary of Old Unlined Landfill Experience

Client/Project	Waste Excavation and Relocation	Closure Design	Leachate Management System	Landfill Gas System	Construction Plans and Specifications (Design)	Construction Cost Estimates	Bidding Assistance	Construction Oversight	Construction Documentation	Alternative Technology Evaluation	Landfill Gas to Energy Recovery Systems
Albert Lea LF	X	X	X	X	X	X	X	X	X	X	
Billings Landfill		X		X	X	X	X	X	X	X	X
Clay County LF	X	X	X		X	X	X	X	X	X	X
Elk River LF	X	X	X	X	X	X	X	X	X	X	X
Fargo Landfill	X	X	X	X	X	X	X	X	X	X	X
Flying Cloud Landfill	X	X	X	X	X	X	X	X	X	X	
GRPUC LF		X	X		X	X	X	X	X	X	
Gofer Landfill	X	X		X	X	X	X	X	X	X	
Hopkins Landfill	X	X	X	X	X	X	X	X	X	X	
Houston County LF	X	X	X	X	X	X	X	X	X		
Ironwood	X	X		X	X	X	X	X	X	X	
Koochiching County LF	X	X		X	X	X	X	X	X		
LaGrand LF	X	X		X	X	X	X	X	X		
Mar-Kit Landfill	X	X	X	X	X	X	X	X	X	X	
Mille Lacs Co Landfill	X	X	X		X	X	X	X	X	X	
Minnesota Sanitation					X	X	X	X	X	X	
Olmsted Co Kalmar LF		X	X	X	X	X	X	X	X		
Olmsted Co Oronoco LF	X	X	X	X	X	X	X	X	X	X	X
OtterTail Power LF		X	X		X	X	X	X	X	X	
Paynesville Landfill	X	X			X	X	X	X	X	X	
Pine Bend LF	X	X	X	X	X	X	X	X	X	X	X
Pine Lane Landfill					X	X	X	X	X		
Polk County LF		X	X	X	X	X	X	X	X	X	
Red Wing ADF		X	X		X	X	X	X	X		
Rapid City Landfill	X		X							X	X
Saskatoon Landfill				X	X	X	X			X	X
Sibley County Landfill	X	X			X	X	X	X	X		
Watonwan County LF	X	X		X	X	X	X	X	X		
Wilmarth ADF	X	X	X		X	X	X	X	X		
Windom LF		X	X	X	X	X	X	X	X	X	
Winona County LF	X	X	X	X	X	X	X	X	X	X	

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PSC-131

RE: Billings Landfill
Witness: Robert Morman

a. **When was the evaluation of the economics of the landfill gas project in Billings conducted?**

b. **Provide any Net Present Value calculation conducted by the Company before it determined to proceed with the Billings Landfill project.**

c. **Provide the natural gas forecast relied upon to determine that the long-term cost of production from the Billings Landfill would be less than the long-term market price of gas.**

Response:

a. Please see Response No. PSC-055c.

b. Please see Response No. PSC-055c.

c. Please see Attachment A for the natural gas forecast.

Projected Natural Gas Commodity Prices 2009-2027

		CIG		Ventura	
	Henry Hub Projected Price	CIG Basis Differential	CIG Projected Price	Ventura Basis Differential	Ventura Projected Price
2009 Sources July 08	$10.08	$3.50	$6.58	$0.51	$9.57
2010 Sources July 08	10.06	3.03	7.03	0.33	9.73
2011 Sources July 08	9.53	2.20	7.33	0.28	9.25
2012 Sources July 08	9.21	1.47	7.74	0.31	8.90
2013 Sources July 08	8.83	1.18	7.65	0.31	8.52
2014 escalactor	9.01	1.18	7.83	0.31	8.70
2015 escalactor	9.19	1.18	8.01	0.31	8.88
2016 escalactor	9.37	1.18	8.19	0.31	9.06
2017 escalactor	9.56	1.18	8.38	0.31	9.25
2018 escalactor	9.75	1.18	8.57	0.31	9.44
2019 escalactor	9.94	1.18	8.76	0.31	9.63
2020 escalactor	10.14	1.18	8.96	0.31	9.83
2021 escalactor	10.35	1.18	9.17	0.31	10.04
2022 escalactor	10.55	1.18	9.37	0.31	10.24
2023 escalactor	10.76	1.18	9.58	0.31	10.45
2024 escalactor	10.98	1.18	9.80	0.31	10.67
2025 escalactor	11.20	1.18	10.02	0.31	10.89
2026 escalactor	11.42	1.18	10.24	0.31	11.11
2027 escalactor	11.65	1.18	10.47	0.31	11.34

Escalator 2%

The 2009 - 2013 projections are the average price of 15 industry sources

The 2014 - 2027 prices are assuming a 2 percent annual escalation factor

MONTANA-DAKOTA UTILITIES CO.
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PSC-139

RE: Billings Landfill Project
Witness: Morman

Provide any and all reports and/or investigations both internal and external that MDU has received regarding the Billings Landfill project.

a. **Please provide a detailed list of similar projects that Wenck engineering was involved in from 2005-2010 and the depth of involvement of Wenck.**

b. **Please provide a detailed and if applicable updated adjustments of the remaining phases of the project, including but not limited to number of wells left to drill, orientation of the pipe, vertical or horizontal, expected annual gas recovery amount from the landfill, timeframe of the remaining phases and all cost changes.**

c. **Please explain why the Company has moved from drilling vertical wells to horizontal wells.**

Response:

Please see Response No. PSC-055c.

a. Please see Response No. PSC-129.

b. The Company has moved from installing vertical wells to installing horizontal wells based on the results of operations in 2011-2012, the experience and knowledge obtained by operations personnel and the City of Billings changing the future development of the landfill.

   Based on discussions Montana-Dakota plant personnel had with operators of other landfill gathering systems, installing horizontal wells while landfill phases are being filled may be the best time to gather the gas, as methane is produced during early stages of landfill solid waste decomposition. During the summer of 2012, Montana-Dakota installed horizontal pipe totaling approximately 1,400 feet. In October 2012 there was sufficient cover to begin withdrawal of methane gas from this section of the landfill. The initial results of the horizontal wells are promising with withdrawal rates sufficient to produce approximately 60 dkt per day of pipeline quality gas.

   In addition, the City of Billings is now filling phases 3, 4 and 5 of the landfill at the same time, which will bring the refuse levels up together. This method of filling the landfill will cause a delay in future production from the new phases

using vertical wells as vertical wells cannot be drilled until the final cap is installed on the top of each phase.

At this time it is Montana-Dakota's intent to continue with the installation of horizontal pipe to maximize landfill gas withdrawal and increase the amount of pipeline quality gas delivered to the tailgate of the facility. Additional horizontal pipe will be required to withdraw landfill gas from the landfill phases 3, 4 and 5. The horizontal pipes will be installed approximately 200 feet apart with 60 feet of vertical spacing. Projections are to install an average of one additional horizontal well annually as the landfill is being filled. Please see Response No. PSC-003, Attachment A for projected production based on the current development.

c. Please see Response No. PSC-139b.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-142

RE: Board Meeting Expenses
Witness: Unknown

a. **What is the allocation to MT gas rate customers for the board meeting held at the Smoke Tree Ranch?**

b. **Do MDU customers pay for the full expense of this board meeting?**

c. **Please explain the logic behind including the expense rate payers pay for the board to hold its meeting at this location.**

Response:

a. The allocation of the expenses associated with the board meeting held at Smoke Tree Ranch is $1,083 for Montana gas customers.

b. No, the cost of Board of Director meetings are allocated to all companies within MDU Resources.

d. The February board meeting is the MDU Resources Group, Inc., planning meeting for the board of directors and executives and it is the practice of the Company to hold the planning meeting in an away location. Because it is a planning meeting, the February meeting is typically a three day meeting while the May, August and November meetings typically are a day and a half. The incremental costs of the February meeting (a three day meeting) compared to the average cost of the other meetings (1.5 day meeting), as allocated to Montana gas operations, is approximately $240, which is not material. On a per day basis, the February meeting costs less than the average daily cost of the other meetings. Expenses incurred for the Company's Board of Directors are prudent and legitimate business expenses.

MONTANA-DAKOTA UTILITIES CO.
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PSC-143

RE: Pension costs
Witness: Applicable

a. **Explain any and all causes of the unfunded liability.**

b. **Distinguish those factors over which MDU has influence and those outside MDU's influence.**

c. **Explain how the Company has managed those factors over which it had influence.**

d. **Explain how the Company anticipated those factors not under its influence, and what actions the Company took.**

e. **Explain to the Commission its understanding of best practices in managing pension costs.**

Response:

a. Unfunded liabilities can be caused by several reasons, including the addition of new participants to pension plans, normal liability growth due to additional service accruals of participants, interest rate volatility, investment market volatility, and funding volatility.

b. The Company has no control over interest rate fluctuations, overall market returns, and the corresponding minimum contributions calculated under ERISA requirements. The Company does have some limited influence over the funding contributions (in excess of minimum required contribution amounts), addition of new participants, and additional accruals for service of active participants. In addition, the Company has the ability to make changes to its investment mix which can in some cases impact investment returns.

c. In January 2006 and July 2007, the Company froze the MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees (MDU Non-Bargaining Pension Plan) and the MDU Resources Group, Inc. Pension Plan for Collective Bargaining Unit Employees (MDU Bargaining Pension Plan), respectively, to new entrants to limit the growth of the future accrued liability. Later, in December 2009, the Company froze all service accruals for employees in the MDU Non-Bargaining Pension Plan. In June 2011, the Company negotiated a freeze of all future service accruals for employees in the MDU Bargaining Pension Plan. In both cases, these plan freezes resulted in providing pension plan participants a replacement contribution in the

Response No. PSC-143 continued.

defined contribution plan and these changes provide more certainty around annual benefit costs. In addition to these changes, the Company has made pension plan contributions in excess of the minimum required contribution to maintain the 80 percent funded status of the plans. The Company has also made changes to the investment mix in an attempt to reduce volatility.

d. The Company closely monitors interest rates and investment markets, however, the movement of these are outside the Company's control. The Company is careful not to make speculative judgments as it pertains to future interest rate or investment movements. The Company continually monitors its investment portfolio performance and will make changes to the mix as warranted. Some examples of changes the Company has made include, the addition of fixed income investments which may produce lower volatility than equity investments, and lengthening the duration of fixed-income investments over time to more closely match the duration with that of the liabilities which reduces sensitivity to interest rate fluctuations. The changes the Company has made to freeze the plans to new entrants as well as active participant future service accruals also assist in controlling the sensitivity of the liability to these outside factors by limiting their growth. The Company does not, however, make speculative changes based on the perceived or forecasted movement of interest rates or investments.

e. There are several ways to manage pension costs, including changing plan design and reducing the accrued liability. This can be accomplished by reducing future service accruals, eliminating new participants into the plan, and continuously monitoring the investment mix of the plans to maintain the proper balance as it relates to the plan liabilities.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-145

RE: Accounting System
Witness: Applicable

Please provide the Commission an update of the jurisdictional allocation accounting review mentioned in the settlement agreement regarding Case No. PU-10-124.

a. If this review has not been started, please provide the estimated start and completion dates.

Response:

To date the North Dakota Commission Staff and Montana-Dakota personnel have had discussions.

a. The review is ongoing and no schedule has been set.