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

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

October 13, 2015

Mr. Robert Nelson
Montana Consumer Counsel
111 North Last Chance Gulch, Suite 1B
PO Box 201703
Helena, MT 59620-1703

Re: General Electric Rate Application
Docket No. D2015.6.51

Dear Mr. Nelson:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Consumer Counsel's data requests dated September 29, 2015.

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments
cc: Service List

Montana-Dakota Utilities Co.
Docket No. D2015.6.51
Service List

Mr. Will Rosquist
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601
kwhitney@mt.gov

Robert Nelson
Monica Tranel
Montana Consumer Counsel
111 N. Last Chance Gulch, Suite 1B
PO Box 201703
Helena, MT 59620-1703
robnelson@mt.gov
mtranel@mt.gov

Mike Green
900 N. Last Chance Gulch
Suite 200
Helena, MT 59601
mgreen@crowleyfleck.com

Charles Magraw
501 8th Ave
Helena, MT 59601
c.magraw@bresnan.net

Thorvald A. Nelson
Holland & Hart LLP
6380 South Fiddlers Green Circle
Suite 500
Greenwood Village, CO 80111
tnelson@hollandhart.com

David Wooley
Keyes, Fox & Wiedman LLP
436 14th Street, Suite 1305
Oakland, CA 94612
dwooley@kfwlaw.com

Nikolas S. Stoffel
Holland & Hart LLP
6380 South Fiddlers Green Circle
Suite 500
Greenwood Village, CO 80111
nsstoffel@hollandhart.com

Kelly Crandall
Keyes, Fox & Wiedman LLP
1400 16th St
16 Market Square, Suite 400
Denver, CO 80202
kcrandall@kfwlaw.com

Albert Clark
142 Buccaneer Drive
Leesburg, GL 34788
aclark154@yahoo.com

Jack Pous
14 Shell Avenue SE
Ft. Walton Beach, FL 32548
jpous@ducinc.net

John Wilson
J W Wilson & Associates Inc.
1601 N. Kent Street, Suite 1104
Arlington, VA 22209-2105
john@jwwa.com

Electronic Service Only:
ppenn@hollandhart.com
aclee@hollandhart.com
crmayers@hollandhart.com

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-113

Regarding: Demand Allocation Factors
Witness: Sara J. Cardwell

Please provide in electronic format supporting documentation and worksheets for the 12-CP and 4-CP allocation factors provided in response to data request MCC-090. Also please provide the 1-CP allocation factor for each of the rate classes in Schedule L-3 along with its supporting worksheets in electronic format.

Response:

Please see Revised Response No. LCG – 010 and the file titled "MCC-113 - 4, & 1 CP" for all supporting workpapers for the 12, 4, and 1 CP.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-114

Regarding: Demand and Energy Determinants
Witness: Sara J. Cardwell

Please explain in detail if the source data for all demand and energy determinants corresponding to each class and used throughout the embedded cost of service study and the marginal cost study are from 2014 actual billings or they otherwise correspond to actual 2014 demand and energy for MDU's system in Montana.

Response:

All billing determinants are derived from actual 2014 sales data. A pro forma adjustment was made to Rate 30 Secondary to account for a new customer that started service in August of 2014 as noted in Response No. MCC-001.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-115

Regarding: Class Load Factors
Witness: Sara J. Cardwell

a. **Please provide in electronic format all supporting documentation, worksheets and calculations for the development of the class load factors used in calculating the non-coincident peak (NCP) demand for each class at meter, as shown in the calculation of the Average & Excess Demand allocator (Factor 2). These class load factors are also shown on tab "Demand and Energy Data" of the file Marginal Cost Study Exhibit SJC1-SJC11.xlsx.**

b. **Tab "Demand and Energy Data" of the file Marginal Cost Study Exhibit SJC1-SJC11.xlsx shows System Coincidence percentages for each rate class. Please explain in detail how they were calculated and provide all data and supporting documentation in electronic format.**

Response:

a. Please see Response No. LCG-009.
b. Montana-Dakota evaluated available fixed network interval data by rate class. Within this valid sampled data an average Kwh, Non-Coincident, and Coincident peaks were developed by month by class. These average values were then applied to active customers by month by rate to determine a Non-Coincident peak for that class. This information was used in the Marginal study on the Demand and Energy Data worksheet.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-116

Regarding: Average & Excess Demand Allocator
Witness: Sara J. Cardwell

Please explain in detail why an Average & Excess demand allocator (Factor No. 2) based on non-coincident peak demand results in better allocation of production and transmission cost rather than an Average & Excess demand allocator based on coincident peak demand.

Response:

The reason a non-coincident peak is used as opposed to a coincident peak to allocate the excess demand is that by definition the Average and Excess demand method uses a non-coincident peak to allocate the excess portion of demand.

In Docket Nos. D2007.7.79, D2009.4.56 and D2010.8.82 the AED allocation method was used to allocate Production and Transmission plant and was determined to be appropriate for Montana electric operations.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-117

Regarding: Minimum and Normal System Analysis
Witness: Sara J. Cardwell

Please provide in electronic format all supporting documents and worksheets used in developing Attachment A included in response to MCC-093. In other words, please provide the complete analysis used to classify Poles, Overhead Conductors and URD Conductor as customer and demand related, including all data, formulas, itemized cost for the minimum and normal system, and all supporting source documentation.

Response:

Please see the file named MCC-117 – Distribution System on the enclosed CD.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-118

Regarding: Weighted Customers
Witness: Sara J. Cardwell

Please provide in electronic format all supporting documents, cost bases and worksheets, with formulas and links intact, for the development of customer weights for meters, services, transformers and customers accounts as shown on Statement Workpapers, Statement L, page L-14.

Response:

Please see the files titled MCC-118 Meter & Customer Weights, MCC-118 Service Weights and MCC-118 Transformers on the enclosed CD.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-119

Regarding: Statement L – Line Transformer Investment
Witness: Sara J. Cardwell

In response to MCC-094 you refer to Statement Workpapers Statement L, page L-23 for the calculation of customer weights for line transformers. Please provide an electronic copy, including all formulas, links, workpapers, cost bases and supporting documents, of these calculations, including pages L21 through L24, which relate to meters, services and customer accounts. Please provide detailed information about the typical cost of each type of equipment or expense required to serve each customer class, as well as how the base cost was determined.

Response:

For an electronic copy of page L-23 please see the file provided in Response No. MCC-118 titled MCC-118Transformers.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-120

Regarding: Annual Cost of a Combustion Turbine
Witness: Sara J. Cardwell

In reference to the workpapers – Attachment A provided in response to MCC-097, please provide in electronic format all data, assumptions and calculations used in developing a 2016 capacity cost of $816.00/KW for a combustion turbine.

Response:

The basis for the cost of $816.00 per kW for a combustion turbine is a report prepared by SEGA Engineering and Technical Services provided as Attachment A and also included as Attachment E in the 2015 IRP.

Response No. MCC-120
Attachment A

Attachment E

Supply-Side Resources Study

Montana-Dakota Utilities Co.

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

Explanation of IRP Supply-Side Resources Cost Analysis

April 3, 2015

Sega
ENGINEERING & TECHNICAL SERVICES

Project No. 14-0257

TABLE OF CONTENTS

		Page No.
LIST OF ABBREVIATIONS		*- iii -*
SECTION 1	**EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS**	**1 - 1**
1.1	Introduction	1 - 1
1.2	Performance Basis	1 - 1
1.3	Supply-Side Resources Considered	1 - 2
1.4	Deliverables	1 - 3
1.5	CTG Options	1 - 5
1.6	Reciprocating Internal Combustion Engine Option	1 - 17
1.7	Renewable Fuel Boiler Options	1 - 18
1.8	Coal Boiler Options	1 - 21
1.9	Renewable Non-Fuel Options	1 - 22
SECTION 2	**APPENDIX A - COST ANALYSIS TABLES**	
A-1	EGEAS Model Input Summary, 2015$	A - 1
A-2	CTG Cost Basis and Capital Cost, 2015$	A - 2
A-3	CTG O&M Fixed Cost ($/MW-Year), 2015$	A - 3
A-4	CTG O&M Major Maintenance ($/MW-Year), 2015$	A - 4
A-5	CTG EGEAS Model Input Summary, 2015$	A - 5
A-6	RICE Costs Basis and Capital Costs, 2015$	A - 6
A-7	RICE EGEAS Model Input Summary, 2015$	A - 7
A-8	Renewable Fuel Boiler Cost Basis and Results	A - 8

		Page No.
A-9	Renewable Fuel and Coal Boiler EGEAS Model Input Summary, 2015$	A - 9
A-10	Renewable Non-Fuel EGEAS Model Input Summary, 2015$	A - 10
A-11	Geothermal and Solar Input Summary, 2015$	A - 11

LIST OF ABBREVIATIONS

Allowance for Funds Used During Construction (AFUDC)

Best Available Control Technology (BACT)

Bubbling Fluidized Bed (BFB)

Circulating Fluidized Bed Combustion (CFBC)

Combustion Turbine Generator (CTG)

Dry Low NO_X (DLN)

Electric Generation Expansion Analysis System (EGEAS)

Engineering and Supervision and General and Administrative (ES&GA)

Full-Time Equivalent (FTE)

General Electric (GE)

Generator Step-Up (GSU)

Hazardous Air Pollutant (HAP)

Heat Recovery Steam Generator (HRSG)

Integrated Resource Plan (IRP)

Municipal Solid Waste (MSW)

New Source Performance Standards (NSPS)

Operation and Maintenance (O&M)

Original Equipment Manufacturer (OEM)

Photo-Voltaic (PV)

Plant Engineering and Construction Estimator (PEACE)

Reciprocating Internal Combustion Engine (RICE)

Selective Catalytic Reduction (SCR)

Spray Intercooling for Power Augmentation (SPRINT)

Total Capital Investment (TCI)

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

1.1 INTRODUCTION

Montana-Dakota Utilities Co. (Montana-Dakota) requested Sega Inc. (Sega) to conduct a cost analysis of supply-side resources to be included in Montana-Dakota's 2015 Integrated Resource Plan (IRP) model.

This report includes costs for 23 supply-side options. Of these, the overall model costs for the four wind and the two coal alternative resources have been developed by Montana-Dakota and included in this report. These six options are based on Montana-Dakota's knowledge from the construction of three self-built wind farms, as well as *"A Study of Lignite-Based Advanced Generation Technology Systems"* completed by WorleyParson's for the Lignite Energy Council. The information was supplied by Montana-Dakota and is included in the report in order to provide a comprehensive data set for the model.

The results of the current IRP Supply-Side Resource Costs Analysis will be used for Montana-Dakota's 2015 IRP and input into the Electric Generation Expansion Analysis System (EGEAS).

1.2 PERFORMANCE BASIS

The following assumptions (provided by Montana-Dakota) were used in the combustion models. The site-specific inputs were based on Williston, North Dakota, whose geography and weather conditions are close averages to that of most western North Dakota and eastern Montana locations. For the 2x1 7EA Heskett Station Unit 3 (Heskett 3) expansion option, site specific elevation, humidity, and temperature were used, which is detailed in Section 1.5.2.

1. Elevation: 1,950 feet AMSL.

2. Humidity: 36 percent.

3. Temperature: 82.1 degrees F.

4. Generation Power Factor: 0.85.

5. Generator Terminal Voltage: 13.8-kV.

6. Interconnection Voltage: 115-kV.

7. Fuel for Combustion Turbine Generators (CTGs): Natural gas.

8. LHV to HHV Ratio: 1.11.

9. Fuel for Landfill Gas: GT PRO default.

10. Fuel for Biomass: GT PRO default (wood pellets).

11. Fuel for Solid-Waste Burner: GT PRO default.

1.3 SUPPLY-SIDE RESOURCES CONSIDERED

The cost analysis includes the following generating facilities:

1. Simple-Cycle CTGs:

    a. GE 7EA (frame, natural gas-fired).

    b. GE LMS100PB (aero-hybrid, natural gas-fired).

    c. GE LM6000PH (aero derivative, natural gas-fired).

    d. Solar Titan 250 (frame, landfill gas-fired).

2. Combined-Cycle CTGs:

    a. 1x1 General Electric (GE) LM6000PH (aero derivative, natural gas-fired).

    b. 1x1 GE 7EA (frame, natural gas-fired).

    c. 2x1 GE 7EA (frame, natural gas-fired, add an additional GE 7EA to existing R.M. Heskett 3).

    d. 1x1 GE 7FA.05 (frame, natural gas-fired).

e. 2x1 GE 7FA.05 (frame, natural gas-fired).

f. 3x1 Siemens SGT 800 (frame, natural gas-fired).

3. Reciprocating Internal Combustion Engine (30 MW):

   a. Wartsila 20V34SG (natural gas-fired).

4. Fuel Boilers:

   a. Generic solid-waste burner (15 MW).

   b. Generic biomass (30 MW).

   c. Generic coal with CO_2 capture (122 MW).

   d. Generic coal without CO_2 capture (185 MW).

5. Renewable Non-Fuel:

   a. Generic photovoltaic solar (30 MW).

   b. Generic concentrated solar (30 MW).

   c. Generic thermal solar (30 MW).

   d. Generic geothermal (30 MW).

   e. Generic wind North Dakota (20 MW).

   f. Generic wind North Dakota (50 MW).

   g. Generic wind Montana (20 MW).

   h. Generic wind Montana (50 MW).

1.4 DELIVERABLES

Sega performed the cost analysis of these supply-side options by developing/updating design-costing models, requesting vendor data, researching cost information sources, and creating an IRP cost analysis spreadsheet. Tables from this spreadsheet are provided in Appendix A. For each option considered, the following deliverables are presented in Table A-1, which is a roll-up summary of the IRP costing spreadsheet for all of the options:

1. Plant Size (MW, net): Based on the data specified in the performance basis.

2. Capital Cost ($/kW) - Total Capital Investment (TCI) Unloaded, divided by the plant size.

3. Fixed Operation and Maintenance (O&M) ($/kW-month): Total of the O&M fixed costs including labor, maintenance, and other expenses.

4. Variable O&M ($/MWh): Total of the O&M variable costs including maintenance, utilities, and chemicals.

5. Major maintenance ($/kW-month).

6. Full load heat rate (Btu/kWh, net).

7. Carbon intensity (lb/MWh).

8. NO_x (ppmvd at 15-percent O_2).

9. CO (ppmvd at 15-percent O_2).

10. Fuel Cost ($/MBtu): Landfill gas and municipal solid waste (MSW) cost provided by Sega, all other fuel costs provided by Montana-Dakota.

Each cost includes the applicable emissions equipment, (i.e., water injection, duct burner, SCR, CatOx, etc.) as noted in summary Tables A-1 to A-9.

Capital costs were evaluated on a TCI-unloaded and TCI-loaded basis. The unloaded costs include the generator step-up (GSU) transformer, however, interconnection costs (i.e., transmission, gas, and system upgrades), land, interest during construction, spare parts and materials, financing, and project administration and developer's fees have not been included as listed in *Figure 1.* Sega estimated the TCI-loaded cost by rerunning the unloaded cost analysis with a project administration and developer's fee of 1 percent and a financing cost of 4 percent for CTGs and 1 percent for the boiler options. The TCI-loaded cost was used as a basis to calculate the fixed costs of property tax and insurance for the CTG options.

	Not in TCI-Unloaded
Transmission Interconnect and Upgrades (Except for GSU*)	✓
Interest During Construction	✓
Fuel Supply Pipeline	✓
Land	✓
Spare Parts and Materials	✓
Project Administration and Developer's Fee	✓
Financing	✓
* GSU transformer cost is included in project TCI.	

Figure 1 - Project-Specific Costs
***Not* Included in TCI-Unloaded**

1.5 CTG OPTIONS

A capital cost analysis was performed for the CTGs using Thermoflow Inc.'s thermal engineering software GT PRO that includes a Plant Engineering and Construction Estimator (PEACE) module for determining capital costs. Thermoflow uses information from Original Equipment Manufacturers (OEMs), material suppliers, engineering firms, and contractors to determine the cost indices contained in the PEACE module. The cost indices are refreshed on a routine basis (typically, bi-annual) to reflect current market conditions. The PEACE costs are based on site works, foundations, mechanical installation and materials, electrical installation and materials, and engineering design and startup for specific models of CTG. For example, a CTG requiring a selective catalytic reduction (SCR) system will require additional material and labor for the installation of the SCR and related equipment.

For the Thermoflow model runs, the natural gas quality specified by Montana-Dakota (see *Figure 2*) was customized as a user-defined fuel in Thermoflow for each of the nine natural gas-fired CTG options. For each of the CTGs, the inlet air filter pressure drop was assumed to be 2"H_2O with a duct and stack draft loss of 5.5"H_2O.

Natural Gas Quality	Volume Percent
CH_4	90.0
C_2H_6	6.35
C_3H_8	0.55
C_4H_{10}	0.13
C_5H_{12}	0.04
C_6H_{14+}	0.02
N_2	1.18
CO_2	1.11
H_2	0.07
He	0.55
Total	100
Fuel Gas Temperature	80 °F
Fuel Gas Pressure (Range)	375 - 1,000 psig
Fuel Heating Value (LHV)	20,393 Btu/lb
LHV to HHV Factor	1.11

Figure 2 - Natural Gas Quality Assumed for CTG Analyses

Once these assumptions, along with the site-specific assumptions from Section 1.2, were entered into Thermoflow, the only information that varied between the natural gas-fired CTG cases were the plant cycle set up, the CTG type, and the emission reduction techniques, which included an oxidation catalyst for CO reduction and a SCR system for NO_x control. All plant information, TCI-loaded, TCI-unloaded, NO_x, CO, and CO_2 emissions could be either found directly in or calculated from Thermoflow's text or PEACE outputs. The plant size, performance, emission controls, operational parameters, emissions, capital costs, fixed costs, variable costs, and summary for all CTG plant options considered are shown in Tables A-2 through A-5.

1.5.1 Simple-Cycle CTGs

Figure 3 summarizes key performance and descriptors for the three natural gas-fired simple-cycle CTGs assessed.

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NO_X (ppmdv)	Pre-SCR NO_X Control	Gas Pressure Needed (psig)	Dual-fuel Capable	Technology Type	Model Maturity
GE 7EA	84.1 10,634	9	Dry	311	Yes	Frame	Mature
GE LMS100PB	99.5 8,540	25	Dry	975	No	Aero-Hybrid	Some actual models operating
GE LM6000PH	51.0 8,912	15	Dry	700	No	Aero	LM6000 mature; PH very new model

* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.

Figure 3 - Summary of Gas-Fired Simple-Cycle CTGs

The following paragraphs provide a summary of key assumptions in the assessment for each of the CTGs.

The simple-cycle GE 7EA CTG utilizes dry low NO_X (DLN) technology to minimize NO_X emissions to less than 9 parts per million by dry volume (ppmvd at 15-percent O_2). Because of this very low CTG emission level as a starting point the incremental emission reduction cost ($/ton removed) for adding SCR would be relatively high. Therefore, Sega has assumed the additional emission control equipment of SCR would not be needed for permitting to meet Best Available Control Technology (BACT) requirements. Similarly, Sega assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT. This assumption is also based on the relatively high emission reduction cost effectiveness for adding oxidation catalyst to a simple cycle CTG.

The simple-cycle GE LMS100PB utilizes DLN technology to minimize NO_X emissions. However, even with reduction technologies, the LMS100 has an uncontrolled NO_X emission level of 25 parts per million by dry volume (ppmvd at 15-percent O_2). With the relatively high starting point of 25 ppmdv, Sega concludes that the incremental emission reduction cost ($/ton removed) will be low enough to require the use of SCR for permitting to meet BACT. The SCR NO_X reduction effectiveness was set to 90 percent (2.5 ppmdv outlet), ammonia slip was set to 5 ppmvw using a 19-percent aqueous ammonia solution; urea usage was not included in the analysis. The SCR auxiliary power and SCR capital investment were determined by the difference of two cases separately run in Thermoflow; one with SCR and one without SCR. Sega assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT. This assumption is based on the relatively high emission reduction cost effectiveness for adding oxidation catalyst to a simple-cycle CTG.

The simple-cycle GE LM6000PH also utilizes DLN, with a NO_X emission level of 15 ppmdv. With the starting point of 15 ppmdv, Sega concludes that the incremental emission reduction cost ($/ton removed) will be low enough to require the use of SCR for permitting to meet BACT. The SCR NO_X reduction effectiveness was set to 80 percent (3 ppmdv outlet), ammonia slip was set to 5 ppmvw using a 19-percent aqueous ammonia solution. Sega also assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT.

1.5.2 Combined-Cycle CTGs

Figure 4 summarizes key performance and descriptors for the six combined-cycle CTG facilities assessed.

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NO_X (ppmdv)	Pre-SCR NO_X Control	Gas Pressure Needed (psi)	Dual-Fuel Capable	Technology Type	Model Maturity
GE LM6000PH Sprint (1x1)	62.8 7,663	15	Dry	700	No	Aero	LM6000 mature; PH very new model
GE 7EA (1x1)	127.6 7,608	9	Dry	350	Yes	Frame	Mature
GE 7EA (2x1) Heskett 3 Expansion	256.7 7,570	9	Dry	350	Yes	Frame	Mature
GE 7FA.05 (1x1)	294.6 6,672	9	Dry	600	Yes	Frame	Mature
GE 7FA.05 (2x1)	593.0 6,631	9	Dry	600	Yes	Frame	Mature
Siemens SGT 800 (3x1)	213.9 7,347	15	Dry	350	Yes	Frame	Mature

* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.

Figure 4 - Summary of Combined-Cycle CTGs

The following paragraphs provide a summary of key assumptions in the assessment for each of the facilities.

The combined-cycle with an LM6000PH CTG was set up in a similar way as the simple-cycle CTG except that it includes spray intercooling for power augmentation (SPRINT) and a 1x1 single-pressure combined-cycle plant with an extraction condensing turbine. SPRINT was included in this case because the demineralized water, which is required for injection, will already be available as part of the steam generation system equipment. Sega assumes that the cycle cooling system will include a mechanical draft cooling tower. As with the simple-cycle case, an SCR system was included with a NO_X reduction effectiveness of 80 percent (3.0 ppmdv outlet). Sega assumes that an oxidation catalyst would be required

for permitting to meet BACT for CO reduction. This conclusion is based on the relatively low incremental emission reduction cost effectiveness of installing oxidation catalyst in a heat recovery steam generator (HRSG). The catalyst was included at 80-percent CO reduction effectiveness.

The two GE 7EA combined-cycle cases were modeled as a dual-pressure no-reheat 1x1 combined-cycle plant with a mechanical draft cooling tower and a 2x1 dual-pressure no-reheat combined-cycle with a mechanical draft cooling tower. A duct burner was included in each case and the firing temperature was specified at 1,200 degrees F. Sega assumes that an SCR system would be required for permitting to meet BACT for NO_X reduction. This conclusion is based on the relatively low incremental emission reduction cost effectiveness of installing an SCR system in a HRSG, and that the combined-cycle facility would not have any limitations of annual hours of operation. The SCR was included at 80-percent reduction effectiveness resulting in an outlet level of approximately 2.0 ppmdv, which is the lowest consistently achievable level. Sega assumes that an oxidation catalyst would be required for permitting to meet BACT for CO reduction. As with the other combined-cycle options, this conclusion is based on the relatively low incremental emission reduction cost effectiveness of installing oxidation catalyst in a HRSG and that the combined-cycle facility would not have any limitations of annual hours of operation. The catalyst was included at 80-percent CO reduction effectiveness.

The GE 7EA 2x1 combined-cycle is a unique case that incorporates the existing simple-cycle 7EA located at the Heskett 3 into a new 2x1 arrangement. The performance is based on the Thermoflow model for a complete and new plant site including two engines, two HRSGs, a common cooling tower, and a common steam turbine similar to the other combined-cycle options.

The GE 7EA combined-cycle plant output, performance, and all operational parameters for the 1x1 plant were based on the design site average conditions specified by Montana-Dakota (82.1 degrees F, 36-percent relative humidity, and elevation of 1,950 AMSL). The plant output, performance, and all operational parameters for the 2x1 plant were based on the design site average conditions specified by Montana-Dakota for Heskett 3

(83.8 degrees F, 40-percent relative humidity, and elevation of 1,695 ft. AMSL). For both the 1x1 and 2x1 plant, the steam turbine, HRSG, and condenser were sized for a cooler condition of 40 degrees F and 40-percent relative humidity since this equipment must be sized to accommodate higher CTG output at reduced ambient temperatures. However, the cooling tower was still sized for the design site average condition for each plant since it must be sized to accommodate the warmer site design condition. Thus, all plant information (output, performance, operational parameters, etc.) listed in Tables A-2 through A-5 are associated with the design site average conditions for that plant, whereas, all TCI information (except for the cooling tower) are based on the cooler conditions.

The GE 7FA.05 combined-cycle cases were modeled as a triple-pressure reheat 1x1 combined-cycle plant with a mechanical draft cooling tower, and as a triple-pressure reheat 2x1 combined-cycle plant with a mechanical draft cooling tower. For the same reasons described for the GE 7EA combined-cycle options, the NO_X reduction effectiveness of SCR was set to 80 percent (2.0 ppmdv outlet) and an oxidation catalyst was included at 80-percent CO reduction effectiveness. Like the GE 7EA 1x1 plant, all plant information (output, performance, operational parameters, etc.) listed in Tables A-2 through A-5 are associated with the design site average conditions, whereas all TCI information (except for the cooling tower) are based on the cooler condition.

The Siemens SGT 800 combined-cycle case was modeled as a dual-pressure no-reheat 3x1 combined-cycle plant with a mechanical draft cooling tower. Similar to the other CTG combined-cycle options, the NO_X reduction effectiveness of SCR was set to 80 percent (3.0 ppmdv outlet), and an oxidation catalyst was included at 80-percent CO reduction effectiveness. All plant information (output, performance, operational parameters, etc.) listed in Tables A-2 through A-5 are associated with the design site average conditions, whereas, all TCI information (except for the cooling tower) are based on the cooler condition.

1.5.3 Landfill Gas-Fired CTG

A simple-cycle Solar Titan 250 was modeled to develop a cost estimate for a landfill gas-fueled plant. *Figure 5* shows the makeup of the Thermoflow defined landfill gas that was selected for the fuel. Note that the siting of a landfill gas-fired plant of this size would require a location where there is a substantially sized landfill to produce enough gas to support a CTG-based plant. This may significantly limit the possible locations of such a facility in Montana-Dakota's service territory in the eastern interconnection. *Figure 6* summarizes key performance and descriptors for the CTG assessed. The following paragraph provides a summary of key assumptions in the assessment for the CTG.

The simple-cycle Titan 250 CTG utilizes SoLoNO$_x$ technology to minimize NO$_x$ emissions to less than 15 ppmdv. Because of this lower CTG emission level, Sega has assumed the additional emission control equipment of SCR would not be needed for permitting to meet BACT. When firing landfill gas, there is a general industry concern of contaminates in the gas which may poison the catalyst and make NO$_x$ reduction ineffective.

Sega assumes that an oxidation catalyst would be required for permitting to meet BACT for CO reduction. This conclusion is based on the lower incremental emission reduction cost effectiveness resulting from the relatively high CO emissions from the Titan 250 firing landfill gas. The catalyst was included at 80-percent CO reduction effectiveness.

Constituent		
Hydrogen, H_2	% vol	2.5
Carbon Dioxide, CO_2	% vol	33.0
Methane, CH_4	% vol	63.5
Hydrogen Sulfide, H_2S	% vol	1.0
Higher Heating Value (at 77°F)	Btu/lb	9,908

Figure 5 - Assumed Landfill Gas Properties

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NO_x (ppmdv)	Pre-SCR NO_x Control	Gas Pressure Needed (psi)	Dual-Fuel Capable	Technology Type	Model Maturity
Solar Titan 250	21.7 9,740	15	Dry	450	Yes	Frame	Mature
* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.							

Figure 6 - Summary of Landfill Gas-Fired CTG

1.5.4 CTG Cost Estimation

The cost basis, capital costs, and annual costs are contained in Tables A-2 through A-5 of the IRP cost analysis spreadsheet in Appendix A. The PEACE economic model was updated with 2014 pricing data. These costs were escalated to 2015 dollars at 3-percent per year. The estimated annual O&M costs for each of the CTGs assessed are contained in these tables as well as the pertinent CTG performance data, identification of additional information specific to the CTGs assessed, TCI, labor costs, and emissions. The performance, capital investment, and emissions were outputs from the Thermoflow model for the specific CTGs assessed. The 2015$ labor rate was provided by Montana-Dakota.

It should be noted, while the performance design of the 7EA 2x1 is very similar to the other CTG cases, it differs in the fact that the cost estimate is a hybrid approach because the facility includes an existing 7EA unit. The cost estimate for the hybrid system subtracts the cost of a single 7EA from the total cost of the new 2x1 total plant cost. All other methods of analysis for the cost estimate remain the same as the other CTG cases.

The basis for and results of calculating the O&M fixed costs ($/kW-month, 2015$) are shown in Table A-3. The basis for the calculations are from Montana-Dakota and discussions with Sega staff. Montana-Dakota provided maintenance rates based on 2010$, which were escalated to 2015$ at a 3-percent per year rate. The total fixed annual cost for each CTG assessed is shown at the bottom of the table.

Table A-4 lists the basis for and results of calculating the annual O&M variable costs ($/MWh, 2015$). The basis for the calculations were from Montana-Dakota, output from the Thermoflow model, and discussions between Sega and Montana-Dakota staff. Montana-Dakota provided maintenance rates based on 2010$, which were escalated to 2015$ at a 3-percent per year rate.

Landfill gas prices were estimated using the median value of prices reported to EPA current as of 2013 and escalated to 2015$ at 3-percent per year.

1.5.5 CTG Fixed and Variable O&M Annual Cost Estimation

Table A-1 (summary results) includes the rolled-up summary of the capital cost along with the fixed and variable O&M costs for each option. Table A-2 (cost basis) provides a listing of the cost basis and assumptions for the cost calculations (used in Table A-3) including the assumed labor rate and the plant consumption rate of fuel, ammonia, water, and auxiliary power. The plant consumption rates are outputs from the Thermoflow model runs for the specific CTG models. Note that some CTG options have zero consumption rates in some categories, for example, the GE 7EA has no ammonia consumption since it is assumed to not have an SCR, whereas the GE LM6000PH has an ammonia consumption rate since it is assumed to have an SCR. The hourly labor rate of $59.10 (2015$), provided by Montana-Dakota, is multiplied by the full-time equivalent (FTE) amount of 2,080 work hours per year to calculate the annual FTE cost of $122,928 for plant O&M labor costs used in Table A-3.

1.5.5.1 CTG O&M Fixed Costs (Table A-3)

Table A-3 shows the calculated buildup of the total annual fixed O&M costs for the CTG options. Fixed O&M costs are those which can be expected to be the same each year based on the type and size of equipment at the plant and are not a function of the number of operating hours. These calculations are separated by: 1) labor costs, 2) maintenance costs, and 3) other expenses. All calculated costs are shown in units of $ per MW-year, which is

the total annual cost divided by the total MW capacity of the plant. The total fixed O&M cost is summed at the bottom of the table. The following paragraphs explain the process of calculating the three categories of fixed costs noted:

1. Labor Costs:

   The annual fixed labor cost is the cost of the number of FTE operating staff required at the plant to perform the duties necessary to run the plant. There are separate categories of labor depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M fixed labor costs, whereas, the GE 7EA does not since this option is assumed to not have SCR. The number of FTE for each category was provided by Montana-Dakota based on actual experience or result of research. The number of FTE shown for a labor category is multiplied by the FTE rate ($122,928/yr) and then divided by the MW capacity of the plant to calculate the $/MW-yr values shown in the table for each option.

2. Maintenance Costs:

   The annual fixed maintenance cost is the cost to perform regular maintenance of the equipment at the plant, including regular contracted services, and is not a function of the number operating hours. There are separate categories of maintenance cost depending on the type of CTG and specific equipment at the plant option. The maintenance rate in $/MW-yr for each category was provided by Montana-Dakota based on actual experience or result of research. The maintenance rate shown for a maintenance category is simply transferred over to the CTG option columns since it is already in the required units of measure.

3. Other Expenses:

   The annual fixed cost for other expenses is the cost associated with administration, property tax, and insurance. Administration cost is shown as a fixed rate in $/MW-yr and was provided by Montana-Dakota based on actual experience. This rate is transferred over to the CTG option columns since it is already in the required units of measure. The property tax and insurance are a function of the TCI shown in Table A-2. The property tax and insurance rate shown is multiplied by the TCI for that option and then divided by the MW capacity of the plant to calculate the $/MW-yr values shown in the table for each option

1.5.5.2 CTG O&M Variable Costs (Table A-4)

Table A-4 shows the calculated buildup of the total annual variable O&M costs for the CTG options. Variable O&M costs are those which are expected to be a function of how much the CTGs are operated in terms of the number of MWhs generated. These calculations are separated by: 1) maintenance, 2) utilities, and 3) chemicals. All calculated costs are shown in units of $ per MWh. The total variable O&M cost is summed at the bottom of the table. The following paragraphs explain the process of calculating the three categories of variable costs noted:

1. Maintenance:

   The variable-maintenance cost is the cost to perform the particular maintenance activities which are needed after operating for a certain number of MWhs. This cost includes both labor and parts. There are separate categories of maintenance depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M variable-maintenance costs (for catalyst replacement), whereas, the Solar Titan 250 does not since this option is assumed not to have SCR (SCR catalysts must be replaced periodically as a function of operating hours). The variable-cost rate shown in $/MWh for each category was provided by Montana-Dakota based on actual experience or result of research, or input from and discussions with Sega based on engineering estimates. This rate is transferred over to the CTG option columns since it is already in the required units of measure.

2. Utilities:

   The variable-utilities cost is the cost of auxiliary power to operate the plant. There are separate categories of utilities depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M utilities costs (for powering the SCR-related equipment such as pumps, fans, and heaters). For the "all models" category, the rate shown in $/MWh was provided by Montana-Dakota. This rate is transferred over to the CTG option columns since it is already in the required units of measure. The utilities cost for the other two categories (SCR and Intercooling auxiliary power) are the utility cost rate of 25.16 $/MWh, provided by Montana-Dakota, times the amount of auxiliary power required by the equipment. The utility rate for a category is multiplied by the auxiliary power required (shown in Table A-2) and then divided by the MW capacity of the plant to calculate the $/MWh values shown in the table for each option.

3. Chemicals:

   The variable-chemicals cost is the cost of chemicals (including water) to operate the plant. There are separate categories of chemicals depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M chemicals costs (for ammonia), whereas, the Solar Titan 250 does not since this option is assumed not to have SCR. For the "all models" and "intercooling heat rejection equipment" categories, the rate shown in $/MWh was provided by Montana-Dakota. These rates are transferred over to the CTG option columns since they are already in the required units of measure. The chemicals cost for the other category applicable to simple-cycle CTG options (SCR ammonia) is the ammonia cost rate of 1.4 $/gal, provided by Sega, as an estimate. The ammonia cost rate is multiplied by the use rate in gal/hr from the Thermoflow model output (shown in Table A-2) and then divided by the MW capacity of the plant to calculate the $/MWh values shown in the table for each option.

A summary of the cost analysis for all CTG options is presented in Table A-5.

1.6 RECIPROCATING INTERNAL COMBUSTION ENGINE OPTION

A cost analysis was performed for the reciprocating internal combustion engine (RICE) selected for the assessment. The Wartsila 20V34SG is a spark ignition 4-stroke engine. *Figure 7* summarizes key performance and descriptors for the RICE assessed.

RICE Model	ISO Ratings* (MW) Heat Rate (Btu/kWh)	NO_x Emissions (ppm)	Gas Pressure Needed (psi)	Duel-Fuel Capable	Technology Info	Model Maturity
Wartsila 20V34SG	9.3 8,293	5	75	No	4 Stroke Spark Ignition	Growing in Use
* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.						

Figure 7 - Reciprocating Internal Combustion Engines

The RICE was assumed to meet the federal new source performance standards (NSPS) and 40 CFR 63 hazardous air pollutant (HAP) emission standards and therefore quoted to have both SCR and oxidation catalyst installed as part of the base package. The plant size, performance, emission controls, operational parameters, CO_2 emissions, capital costs, fixed costs, variable costs, and summary for the RICE plant options considered are shown in Table A-6.

1.6.1 RICE Cost Estimation

Sega requested budgetary quotations from Wartsila for capital and operational costs for the Wartsila 20V34SG model. All cost and performance numbers for the engines were provided by Wartsila. Sega adjusted these numbers to account for any information not provided by Wartsila. This information is contained in Table A-6 of the IRP cost analysis spreadsheet. The spreadsheet includes a breakdown of the capital costs by equipment, installation, loaded and unloaded Owner's soft costs, and loaded and unloaded TCI.

1.7 RENEWABLE FUEL BOILER OPTIONS

A capital cost analysis was performed for two renewable fuel-fired boilers using the Thermoflow engineering software with a PEACE module (see Section 1.5 for Thermoflow/PEACE details). The Thermoflow models incorporate a bubbling fluidized bed (BFB) boiler and a mechanical draft cooling tower. Inputs to the model also included Montana-Dakota defined baseline assumptions as well as a user selected fuel. All other inputs besides the baseline assumptions and the fuel were left at default values. The plant size, performance, emission controls, operational parameters, CO_2 emissions, capital costs, fixed costs, variable costs, and summary for both renewable fuel and coal fired boiler options are shown in Tables A-8 and A-9.

1.7.1 Municipal Solid-Waste Fuel

A Thermoflow defined municipal solid-waste fuel was selected for the solid-waste burner; the composition of this fuel can be found in *Figure 8*. Note that the siting of a municipal solid-waste fired plant of this size would require a location where there is a substantially sized population to produce enough fuel to support a solid waste based plant. This may significantly limit the possible locations of such a facility in Montana-Dakota's service territory in the eastern interconnection.

Constituent		
Moisture	% wt	35.70
Ash	% wt	32.00
Carbon	% wt	16.90
Nitrogen	% wt	0.20
Chlorine	% wt	0.35
Sulfur	% wt	0.15
Oxygen	% wt	12.40
Higher Heating Value	Btu/lb	3,001

Figure 8 - Assumed Municipal Solid-Waste Properties

1.7.2 Biomass

Wood pellets, the fuel for the biomass plant, was chosen from Thermoflow's fuel library and its makeup can be found in *Figure 9*. Note that the siting of a wood pellet fired plant of this size would require close proximity to a location where there is a substantial supply of the fuel from trees and wood-related manufacturing industries. Sega anticipates a woody biomass product to be in short supply in North Dakota and this may significantly limit the possible locations of such a facility in the state.

Constituent		
Moisture	% wt	8.70
Ash	% wt	0.50
Carbon	% wt	45.80
Nitrogen	% wt	0.08
Chlorine	% wt	0.01
Sulfur	% wt	0.01
Oxygen	% wt	39.40
Higher Heating Value	Btu/lb	7,824

Figure 9 - Assumed Biomass - Wood Pellet Properties

1.7.3 Cost Estimation

The capital and annual costs are contained in Tables A-8 and A-9 of the IRP cost analysis spreadsheet. PEACE outputs are current as of 2014 and were escalated to 2015$ at 3-percent annually. The fixed and variable O&M are from assumptions made in the Department of Energy Annual Energy Outlook from 2013 which were escalated to 2015$ at 3-percent annually.

1.8 COAL BOILER OPTIONS

For a new coal-fired power plant, Montana-Dakota used the results of a 2012 study completed by WorleyParsons for the Lignite Energy Council, which evaluated advanced generation technology alternatives viable for a generating station burning North Dakota lignite coal. Four technologies were selected and a comparative evaluation based on performance and cost was completed. The evaluation examined these technologies with and without CO_2 capture. Technologies included in the evaluation were:

1. Subcritical atmospheric fluidized bed combustion,
2. Pressurized fluidized bed combustion,
3. Gasification, and
4. Oxycombustion circulating fluidized bed combustion (CFBC).

The overall assessment evaluated both quantitative and qualitative criteria. The assessed criteria included, but were not limited to, lignite experience, technology development and risk, permit ability, environmental impact, performance, emissions, capital cost, and operating cost. The results of the study ranked subcritical CFBC technology the best among all other technologies evaluated when including, and not including, CO_2 capture. The CFBC technology options were used as inputs to the resource expansion analysis, with the cost estimates escalated to 2015$. The coal option inputs to the resource expansion analysis are included in *Figure 10* and in Table A-9.

	CFBC with CO_2 Capture	CFBC without CO_2 Capture
Plant Size (MW, net)	122	185
Capital Cost ($/kW)	$7,099	$3,882
Fixed O&M ($/kW-month)	$22.55	$18.49
Variable O&M ($/MWh)	$19.81	$12.49
Major Maintenance ($/kW-month)	$0.00	$0.00
Net Full Load Heat Rate (Btu/kWh HHV)	13,781	9,974
Carbon Intensity (lb/MWh)	248	1,945
WorleyParsons. 2012. *A Study of Lignite-Based Advanced Generation Technology Systems. Unpublished manuscript.*		

Figure 10 - Coal Inputs to the Resource Expansion Analysis

The CO_2 capture option was based on nominally 90-percent CO_2 capture, resulting in a carbon intensity of 248-lb CO_2/MWh, which ensures compliance with the proposed EPA CO_2 regulatory limit of 1,000-lb CO_2/MWh. Sequestration costs associated with CO_2 capture are not included in the cost estimate.

1.9 RENEWABLE NON-FUEL OPTIONS

A cost analysis was performed for the four non-fuel renewable energy options listed in *Figure 11*. These costs are contained in Tables A-10 and A-11 of the IRP cost analysis spreadsheet in Appendix A.

Non-Fuel Option	Size (MW net)
Photo-Voltaic (PV) Solar	30
Concentrated Solar	30
Thermal Solar	30
Geothermal	30
Wind (ND & MT)	20
Wind (ND & MT)	50

Figure 11 - Renewable Non-Fuel Options

1.9.1 Solar and Geothermal

Sega used estimates and updates from the following three documents to develop costs for the solar and geothermal options for the 2015 model:

1. **Black & Veatch. 2012.** *Cost and Performance Data for Power Generation Technologies.* 2012.

2. **Delaquil, Pat, Goldstein, Gary and Wright, Evelyn. 2008.** US Technology Choices, Costs and Oppurtunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways. *drdc.org.* [Online] 2008. [Cited: January 14, 2013.] http://docs.nrdc.org/globalwarming/files/glo_08051401A.pdf.

3. **U.S. Energy Information Administration. 2013.** *Assumptions to the Annual Energy Outlook 2013.*

Costs from each report are presented in Tables A-10 and A-11 after applying 3-percent escalation to 2015$. There was a large variance in the cost for some of the technologies between the different reports. Sega chose DOE/EIA Annual Energy Outlook 2013 as a default where updates were available to the original 2012 report (regardless of whether it was higher). Note that in the case of Concentrated Solar, Sega used "Cost and Performance Data for Power Generation Technologies" since the DOE/EIA document did not provide costs for this option. This particular alternate reference was used because its costs were closest to the DOE/EIA reference costs for the Thermal Solar category. Some of the reports did not separate the cost for Concentrated Solar and Thermal Solar and put both technologies under Thermal Solar. In these cases, the Concentrated Solar costing included thermal storage. Thermal Solar did not include storage.

1.9.2 Wind

The analysis for the wind farms was based on indicative turbine pricing from GE for wind farm sizes of 20 MW and 50 MW. Costs associated with construction and O&M were estimated based on Montana-Dakota's experience constructing the Cedar Hills Wind Farm and the Diamond Willow Wind Farms.

1.9.3 Wind Cost Estimate

An analysis was performed to estimate the cost of a self-built 20 MW or 50 MW wind farm in Montana-Dakota's service territory. GE was contacted by Montana-Dakota to provide indicative pricing for wind turbines that could provide the generation required for these wind farms. The performance and cost estimates in this analysis assumed the GE 2.0-116 Series 2.0 MW wind turbines for both the 20 MW and 50 MW wind farms. Budgetary turbine prices, provided by GE, are provided in *Figure 12*. Sales tax was not included in the estimate, as North Dakota House Bill 1382, relating to sales tax exemption for a wind-powered electrical generating facility, was extended until January 1, 2017, and the state of Montana does not charge sales tax.

	North Dakota Site	**Montana Site**
20 MW Wind Farm or 10 x 2.0 MW Wind Turbines	$2.442M per turbine	$2.505M per turbine
50 MW Wind Farm or 25 x 2.0 MW Wind Turbines	$2.405M per turbine	$2.468M per turbine

Figure 12 - GE-Supplied Budgetary Turbine Price

To estimate the capital cost for the new wind farm options, a cost comparison was made to the total construction cost Montana-Dakota incurred during the 2010 Cedar Hills Wind Farm build. Engineering and supervision and general and administrative (ES&GA) and allowance for funds used during construction (AFUDC) were subtracted from the total construction costs to allow the cost basis to be unloaded. Wind turbine costs for Cedar Hills Wind Farm were replaced by the new indicative pricing supplied by GE, and the construction and installation costs for Cedar Hills Wind Farm were escalated at an annual

capital cost increase of 4 percent to bring it to 2015$. Based on Montana-Dakota's experience with the new Thunder Spirit Wind Farm, an additional 20-percent project development and management fee was added to the total cost.

O&M costs were determined using the costs incurred over the nine cumulative years of data Montana-Dakota has compiled operating and maintaining Diamond Willow 1 Wind Farm, Diamond Willow 2 Wind Farm, and Cedar Hills Wind Farm. The wind option inputs to the resource expansion analysis are shown in *Figure 13*.

	ND - 20 MW	**ND - 50 MW**	**MT - 20 MW**	**MT- 50 MW**
Plant Size (MW, net)	20.0	50.0	20.0	50.0
Capital Cost ($/kW)	$2,032	$1,879	$2,069	$1,916
Fixed O&M ($/kW-month)	$2.58	$2.58	$2.58	$2.58
Variable O&M ($/MWh)	$0.00	$0.00	$0.00	$0.00
Major Maintenance ($/kW-month)	$0.00	$0.00	$0.00	$0.00
Net Full Load Heat Rate (Btu/kWh HHV)	-	-	-	-
Carbon Intensity (lb/MWh)	-	-	-	-

Figure 13 - Wind Inputs for the Resource Expansion Analysis

Table A-1. EGEAS Model Input Summary, 2015 $ Summary Results for All Supply-Side Options Assessed

CATEGORY	FUEL	MODEL	PLANT SIZE (MW,net plant output)	CAPITAL COST ($/kW)[a]	FIXED O&M ($/kW-month)	VARIABLE O&M ($/MWh)	MAJOR MAINTENANCE ($/kW-month)	FULL LOAD HEAT RATE (BTU/kWh)	CARBON INTENSITY (lb/MWh)	NOx (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	Fuel Cost ($/MBtu)
CT	NATURAL GAS	7EA	75.0	816	0.98	2.32	0.03	11,436	1,368	2.0	5.0	2.96
		LMS100PB	85.9	1,056	1.47	4.49	0.03	9,206	1,088	2.5	25.0	2.96
		LM6000PH	37.3	1,295	2.12	3.95	0.03	9,960	1,175	3.0	100.0	2.96
		LM6000PH Sprint (1X1)	62.8	1,463	1.82	4.50	0.03	7,663	746	3.0	20.0	2.96
		7EA (1X1)	127.6	1,081	1.04	2.99	0.03	7,608	899	2.0	5.0	2.96
		7EA (2X1) Heskett 3 Expansion	256.8	768	0.77	3.57	0.03	7,592	896	2.0	5.0	2.96
		7FA.05 (1X1)	294.6	779	0.69	2.88	0.03	6,672	788	2.0	2.0	2.96
		7FA.05 (2X1)	593.2	742	0.63	3.46	0.03	6,631	783	2.0	2.0	2.96
		5GT800 (3X1)	213.9	1,040	0.96	3.58	0.03	7,347	867	3.0	2.0	2.96
	LANDFILL GAS	TITAN 250	17.3	1,341	2.66	2.32	0.03	10,427	1,221	15.0	5.0	2.65
RICE	NATURAL GAS	20V34SG	28.0	1,550	0.92	9.63	0.45	8,542	970	5.0	15.0	2.96
BOILER	SOLID WASTE-MSW	SOLID WASTE	15.0	17,475	9.73	5.82	0.03	16,002	3,685	70.0	76.0	3.00
	BIOMASS-WOOD PELLETS	BIOMASS	29.3	3,986	9.73	5.82	0.03	11,056	2,436	70.0	76.0	6.75
	COAL-LIGNITE	COAL (Lignite) with CO2 capture	122.0	7,099	22.55	19.81	0.00	13,781	248	15.0	40.0	1.91
		COAL (Lignite) without CO2 Capture	185.0	3,882	18.49	12.49	0.00	9,974	1,945	15.0	40.0	1.91
RENEWABLE	NON-FUEL	PV SOLAR	30.0	4,037	1.61	0.00	0.00	-	-	-	-	0.00
		CONC. SOLAR	30.0	7,715	4.55	0.00	0.00	-	-	-	-	0.00
		THERMAL SOLAR	30.0	5,282	6.19	0.00	0.00	-	-	-	-	0.00
		GEOTHERMAL	30.0	2,723	10.49	0.00	0.00	-	-	-	-	0.00
		WIND ND - 20MW	20.0	2,032	2.58	0.00	0.00	-	-	-	-	0.00
		WIND ND - 50MW	50.0	1,879	2.58	0.00	0.00	-	-	-	-	0.00
		WIND MT -20MW	20.0	2,069	2.58	0.00	0.00	-	-	-	-	0.00
		WIND MT-50MW	50.0	1,916	2.58	0.00	0.00	-	-	-	-	0.00

Table A-2. CTG Cost Basis and Capital Cost 2015 $

	GE 7EA[1] (simple cycle)	GE LMS100PB[2] (simple cycle)	GE LM6000PH[3] (simple cycle)	GE LM6000PH Sprint[4] (1X1)	GE 7EA[5] (1X1)	GE 7EA[6] (2X1) Heskett 3 Expansion	GE 7FA.05[7] (1X1)	GE 7FA.05[8] (2X1)	SIEMENS SGT 800[9] (3X1)	Solar Solar Titan 250[10] (simple cycle landfill gas)
Plant Information										
Fuel Fired	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Landfill Gas
Number of CTs	1	1	1	1	1	2	1	2	3	1
Unit Size (MW, net)	75.0	85.9	37.3	62.8	127.6	128.4	294.6	296.5	71.3	17.3
Unit Size (MMBtu/hr HHV)	869	791	371	481	871	975	1,966	1,966	524	181
Plant Size (MW, net)	75.0	85.9	37.3	62.8	127.6	256.8	294.6	593.0	213.9	17.3
Plant Size (MMBtu/hr HHV)	869	791	371	481	971	1,950	1,966	3,932	1,571	181
Net Heat Rate (Btu/kWh HHV)	11,436	9,206	9,960	7,663	7,608	7,592	6,672	6,631	7,347	10,427
SCR Aux Power (MW)	-	0.135	0.084	0.081	0.165	0.330	0.300	0.600	0.225	-
Aq. Ammonia (19%), lb/hr	-	136	46	48	57	115	124	249	165	-
Aq. Ammonia (19%), gal/hr	-	17.5	5.9	6.2	7.4	14.8	16.1	32.2	21.4	-
Water (1,000 lb/hr)	-	-	-	193.2	391.2	779.7	663.8	1315.1	575	-
Water (1000 gallons/hr)	-	-	-	23	47	94	80	158	69	-
Intercooling Aux Power (MW)	-	1.5	-	-	-	-	-	-	-	-
Additional Plant Information										
CatOx	N	N	N	Y	Y	Y	Y	Y	Y	Y
SCR	N	Y	Y	Y	Y	Y	Y	Y	Y	N
Water Injection	N	N	N	Y	N	N	N	N	N	N
Intercooling	N	Y	N	N	N	N	N	N	N	N
Aeroderivative or Aero-hybrid	N	Y	Y	Y	N	N	N	N	N	N
Multi-Unit combination	N	N	N	N	N	Y	N	Y	Y	N
Cost Information										
Total Capital Investment (TCI-ULI-Unloaded, 2015 $)[11]	61,197,392	90,735,208	48,297,168	91,846,864	137,992,438	197,332,463	229,639,419	439,866,608	222,464,501	23,206,058
Total Capital Investment (TCI)-Loaded, 2015 $	64,139,575	95,097,478	50,639,147	96,186,629	144,626,690	206,819,601	240,679,775	461,014,041	233,742,210	24,321,734
SCR Capital Investment (TCI), 2015 $	0	5,898,259	4,804,075	2,527,230	4,799,369	9,565,296	6,171,495	11,623,798	7,984,002	0
Labor Rate ($/hr), 2015 $	59.10	59.10	59.10	59.10	59.10	59.10	59.10	59.10	59.10	59.10
FTE Hours (hr/yr), 2015 $	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080
FTE Cost ($/yr), 2015 $	122,928	122,928	122,928	122,928	122,928	122,928	122,928	122,928	122,928	122,928
Pollutant Information										
CO2 (lb/hr)	102,621	93,429	43,842	46,858	114,720	230,214	232,170	464,341	185,523	21,115
CO2 (lb/MWh, net)	1,368	1,088	1,175	746	899	896	788	783	867	1,221
NOx (ppmvd @ 15% O2) Uncontrolled	9.0	25.0	15.0	15.0	9.0	9.0	9.0	9.0	15.0	15.0
NOx (ppmvd @ 15% O2) Controlled	2.0	2.5	3.0	3.0	2.0	2.0	2.0	2.0	3.0	15.0
CO (ppmvd @ 15% O2)	5	25	100	20	5	5	2	2	2	5

1. Simple cycle gas turbine, one GE 7EA engine
2. Simple cycle gas turbine , one GE LMS100PB engine
3. Simple cycle gas turbine, one GE LM6000PH engine
4. Single pressure cc; extraction condensing turbine, water cooling with mechanical draft cooling tower
5. Double pressure, no reheat cc
6. Double pressure, no reheat cc. New CT,HRSGs, and ST, stack, cooling tower, added to the existing 7EA
7. Triple pressure reheat cc, reheat before IP. water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
8. Two Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions. ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
9. Three Siemeens engines, plant configuration GT, HRSG, and condensing non-reheat ST
10. Simple cycle gas turbine, one Solar Titan 250 engine
11. Without Owner's AFUDC or Administrative Costs.

Note: Performance and cost results from Thermoflow. Labor rate per Montana-Dakota

Table A-3. CTG O&M Fixed Cost ($/MW-year), 2015 $

	Basis			GE 7EA[1] (simple cycle)	GE LMS100PB[2] (simple cycle)	GE LM6000PH[3] (simple cycle)	GE LM6000PH Sprint[4] (1X1)	GE 7EA[5] (1X1)	GE 7EA6 (2X1) Heskett 3 Expansion	GE 7FA.05[7] (1X1)	GE 7FA.05[9] (2X1)	SIEMENS SGT 800[8] (3X1)	Solar Solar Titan 250[10] (simple cycle landfill gas)
1. Labor													
a. All Models (Operations & Maintenance)	2.25		FTE	$3,688	$3,220	$7,415	$4,404	$2,168	$1,077	$939	$466	$1,293	$15,988
b. All Models (Technical Services)	0.75		FTE	$1,229	$1,073	$2,472	$1,468	$723	$359	$313	$155	$431	$5,329
c. SCR O&M (FTE)	0.25		FTE	-	$358	$824	$489	$241	$120	$104	$52	$144	-
d. Water Injection O&M (FTE)	0.50		FTE	-	-	-	$979	-	-	-	-	-	-
e. Intercooling O&M (FTE)	0.90		FTE	-	$1,288	-	-	-	-	-	-	-	-
f. Intercooling TS (FTE)	0.10		FTE	-	$143	-	-	-	-	-	-	-	-
g. Aeroderivative & Aero-hybrid O&M (FTE)	0.20		FTE	-	$286	$659	$391	-	-	-	-	-	-
h. Aero & Aero-hybrid TS (FTE)	0.10		FTE	-	$143	$330	$196	-	-	-	-	-	-
i. Multi-Unit O&M (FTE)	1.00		FTE	-	-	-	-	-	$479	-	$207	$575	-
			Labor Sub-Total ($/MW-year)	$4,917	$6,511	$11,700	$7,928	$3,131	$2,034	$1,356	$881	$2,443	$21,317
2. Maintenance	Basis: 2010 $	2015 $											
a. All Models (B&C and Electric Plant)	200	232	$/MW-year	$232	$232	$232	$232	$232	$232	$232	$232	$232	$232
b. All Models (Contracted Services)	250	290	$/MW-year	$290	$290	$290	$290	$290	$290	$290	$290	$290	$290
c. SCR Maintenance (1.5% of SCR-only TCI)		1.5%		-	$1,030	$1,932	$604	$561	$559	$314	$294	$560	-
d. Water Injection (water)	25	29	$/MW-year	-	-	-	$29	-	-	-	-	-	-
e. Water Injection (wastewater treatment)	20	23	$/MW-year	-	-	-	$23	-	-	-	-	-	-
f. Intercooling (heat rejection)	100	116	$/MW-year	-	$116	-	-	-	-	-	-	-	-
g. Intercooling (I&C)	50	58	$/MW-year	-	$58	-	-	-	-	-	-	-	-
h. Aeroderivative & Aero-hybrid (CTG)	100	116	$/MW-year	-	$116	$116	$116	-	-	-	-	-	-
i. Aeroderivative & Aero-hybrid (I&C)	50	58	$/MW-year	-	$58	$58	$58	-	-	-	-	-	-
j. Multi-Unit (CTG)	100	116	$/MW-year	-	-	-	-	-	$116	-	$116	$116	-
			Maintenance Sub-Total ($/MW-year)	$522	$1,899	$2,627	$1,351	$1,082	$1,196	$836	$932	$1,198	$522
3. Other Expenses	Basis: 2010 $	2015 $											
a. All Models (Administration)	400	464	$/MW-year	$464	$464	$464	$464	$464	$464	$464	$464	$464	$464
b. All Models (Property Taxes)		0.57%	of TCI-UL	$4,675	$6,053	$7,419	$8,380	$6,197	$4,403	$4,467	$4,250	$5,961	$7,686
c. All Models (Insurance)		0.14%	of TCI-UL	$1,175	$1,521	$1,865	$2,106	$1,557	$1,106	$1,122	$1,068	$1,498	$1,932
d. Aero & Aero-hybrid Insurance		0.11%	of TCI-UL	-	$1,151	$1,411	$1,594	-	-	-	-	-	-
			Other Sub-Total ($/MW-year)	$6,314	$9,189	$11,159	$12,544	$8,218	$5,973	$6,053	$5,782	$7,922	$10,081
			Total Fixed Cost ($/MW-year)	$11,753	$17,599	$25,486	$21,823	$12,431	$9,204	$8,245	$7,595	$11,563	$31,920

1. Simple cycle gas turbine, one GE 7EA engine
2. Simple cycle gas turbine , one GE LMS100PB engine
3. Simple cycle gas turbine, one GE LM6000PH engine
4. Single pressure cc; extraction condensing turbine, water cooling with mechanical draft cooling tower.
5. Double pressure, no reheat cc
6. Double pressure, no reheat cc. New CT,HRSGs, and ST, stack, cooling tower, added to the existing 7EA
7. Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
8. Two Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
9. Three Siemens engines, plant configuration GT, HRSG and condensing non-reheat ST
10. Simple cycle gas turbine, one Solar Titan 250 engine

Note: Performance and cost results from Thermoflow. Labor rate per Montana-Dakota.

Table A-4. CTG O&M Major Maintenance ($/MW-year), 2015 $

	Basis: 2010 $	2015 $		GE 7EA[1] (simple cycle)	GE LMS100PB[2] (simple cycle)	GE LM6000PH[3] (simple cycle)	GE LM6000PH Sprint[4] (1X1)	GE 7EA[1] (1X1)	GE 7EA6 (2X1) Heskett 3 Expansion	GE 7FA.05[7] (1X1)	GE 7FA.05[8] (2X1)	SIEMENS SGT 800[9] (3X1)	Solar Solar Titan 250[10] (simple cycle landfill gas)
All Models (Combustion Turbines)	350	406	$/MW-year	$406	$406	$406	$406	$406	$406	$406	$406	$406	$406

O&M Variable Cost ($/MWh), 2015 $

	Basis: 2010 $	2015 $		GE 7EA[1] (simple cycle)	GE LMS100PB[2] (simple cycle)	GE LM6000PH[3] (simple cycle)	GE LM6000PH Sprint[4] (1x1)	GE 7EA[1] (1X1)	GE 7EA6 (2X1) Heskett 3 Expansion	GE 7FA.05[7] (1X1)	GE 7FA.05[8] (2X1)	SIEMENS SGT 800[9] (3X1)	Solar Solar Titan 250[10] (simple cycle landfill gas)
1. Maintenance	Basis: 2010 $	2015 $											
a. All Models (Combustion Turbine Generator)	1.950	2.261	$/MWh	$2.26	$2.26	$2.26	$2.26	$2.26	$2.26	$2.26	$2.26	$2.26	$2.26
b. SCR Catalyst Replacement		0.190	$/MWh	-	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	-
c. Aeroderivative & Aero-hybrid (CTG)	1.000	1.159	$/MWh	-	$1.16	$1.16	$1.16	-	-	-	-	-	-
d. Multi-Unit (CTG)	0.500	0.580	$/MWh	-	-	-	-	-	$0.58	-	$0.58	$0.58	-
			Major Maintenance Sub-Total ($/MWh)	$2.26	$3.61	$3.61	$3.61	$2.45	$3.03	$2.45	$3.03	$3.03	$2.26
2. Utilities	Basis: 2010 $	2015 $											
a. All Models	0.030	0.035	$/MWh	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
b. SCR Aux Power		25.160	$/MWh of SCR	-	$0.04	$0.06	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	-
c. Water Injection Water	0.050	0.058	$/MWh	-	-	-	$0.06	-	-	-	-	-	-
d. Intercooling Aux Power		25.160	$/MWh of IC	-	$0.44	-	-	-	-	-	-	-	-
			Utilities Sub-Total ($/MWh)	$0.03	$0.51	$0.09	$0.13	$0.07	$0.07	$0.06	$0.06	$0.06	$0.03
3. Chemicals	Basis: 2010 $	2015 $											
a. All Models	0.020	0.023	$/MWh	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
b. SCR Ammonia Consumption		1.400	$/gal	-	$0.29	$0.22	$0.14	$0.08	$0.08	$0.08	$0.08	$0.14	-
C. Water Consumption		1.000	$/1000 gal	-	-	-	$0.37	$0.37	$0.37	$0.27	$0.27	$0.32	-
d. Water Injection Water Treatment	0.200	0.232	$/MWh	-	-	-	$0.23	-	-	-	-	-	-
e. Intercooling Heat Rejection Equipment	0.050	0.058	$/MWh	-	$0.06	-	-	-	-	-	-	-	-
			Chemicals Sub-Total ($/MWh)	$0.02	$0.37	$0.24	$0.76	$0.47	$0.47	$0.37	$0.37	$0.49	$0.02
			Total Variable Cost ($/MWh)	$2.32	$4.49	$3.95	$4.50	$2.99	$3.57	$2.88	$3.46	$3.58	$2.32

1. Simple cycle gas turbine, one GE 7EA engine
2. Simple cycle gas turbine , one GE LMS100PB engine
3. Simple cycle gas turbine, one GE LM6000PH engine
4. Single pressure cc; extraction condensing turbine, water cooling with mechanical draft cooling tower.
5. Double pressure, no reheat cc
6. Double pressure, no reheat cc. New CT,HRSGs, and ST, stack, cooling tower, added to the existing 7EA
7. Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
8. Two Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
9. Three Siemens engines, plant configuration GT, HRSG, and condensing non-reheat ST
10. Simple cycle gas turbine, one Solar Titan 250 engine

Table A-5. CTG EGEAS Model Input Summary, 2015 $

	GE 7EA[1] (simple cycle)	GE LM5100PB[2] (simple cycle)	GE LM6000PH[3] (simple cycle)	GE LM6000PH Sprint[4] (1X1)	GE 7EA[5] (1X1)	GE 7EA6 (2X1) Heskett 3 Expansion	GE 7FA.05[7] (1X1)	GE 7FA.05[8] (2X1)	SIEMENS SGT 800[9] (3X1)	Solar Solar Titan 250[10] (simple cycle landfill gas)
Plant Size (MW,net plant output)	75.0	85.9	37.3	62.8	127.6	256.8	294.6	593.0	213.9	17.3
Capital Cost ($/kW)[11]	$816	$1,056	$1,295	$1,463	$1,081	$768	$739	$742	$1,040	$1,341
Fixed O&M ($/kW-month)	$0.98	$1.47	$2.12	$1.82	$1.04	$0.77	$0.69	$0.63	$0.96	$2.66
Variable O&M ($/MWh)	$2.32	$4.49	$3.95	$4.50	$2.99	$3.57	$2.88	$3.46	$3.58	$2.32
Major Maintenance ($/kW-month)	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Full Load Heat Rate (BTU/kWh)	11,436	9,206	9,960	7,663	7,608	7,592	6,672	6,631	7,347	10,427
Carbon Intensity (lb/MWh)	1,368	1,088	1,175	746	899	896	788	783	867	1,221
NOx (ppmvd @ 15% O2) (Controlled)	2.0	2.5	3.0	3.0	2.0	2.0	2.0	2.0	3.0	15.0
CO (ppmvd @ 15% O_2)	5	25	100	20	5	5	2	2	2	5
Fuel Cost ($/MBtu)[12,13]	$2.96	$2.96	$2.96	$2.96	$2.96	$2.96	$2.96	$2.96	$2.96	$2.65

1. Simple cycle gas turbine, one GE 7EA engine
2. Simple cycle gas turbine , one GE LM5100PB engine
3. Simple cycle gas turbine, one GE LM6000PH engine
4. Single pressure cc; extraction condensing turbine, water cooling with mechanical draft cooling tower
5. Double pressure, no reheat cc
6. Double pressure, no reheat cc. New CT,HRSGs, and ST, stack, cooling tower, added to the existing 7EA
7. Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
8. Two Triple pressure reheat cc, reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% RH); duct burner
9. Three Siemens engines, plant configuration GT, HRSG, and condensing non-reheat ST
10. Simple cycle gas turbine, one Solar Titan 250 engine
11. Total Capital Investment - Unloaded, divided by net output
12. Landfill Gas - Estimated median landfill gas cost based on range of $1-4/MMBtu as stated in the EPA document -- An overview of landfill gas Energy in the united States based on the LMOP database and program. File updated in 2013. Escalated to 2015 $ at 3% a year.
13. Natural Gas Price per Montana-Dakota

Note: All based on net output.

Table A-6. RICE Costs Basis and Capital Costs, 2015 $

	WARTSILA 20V34SG[1]
Plant Information	
Number of Engines	3
Unit Size (MW, net)	9.3
Unit Size (MMBtu/hr HHV)	77
Plant Size (MW, net)	28
Plant Size (MMBtu/hr HHV)	232
Net Heat Rate (Btu/kWh HHV)	8,542
Additional Plant Information	
CatOx	Y
SCR	Y
Cost Information	
Total equipment cost	$16,222,500
BOP/Engineering	$24,333,750
Owner Soft Cost (Loaded)	$3,650,063
Owner Soft Cost (Unloaded)	$1,622,250
Total Capital Investment (TCI-UL)-Unloaded, 2015 $[2]	$42,178,500
Total Capital Investment (TCI)-Loaded, 2015 $	$44,206,313
Pollutant Information	
CO2 (lb/MWh, net)	970
NOx (ppmvd @ 15% O2) (Controlled)	5

Table A-7. RICE EGEAS Model Input Summary, 2015 $

	WARTSILA 20V34SG[1]
Plant Size (MW,net plant output)	28
Capital Cost ($/kW)[2,3]	$1,550
Fixed O&M ($/kW-month)	$0.92
Variable O&M ($/MWh)	$9.63
Major Maintenance ($/kW-month)	$0.45
Full Load Heat Rate (Btu/kWh, HHV, net)	8,542
Carbon Intensity (lb/MWh)	970
NOx (ppmvd @15% O_2)	5
CO (ppmvd @ 15% O_2)	15
Fuel Cost ($/MMBtu)[4]	$2.96

1. All cost and performance numbers supplied by Wartsila.
2. Without Owner's AFUDC or Administrative Costs.
3. Total Capital Investment - Unloaded, divided by net output
4. Montana-Dakota provided

Table A-8. Renewable Fuel Boiler Cost Basis and Results

	BOILER[1] SOLID WASTE	BOILER[2] BIOMASS
Plant Information		
Number of Boilers	1	1
Unit Size (MW, net)	15.0	29.9
Unit Size (MMBtu/hr HHV)	54	359
Plant Size (MW, net)	15.0	29.9
Plant Size (MMBtu/hr HHV)	54	359
Net Heat Rate (Btu/kWh HHV)	16,002	11,056
Water (1,000 lb/hr)	159	218
Water (1000 gallons/hr)	19.2	26.2
Additional Plant Information		
CatOx	N	N
SCR	N	N
Cost Information		
Total Capital Investment (TCI-UL)-Unloaded, 2015 $[3]	$261,426,399	$119,193,386
Total Capital Investment (TCI)-Loaded, 2015 $	$161,248,116	$125,964,969
Labor Rate ($/hr), 2015 $	$59.10	$59.10
FTE Hours (hr/yr), 2015 $	$2,080	$2,080
FTE Cost ($/yr), 2015 $	$122,928	$122,928
Pollutant Information		
CO2 (lb/hr, net)	49,353	72,846
CO2 (lb/MWh, net)	3,299	2,436

1. Municipal solid waste (36% moisture, 32% ash, 17% carbon); water cooling with mechanical draft cooling tower; BFB boiler.

2. Wood pellets; water cooling with mechanical draft cooling tower; BFB boiler.

3. Total Capital Investment - Unloaded, divided by net output

Table A-9. Renewable Fuel and Coal Boiler EGEAS Model Input Summary, 2015 $

	BOILER[1] SOLID WASTE BURNER	BOILER[2] BIOMASS	BOILER - CFBC with CO2 Capture[3] COAL (Lignite)	BOILER - CFBC without CO2 Capture[3] COAL (Lignite)
Plant Size (MW,net plant output)	15.0	29.9	122.0	185.0
Capital Cost ($/kW)[4]	$17,475	$3,986	$7,099	$3,882
Fixed O&M ($/kW-month)[5]	$9.73	$9.73	$22.55	$18.49
Variable O&M ($/MWh)[5]	$5.82	$5.82	$19.81	$12.49
Major Maintenance ($/kW-month)	$0.03	$0.03	$0.00	$0.00
Full Load Heat Rate (Btu/kWh, HHV , net)	16,002	11,056	13,781	9,974
Carbon Intensity (lb/MWh)	3,685	2,436	248	1,945
NOx (ppmvd @15% O_2)	70	70	15	15
CO (ppmvd @ 15% O_2)	76	76	40	40
Fuel Cost ($/MBtu)[6]	$3.00	$6.75	$1.91	$1.91

1. Municipal solid waste (36% moisture, 32% ash, 17% carbon); water cooling with mechanical draft cooling tower; BFB boiler.
2. Wood pellets; water cooling with mechanical draft cooling tower; BFB boiler.
3. Montana-Dakota provided values
4. Without Owner's AFUDC or Administrative Costs. Total Capital Investment - Unloaded, divided by net output
5. Assumptions to the Annual Energy Outlook 2013, EIA/DOE.
6. Solid waste burner fuel costs estimated by Sega Inc. Coal boiler costs provided by Montana-Dakota.

Boiler Input Summary

	BOILERS (BIOMASS OR SOLID WASTE)	
	Fixed O&M $/kw/month	Variable O&M $/MWh
Thermoflow Default Cost	$3.53	$6.37
Cost and Performance Data for Power Generation Technologies[1]	$9.74	$18.45
Assumptions to the Annual Energy Outlook 2013, EIA/DOE[2]	$9.73	$5.82

1. Values adjusted to 2015$ from the 2013 model 3%/yr escalation
2. Values adjusted to 2015 $(based on 2011 $/MWh reported) 3%/yr escalation

Table A-10. Renewable Non-Fuel EGEAS Model Input Summary, 2015 $

	PV SOLAR	CONC. SOLAR	THERMAL SOLAR	GEOTHERMAL	WIND[2] ND - 20MW	WIND[2] ND - 50MW	WIND[2] MT -20MW	WIND[2] MT-50MW
Plant Size (MW,net plant output)	30	30	30	30	20	50	20	50
Capital Cost ($/kW)[1]	$4,037	$7,715	$5,282	$2,723	$2,032	$1,879	$2,069	$1,916
Fixed O&M ($/kW-month)	$1.61	$4.55	$6.19	$10.49	$2.58	$2.58	$2.58	$2.58
Variable O&M ($/MWh)	$0	$0	$0	$0.00	$0.00	$0.00	$0.00	$0.00
Major Maintenance ($/kW-month)	$0	$0	$0	$0	$0.00	$0.00	$0.00	$0.00
Full Load Heat Rate (BTU/kWh, HHV, net)	-	-	-	-	-	-	-	-
Carbon Intensity (lb/MWh)	-	-	-	-	-	-	-	-
NOx (ppmvd @15% O_2)	-	-	-	-	-	-	-	-
CO (ppmvd @ 15% O_2)	-	-	-	-	-	-	-	-
Fuel Cost ($/MBtu)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

1. Assumptions to the Annual Energy Outlook 2013, EIA/DOE.

2. Montana-Dakota provided values

Table A-11. Geothermal and Solar Input Summary, 2015 $

	PV SOLAR		CONC. SOLAR		THERMAL SOLAR		GEOTHERMAL		
	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Variable O&M*
US technology Choices ,Cost and Opportunities under the Lieberman- Warner Security Act: Assessing Compliance Pathways[1]	$5,114	$1.23	$3,690	$2.46	$3,391	$3.69	$3,690	$9.33	$11.86
Cost and Performance Data for Power Generation Technologies[1]	$3,377	$4.55	$7,715	$4.55	$5,365	$4.55	$6,491	$0.00	$33.87
Assumptions to the Annual Energy Outlook 2013[2]	$4,037	$1.61	NA	NA	$5,282	$6.19	$2,723	$10.49	$0.00

1. Values adjusted to 2015$ from the 2013 model 3%/yr escalation

2. Values adjusted to 2015 $(based on 2011 $/MWh reported) 3%/yr escalation

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-121

Regarding: Marginal Transmission Costs
Witness: Sara J. Cardwell

In your testimony at page 15, lines 9 to 10, you state: "The total cost, expressed in 2017 dollars, is divided by the peak load growth to yield a cost per kW." In your marginal cost study you use an average peak ranking instead of the peak load growth between 2005 to 2013. Please explain in detail what this average peak ranking represents and why it should be used instead of the 2005-2013 peak load growth.

Response:

The peak load growth used in the marginal cost of service study represents the peak load growth based on the increase of the 2011-2013 average peak demand over the 2005-2010 average peak demand.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-122

Regarding: Marginal Cost – Distribution Transformers
Witness: Sara J. Cardwell

a. **Please provide in electronic format all supporting documents, cost basis and worksheets, with formulas and links intact, used in developing the table shown on the Excel file of the Marginal Cost Study, tab "Distribution-Transformer Costs" (also Statement Workpapers page L-44), including the data used in calculating the "Zero-Intercept Cost" and slopes for single phase and three phase transformers.**

b. **Please state whether 33,069 Interconnected System Transformers is the total number of MDU transformers in Montana, as shown on the embedded cost study, and please explain how representative a sample of 24,849 transformers, as shown on the tab described above, is to the total number of MDU-Montana transformers.**

Response:

a. Please see the file provided in Response No. MCC-118 titled MCC-118Transformers.

b. The 33,069 Interconnected System Transformers is the total number of transformers in the Interconnected System. The sample of 24,849 transformers represents approximately 75% of all the transformers in the system.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-123

Regarding: Distribution Plant Allocation
Witness: Sara J. Cardwell

Tab "distribution plant" of Statement L (Embedded Cost of Service) shows that the 84/16 split between customer and demand for Poles, OH & UG Conductors & Conduit comes from the "Distribution Engineering Worksheet." Please provide a copy of this worksheet in electronic format, including all underlying data and calculations, supporting documents and formulas and links intact.

Response:

Please see Response No.MCC-117.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-124

Regarding: Marginal Distribution Line Costs
Witness: Sara J. Cardwell

a. **Please provide an electronic copy, with all source data, calculations and supporting documentation, of Statement Workpapers page L-43 and Attachment A provided in response to MCC-102.**

b. **Please explain in detail how the unit/mile costs shown on Attachment A for OHD Three Phase Line, Pole, URD Three Phase Line represent a Normal System, what the difference is between the calculation for these normal system and the calculation for a Minimum System.**

c. **On line 2a) Labor Loading shown on page 1 of Attachment A, it shows a value of 50.0%. Please explain what this 50.0% represents with respect to Total Labor with Loading.**

d. **Please define in detail the meaning of ES & GA, and how the associated percentages were determined.**

e. **Please explain why the total number of customers for Glendive District and Wolf Point District (25,683) is not the same as the Montana Jurisdiction Total Number of Customers (28,206).**

f. **Please provide all detail and supporting data for the Total Material Cost (non-exempt and exempt) of $19,212 (OHD Three Phase Line), $10,247 (Pole) and $39,406 (URD Three Phase Line), as shown on Attachment A provided in response to MCC-102.**

g. **Please verify if the cost amounts shown on Attachment A and Statement Workpapers page L-43 are 2014 dollars.**

Response:

a. Please see the file titled MCC – 124 Attachment A Workpaper L-43 for an electronic copy of Statement Workpaper page L-43 and please see the file titled MCC – 124 Attachment B for a working file including supporting documentation of information provided in Response No. MCC 102 Attachment A.

b. The OH_Min is a basic 1/0 ACSR three-phase line using all 30' pole with a 1000' of 1/0 triplex for service. The 1/0 ACSR one mile three-phase line would be the most basic OH line that the Company would construct, therefore it is a minimum cost line that we would build. The OH_Normal three-phase line based on 10% of the line being 336.4 MCM, 30% 3/0 AAC, and 60% 1/0 ACSR, with different pole being used ranging from 30' to 45' and 500' of 4/0 Quad and

500' of 1/0 triplex for service. The OH_Normal cost represents a more typical three-phase OH line construction cost.

The UG_Min is a basic JCN 1/0 UG three phase line with a 100' of 1/0 triplex UG for service and the line being installed only by trenching. This JCN 1/0 UG line would be the lease cost three-phase underline that the Company would install. The UG_Normal three phase line is based on 10% being JCN 350, 30% JCN 4/0, and 60% JCN 1/0, underground primary being installed and 60' of 1/0 triplex, 30' of 4/0 triplex, and 10' of 350 triplex service line. The installation of the underground is done by directional boring and trenching. The UG_Normal represents a more typical three-phase UG line construction cost.

c. The 50.0% loading factor represents payroll related costs incurred relative to vacation and other compensated absences, workers' compensation premiums, group insurance costs/premiums, post retirement, pension, 401-K plans, and administration costs associated with the Tax-free Options Plan (TOP), unemployment compensation taxes and the employer portion of the FICA tax (Social Security) on behalf of employees of Montana-Dakota.

d. Engineering and Supervision costs are costs that are incurred for salaries and wages, certain materials and other expenses related to engineering and supervisory functions in support of direct construction activities.

   General and Administration costs are costs that are incurred for salaries and wages, certain materials and other expenses related to general and administrative functions in support of direct construction activities.

   The ES & GA percentages are a calculation of the direct construction overhead charges divided by the projected capital expenditures.

e. The count of 25,683 represents the number of service points queried from the GIS system representing a snap shot at a point in time. The difference between that number and customers is attributable to timing and the fact that not all service lines are represented in the GIS.

f. Please see the file titled MCC – 124 Attachment B.

g. Yes. The amounts reported are in 2014 dollars.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-125

Regarding: Monthly Billing Determinants
Witness: Sara J. Cardwell

Data request MCC-107 asked monthly billing determinants for each of the customer classes. However, response to MCC-107 only provided monthly billing determinants at the Primary, Secondary and Substation level. Please provide monthly billing determinants by customer classes.

Response:

Please see Response No. MCC-007 Attachment A, Page 1 for Kwh sales and Response No. MCC-125 KW Sales.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Demand

Year	Month	Rate 10	Rate 20 Primary	Rate 20 Secondary	Rate 25	Rate 30 Primary	Rate 30 Secondary	Rate 31 Primary	Rate 31 Secondary	Rate 32	Rate 35	Rate 41 Municipal Owned Lighting	Rate 41 Company Owned Lighting	Rate 48	Rate 52	Total
2014	January		22.6	26,834.0	35.1	9,216.3	37,202.1	3,397.6	442.9	620.6	30,836.7			2,403.8		111,011.7
	February		22.5	26,185.3	27.2	10,164.6	35,518.9	3,044.8	637.3	565.5	29,362.0			2,354.2		107,882.3
	March		21.7	26,131.9	(17.7)	9,089.6	35,384.5	3,454.4	444.3	607.1	31,646.0			2,525.1		109,286.9
	April		20.2	25,191.1	70.1	6,788.5	34,229.1	3,103.2	423.6	557.8	31,775.2			2,339.3		104,498.1
	May		20.3	24,447.4	537.1	6,057.6	32,933.8	3,661.6	422.8	638.2	30,364.8			2,572.3		101,655.9
	June		19.9	26,168.9	1,533.7	5,802.5	35,629.5	3,272.8	106.7	410.9	29,293.6			2,657.9		104,896.4
	July		16.5	26,190.5	4,555.4	5,884.0	32,703.1	3,648.8	103.0	137.2	28,789.8			3,075.0		105,103.3
	August		17.8	28,109.2	3,739.7	7,957.1	34,505.0	3,389.6	102.1	102.3	29,759.2			2,941.7		110,623.7
	September		17.1	28,812.9	4,216.5	7,601.6	36,085.5	4,208.0	113.6	202.4	30,211.5			3,028.0		114,497.1
	October		17.2	27,794.9	2,404.3	11,278.5	35,808.8	4,287.2	390.1	593.2	30,034.0			2,711.4		115,319.6
	November		16.4	25,654.6	713.1	11,465.3	34,279.4	4,492.0	434.5	668.7	30,690.1			2,400.3		110,814.4
	December		22.0	26,893.3	73.8	11,834.7	36,192.9	4,526.4	478.5	796.1	29,960.0			2,447.4		113,225.1
	Total	-	234.2	318,414.0	17,888.3	103,140.3	420,472.6	44,486.4	4,099.4	5,900.0	362,722.9	-	-	31,456.4	-	1,308,814.5
2015	January		12.0	26,755.2	21.6	13,008.9	35,549.9	3,560.8	443.4	761.1	29,831.3			2,525.4		112,469.6
	February		13.7	26,423.2	15.1	12,302.4	37,430.8	3,569.6	433.7	728.4	30,681.2			2,486.4		114,084.5
	March		14.0	25,981.3	18.2	12,387.7	37,923.6	3,545.6	432.7	778.2	29,831.2			2,605.5		113,518.0
	April		14.5	25,042.2	643.5	11,089.3	36,269.2	3,316.0	402.7	660.6	30,348.9			2,489.6		110,276.5
	May		8.8	23,878.3	2,738.6	10,478.1	34,192.5	2,419.2	362.4	498.4	29,739.7			2,723.4		107,039.4
	June		13.8	25,117.7	3,184.4	9,928.1	35,033.0	3,021.6	339.6	511.0	29,736.4			2,681.7		109,567.3
	July		10.6	26,509.8	4,511.2	11,495.0	36,054.2	3,820.0	316.5	138.0	30,018.0			3,343.8		116,217.1
	August		10.0	27,904.8	6,079.0	10,751.3	36,574.7	3,902.4	359.9	101.4	29,608.8			3,191.2		118,483.5
	Total	-	97.4	207,612.5	17,211.6	91,440.8	289,027.9	27,155.2	3,090.9	4,177.1	239,795.5	-	-	22,047.0	-	901,655.9

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

MCC-126

Regarding: Statement M
Witness: Tamie A. Aberle

a. **Please explain the basis and show supporting calculations for determining the winter rate differential with respect to summer rate for the different classes as applicable (e.g., Residential Electric Service Rate 10 equal to $-0.01997 / kwh, and Small General Service Rate 20 equal to $-0.01880 / kwh, etc), as shown on the different rate tabs of file: Statement M Exhibit TAA-1_TAA-2.xlsx.**

b. **Please explain the basis and show supporting calculations for determining the secondary rate differential with respect to primary rate (e.g., Small General Service Rate 20 equal to $0.00100 / kwh, etc), as shown on the different rate tabs of file Statement M Exhibit TAA-1_TAA-2.xlsx.**

c. **Please explain the difference between the two kwhs values (135,654,617 and 113,115,178) related to winter rate that are shown on tab Rate 10 of the file Statement M Exhibit TAA-1_TAA-2.xlsx.**

Response:

a. The summer/winter differentials were held the same as the authorized rates.

b. The primary/secondary differentials were held the same as the authorized rates.

c. The 113,115,178 value for winter sales under Rate 10 was not used and should not have been included on the referenced schedule.