EXHIBIT
MDU-1
PU-19-306; PU-19-307; PU-19-317

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO. for an Advance Determination of Prudence and a Certificate of Public Convenience and Necessity for an 88 MW Simple Cycle Combustion Turbine	)))))))	Case No. PU-19-____

I. Summary of Application

Montana-Dakota Utilities Co. (Montana-Dakota or Applicant) is the Applicant in the above-entitled proceeding and makes application pursuant to N.D.C.C. § 49-05-16 for an Advance Determination of Prudence and N.D.C.C. Chapters 49-03 and 49-03.1 for a Certificate of Public Convenience and Necessity to construct, own and operate an 88 MW Frame type simple cycle combustion turbine and associated facilities hereinafter referred to as Heskett 4. Heskett 4 will be located on currently owned property that is adjacent to and within the siting boundary of Montana-Dakota's Heskett Unit 3 (Heskett 3), an 88 MW simple cycle combustion turbine located near Mandan, North Dakota. Heskett 4 is required to meet the capacity requirements of Montana-Dakota's electric service customers served by its integrated electric system. The 2019 Integrated Resource Plan (2019 IRP) filed with the Commission on July 1, 2019 (Case No. PU-19-221) describes the need for the resource addition and justification that the addition of this resource is the least cost option for meeting a portion of the identified need.

Montana-Dakota will show in this Application that public convenience and necessity will be served by the construction and operation of the proposed facilities, that

Montana-Dakota is fit, willing and able to provide such service and that Heskett 4 is a prudent and reasonable resource for its North Dakota electric customers.

II. Description of Applicant

Montana-Dakota is a Delaware corporation duly authorized to do business in the State of North Dakota as a foreign corporation and doing business in the State of North Dakota as a public utility subject to the jurisdiction of and regulation by the North Dakota Public Service Commission (Commission) under Title 49, N.D.C.C., as amended. Montana-Dakota's Certificate of Incorporation and amendments thereto have been previously filed with the Commission under Case No. PU-08-710 and such Certificate and Amendments are hereby incorporated by reference as though fully set forth herein. Montana-Dakota provides electric service to approximately 143,000 customers with approximately 93,000 of those customers located in North Dakota. Company witnesses, Darcy Neigum, Director of Electric Systems Operation & Planning, Alan Welte, Director of Generation and Travis Jacobson, Regulatory Analysis Manager will provide testimony in support of this Application.

III. Description of the Project

Montana-Dakota seeks authorization to own and operate Heskett 4, an 88 MW Simple Cycle Combustion Turbine (SCCT) and associated facilities necessary to interconnect with Montana-Dakota's existing electric and natural gas systems. Heskett 4 is proposed to be located on Company owned property that is adjacent to Montana-Dakota's Heskett 3 near Mandan, North Dakota.

Montana-Dakota retained Burns & McDonnell Engineering Company (BMcD) to prepare a supply-side resource technology assessment as part of the 2019 IRP. This assessment evaluated various power generation technologies as self-build supply-side resource options for Montana-Dakota's Electric Generation Expansion Analysis System (EGEAS) modeling. The supply-side analysis is attached as Exhibit 1 (the document is also included in Attachment E of Volume 4 of the 2019 IRP). The specific criteria leading to the selection of Heskett 4 at the existing site included; selection of the combustion turbine type, natural gas supply requirements, electric transmission interconnection, electric transmission network upgrades, Heskett 3 site synergies, environmental permitting and other factors.

Following is a summary from the evaluation of combustion turbines detailed in Exhibit 1:

> **Combustion Turbine Type** – SCCT resources were evaluated as part of the 2019 IRP supply-side analysis. SCCTs are primarily used for peaking service, generally have lower capital costs than other resource types, and can be installed within relatively short time periods. The two primary SCCT types analyzed were: 1) heavy-duty (Frame) type designed to drive stationary generation resources and process plant equipment, and 2) aero-derivative (Aero) type derived from engines used in the aircraft industry. A list of SCCTs considered is provided in Appendix B of Exhibit 1. Heskett 4 was analyzed against the same Frame-size SCCT at a greenfield site in Exhibit 1. The comparative analysis included cost reductions for Heskett 4 associated with natural gas supply requirements, electric transmission

interconnection, electric transmission network upgrades, Heskett 3 site synergies, environmental permitting and other factors. The results of the comparative analysis, provided in Appendix B of Exhibit 1, also showed significant cost savings for Heskett 4 versus other greenfield SCCT resources.

Natural Gas Supply – Aero type SCCTs require a minimum natural gas inlet pressure of 675-1000 psi. Frame type SCCTs, such as proposed for Heskett 4, require lower pressure, typically 350-500 psi. Exhibit 1 assumed the new SCCTs could be supplied with natural gas delivered through the Northern Border Pipeline system (NBPL). NBPL provides the necessary high-pressure deliveries along with the option of firm transportation contracts, eliminating the need for additional on-site natural gas compression equipment and dual fuel capabilities. A 24-mile natural gas pipeline already owned by Montana-Dakota interconnects Heskett 3 to NBPL and is sized to provide enough natural gas capacity to supply Heskett 3 and Heskett 4 in a 2x0 (SCCT-only) configuration or in a 2x1 combined cycle combustion turbine (CCCT) configuration. As provided in Appendix B of Exhibit 1, the additional cost for a new natural gas interconnection pipeline for a greenfield SCCT is estimated at $7.4M for 5 miles of pipeline. This additional cost would not be required for Heskett 4.

Electric Transmission Interconnection – As a member of the Midcontinent Independent Transmission System Operator (MISO), Montana-Dakota assumed a location within the state of North Dakota where the point of generator interconnection would be to MISO transmission facilities currently owned by Montana-Dakota. At the time Exhibit 1 was prepared, the average transmission network upgrade costs for new generator interconnections in MISO's West region were approximately $113 per kW[1]. Montana-Dakota intends to time the in-service date of Heskett 4 so that the existing 103.1 MW of MISO transmission interconnect rights for Heskett 1 and Heskett 2 can be retained for use by Heskett 4 through MISO's generator replacement process[2]. By retaining the transmission interconnect rights of Heskett 1 and Heskett 2, Montana-Dakota believes that Heskett 4 will not incur transmission network upgrade costs. An application for the generator replacement process was filed with MISO in June of 2019. The generator replacement studies were kicked off on July 8, 2019, with final results

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[1] The MISO generator interconnection process has three study (DPP) phases per queue cycle, with network upgrade costs identified at the end of each DPP. Each DPP is also subject to re-study and revision over time, making network upgrade cost averages very dependent on when the average is calculated. The network upgrade cost assumption of approximately $113 per kW used in Exhibit 1 was based on the 2016-Feb MISO West DPP3 average network upgrade costs for NRIS service prior to addition of project G359R to and re-study of the 2016-Feb cycle. As of August 14, 2019, three queue cycles in MISO West (2016-Feb, 2016-Aug, 2017-Feb) have completed DPP1 and DPP2, and two queue cycles (2016-Feb, 2016-Aug) have completed DPP3. The corresponding network upgrade costs for NRIS service have approximately averaged $650/kW (DPP1), $385/kW (DPP2), and $111/kW (DPP3).

[2] The MISO generator replacement study process allows for a new generator to retain the existing MISO transmission interconnection rights of a generator that is being retired if the changes don't have major impacts to the larger MISO transmission system. The primary advantages to using the MISO generator replacement process are to avoid the lengthy MISO generator interconnection process and the cost risks associated with MISO transmission network upgrades.

expected by December 2019. As shown in Exhibit 1, Appendix B, the additional cost for transmission interconnection, including 15 miles of 115kV transmission line, and MISO transmission network upgrades for a greenfield SCCT of the same size as Heskett 4 is $25.5M. This additional cost would not be required for Heskett 4.

Environmental Permitting – Preliminary indications are that there are no significant concerns foreseen in permitting Heskett 4. Montana-Dakota is expecting that decommissioning of Heskett 1 and 2 will allow for air emissions netting of Heskett 4 which should streamline air permitting for the SCCT. Utilizing the developed site location next to Heskett 3 will minimize disturbance to the environment and is a benefit over a greenfield site. Utilizing existing infrastructure (to the extent possible) for water sourcing and handling waste streams also provides benefits over greenfield location permitting.

Other Factors – During the design and construction of Heskett 3, the possibilities of expanding the site in the future to a 2x0 (SCCT - only) configuration or a 2x1 CCCT configuration were taken into consideration. Included in these considerations were the sizing and location of the natural gas supply pipeline, underground fire protection loop, storm and waste water drainage, electrical equipment room, and underground electrical conduit, among others. It is expected that Heskett 4 will take advantage of this existing infrastructure, which will reduce the overall capital cost of the project as compared to a greenfield site. Montana-Dakota expects to reuse the existing construction parking, equipment laydown area, and overall site layout with minimal modifications. This will reduce the amount of pre-construction work to be completed, supporting an overall shorter construction schedule and reduced project cost as compared to a greenfield site. The Heskett 3 site also offers the potential for sharing of facilities, equipment, spare parts, supervision, labor, and land.

As detailed in Exhibit 1, the information provided by BMcD was screening-level in nature and for comparative purposes only (not to be used for construction purposes). BMcD recommended that for any self-build supply-side resource options of interest to Montana-Dakota, their analysis should be followed by additional detailed studies. As an interim step prior to hiring a consultant to perform additional detailed studies of Heskett 4, Montana-Dakota used its experience obtained from the construction of Heskett 3 to perform a more detailed internal cost investigation of Heskett 4. This investigation provided a more refined cost estimate for inclusion in the final EGEAS modeling and is provided in Exhibit 2 (the document is also included in Attachment E of Volume 4 of the 2019 IRP).

In summary, installing Heskett 4 adjacent to Montana-Dakota's Heskett 3 near Mandan, North Dakota, provides a significant advantage over a greenfield site. The capital cost is lower because the existing infrastructure, including the natural gas and electric transmission interconnections, can be used without the need for significant expansion. Costs associated with MISO transmission network upgrades are expected to be avoided due to the planned retirement of Heskett 1 and 2. In addition, the location provides the opportunity for sharing of facilities, equipment, spare parts, supervision, and labor with Heskett 3 that will result in reduced operating costs and beneficial use of existing land rights on the station site.

A summary of the total estimated unloaded capital cost and estimated capacity for Heskett 4 is as follows:

	Greenfield SCCT (BMcD Assessment)[3]	**Heskett 4 (Montana-Dakota Estimate)[4]**
Capital Cost Estimate (2019$ millions)	$124.3	$68.7
Summer Net Output (kW)	78,280	78,280
Summer Net Output ($ per kW)	$1,588	$878
Winter Net Output (kW)	97,680	97,680
Winter Net Output ($ per kW)	$1,273	$703

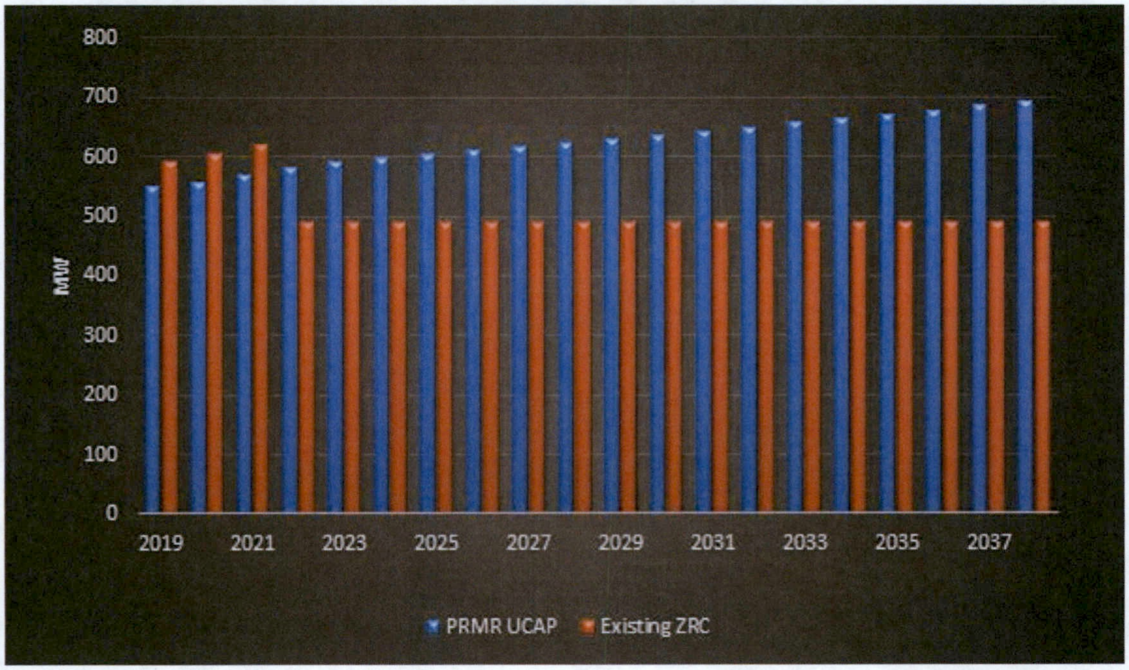
IV. Need and Justification for the Project

The need for Heskett 4 has been determined and documented through the 2019 IRP process. As shown below, Montana-Dakota is forecasting a capacity deficit to occur beginning in 2022 associated with the retirement of the Lewis & Clark 1, Heskett 1, and Heskett 2 coal-fired power plants (assumed to occur and the end of 2021 for modelling purposes). Under the base forecast the capacity deficit is predicted to be 92 zonal

[3] Exhibit 1, Appendix B.
[4] Exhibit 2, page 5. Montana-Dakota's estimated cost including AFUDC is $73.0 Million. The cost of $68.7 Million was the input used in the 2019 IRP EGEAS modelling as the EGEAS model separately applies AFUDC to each project.

resource credits (ZRCs) by the summer of 2022. Heskett 4 will provide approximately 78 ZRCs.

Planning Resource Credit and
Planning Reserve Margin Requirement Base Forecast



Heskett 4 is shown to be a least cost resource as part of the resource plan additions required in 2019 IRP in the 2019-2023 time period under each of the sensitivity scenarios analyzed. The Supply-Side and Integration Analysis Documentation provided in Attachment C of Volume 4 of the 2019 IRP offers a complete description of capacity resources and supply-side alternatives considered in the study. EGEAS was used to perform the resource expansion analysis and to develop the least-cost integrated resource expansion plan. Resource alternatives considered included simple cycle combustion turbines, combined cycle combustion turbines, reciprocating engine generation, coal generation, wind generation, solar generation plus battery storage, biomass, purchased capacity, and purchased wind energy. A Request for Proposal was issued on August 1, 2018, to solicit proposals for capacity and/or energy resources that could also be considered as part of Montana-Dakota's resource evaluation. Thirteen planning scenarios, including a base case and nine sensitivity runs, were considered. The sensitivity scenarios consisted of various assumptions regarding the following:

- Decrease in forecasted MISO energy market purchase prices of $3 per MWh under the base case assumptions.
- Increase in forecasted MISO energy market purchase prices of $5 and $10 per MWh over the base case assumptions.
- Decrease in forecasted natural gas purchase prices of $1 per MMBtu under the base case assumptions.
- Increase in forecasted natural gas purchase prices of $2 and $5 per MMBtu over the base case assumptions.
- Forecasted requirements assuming low growth at 0.5 percent per year over the 20-year forecast.
- Forecasted requirements assuming high growth at 4.4 percent per year over the 20-year forecast.
- A twenty percent increase in capital and O&M costs for future combustion turbines to account for associated increases in combustion turbine costs.
- A ninety percent MISO coincident factor to account for increased capacity requirements under MISO resource adequacy construct.
- A $30 per ton carbon tax was added in 2025 to every ton of CO_2 emitted from Montana-Dakota's coal fired units and natural gas fired combustion turbines, MISO energy purchases and new fossil generating units.

- Increase in both MISO forecasted energy market purchase prices of plus $25 per MWh and forecasted natural gas purchase price of $5 per MMBtu over the base case assumptions.

While the total cost of the generation portfolio changed with each scenario, the addition of Heskett 4 remained part of the least cost resource mix in each of the scenarios studied.

In addition to the sensitivity analysis described above, a separate model was prepared comparing the estimated revenue requirement assuming Lewis & Clark 1, Heskett 1 and Heskett 2 continue to run to the estimated revenue requirement associated with the post-retirement costs for Lewis & Clark 1, Heskett 1 and Heskett 2 plus the cost of replacing the output from those plants with market energy purchases, replacement capacity purchases and Heskett 4. The results of the modeling provided in Exhibit No.___(TRJ-1) to Mr. Jacobson's testimony showed the total cost of the retirement and replacement option was approximately $20 million less on an annual basis in 2023 compared to the total cost to run the units to be retired. This analysis further supports the addition of Heskett 4.

V. Cost Estimate

The Heskett 4 cost is estimated to be $73.0 million with North Dakota's allocated share of the estimated cost of Heskett 4 approximately $51.8 million.

VI. Contracting Approach

Montana-Dakota intends to hire an engineering consultant to perform the detailed design, assist with the procurement process from bid phase through administration of contracts after award, and manage on-site construction, commissioning, and startup activities for Heskett 4. This contracting approach is commonly referred to as an Engineer, procurement support, and Construction Management (EpCM) contracting approach, and is very similar to the multiple contracts approach used for Heskett 3. Montana-Dakota expects that there will be at least seven major equipment contracts, one or more major construction contracts, and several smaller contracts for specialized equipment, construction, and services for Heskett 4. Major contracts for equipment, construction, and services will be directly between Montana-Dakota and the associated vendor.

While there are advantages and disadvantages to every contracting approach commonly used for electric generation construction projects, Montana-Dakota believes the EpCM approach is the best fit for Heskett 4 and will provide the following benefits.

- Montana-Dakota will have more control over the design, procurement, and construction of Heskett 4 versus using a turnkey approach. This allows Montana-Dakota more flexibility to make changes as the project progresses to address inadequate design features, construction field changes, and other unexpected issues that arise.
- Montana-Dakota can leverage the technical specifications and commercial terms that were developed for Heskett 3 to help keep procurement support costs low. Montana-Dakota expects that the major contracts required for

Heskett 4 equipment, construction, and services will be very similar to Heskett 3 and that the associated technical specifications and commercial terms from Heskett 3 will require minimal changes to be used for Heskett 4.

- Montana-Dakota can leverage equipment vendors that bid on Heskett 3 to shorten the vetting process for Heskett 4 equipment procurement. In addition to helping keep procurement support costs low, this approach may also allow Montana-Dakota to take advantage of existing operating experience (less training) and to maintain fewer spare parts in inventory if identical vendors/equipment are selected during the Heskett 4 equipment procurement process.
- Montana-Dakota can manage project risks internally to lower the overall project cost. The typical markup to have a turnkey contractor manage project risks is 5-10% of the project costs. Because Heskett 4 is a brownfield project expected to be very similar to Heskett 3 in design and execution, Montana-Dakota believes the risk profile for the Heskett 4 project is low.

VII. Construction Timeline

Below is a table showing major construction milestones.

Begin Permitting Process	March-2019
Submit MISO Generator Replacement Application	June-2019
Receive MISO Generator Interconnect Agreement	January-2020
Begin Detailed Engineering Work	January-2021
Begin Major Equipment Procurement	February-2021
All Required Permits Received	June-2021
Award SCCT Contract	June-2021
Award Construction Contract	November-2021

Begin Construction	March-2022
All Major Equipment Delivered to Site	July-2022
Back Energize Substation	October-2022
Begin Performance/Emissions Testing	January-2023
Commercial Operation Date	February-2023

VIII. Reasonableness and Prudence of the Project

Montana-Dakota requests an advance determination of prudence for the construction and operation of Heskett 4. A finding that this investment will be deemed reasonable and prudent and recoverable through rates at a point in the future is necessary in order to facilitate the approximate $73.0 million investment associated with this resource addition. As provided in N.D.C.C. § 49-05-16 the Commission may issue an order approving the prudence of an electric resource addition if the following conditions are met:

a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;
b. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars;
c. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
d. The commission determines that the resource addition is prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

Montana-Dakota has met the above conditions and requests that the Heskett 4 generating unit be deemed a reasonable and prudent investment for Montana-Dakota's North Dakota electric customers.

IX. Conclusion

Applicant respectfully requests that the Commission:

1. Give Notice of Opportunity to request a hearing to interested parties and, if no hearing is requested within twenty days, to waive the hearing in accordance with §49-

03.1-05, N.D.C.C.;

2. Enter an Order making a determination that the Heskett 4 generating unit is prudent pursuant to the requirements of to N.D.C.C. §49-05-16:

3. Enter an Order and issue a Certificate of Public Convenience and Necessity authorizing the Applicant to construct, own and operate an 88 MW simple cycle combustion turbine; and.

3. Grant such other relief as the Commission shall deem appropriate.

Dated this 28th day of August, 2019.

Tamie A Aberle

Tamie A. Aberle
Director of Regulatory Affairs

Subscribed and sworn to before me this 28th day of August, 2019.

Caitlin Straabe

CAITLIN STRAABE
Notary Public
State of North Dakota
My Commission Expires August 28, 2023

Caitlin Straabe, Notary Public
Burleigh County, North Dakota
My Commission Expires: 09/28/2023

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BURNS McDONNELL

2019 IRP Technology Assessment

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

Montana-Dakota Utilities Co.

2019 IRP Technology Assessment
Project No. 109770

Revision 3
March 2019

2019 IRP Technology Assessment

prepared for

Montana-Dakota Utilities Co.
2019 IRP Technology Assessment
Bismarck, North Dakota

Project No. 109770

Revision 3
March 2019

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BMcD	Burns & McDonnell Engineering Company, Inc.
BACT	Best Available Control Technology
BFB	Bubbling Fluidized Bed
CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
COD	Commercial Operating Date
DLN	Dry Low NOx
DOE	Department of Energy
EPA	Environmental Protection Agency
EpCM	Engineer, Procurement-Assistance, Construction Management
FAA	Federal Aviation Administration
FGD	Flue Gas Desulfurization
FTE	Full-Time Equivalent
GCF	Gross Capacity Factor
GSU	Generator Step-Up Transformer
GTG	Gas Turbine Generator
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
ITC	Investment Tax Credit

Abbreviation	**Term/Phrase/Name**
LAES	Liquid Air Energy Storage
LEC	Lignite Energy Council
LHV	Lower Heating Value
LLI	Late Lean Injection
MCFC	Molten-Carbonate Fuel Cell
MDU	Montana-Dakota Utilities Co.
MECL	Minimum Emissions Compliant Load
NCF	Net Capacity Factor
NOx	Nitrous Oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
OEM	Original Equipment Manufacturer
PM	Particulate Matter
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SOFC	Solid Oxide Fuel Cell
STG	Steam Turbine Generator
VOC	Volatile Organic Compounds

1.0 INTRODUCTION

Montana-Dakota Utilities Co. (Montana-Dakota or Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various power generation technologies in support of its power supply planning efforts. The 2019 IRP Technology Assessment (Assessment) is screening-level in nature and includes a comparison of technical features, cost, performance, and emissions characteristics of the generation technologies listed below. Information provided in this Assessment is preliminary in nature and is intended to highlight indicative, differential costs associated with each technology. Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. The basis for all estimates and projections is included in this report in Section 2.0.

It is the understanding of BMcD that this Assessment will be used for preliminary information in support of the Owner's long-term power supply planning process and should not be used for construction purposes. Any technologies of interest to the Owner should be followed by additional detailed studies to further investigate each technology and its direct application within the Owner's long-term plans.

1.1 Evaluated Technologies

- Simple cycle gas turbine (SCGT) technologies
  - LM6000 PF+ Aeroderivative
    - SCR option
  - LMS 100 PB+ Aeroderivative
    - SCR and CO Oxidation Catalyst Included
  - 7E.03 LLI SCGT
    - SCR option
    - R.M. Heskett expansion option
  - All options include evaporative coolers
  - Natural gas only
- Reciprocating engine technology:
  - 4x 9MW engine plant
  - 3x18MW engine plant
  - Natural gas only
  - SCR and CO Catalyst included
- Combined cycle gas turbine (CCGT) technologies
  - 2x1 SGT-800

    - SCR and CO Catalyst included
  - 1x1 F class
    - SCR and CO Catalyst included
  - 2x1 7E.03 LLI R.M. Heskett Expansion
    - SCR option
  - Incremental duct firing option included for all CCGT technologies
  - Evaporative coolers included for all CCGT technologies
  - Natural gas only
- Wind Generation
  - 20 MW – 9 x GE 2.72-116
  - 50 MW – 23 x GE 2.72-116
- Solar PV
  - 5 MWac
    - Single axis tracking
    - Add-On Cost for 1 MW / 4 MWh co-located Li-Ion battery energy storage
  - 50 MWac
    - Single axis tracking
    - Add-On Cost for 10 MW / 40 MWh co-located Li-Ion battery energy storage
- Biomass
  - 25 MW
    - Bubbling Fluidized Bed
  - Grasses Fuel Design
- Coal
  - Circulating Fluidized Bed without Carbon Capture
  - Circulating Fluidized Bed with Carbon Capture
  - Coal technology information provided by Montana-Dakota, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council (2012).

1.2 Assessment Approach

This report accompanies the 2019 IRP Technology Assessment spreadsheet file (Summary Table) provided by BMcD in Appendix B.

This report compiles the assumptions and methodologies used by BMcD during the Assessment. Its purpose is to articulate that the delivered information is in alignment with Montana-Dakota's intent to advance its resource planning initiatives. Appendix A includes a scope assumptions matrix that was sent to Montana-Dakota and incorporates comments from Montana-Dakota.

1.3 Statement of Limitations

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

2.0 STUDY BASIS AND ASSUMPTIONS

2.1 Scope Basis and Assumptions Matrix

Scope and economic assumptions used in developing the Assessment are presented below. A spreadsheet-based scope matrix was delivered to Montana-Dakota at the start of the project. An updated matrix is included for reference in Appendix A.

2.2 General Assumptions

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M estimates are stated in 2019 US dollars (USD). Escalation is excluded.
- Estimates assume an EpCM philosophy for project execution. This philosophy assumes that the contractor will provide engineering services, aid in procurement activities like specification development and bid analysis and provide construction management services.
- Unless stated otherwise, all options are based on a generic site with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material.
- Sites are assumed to be flat, with minimal rock and with soils suitable for spread footings.
- Ambient conditions are based on Montana-Dakota requests:
  - North Dakota
    - Elevation: 1690 ft.
    - Winter Conditions: 6.8°F and 70% RH
    - Summer Conditions: 84.5°F and 40% RH
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- The primary fuel for the SCGT, CCGT, and reciprocating engine options is pipeline quality natural gas. SCGT, CCGT and reciprocating engine performance is based on natural gas operation.
- Interconnection allowances for water, natural gas, and transmission are listed in the Summary Table and general assumptions are discussed in the Owner Cost section of this report.

- Supplemental metering and regulation equipment is included for natural gas technology options. This equipment is not intended for billing purposes, but rather for Owner confirmation and regulation of fuel provided by the gas company.
- Based on the provided natural gas, it is assumed that fuel gas compression is unnecessary. Pressure regulation and dew point heaters are included for applicable technologies.

- Incremental impacts of duct firing are included in the Summary Table for capital costs and performance estimates for combined cycle plant options.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- Effluent discharge to ponds onsite as applicable.
- EpCM electrical scope is assumed to end at the high side of the generator step up transformer (GSU). Unless otherwise stated, GSU costs assume 115 kV transmission voltage. Allowances for equipment after the high side of the GSU and network upgrades are discussed in subsection 2.4.
- Demolition or removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- Emissions are estimated at base load operation at ISO conditions.
- Water and ammonia consumption are estimated at ISO conditions.

2.3 EPC Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing and CEMS/stack emissions testing (where applicable)
- Construction/startup technical service
- Engineering and construction management
- Freight
- Startup spare parts

2.4 Owner Costs

Allowances for the following Owner's costs are included in the pricing estimates:

- Owner's project development
- Owner's operational personnel prior to COD
- Owner's project management
- Owner's legal costs

- Owner's Start-up Engineering
- Land allowance, as applicable:
  - Allowance is $5,000/acre for all applicable technology options
  - Exceptions:
    - Wind and PV projects assumed leased land. Land costs are excluded from Owner costs and covered instead in the O&M category.
    - Wind options assume typical industry spacing expected to meet any minimum site control requirement.
    - Solar options assume 8 acres/MW for tracking.
    - All options located at R.M. Heskett Station.
- Permitting and licensing fees
- Construction power, temporary utilities
- Startup consumables
- Site security
- Operating spare parts
- Switchyard (assumes 115 kV for transmission voltage)
  - Exceptions: Storage and PV options assume interconnection at distribution voltage.
- Transmission interconnection
  - Allowances for 15 miles of transmission at 115 kV. Simple cycle options assume a single circuit while combined cycle plant options assume double circuit transmission, unless otherwise noted on the Summary Table. Costs are based on public planning documents. Assumes no major geographic obstructions to the line.
- Gas Interconnection
  - Allowances for a five mile pipeline, utility interconnection and metering station, unless otherwise noted on the Summary Table. Assumes no major geographic obstructions to the line. The pipeline diameters assumed for each of the technologies in the assessment are listed below:
    - 4": LM6000 PF+, Reciprocating Engines, Coal and Biomass options
    - 6": LMS100 PB+, 7E.03 LLI (SCGT)
    - 8": 2x1 SGT-800, 1x1 F class
- Water Interconnection
  - Allowances for site wells and piping for raw water supply.

- MISO Queue Fees and Network Upgrades are presented as allowances as provided by Montana-Dakota.
- Political concessions / area development fees for greenfield projects as applicable.
- Permanent plant equipment and furnishings.
- Builder's risk insurance at 0.45% of construction cost.
- Owner project contingency at 10% of total costs for screening purposes.

2.5 Project Capital Cost Estimate Exclusions

The following costs are excluded from all Project Capital Cost estimates:

- Financing fees
- Escalation
- Sales tax
- Property tax and property insurance. Included in O&M with rates provided by Montana-Dakota.
- Off-site infrastructure
- Utility demand costs
- Decommissioning costs
- Salvage values

2.6 Loaded Costs

Interest During Construction (IDC) is presented in the Summary Table as determined by Montana-Dakota based on cash flows provided by BMcD.

2.7 Operating and Maintenance Assumptions

Operations and maintenance (O&M) estimates are based on the following assumptions:

- O&M costs are based on a greenfield facility with new and clean equipment.
- O&M costs are in 2019 USD.
- O&M estimates exclude emissions credit costs.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.
- Land lease allowance included for PV and onshore wind options.
- Where applicable, fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.

- Personnel counts for each technology are included in the scope matrix in Appendix A.
- Where applicable, variable O&M costs include routine maintenance, makeup water, water treatment, water disposal, ammonia, selective catalytic reduction (SCR) replacements, and other consumables not including fuel.
- Fuel costs are excluded from O&M estimates.
- Where applicable, major maintenance costs are shown separately from variable O&M costs.
- Gas turbine and reciprocating engine major maintenance assumes third party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer (OEM).
- Base O&M costs are based on performance estimates at ISO conditions.

3.0 SIMPLE CYCLE GAS TURBINE TECHNOLOGY

3.1 Simple Cycle Gas Turbine Technology Description

An SCGT plant utilizes natural gas to produce power in a gas turbine generator. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Simple cycle gas turbines are typically used for peaking power due to their fast load ramp rates and relatively low capital costs. However, the units have high heat rates compared to combined cycle technologies. Simple cycle gas turbine generation is a widely used, mature technology.

Evaporative coolers or inlet foggers are often used to cool the air entering the gas turbine by evaporating additional water vapor into the air, which increases the mass flow through the turbine and therefore increases the output. Evaporative coolers or inlet foggers, depending on the turbine OEM, are included as options on all SCGT technologies in this assessment.

While this is a mature technology category, it is also a highly competitive marketplace. Manufacturers are continuously seeking incremental gains in output and efficiency while reducing emissions and onsite construction time. Frame unit manufacturers are striving to implement faster starts and improved efficiency. Combustor design updates allow improved ramp rates, turndown, fuel variation, efficiency, and emissions characteristics. Aeroderivative turbines also benefit from the research and development (R&D) efforts of the aviation industry, including advances in metallurgy and other materials.

Low load or part load capability may be an important characteristic depending on the expected operational profile of the plant. Low load operation allows the SCGT's to remain online and generate a small amount of power while having the ability to quickly ramp to full load without going through the full start sequence. Most turbines can sustain stable operation at synchronous idle, when the SCGT generator is synched with the grid but there is virtually no load on the turbine. At synchronous idle, a turbine runs on minimal fuel input and generates minimal power.

3.1.1 Aeroderivative Gas Turbines

Aeroderivative gas turbine technology is based on aircraft jet engine design, built with high quality materials that allow for increased turbine cycling. The output of commercially available aeroderivative turbines ranges from less than 20 MW to approximately 100 MW in generation capacity. In simple cycle configurations, these machines typically operate more efficiently than larger frame units and exhibit shorter ramp up and turndown times, making them ideal for peaking and load following applications. Aeroderivative units typically require fuel gas to be supplied at higher pressures (i.e. 675 psig to 960 psig for many models) than more traditional frame units.

A desirable attribute of aeroderivative turbines is the ability to start and ramp up load quickly. Most manufacturers will guarantee ten-minute starts, measured from the time the start sequence is initiated to when the unit is at 100 percent load. Simple cycle gas turbine starts are generally not affected by cold, warm, or hot conditions. However, all gas turbine start times in this Assessment assume that all start permissives are met, which can include purge credits, lube oil temperature, fuel pressure, etc. Available aeroderivative gas turbines models include both Dry Low NOx (DLN) and water injection methods to control emissions during natural gas operation. Additionally, some aeroderivative models include intercooler or fogging systems that would also require greater water usage. Both factors can greatly influence variable O&M to acquire water of the quality necessary to meet these needs.

Aeroderivative turbines are considered mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including General Electric (GE), Siemens (including Rolls Royce turbines), and Mitsubishi-owned Pratt & Whitney Power Systems (PWPS). This assessment includes GE LM6000 and GE LMS100 options.

3.1.2 Frame Gas Turbines

Frame style turbines are industrial engines, more conventional in design, that are typically used in intermediate to baseload applications. In simple cycle configurations, these engines typically have higher heat rates when compared to aeroderivative engines. The smaller frame units have simple cycle heat rates around 11,000 Btu/kWh (HHV) or higher while the largest units exhibit heat rates approaching 9,000 Btu/kWh (HHV). However, frame units have higher exhaust temperatures (≈1,100°F) compared to aeroderivative units (≈850°F), making them more efficient in combined cycle operation because exhaust energy is further utilized. Frame units typically require fuel gas at lower pressures than aeroderivative units (i.e. ~500 psig).

Traditionally, frame turbines exhibit slower startup times and ramp rates than aeroderivative models, but manufacturers are consistently improving these characteristics. Conventional start times are commonly 30 minutes for frame turbines, but fast start options allow 10 to 15 minute starts. Most available frame gas turbine models utilize DLN to control emissions during natural gas operation. This can result in decreased water usage in comparison to aeroderivative gas turbines which can influence variable O&M.

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Alstom. Commercially available frame units range in size from approximately 5 MW to 425 MW for 60 Hz applications. Continued development by gas turbine manufacturers has resulted in the separation of gas turbines into several classes, grouped by output and firing temperature: E class turbines (nominal 85 to 100 MW); F class turbines (nominal 200 to 240 MW); G/H class turbines (nominal 270 to 300 MW); and J class turbines (nominal 325 to 400 MW). This Assessment includes a GE 7E.03 LLI option.

3.2 Simple Cycle Gas Turbine Emissions Controls

All emissions discussion below is preliminary and should not be used for permitting purposes. It assumes that completed sites would be considered a major emissions source located at a greenfield non-listed source. For all options located at the R.M. Heskett Station, further analysis would be required to provide the same level of information.

Emissions levels and required NO_x and CO controls vary by technology and site constraints. Historically, natural gas SCGT peaking plants have not required post-combustion emissions control systems because they normally operate at low capacity factors. However, permitting trends suggest post-combustion controls may be required depending on annual number of gas turbine operating hours, proximity of the site to a non-attainment area, and current state regulations.

In addition, there is a New Source Performance Standard (NSPS) limit for NO_x emissions measured in parts per million (ppm), independent of operating hours. Per NSPS, units with heat inputs below 850 MMBtu/hr have a NO_x limit of 25 ppm, but units with heat inputs greater than 850 MMBtu/hr have a NOx limit of 15 ppm. Furthermore, in the event the overall facility has the potential to emit greater than 250 tons per year of NO_x emissions, a new source review as a major emissions source at a non-listed facility could be triggered. In that case, selective catalytic reduction may be required or the number of operating hours available for the facility may be limited. Additionally, under Subpart TTTT, newly constructed stationary combustion turbines must emit less than 1000 lb CO_2/MWh (gross) or be limited to a net capacity factor of its design efficiency (or 50 percent; whichever is lower).

Most turbine manufacturers will guarantee emissions down to a specified minimum load, commonly 40 to 50 percent load. Below this load, turbine emissions may spike. As such, emissions on a ppm basis may be significantly higher at low loads.

The greenfield 7E.03 LLI gas turbine in this evaluation uses dry-low-NO_x (DLN) combustors to achieve minimum NO_x emissions of 5 ppm at 15 percent O_2 at full load and ISO conditions while operating on natural gas fuel. Since these units emit less than 15 ppm NO_x, and because emissions will be less than 250 tpy using a capacity factor of 15 percent, it is assumed that an SCR is not required. For a single unit installation as investigated in this Study, no capacity factor is expected to trigger operating limits by exceeding the 250 tpy NO_x limit. However, using the summer design efficiency and output without evaporative coolers of 29 percent (HHV) and 73,800 kW respectively, the 7E.03 LLI has a maximum net generation limit of 192,780 MWh on a 12-operating month basis. This corresponds to a maximum net capacity factor of approximately 29.8 percent. The 7E.03 LLI gas turbine located at R.M. Heskett station utilizes the same emissions control technology but may face different emissions controls requirements.

Capital and owner's costs for an SCR system are included as optional costs in the Summary Table for the 7E.03 LLI simple cycle gas turbine option in this Assessment.

Aeroderivative units commonly have options for DLN combustors or water injection to control NOx emissions to approximately 15-25 ppm. The GE LM6000 PF+ option in this Assessment utilizes DLN combustors to achieve NO_x emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel. Because the LM6000 PF+ has a heat input below 850 MMBtu/hr, it is expected to meet the appropriate 25ppm NO_x limit per the NSPS limits discussed previously. Furthermore, because NO_x emissions will be less than 250 tpy using an assumed capacity factor of 15 percent, it is assumed that an SCR is not required. For a single unit installation as investigated in this Study, the LM6000 PF+ no capacity factor is expected to trigger operating limits by exceeding the 250 tpy NOx limit. However, using the summer design efficiency and output without evaporative coolers of 35 percent (HHV) and 47,900 kW respectively, the LM6000 PF+ has a maximum net generation limit of 127,540 MWh on a 12-operating month basis. This corresponds to a maximum net capacity factor of approximately 35.8 percent.

Capital and owner's costs for an SCR system are included as optional costs for the LM6000 PF+ option in this Assessment.

Similarly, the GE LMS100 PB+ option ins this Assessment utilizes DLN combustor to achieve NO_x emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel. However, this unit has an expected heat input greater than 850 MMBtu/hr and a design NO_x emissions rating of 25 ppm at 15 percent O_2 while operating on natural gas fuel. This means that an SCR system would be required. Additionally, using the summer design efficiency and output without evaporative coolers of 38 percent (HHV) and 90,300 kW respectively, the LMS100 PB+ has a maximum net generation limit of 301,630 MWh on a 12-operating month basis. This corresponds to a maximum net capacity factor of 38.9 percent. Capital and owner's costs for an SCR system are included in the base option.

Oxidation catalysts can be used to control CO emissions while operating on natural gas fuel. It is assumed that CO controls are not required on the base LM6000 PF+ and 7E.03 LLI options, but the costs of the CO catalyst are included in the SCR costs. CO catalysts are included in the SCR costs for the LMS100 PB+ to control CO emissions to 4 ppm at 15 percent O_2.

Volatile Organic Compounds (VOC) are primarily the result of incomplete combustion. VOCs include a wide spectrum of volatile organic compounds, some of which some are hazardous air pollutants. Some VOC destruction is expected to occur in the oxidation catalyst when installed to control CO emissions. Otherwise, VOCs are not controlled beyond good combustion practice.

Outside of good combustion practices, it is assumed that emissions control equipment is not required for CO_2 and particulate matter (PM). Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines.

Emissions estimates are shown in the Summary Tables for full load operation at ISO conditions. Emissions are also shown for units equipped with SCR and CO catalyst systems.

3.3 Simple Cycle Gas Turbine Performance

Performance results are shown in the Summary Table. Estimated performance results are based on data outputs from proprietary GE software. Full load and minimum load performance estimates are shown for winter and summer conditions.

Minimum load is defined as the minimum emissions compliant load (MECL), as reflected in the OEM ratings.

The general assumptions in Section 2.0 apply to the evaluation of all SCGT options, and additional assumptions are listed in the scope matrix in Appendix A.

- All performance ratings are based on natural gas fuel.
- Summer ratings include evaporative coolers.

The frame 7E.03 LLI SCGT option does not include fast start capability. Fast start packages allow simple cycle frame units to compare more favorably with aeroderivative units, which commonly start in 10 minutes as standard. However, depending on the OEM, fast-start packages may impact turbine maintenance costs and/or performance. SCGT start times assume that purge credits are available.

Outage and availability statistics are also shown in the Summary Tables. They were collected using the NERC Generating Availability Data System (GADS). Simple cycle gas turbine GADS data are based on the 2012 to 2016 operating statistics for applicable North American units that are no more than 10 years old.

3.4 Simple Cycle Gas Turbine Cost Estimates

The simple cycle gas turbine cost estimate results are included in the Summary Tables. The project cost includes all equipment procurement, construction, and indirect costs for a greenfield simple cycle gas turbine project.

Additional cost clarifications and assumptions are shown below:

- Balance of Plant (BOP) Equipment Assumptions:
  - Mechanical equipment, electrical equipment, instrumentation and controls, chemical storage, fire protection equipment, and other miscellaneous items as required.
  - Includes supplemental fuel gas metering equipment for verification of billing/consumption information provided by gas supplier.
  - Fuel gas metering and conditioning equipment owned by the gas supplier is excluded from the EpCM estimate and included as an Owner's cost allowance.
  - Onsite water treatment systems are not included. SCGT plants assume that trailers are used to treat raw water for service use.
- Construction
  - Accounts for labor adjustments for each service area.
  - Includes major equipment erection, civil/structural construction, mechanical construction, and electrical construction.
- Costs are for units firing natural gas only.
- The estimate assumes the turbines are installed outdoors with OEM standard enclosures.
- Greenfield cost estimates include a building with administrative/control spaces and a warehouse.
- Brownfield cost estimate at R.M. Heskett assumes that the administrative/control spaces and warehouses will be re-utilized as well as some plant controls.
- Interconnection allowances are presented as Owner's Costs as described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

3.5 Simple Cycle Gas Turbine O&M

The results of the simple cycle gas turbine O&M evaluations are shown in the Summary Tables. Additional assumptions are listed in the scope matrix in Appendix A.

Fixed O&M costs include four (4) FTE personnel for greenfield options and two (2) FTEs for the option at R.M. Heskett. Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.

Major maintenance costs for aeroderivative engines are estimated on a dollar per gas turbine hourly operation ($/GTG-hr) basis and are not affected by number of starts. Major maintenance in $/MWh is calculated assuming 75% of net capacity for operating hours. Variable O&M and major maintenance costs are based on natural gas operation. Fixed costs include an allowance for four full time employees as requested by Montana-Dakota.

Major Maintenance costs for the frame engines are estimated on a dollar per gas turbine start ($/GT-start) basis. In general, if there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27 hours per start, maintenance will be start-based. Note that the $/GT-hr and $/start costs are not meant to be additive or combined in any way. The operational profile determines which value to use to determine annual major maintenance costs. Major maintenance in $/MWh is calculated assuming 75% of net capacity for operating hours.

4.0 RECIPROCATING ENGINE TECHNOLOGY

This Assessment includes two (2) simple cycle reciprocating engine plants for comparison among the SCGT options.

4.1 Reciprocating Engine Technology Description

The internal combustion reciprocating engine operates on a four-stroke cycle for the conversion of pressure into rotational energy. Utility scale engines are commonly compression-ignition models, but some are spark-ignition engines. By design, cooling systems are typically closed-loop radiators, minimizing water consumption.

Reciprocating engines are generally less impacted by altitude and ambient temperature than gas turbines. With site conditions below 3,000 feet and 95°F, altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines, though the efficiency may be slightly affected.

Reciprocating engines can start up and ramp load more quickly than most gas turbines, but it should be noted that the engine jacket temperature must be kept warm to accommodate start times under 10 minutes. However, it is common to keep water jacket heaters energized during all hours that the engines may be expected to run (associated costs have been included within the fixed O&M costs).

Many different vendors, such as Wärtsilä, Fairbanks Morse (MAN Engines), Caterpillar, Hyundai, Rolls Royce, etc. offer reciprocating engines and they are becoming popular as a means to follow wind turbine generation with their quick start times and operational flexibility. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and quick start up when compared to gas turbines.

Utility scale applications most commonly rely on medium speed engines in the 9-10 MW and 18-20 MW classes. All the OEMs indicated above offer a spark ignition engine in the 9-10 MW class, but only Wärtsilä and MAN have commercially available 18-20 MW class engines in the US. Wärtsilä and MAN are also the only major OEMs who offer compression ignition engines in either class that can operate on natural gas or liquid fuels.

The 4x 9 MW and 3 x 18 MW plants evaluated in this Assessment are based on Wärtsilä natural gas only engines, models 20V34SG and 18V50SG respectively. These heavy duty, medium speed engines are easily adaptable to grid-load variations.

4.2 Reciprocating Engine Emissions Controls

Emissions estimates are shown in the Summary Tables for full load at ISO conditions on natural gas fuel. In addition to good combustion practices, it is expected that reciprocating engines will require SCR and CO catalysts to control NO_x and CO emissions. Operation on natural gas fuel with an SCR yields reduction of NO_x emissions to 5 ppm at 15 percent excess O2, while a CO catalyst results in anticipated CO emissions of 15 ppm. Some VOC destruction is expected to occur in the oxidation catalyst, otherwise, VOCs are not controlled beyond good combustion practice. It is assumed that emissions control equipment is not required for CO_2 and particulate matter (PM). Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel. It is assumed that CEMS monitoring systems are also not required.

4.3 Reciprocating Engine Performance

Performance results are shown in the Summary Table. Estimated performance results are based on data from OEM ratings. Full load and minimum load performance estimates are shown for winter and summer conditions. Minimum load assumes a single engine at 50% load. The general assumptions in Section 2.0 apply to the evaluation of reciprocating engine options, and additional assumptions are listed in the scope matrix in Appendix A.

The Summary Tables includes startup times for engine options. Start times of 5-10 minutes require that the engine jacket temperatures are kept warm for standby operation (this is addressed in the O&M costs). Outage and availability statistics are also shown in the Summary Tables. They were collected using the NERC Generating Availability Data System (GADS). It should be noted that EFOR data from GADS may not accurately represent the benefits of a reciprocating engine plant, depending on how outage events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so only a portion of the plant would be unavailable.

Reciprocating engines consume minimal water (approximately 5 gallons per engine, per week for cooling loop makeup, plus a gallon per day for turbo rinses). Depending on site conditions and access to water, the low water consumption rate can be advantageous for comparison to other simple cycle plants.

4.4 Reciprocating Engine Cost Estimates

The cost estimate results are included in the Summary Table. The project cost includes all equipment procurement, construction, and indirect costs for a greenfield reciprocating engine project.

Additional cost clarifications and assumptions are shown below:

- SCR and CO catalysts are included for reciprocating engines. It is assumed that CEMS equipment is not required.
- Pressure regulation and dew point heating are included.
- The reciprocating engine plant includes an indoor engine hall with associated administrative/ control/ warehouse facilities.
- All engines are tied to a single, three-winding GSU.
- Interconnection allowances are presented as Owner's Costs as described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

4.5 Reciprocating Engine O&M

The results of the O&M evaluations are shown in the Summary Tables. Additional assumptions are listed in the scope matrix in Appendix A.

Fixed O&M costs include four (4) FTE personnel for both the 4 x 20V34SG and 3 x 18V50SG engine blocks. Fixed O&M also includes an estimate for standby electricity costs to keep the engines warm and accommodate start times of less than ten minutes. Additional fixed O&M costs include allowances for administrative, communications, and other routine maintenance items. Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.

Major maintenance costs are shown per engine, regardless of configuration. It is assumed that an LTSA with the OEM or other third party would include parts and labor for major overhauls and catalyst replacements.

Variable costs account for lube oil, SCR reagent, routine BOP maintenance, and scheduled minor engine maintenance. It is expected that the maintenance agreement would include supervision and parts for these minor intervals (i.e. ~2,000 hour intervals), but that these may not be considered capital maintenance intervals, so they are included in the variable O&M.

5.0 COMBINED CYCLE GAS TURBINE TECHNOLOGIES

5.1 Combined Cycle Technology Description

The basic principle of the combined cycle gas turbine (CCGT) plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. The use of both gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing. The heat rate will increase during duct fired operation, though this incremental duct fired heat rate is generally less than the resultant heat rate from a similarly sized SCGT peaking plant.

As discussed in prior sections, continued development by gas turbine manufacturers has resulted in the separation of gas turbine technology into various classes. For this assessment, BMcD is evaluating greenfield 2x1 SGT-800 and 1x1 F Class options. For comparisons purpose, the 2x1 7E.03 R.M. Heskett expansion was included in the Summary Table.

5.2 Combined Cycle Emissions Controls

Emissions estimates are shown in the Summary Tables for base load and peak (duct-fired) load, assuming natural gas operation at ISO conditions.

Greenfield combined cycle plants are designed for capacity factors consistent with intermediate or base load operation, and therefore it is expected that NO_x and CO emissions will need to be controlled. An SCR will be required to reduce NO_x to approximately 2 ppm at 15 percent O_2 which correlates to approximately 0.01 lb/MMBtu. It is expected that a CO catalyst will also be required to reduce CO emissions. This assessment assumes CO emissions will be controlled to 2 ppm CO at 15 percent O2, which correlates to approximately 0.006 lb/MMBtu. Some VOC destruction is expected to occur in the oxidation catalyst, otherwise, VOCs are not controlled beyond good combustion practice. Emissions rates for the CCGT options in this Assessment are included in the Summary Table.

For the R.M. Heskett expansion, no SCR or CO controls are included in the base cost estimate. Add-on costs are provided for an SCR on both gas turbines.

The use of an SCR and CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with NO_x molecules. This requires on-site ammonia storage and provisions for ammonia unloading and transfer. The costs associated with these requirements have been included in this Assessment.

For all CCGT options, untreated CO_2 emissions are estimated to be 120 lb/MMBtu. Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Sulfur dioxide emissions of a CCGT plant are very low compared to coal technologies, and the emission rate of sulfur dioxide for a combined cycle unit is estimated to be less than 0.001 lb/MMBtu.

5.3 Combined Cycle Performance

Estimated performance results are shown in the Summary Table, based on data outputs from Ebsilon heat balance models. The general assumptions in Section 2.0 apply to the evaluation of CCGT options, and additional assumptions are listed in the scope matrix in Appendix A.

Additional cost clarifications and assumptions are shown below:

- Evaporative cooling is included in the performance and capital cost of the base plants.
- Performance estimates are based on heat rejection through wet cooling towers.
- Duct fired options include capability for duct firing to 1,600°F for greenfield options. Incremental duct fired output and heat rate are provided. The incremental heat rate is only applicable to the fired output. It does not represent the total plant heat rate when duct firing is operational.
- All greenfield CCGT plants assume SCR and CO catalyst technologies are installed.

The Summary Table includes combined cycle start times to stack emissions compliance and base load according to cold start conditions. Stack emissions compliance is commonly driven by the time required for the CO catalyst to reach its optimum temperature, which typically occurs after the turbine reaches MECL. Start times reflect unrestricted, conventional starts for all gas turbines. Capital costs assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. GTG fast start options are not reflected in combined cycle startup information.

Outage and availability statistics are also shown in the Summary Table. They were collected using the NERC Generating Availability Data System (GADS). Combined cycle plant GADS data are based on the 2012-2016 operating statistics for applicable North American units that are no more than 10 years old.

Full load, part load, and minimum load performance estimates are shown for winter and summer conditions. All performance assumes new and clean equipment. Emissions estimates assume that SCR and CO catalyst systems are installed.

5.4 Combined Cycle Cost Estimates

The combined cycle plant cost results are included in the Summary Tables. The project cost includes all equipment procurement, construction, and indirect costs for combined cycle projects. The general cost assumptions in Section 2.0 apply to the combined cycle options.

Cost estimates were developed using in-house information based on BMcD project experience. Cost estimates assume an EpCM project plus typical Owner's costs. In line with the assumptions matrix in Appendix A, the following items are highlighted:

- Steam Turbine Basis:
  - 2x1 SGT-800: Two pressure condensing steam turbine.
  - 1x1 7F.05: Three pressure condensing steam turbine.
  - 2x1 7E.03 R.M. Heskett Expansion: New two pressure condensing steam turbine.
- HRSG Basis:
  - 2x1 SGT-800: Two pressure HRSG (no reheat), duct firing add-on costs included in the Summary Table.
  - 1x1 7F.05: Three pressure HRSG (including reheat), duct firing add-on costs included in the Summary Table.
  - 2x1 7E.03 R.M. Heskett Expansion: Two pressure HRSG (no reheat), duct firing add-on costs included in the Summary Table.
- BOP Equipment Assumptions:
  - Mechanical equipment, electrical equipment, instrumentation and controls, chemical storage, fire protection equipment, and other miscellaneous items as required.
  - Includes supplemental fuel gas metering equipment for verification of billing/consumption information provided by gas supplier.
  - Pressure regulation and dew point heating are included.
  - Fuel gas metering and conditioning equipment owned by the gas supplier is excluded.
  - Onsite water treatment systems.
- Construction
  - Accounts for labor adjustments

  - Includes major equipment erection, civil/structural construction, mechanical construction, and electrical construction
- Indirect Costs and Fees
- Capital costs assume the inclusion of terminal point desuperheaters, full bypass, and associated controls to accommodate the startup times shown in the Summary Table.
- Base unit estimates assume natural gas operation.
- Evaporative cooling is included in the base project costs.
- The estimate assumes that gas turbines are installed outdoors in OEM standard enclosures.
- The estimate assumes that HRSGs and steam turbines are installed indoors.
- An administrative/control building and a warehouse are included for greenfield options.
- Interconnection allowances are presented as Owner's Costs and described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.
- The owner's cost for a switchyard assumes a breaker and ½ configuration for 115kV interconnection.

5.5 Combined Cycle O&M

The results of the combined cycle O&M evaluations are shown in the Summary Table. In line with the assumptions matrix in Appendix A, the following items are highlighted:

- O&M estimates are based on plant performance at ISO conditions.
- Incremental O&M costs for optional items are meant to be added directly the base fixed or variable O&M costs, as applicable.
- Greenfield combined cycle plants assume the following FTE personnel quantities.
  - 1x1: 22 FTE
  - 2x1: 25 FTE
- The R.M. Heskett expansion combined cycle plant assumes 20 FTE.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.
- SCR systems are included in the O&M evaluations for all greenfield combined cycle plants. SCR systems assume 19 percent aqueous ammonia and 25,000 hours as applicable.
- Major maintenance costs are based on \$/GT-hr, but are also shown in \$/MWh. These numbers reflect the same total annual cost and are not meant to be combined.
- Note that major maintenance costs vary by term coverage and scope, OEM, and operational profile.

- Chemical costs were updated based on recent BMcD experience.

6.0 RENEWABLE TECHNOLOGY – ONSHORE WIND

6.1 Wind Energy General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, which can be used to generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW operate are horizontal-axis. Subsystems for either configuration typically include the following: a blade/rotor assembly to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital. According to the Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), Class 3 wind areas (wind speeds of 14.5 mph) are generally considered to have suitable wind resources for wind generation development.

6.2 Wind Energy Emission Controls

No emission controls are necessary for a wind energy installation.

6.3 Wind Performance

This Assessment includes 20 MW and 50 MW wind generating facilities in the Montana-Dakota service area. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. A generic project location in southwestern North Dakota was selected as directed by Montana-Dakota for its proximity to relatively high wind speeds in accordance with NREL wind maps but is otherwise arbitrary. The location was not selected with respect to actual, expected, or preferred locations for current or future wind development.

As instructed by Montana-Dakota, the GE 2.72-116 wind turbine model was assumed for this analysis, with a nameplate capacity of 2.72 MW, a rotor diameter of 116 meters, and a hub height of 80 meters. The maximum tip height of this package is under 500 feet, which means there are less likely to be conflicts with the Federal Aviation Administration (FAA) altitudes available for general aircraft. BMcD utilized the GE product information provided by Montana-Dakota to develop performance estimates at standard atmospheric conditions (sea level air density and normal turbulence intensity). Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition.

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated for the appropriate hub height to determine a representative wind speed. Using a Rayleigh distribution and power curve for the turbine technology described above, a gross annual capacity factor (GCF) was subsequently estimated for each site.

Annual losses for a wind energy facility were estimated at approximately 15 percent, which is a common assumption for screening level estimates in the wind industry. This loss factor was applied to the gross capacity factor estimates to derive a net annual capacity factor (NCF) for each potential site. Ideally, a utility-scale generation project should have an NCF of 30 percent or better. The NCF estimates are shown in the Summary Table.

6.4 Wind Cost Estimate

The wind energy cost estimate is shown in the Summary Tables. The cost estimate assumes a two-contract approach with the Owner awarding a turbine supply contract and a separate BOP contract. Typical Owner's costs are also shown. Costs for 20 and 50 MW plants are based on 2.72 MW turbines (9 and 23 total turbines respectively) and 80 meter hub heights.

- The project scope includes a GSU transformer for interconnection at 115 kV.
- Land costs are excluded from the project and Owner's cost. For the study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate.
- Interconnection allowances are presented as Owner's Costs and described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

6.5 Wind Energy O&M Estimates

O&M costs in the Summary Tables are derived from in-house information based on BMcD project experience and vendor information. Wind O&M costs are modeled as fixed O&M, including all typical operating expenses with the following breakdown:

- Labor costs
- Turbine O&M
- BOP O&M and other fixed costs (G&A, insurance, environmental costs, etc.)
- Land lease payments
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.

No allowances for capital replacement costs are included within the annual O&M estimate in the Summary Table. A capital expenditures budget for a wind farm is generally a reserve that is funded over the life of the project that is dedicated to major component failures. An adequate capital expenditures budget is important for the long-term viability of the project, as major component failures are expected to occur, particularly as the facility ages.

6.6 Wind Energy Production Tax Credit

Tax credits such as the production tax credit (PTC) and investment tax credit (ITC) are not factored into the cost or O&M estimates in this Assessment, but an overview of the PTC is included below for reference.

To incentivize wind energy development, the PTC for wind was first included in the Energy Policy Act of 1992. It began as a $15/MWh production credit and has since been adjusted for inflation, currently worth approximately $24/MWh.

The PTC is awarded annually for the first 10 years of a wind facility's operation. Unlike the ITC that is common in the solar industry, there is no upfront incentive to offset capital costs. The PTC value is calculated by multiplying the $/MWh credit times the total energy sold during a given tax year. At the end of the tax year, the total value of the PTC is applied to reduce or eliminate taxes that the owners would normally owe. If the PTC value is greater than the annual tax bill, the excess credits can potentially go unused unless the owner has a suitable tax equity partner.

Since 1992, the changing PTC expiration/phaseout schedules have directly impacted market fluctuations, driving wind industry expansions and contractions. The PTC is currently available for projects that begin construction by the end of 2019, but with a phaseout schedule that began in 2017. Projects that started construction in 2015 and 2016 will receive the full value of the PTC, but those that start or have started construction in later years will receive reduced credits:

- 2017: 80% of the full PTC value
- 2018: 60% of the full PTC value
- 2019: 40% of the full PTC value
- 2020: PTC Expires

To avoid receiving a reduction in the PTC, a "Safe Harbor" clause allowed for developers to avoid the reduction through an upfront investment in wind turbines by the end of 2016. The Safe Harbor clause allowed for wind projects to be considered as having begun construction by the end of the year if a minimum of 5% of the project's total capital cost was incurred before January 1st, 2017.

Many wind farms were planned for construction and operation when it was assumed they would receive 100% of the PTC. However, with the reduction in the PTC some of these projects are no longer financially viable for developers to operate. This may result in renegotiated or canceled PPAs, or transfers to utilities for operation.

7.0 RENEWABLE TECHNOLOGY – SOLAR PHOTOVOLTAIC

This Assessment includes a 5 MW and a 50 MW single axis tracking photovoltaic (PV) option with add-on costs for co-located battery energy storage of 1 MW / 4 MWh and 10 MW/ 40 MWh respectively.

7.1 PV General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 2% in the first year and 0.5% per year thereafter. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80% of its initial efficiency.

7.2 PV Emission Controls

No emission controls are necessary for a PV system.

7.3 PV Performance

BMcD ran simulations of the PV options using PVsyst software. The resultant capacity factors for the single axis tracking systems are shown in the Summary Table. The inverter loading ratio for the systems are 1.32 at the inverter and 1.35 at the point of injection. Model outputs are intended to be representative of plant of performance in North Dakota.

Capacity factors are better for tracking systems, but costs are generally higher for similar ILR ratios. Further analysis would be required to select which mounting system is best suited for a given site.

Panel technologies may also exhibit different performance characteristics depending on the site. Thin film technologies are typically cheaper per panel, but they are also less energy dense, so it’s likely that more panels would be required to achieve the same output. In addition, the two technologies respond differently to shaded conditions. Additional assumptions are listed in the scope matrix in Appendix A.

7.4 PV Cost Estimates

Cost estimates were developed using in-house information based on BMcD project experience. Cost estimates assume an EPC project plus typical Owner's costs.

PV cost estimates for the single axis tracking system are included in the Summary Tables. Costs are based on the DC/AC ratios mentioned in the PV Performance section of this report. The project scope assumes a medium voltage interconnection and the Owner's costs include an allowance for interconnection downstream of the 34.5 kV circuit breaker. Add-on costs for co-located Lithium Ion battery energy storage are included for a 1 MW / 4 MWh and 10 MW / 40 MWh.

PV installed costs have steadily declined for years. The main drivers of cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. All PV costs have been updated to account for the impacts of US tariffs on PV panels and steel imports. The panel tariffs only impact crystalline solar modules, however the availability of CdTe is limited for the next couple years, so it is prudent to assume similar cost increases for thin film panels until the impacts of the tariff are clearer.

The 2018 Assessment excludes land costs from capital and Owner costs. It is assumed that all PV projects will be on leased land with allowances provided in the O&M costs.

7.5 PV O&M Cost Estimate

O&M costs for the PV options are shown in the Summary Tables. O&M costs are derived from BMcD project experience and vendor information. The Assessment includes allowances for a land lease.

The following assumptions and clarifications apply to PV O&M:

- O&M costs assume that the system is remotely operated, and all O&M costs are modeled as fixed costs, shown in terms of $MM per year.
- O&M costs include a land lease allowance.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.
- Equipment O&M costs account for inverter maintenance, other routine equipment inspections and an allowance for potential inverter replacements.
- BOP costs account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs.

8.0 BIOMASS

This Assessment includes a 25 MW biomass facility based on the information provided by Montana-Dakota on the feasibility of supplying biomass to the Spiritwood Industrial Park submitted by Great River Energy, the Great Plains Institute and others.

8.1 Biomass General Description

The term "biomass" refers to any regenerative organic material used as a fuel for energy production, which can be grown, harvested and re-grown. Biomass fuel typically consists of forestry materials, wood residues, agricultural residues, and energy crops. Biomass power generation facilities are typically located near the source of the fuel to reduce transportation costs in fuel delivery.

In a bubbling fluidized bed (BFB) boiler, combustion occurs on a sand bed at the base of the boiler. The bed becomes suspended or fluidized bed upon the introduction of air flow from the bottom of the boiler. Solid fuels are introduced on the bed for combustion, and ash particles fall to the bottom for periodic removal. This study evaluates a BFB boiler burning 100% grass biomass assumed to be in a concentrated form and of moderate moisture content. The nominal size of the biomass facility was sized to require less annual fuel than estimated to be available for the highest ranked biomass resource recommended for co-firing at the Spiritwood Facility, CRP grasses and switchgrass.

8.2 Biomass Emissions Controls

The BFB option is assumed to require SNCR to control NO_x emissions. SO_2 emissions are controlled by furnace limestone injection followed by a polishing scrubber using hydrated furnace ash as sorbent. This evaluation also includes a baghouse to remove particulate from the flue gas, dry sorbent injection to control acid gases, and a carbon injection system to control mercury. It is assumed that CO emissions are controlled through sound combustion practices. Due to the expected makeup of the particulates in the flue gas, an oxidation catalyst is not likely feasible.

8.3 Biomass Performance

Performance and cost estimates are shown in the Summary Table.

8.4 Biomass Cost Estimates

Biomass BFB cost information from prior BMcD research was evaluated in comparison to industry research documents. Cost estimates assume an EPC project plus typical Owner's costs. The general cost assumptions in Section 2.0 apply to the evaluation of the BFB option.

Additional cost clarifications and assumptions are shown below:

- Assumes one BFB boiler and one STG with wet cooling for heat rejection.
- Estimate includes selective non-catalytic reduction (SNCR), dry sorbent injection, baghouse, and activated carbon injection.
- The switchyard cost estimate assumes a 3-position ring bus.
- Interconnection allowances are presented as Owner's Costs and described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

8.5 Biomass O&M Cost Estimate

General assumptions for fixed and variable O&M costs are listed in Section 2.7. Additional assumptions are listed in the Scope Matrix.

- O&M Costs are derived from in-house information based on BMcD experience and industry research.
- Variable O&M accounts for costs due to routine maintenance, major maintenance and emissions controls consumables.

9.0 COAL

9.1 General Description

The Coal performance and cost information represented in this assessment is provided by Montana-Dakota and based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council (LEC Study, 2012).

9.2 Circulating Fluidized Bed (CFB)

The combustion process within a CFB boiler occurs in a suspended or fluidized bed of solid particles. The solid particles are a mixture of fuel, ash products from prior combustion, and some form of inert material such as sand, slag, etc. The boiler operates by blowing air into the boiler through air nozzles in the bottom as fuel is injected into the furnace, thereby creating a fluidized bed of material. As combustion takes place, smaller particles are carried out of the boiler and collected by solid separators. This material is circulated back into the bottom of the furnace to combine with the large particles that did not get carried out and provides the ignition source for the new fuel being fed into the unit. CFB combustion is a mature technology with inherently low emission rates compared to pulverized coal combustion.

Due to the combustion process, CFB technology is well suited to burn fuels with large variability in constituents. Deviations in fuel type, size, and heat content have minimal effect on the furnace performance characteristics. Unlike pulverized coal units, CFB units do not require tuning of the burners for each fuel to obtain the appropriate air fuel mixture and optimal settings. Sites with access to abundant sources of fuels that vary significantly in constituents or that present combustion challenges to other boiler types are typically good prospects for CFB plants.

9.3 Coal CFB Emissions Controls

The CFB combustion process yields inherently low NO_x emissions, while some SO_2 emissions are typically removed by limestone in the furnace. CO emissions are assumed to be uncontrolled. The study used for this assessment assumes installation of a Selective Non-Catalytic Reduction (SNCR) system to further reduce NO_x emissions. The most economical and efficient form of additional SO_2 removal on a CFB is a polishing dry FGD. Dry scrubbing involves spraying an atomized solution of an alkaline reagent, typically lime-based, into hot flue gas for the absorption of SO_2. Moisture in the spray then evaporates so that the absorbed SO_2 is carried in suspension out of the boiler and collected in the baghouse filtration system.

This assessment also includes an option with carbon capture utilizing an amine process. In advanced amine processes, a continuous scrubbing system is used to separate CO_2 from the flue gas stream. These systems consist of two main elements: an absorber where CO_2 is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where CO_2 is released (in concentrated form) from the solvent and the original solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the CO_2 in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat recovery exchanger and is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated CO_2 gas stream. The hot CO_2-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added as make up for losses incurred in the process.

Emissions control for the coal options in this assessment are based on the information provided by Montana-Dakota in the LEC Study which were designed to meet EPA regulation at the time of its writing (2012). No update to emissions control requirements or operating limits for new energy generating units firing coal is included.

9.4 Coal Performance

Coal performance information is shown in the Summary Table. Performance information is provided by Montana-Dakota and based on the LEC Study.

9.5 Coal Cost Estimates

Coal capital cost estimates are shown in the Summary Table. Project cost information is provided by Montana-Dakota and based on the LEC Study.

The general assumptions in Section 2.4 for Owner's Costs govern as applicable for the Coal options with additional assumptions listed in the Summary Table.

9.6 Coal O&M Cost Estimates

Coal O&M estimates are shown in the Summary Table. O&M information is provided by Montana-Dakota and based on the LEC Study.

10.0 EMERGING TECHNOLOGIES

10.1 General Description

To support Montana-Dakota's integrated resource planning, the following emerging technologies are described below:

- Flow batteries
- Liquid Air Energy Storage (LAES)
- Fuel Cells

These technologies have begun to see commercial applications and are beginning to accrue operating hours in some installations.

10.1.1 Flow Batteries

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Depending on the technology and design, some flow battery technologies are able to scale power and energy independently, such that the storage duration can be increased by adding electrolyte volume. Other technologies may also need to add surface area to the electrode cell stack in addition to adding electrolyte volume. Round trip efficiencies for flow battery technologies are generally in the 65% - 75% range, depending on the technology type and system losses.

Flow battery technology is generally believed to be better suited for long duration (>6 hours) storage than other leading battery technologies such as lithium ion. The demand for long duration storage is expected to increase as renewable energy penetration increases, and therefore manufacturers are rapidly developing products to meet potential future demand.

Operation and maintenance for flow batteries differs from lithium ion storage technology because there is more mechanical equipment, but there is generally no performance degradation. Lithium ion battery performance degrades over time regardless of operation, and degradation increases with each charge/discharge cycle. So, while there may be routine maintenance requirements for pumps, tanks, valves, and electrolyte chemistry, flow batteries do not require regular augmentation or over-sizing to maintain guaranteed system performance.

There are several flow battery manufacturers offering products in various stages of commercial development, and some with utility scale, multi-MW installations installed or planned. It is recommended that Montana-Dakota monitor flow battery market and product development in the coming years.

10.1.2 Liquid Air Energy Storage

Liquid Air Energy Storage (LAES) systems convert ambient air to liquefied air stored in above-ground cryogenic storage tanks which is expanded to meet power demand. LAES systems are typically advantageous when co-located with industrial processes that result in waste heat and might produce electricity. In these applications, LAES systems can serve to manage energy demand and reduce peak hour energy use.

During periods of low demand, lower cost electrical energy can be used to draw air from the environment, filter for contaminants, and then compress the air through multiple stages to supply the storage tanks at medium-pressure and low temperature. The liquid air is stored in these tanks resulting in scalable amounts of potential energy storage. The tanks used in LAES systems are similar to those used in other industries for bulk storage of nitrogen, oxygen and liquefied natural gas. When power is to be discharged from the LAES system, the liquid air is pumped to a higher pressure, evaporated and superheated. This high-pressure fluid is expanded across a turbine to recuperate the energy stored. With additional sources of waste heat, from industrial processes or co-located energy generation assets, the air can be superheated to a greater extent. This additional energy input results in a higher-pressure fluid to expand through the turbine leading to greater energy generated in the discharge phase.

Due to the modular nature of the storage components, LAES systems can be scaled to meet the applications' needs with commercially available options existing in the 5-100 MW range. LAES systems differ from other energy storage options as they do not involve an electrochemical reaction and are based mechanical compression and expansion. However, their construction does not require limited geologic conditions as compressed air energy storage systems (CAES) which are limited to suitable caverns.

LAES systems exhibit round trip efficiencies in the 60% - 70% range. Like flow batteries, an advantage of LAES is long project life and minimal performance degradation over that life. There is a 5MW / 15MWh system installed in the United Kingdom, so the technology is commercially available, but there is little market penetration currently in the USA. It is recommended that Montana-Dakota monitor the market and technology development for LAES systems in the coming years.

10.1.3 Fuel Cells

Fuel cells consist of an electrolyte material held between a negatively charged anode and a positively charged cathode, and then placed between two flow field plates. Via the flow plates, hydrogen fuel is forced through the anode while oxygen (air) flows through the cathode. The resultant chemical reaction splits the hydrogen into particles by charge. The electrolyte is impermeable to the negatively charged particles, which are then forced through a circuit, generating current. Positively charged particles pass through the electrolyte and recombine with oxygen and the negatively charged particles at the anode to form water and carbon dioxide byproducts. This process also yields heat which can be recuperated to generate high temperature steam used in the reformation of natural gas to produce the hydrogen fuel.

As fuel cell technology matures and installations accrue more operating hours, research and development continues in both private and government funded institutions to optimize operating efficiency and reduce costs. Many states offer financial incentives that can reduce the installed cost of fuel cells.

Molten-carbonate fuel cells (MCFCs) utilize a high temperature salt (typically sodium or magnesium) based electrolyte core. The electrolyte compound is held in molten state, operating at 1,100°F to 1,300°F. While this yields relatively high thermal efficiencies in the range of 50 percent to 60 percent, the elevated temperatures also result in increased corrosiveness of the liquid electrolyte. MCFCs are currently being marketed as commercially available technology for megawatt-scale generation needs, however this is still a developing generation technology with limited operational experience compared to simple cycle turbine and engine technologies. Research and development efforts are focused on increased size and reliability while reducing the cost of manufacture.

Solid Oxide fuel cells (SOFCs) utilize a solid ceramic and metal oxide based electrolyte but operate at even higher temperatures than the MCFC, in the range of 1,200°F to 1,800°F at similar thermal efficiencies. Elevated operating temperatures yield the possibility of internal gas reformation and can limit cell component life. However, elevated temperatures can provide benefits in steam co-generation applications. SOFCs are commercially available, but like MCFCs, they are a relatively recent development in fuel cell technology with limited operating experience in the utility market.

Due to the configuration of the cell and electrolyte core, MCFCs are more commonly scalable and are commercially available in modular units approaching 3,000 kW output. This scalability lends the MCFC to better suitability for distributed generation applications at the utility scale, particularly in excess of 1 to 2 MW of output. Recent domestic SOFC installations have trended more towards single consumer use at large company headquarters, rather than for the sole purpose of power generation and sale to the grid. In addition, manufacture of SOFCs is limited, which has led to high cell cost and concern over product value. There are technologies including phosphoric acid fuel cells and polymer electrolyte membrane fuel cells, but these are better suited for residential, commercial, or transportation applications.

Fuel cells do not rely on fuel combustion and therefore NO_x, CO, and PM emissions are inherently low compared to most generation technologies. CO_2 emission rates are comparable to natural gas combustion technologies. No external emission control technologies are expected for fuel cell technologies. Fuel cell heat rates are generally in line with modern combined cycle plant heat rates.

Fuel cell costs are generally declining as the technology matures, and installations are increasing in areas with high electricity costs (i.e. California) and/or prominent incentives (i.e. Connecticut). The two leading fuel cell manufacturers in the utility space commonly offer full turnkey solutions, in which they engineer, construct, own, and operate their facilities, selling electricity directly to their customer. It is recommended that Montana-Dakota monitor the market and technology development for fuel cell systems in the coming years.

11.0 CONCLUSIONS

This Assessment provides information to support Montana-Dakota's power supply planning efforts. Information provided in this Assessment is preliminary in nature and is intended to highlight indicative, differential costs associated with each technology. Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD recommends that Montana-Dakota use this information to update production cost models for comparison of generation alternatives and their applicability to future resource plans. Montana-Dakota should pursue additional engineering studies to define project scope, budget, and timeline for technologies of interest.

Of all technologies evaluated, the simple cycle 7E.03 LLI option exhibits the lowest capital cost per kW generated. If an SCR is required for the simple cycle application, or other emissions regulations where to pass, then the 7E.03 LLI cost could increase, or would face other operational limits.

Aeroderivative turbines generally exhibit excellent heat rates, fast start and ramp rates, and reliable operation, but they also tend to be more expensive than frame units on a $/kW scale.

Reciprocating engine plants offer the lowest heat rates and fastest start times when compared to simple cycle gas turbine options. Reciprocating engine plants are also likely to exhibit the greatest capacity range among simple cycle options, with a minimum load of a single engine at 25% - 50% load. Variable O&M for engine plants is higher than frame GTs and should be considered in an analysis. It is expected that reciprocating engine plants will require SCR systems and CO catalysts to control emissions.

Combined cycle plants offer better heat rates than all other combustion plants evaluated. Of the evaluated greenfield plants, the 1x1 F class option shows the lowest capital cost per kW.

Renewable options include PV and wind systems. PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals. PV capital costs have steadily declined for years, but recent import tariffs on PV panels and foreign steel have impacted market trends. Wind energy generation is a proven technology and turbine costs have dropped considerably over the past few years.

Biomass and coal information are also presented in this Assessment based on information provided by Montana-Dakota Utilities and prepared by others.

In addition to the technologies included in the Summary Table of the Assessment, flow batteries, liquid air energy storage and fuel cells were discussed as emerging technologies for informational purposes. It is recommended that Montana-Dakota Utilities monitor the development of these technologies in the coming years.

APPENDIX A – SCOPE MATRIX

2019 MDU TECHNOLOGY ASSESSMENT ASSUMPTIONS

	Simple Cycle	Reciprocating Engines	Combined Cycle	Wind	PV	PV + Storage	Biomass	Coal (Note 1)
Project Description								
Plant Size(s):	Aero LM6000 PF+	4x 9MW Engines	2 x 1 SGT-800 with Duct Firing	20 MW	50 MW - Single Axis Tracking	Co-Located w/50 MW PV 10 MW / 40 MWh Storage	25 MW Bubbling Fluidized Bed	Circulating Fluidized Bed w/o CC
	Aero LMS100 PB+	3x 18MW Engines	1 x 1 7F.05 with Duct Firing	50 MW	5 MW Single Axis Tracking PV	Co-Located w/5 MW PV 1 MW / 4 MWh Storage		Circulating Fluidized Bed w/ CC
	GE 7E.03 LLI (Greenfield & at RM Heskett)		2 x 1 7EA with Duct Firing Heskett Expansion					
Fuel:	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	N/A	Grasses (CRP and Switchgrass)	100% Raw ND Lignite
Project Location:	North Dakota							
Contract Philosophy:	Multiple Contract Approach (EpCM)							
Project COD:	Shown in 2019 USD (i.e. no escalation)							
Labor Type:	Union							
Labor Incentives:	50 hrs / week & $80 per day per diem							
Site Description:	Greenfield (with exception to RM Heskett Expansion)							
Scope Basis / Assumptions:								
Redundancy:	Reflective of typical utility service. Redundant installed components (2 x 100%, 3 x 50%) where component failure could cause outage of the plant. No spare GSU. 2 x 100% boiler feed pumps and ID/FD/ PA fans							
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and coal plant stacks.							
Site Elevation:	1690 ft AMSL							
Site Summer Ambient Conditions:	84.5°F / 40% RH							
Site Winter Ambient Conditions:	6.8°F / 70% RH							
Water Supply:	Fresh Water supply from wells or surface water; pipeline/intake excluded from cost.							
Waste Water Disposal:	Effluent discharge to evaporation pond onsite.	Discharge offsite, piping beyond site boundary excluded.	Effluent discharge to evaporation pond onsite.	N/A	N/A	N/A	Effluent discharge to pond onsite.	Not specified in report provided by MDU
Performance Basis								
Steam Design Pressure:	N/A	N/A	2400 psia (7F.05) 1400 psia (SGT-800) 1500 psia (Heskett)	N/A	N/A	N/A	1500 psia	2400 psia
Steam Design Temperature:	N/A	N/A	1050 F/ 1050F 1000 F (SGT-800) 1000 F (Heskett)	N/A	N/A	N/A	950 F	1050 F
Inlet cooling	Evaporative Cooling Included for Summer Performance	N/A	Evaporative Cooling Included for Summer Performance	N/A	N/A	N/A	N/A	N/A
Heat Rejection Design:	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Wet Cooling Tower	N/A	N/A	N/A	Wet Cooling Tower	50% Wet Colled / 50% Air Cooled
Availability Metrics	GADS data, as applicable.							
Fuel, Sorbent, and Ash Landfill								
Design Fuel:	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	N/A	Grasses (CRP and Switchgrass)	100% Raw ND Lignite
Back-up Fuel:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Start-up Fuel:	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	N/A	Natural Gas Assumed	Natural Gas Assumed
Fuel for Duct Burners:	N/A	N/A	Natural Gas	N/A	N/A	N/A	N/A	N/A
Unloading System:	N/A	N/A	N/A	N/A	N/A	N/A	Truck Dumper	Not specified in report provided by MDU
Live Storage:	N/A	N/A	N/A	N/A	N/A	N/A	Covered Storage	Day Silos
Long-term storage:	N/A	N/A	N/A	N/A	N/A	N/A	Open Pile	Not specified in report provided by MDU
SO_2 Control Reagent:	N/A	N/A	N/A	N/A	N/A	N/A	Limestone / Lime in Polishing Scrubber	FDA + LKP
SO_2 Control Reagent Delivery:	N/A	N/A	N/A	N/A	N/A	N/A	Truck	Not specified in report provided by MDU
SO_2 Control Reagent Storage:	N/A	N/A	N/A	N/A	N/A	N/A	Outdoor, uncovered pile	Not specified in report provided by MDU
Ammonia:	Aqueous Ammonia delivered by truck for LMS100	Urea delivered by truck	Aqueous Ammonia delivered by truck for units with SCR	N/A	N/A	N/A	Aqueous Ammonia delivered by truck	Not specified in report provided by MDU
Mercury Sorbent Storage:	N/A	N/A	N/A	N/A	N/A	N/A	Silo	Not specified in report provided by MDU
Fly Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	Onsite Landfill	Onsite Silo
Scrubber Sludge / Byproduct Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	Included in Fly Ash	Included in Fly Ash
Bottom Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	Onsite Landfill	Onsite Silo
Landfill Size:	N/A	N/A	N/A	N/A	N/A	N/A	5 Year Cell	Not specified in report provided by MDU
Landfill delivery:	N/A	N/A	N/A	N/A	N/A	N/A	Truck	Not specified in report provided by MDU
Enclosures:								
Gas Turbine or Engine:	Outdoor	Indoor	Outdoor	N/A	N/A	N/A	N/A	N/A
Steam Turbine:	N/A	N/A	Indoor	N/A	N/A	N/A	Indoor	Not specified in report provided by MDU
Boiler or HRSG:	N/A	N/A	Indoor	N/A	N/A	N/A	Indoor	Not specified in report provided by MDU
Scrubber:	N/A	N/A	N/A	N/A	N/A	N/A	Indoor	Not specified in report provided by MDU
Buildings:								
Administration Building	Included	Included in Engine Hall	Included	Included	Included	Co-Located with PV	Included	Included
Warehouse	Included	Included in Engine Hall	Included	Included	Included	Co-Located with PV	Included	Included
Maintenance	Included	Included in Engine Hall	Included	Included	Included	Co-Located with PV	Included	Included
Misc. Equipment Enclosures	Minimal Included. Limited to Electrical Equipment, CEMS enclosure, etc							

2019 MDU TECHNOLOGY ASSESSMENT ASSUMPTIONS

	Simple Cycle	Reciprocating Engines	Combined Cycle	Wind	PV	PV + Storage	Biomass	Coal (Note 1)
Emissions and Emissions Controls*								
NOx Control:	DLN, SCR included for LMS100 PB+, option for all others	SCR	DLN / SCR	N/A	N/A	N/A	SNCR	SNCR
CO Control:	Good Combustion Practice, Catalyst included for LSM100PB+	CO Catalyst	CO Catalyst	N/A	N/A	N/A	Good Combustion Practice	Good Combustion Practice
SO_2 Control:	Low Sulfur Fuel	Low Sulfur Fuel	Low Sulfur Fuel	N/A	N/A	N/A	Dry Sorbent Injection	FDA + LKP
SO_3 Control:	N/A	N/A	N/A	N/A	N/A	N/A	Polishing Scrubber	Not specified in report provided by MDU
PM10 Control (filterable & condensable particulate):	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	N/A	N/A	N/A	Baghouse	Baghouse
Mercury Control:	N/A	N/A	N/A	N/A	N/A	N/A	Activated Carbon Injection into Exhaust Gas	Activated Carbon Injection into Exhaust Gas
VOC Control:	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	N/A	N/A	N/A	Good Combustion Practice	Good Combustion Practice
CO2 Capture/Compression	N/A	N/A	N/A	N/A	N/A	N/A	N/A	CO2 Capture as described in option description
Interconnection:								
Switchyard:	Included with position for generators & 2 outgoing lines. PV + Storage assume interconnection at distribution voltage.							
Transmission Interconnect:	Cost for 15 mile of transmission line at interconnection voltage, excludes land costs.							
Interconnection Voltage:	115 kV for all except PV + Storage which is at 34.5 kV							
Gas Interconnection:	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4": LM6000 PF+ 6": LMS100 PB+, 7E.03 LLI	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4"	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 8": 2x1 SGT-800, 1x1 7F.05	N/A	N/A	N/A	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4"	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4"
Water Interconnection:	Interconnection includes onsite wells and associated piping.	Interconnection includes onsite wells and associated piping.	Interconnection includes onsite wells and associated piping.	N/A	N/A	N/A	Interconnection includes onsite wells and associated piping.	Interconnection includes onsite wells and associated piping.
MISO Queue Fees:	Included							
Network Upgrades:	Included as provided by MDU							
Miscellaneous Equipment:								
Fire protection:	New Fire Pump and Emergency Diesel Backup for dedicated onsite storage			N/A	N/A	N/A	Included	Not specified in report provided by MDU
Emergency Generator:	New Diesel Generator			N/A	N/A	N/A	Included	Not specified in report provided by MDU
Auxiliary Boiler:	N/A	N/A	Included	N/A	N/A	N/A	Included	Not specified in report provided by MDU
Black Start:	Excluded							
Miscellaneous Contract Costs:								
Startup Spare Parts:	Allowance Included							
Construction Indirects:	Construction Mgmt, Engineering, Performance testing and start-up, initial fills and consumables, startup, surveys, and site security Included							
Performance Bonds:	Allowance is 1% of Project Cost							
Indirect / Owner's Indirect Costs:								
Project Development	Allowance Included							
Owner Operations Personnel Prior to COD	Allowance Included							
Owner's Project Management	Allowance Included							
Owner Engineering	Excluded							
Owner Legal Council	Allowance Included							
Operator Training	Allowance Included							
Permitting & License Fees	Allowance Included							
Land	Allowance Included							
Labor Camp	Assumed to not be required. Plant has local towns/ housing							
Construction Power	Allowance Included							
Fuel Consumed during Commissioning	Allowance Included							
Power Generated & Sold during Commissioning	Allowance Included							
Initial Fuel Inventory	Allowance Included							
Builder's Risk Insurance	Allowance Included							
Operating Spare Parts	Allowance Included for critical equipment only & minor parts. No spare GSU included							
Workshop Tools & Test Equipment	Allowance Included							
Warehouse Shelves	Allowance Included							
Mobile Equipment, Vehicles	Allowance Included							
Laboratory Equipment & Furniture	Allowance Included							
Kitchen Furniture	Allowance Included							
Locker Room Furniture	Allowance Included							
Building Furniture	Allowance Included							
Owner's Contingency:	Included @ 10% to reflect anticipated spent contingency for screening purposes.							
Financing Fees	Excluded							
Interest During Construction	Provided by MDU							
Sales Tax	Excluded							
Notes								
Note 1	Coal technology option information provided by MDU, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council. Their assumptions govern the information presented and may not be completely represented in the table above.							

2019 MDU TECH ASSESSMENT OPERATING ASSUMPTIONS

	Simple Cycle - Aero	Simple Cycle - Frame	Reciprocating Engines	Combined Cycle	Wind	PV / PV + Storage	Biomass	Coal (Note 1)
General								
Staffing:								
Number of Personnel:	4	4	4	1x1: 22, 2x1: 25 RM Heskett Expansion: 20	2	2	44	Not specified in report provided by MDU
Labor Cost:	$120,000 per person per year (all in including burdens, benefits, bonuses, and overtime							
Operating Hours Considered:	1,314 Hours	1,314 Hours	1,314 Hours	6,132 Hours	N/A	N/A	7,446 Hours (85% CF)	7,884 Hours w/o CC, 7446 Hours w/CC
Standby Power:	Included for Non-Operating Hours							
Standby Power Cost:	$21/MWh							
Property Insurance:	Included, rate provided by MDU. (0.15% of Total Loaded Project Cost)							
Property Tax:	Included, rate provided by MDU. (0.416% of Total Loaded Project Cost)							
Maintenance Considerations								
Major Maintenance Basis	Major Maintenance assumes third party contract	Major Maintenance assumes third party contract	Major Maintenance assumes third party contract	Major Maintenance assumes third party contract	Wind Turbine maintenance assumes third party contract	Storage assumes third party contract for augmentation.	Major Maintenance assumes third party contract	Not specified in report provided by MDU
Service Director Included:	No	Yes	No	Yes	N/A		N/A	N/A
Engine Lease Agreement Included (Engine Swap)	No	No	No	No	N/A			
SCR and CO Catalyst Replacements:	25,000 hours as applicable							
Fuel / Ash Handling Mobile Equipment:	N/A							
Scope Basis / Assumptions								
Water Supply Cost:	Raw water assumes $0.10/kgal.							
Water Quality Assumptions:	Suitable for use in evaporative coolers / cooling towers with 4 cycles of concentration and without any pretreatment. Standard chemical treatment for corrosion / biological growth only							
Demineralizer System	N/A	N/A	N/A	Permanent On-Site RO w/Mixed Bed Polisher	N/A		Permanent On-Site RO w/Mixed Bed Polisher	Not specified in report provided by MDU
Water Discharge Treatment:	Neutralize Only for discharge to onsite evaporation pond, as applicable							Not specified in report provided by MDU
Water Discharge Cost:	Water Discharge Treatment Cost included in Variable O&M, No Water Discharge Demand Cost included.							Not specified in report provided by MDU
Fuel, Sorbent, and Ash Landfill								
SO2 Control:	N/A	N/A	N/A	N/A	N/A	N/A	Furnace Limestone Injection Followed by a Polishing Scrubber Utilizing Hydrated Furnace Ash for Sorbent	Sulfur Capture in Circulating Fluid Bed with Subsequent Polishing in Flash Dryer Absorber and Baghouse
Lime Costs:	N/A	N/A	N/A	N/A	N/A	N/A	None (assumes that excess lime from boiler is hydrated and utilized in the polishing scrubber)	Not specified in report provided by MDU
NOx Control:	DLN combustors with SCR option for LM6000. DLN combustors with SCR standard for LMS100.	DLN with SCR option.	SCR	DLN and SCR for greenfield options DLN only for RM Heskett Expansion	N/A	N/A	SNCR	SNCR
CO Control:	Good Combustion Practice Oxidation Catalyst for LMS100PB+	Good Combustion Practice	Oxidation Catalyst	Oxidation Catalyst Good Combustion Practice for Heskett Expansion	N/A	N/A	Good Combustion Practice	Good Combustion Practice
Ammonia Type:	Aqueous	N/A	Urea	Aqueous	N/A	N/A	Aqueous	Anhydrous or Aqueous not specified in report provided by MDU
Mercury Sorbent Type:	N/A	N/A	N/A	N/A	N/A	N/A	Activated Carbon Injection	Activated Carbon Injection
CO2 Control	N/A	N/A	N/A	N/A	N/A	N/A	N/A	CO2 Capture as Applicable
Fly Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Bottom Ash / Slag Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Scrubber Sludge / Sulfur Byproduct Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Fly Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Emissions and Emissions Controls								
NOx Emissions Allowance Costs:	Excluded							
SOx Emissions Allowance Costs:	Excluded							
Mercury Emissions Allowance Costs:	Excluded							
Carbon Dioxide Emissions Allowance Costs / Tax:	Excluded							
Emissions and Emissions Controls								
Note 1	Coal technology option information provided by MDU, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council. Their assumptions govern the information presented and may not be completely represented in the table above.							

APPENDIX B – 2019 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
December 2018 - Revision 3

PROJECT TYPE	1x Aeroderivative SCGT - Natural Gas	1x Aeroderivative SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion	Reciprocating Engine (9MW Engines)	Reciprocating Engine (18 MW Engines)
BASE PLANT DESCRIPTION						
Number of Gas Turbines/Engines/Units	1	1	1	1	4	3
Representative Class Gas Turbine	GE LM6000 PF+	GE LMS100 PB+	GE 7E.03 LLI	GE 7E.03 LLI	Wartsila 20V34SG	Wartsila 18V50SG
Capacity Factor (%)	15%	15%	15%	15%	15%	15%
Startup Time to Maximum Load, minutes (Notes 1, 2)	5	5	30	30	5	5
Startup Time to MECL, minutes (Note 3)	4	4	20	20	4	4
Startup Time to Stack Emissions Compliance, minutes (Note 20)	9	30	25	25	30	30
Maximum Ramp Rate, MW/min (Online)	14	25	24	24	18	28
Forced Outage Factor (%) (Notes 4, 5)	3.8%	3.8%	0.7%	0.7%	1.8%	1.8%
Equivalent Forced Outage Rate (%) (Notes 4, 5)	25.9%	25.9%	5.8%	5.8%	4.5%	4.5%
Availability Factor (%) (Notes 4, 5)	90.6%	90.6%	93.8%	93.8%	95.3%	95.3%
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger & Intercooler	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NO_x Control	DLN	DLN & SCR	DLN	DLN	SCR	SCR
CO Control	Good Combustion Practice	Oxidation Catalyst	Good Combustion Practice	Good Combustion Practice	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
ESTIMATED PERFORMANCE (Note 6)						
WINTER AMBIENT						
Base Load Performance @ 6.8°F / 70% RH (MDU Winter)						
Gross Plant Output, kW	55,570	101,470	99,470	99,470	37,480	56,450
Net Plant Output, kW	54,730	99,340	97,680	97,680	36,540	55,040
Net Plant Heat Rate, Btu/kWh (HHV)	9,210	8,860	11,180	11,180	8,450	8,310
Heat Input, MMBtu/h (HHV)	504	880	1,093	1,093	309	458
Minimum Load Operational Status @ 6.8°F / 70% RH (MDU Winter)					(Single Engine)	(Single Engine)
Gross Plant Output, kW	27,780	50,730	49,740	49,740	3,710	7,480
Net Plant Output, kW	27,370	49,670	48,840	48,840	3,620	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,850	10,820	14,490	14,490	10,220	9,630
Heat Input, MMBtu/h (HHV)	324	537	708	708	37	70
SUMMER AMBIENT						
Base Load Performance @ 84.5°F / 40% RH (MDU Summer, Incl. Evap Cooler)						
Gross Plant Output, kW	46,020	92,510	80,290	80,290	37,480	56,450
Net Plant Output, kW	45,280	90,660	78,280	78,280	36,540	55,040
Net Plant Heat Rate, Btu/kWh (HHV)	9,510	9,050	11,770	11,770	8,470	8,310
Heat Input, MMBtu/h (HHV)	431	821	922	922	309	458
Minimum Load Operational Status @ 84.5°F / 40% RH (MDU Summer)					(Single Engine)	(Single Engine)
Gross Plant Output, kW	20,640	45,160	37,590	37,590	3,710	7,480
Net Plant Output, kW	20,330	44,210	36,910	36,910	3,620	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	13,210	11,330	15,790	15,790	10,240	9,630
Heat Input, MMBtu/h (HHV)	269	501	583	583	37	70

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
December 2018 - Revision 3

PROJECT TYPE	1x Aeroderivative SCGT - Natural Gas	1x Aeroderivative SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion	Reciprocating Engine (9MW Engines)	Reciprocating Engine (18 MW Engines)
ESTIMATED CAPITAL AND O&M COSTS						
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$58**	**$102**	**$70**	**$66**	**$54**	**$70**
Project Cost Per Summer kW, 2019 $/kW	**$1,280**	**$1,120**	**$890**	**$840**	**$1,470**	**$1,280**
Owner's Costs, 2019 MM$	**$47**	**$58**	**$55**	**$15**	**$46**	**$49**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Engineer	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Management	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Owner's Legal Costs	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Owner's Start-up Engineering	$1.2	$1.2	$1.2	$1.2	$0.9	$0.9
Temporary Utilities	$0.5	$0.5	$0.5	$0.1	$0.5	$0.5
Permitting and Licensing Fees	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Switchyard (Note 18)	$4.0	$4.0	$4.0	$1.0	$4.0	$4.0
Land (Note 17)	$0.1	$0.1	$0.1	N/A	$0.1	$0.1
Transmission Interconnection (Notes 7, 19)	$15.0	$15.0	$15.0	$0.5	$15.0	$15.0
Gas Interconnection (Note 8)	$7.4	$8.7	$8.7	$1.3	$7.4	$7.4
Water Interconnection (Note 9)	$0.1	$0.1	$0.1	Existing	$0.1	$0.1
MISO Queue Fees (Note 10)	$0.3	$0.3	$0.3	$0.1	$0.2	$0.3
Network Upgrades	$6.2	$11.2	$11.0	$0.0	$4.1	$6.2
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.0	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.5	$0.5	$0.5	$0.5	$1.4	$1.4
Site Security	$0.4	$0.4	$0.4	$0.0	$0.4	$0.4
Operating Spare Parts	$1.8	$1.8	$1.8	$0.0	$2.0	$2.0
Permanent Plant Equipment and Furnishings	$0.3	$0.3	$0.3	$0.0	$0.3	$0.3
Builders Risk Insurance (0.45% of Construction Costs)	$0.3	$0.5	$0.3	$0.3	$0.2	$0.3
Owner's Contingency (10% for Screening Purposes)	$5.8	$10.2	$7.0	$6.6	$5.4	$7.0
Total Project Costs, 2019 MM$	**$105**	**$160**	**$124**	**$80**	**$99**	**$120**
Total Cost Per Summer kW, 2019 $/kW	**$2,320**	**$1,760**	**$1,590**	**$1,030**	**$2,710**	**$2,180**
Loaded Costs						
Interest During Construction, MM$	$5	$8	$8	$5	$5	$6
Total Project Costs, 2019 MM$ (Loaded)	**$110**	**$168**	**$132**	**$85**	**$104**	**$126**
Total Cost Per Summer kW, 2019 $/kW (Loaded)	**$2,440**	**$1,850**	**$1,680**	**$1,090**	**$2,850**	**$2,290**
SCR ADD-ON COSTS						
Capital Costs, 2019 MM$	$5.3	Included	$19	$19	Included	Included
Owner's Costs, 2019 MM$	$0.3	Included	$1.1	$1.1	Included	Included
Loaded Costs, Interest During Construction, 2019 MM$	$0.3	Included	$1.2	$1.2	Included	Included

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3						
PROJECT TYPE	**1x Aeroderivative SCGT - Natural Gas**	**1x Aeroderivative SCGT - Natural Gas**	**1x GE 7E.03 LLI SCGT - Natural Gas**	**1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion**	**Reciprocating Engine (9MW Engines)**	**Reciprocating Engine (18 MW Engines)**
FIXED O&M COST						
Fixed O&M Cost, 2019$/kW-mo (Note 11)	$2.50	$1.20	$1.40	$0.80	$2.60	$1.80
Property Tax, 2019 $/kW-mo (Note 21)	$0.80	$0.60	$0.60	$0.40	$1.00	$0.80
Property Insurance, 2019 $/kW-mo (Note 22)	$0.30	$0.20	$0.20	$0.10	$0.30	$0.30
NON-FUEL VARIABLE & MAINTENANCE COSTS						
Major Maintenance Cost, 2019$/Unit-hr (Notes 2, 12, 16)	$170.0	$300	$330.0	$330.0	$25	$22
Major Maintenance Cost, 2019$/Unit-Start	N/A	N/A	$9,000.0	$9,000.0	N/A	N/A
Major Maintenance Cost, 2019$/MWh (Note 23)	$5.00	$4.40	$5.60	$5.60	$2.60	$1.20
Variable O&M Cost, 2019$/MWh (Note 13)	$0.9	$1.7	$0.9	$0.9	$4.4	$4.6
SCR O&M Costs						
Incremental Fixed O&M Costs, 2019$/kWh	$0.00	Included	$0.00	$0.00	Included	Included
Incremental Variable O&M Cost, 2019$/MWh	$0.70	Included	$0.60	$0.60	Included	Included
ESTIMATED BASE LOAD OPERATING EMISSIONS (ISO) (Note 14)						
Turbine/Engine Only						
Gross Carbon Intensity (lb/MWh)	1,110	1,050	1,460	1,460	N/A	N/A
NO_X [lb/MMBtu, HHV]	0.090	0.100	0.020	0.020	N/A	N/A
NO_X [ppmvd @ 15% O_2]	25	25	5.0	5.0	N/A	N/A
NO_X [lb/hr]	40.0	86	19.0	19.0	N/A	N/A
CO [lb/MMBtu, HHV]	0.050	0.500	0.050	0.050	N/A	N/A
CO [ppmvd @ 15% O_2]	25	187	25	25	N/A	N/A
CO [lb/hr]	24.0	390	55.0	55.0	N/A	N/A
CO_2 [lb/MMBtu, HHV]	120	120	120	120	N/A	N/A
CO_2 [ppmvd @ 15% O_2]	49,500	34,400	34,700	34,700	N/A	N/A
CO_2 [lb/hr]	53,200	103,900	121,000	121,000	N/A	N/A
PM/PM_{10} [lb/MMBtu, HHV]	0.007	0.005	0.004	0.004	N/A	N/A
PM/PM_{10} [lb/hr]	3.00	4	4.20	4.20	N/A	N/A
Turbine /Engine with SCR and CO Catalyst						
Gross Carbon Intensity (lb/MWh)	1,120	1,050	1,460	1,460	990	970
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.010	0.010	0.020	0.020
NO_X [ppmvd @ 15% O_2]	2.5	2.5	2.0	2.0	5.0	5.0
NO_X [lb/hr]	4.40	8.60	8.30	8.30	1.20	2.50
CO [lb/MMBtu, HHV]	0.000	0.010	0.010	0.010	0.030	0.030
CO [ppmvd @ 15% O_2]	2.0	4.00	2.00	2.00	15.0	15.0
CO [lb/hr]	2.20	8.40	5.00	5.00	2.50	5.00
CO_2 [lb/MMBtu, HHV]	120	120	120	120	120	120
CO_2 [ppmvd @ 15% O_2]	34,300	34,300	34,300	34,300	N/A	N/A
CO_2 [lb/hr]	53,200	104,000	121,000	121,000	9,300	18,300
PM/PM_{10} [lb/MMBtu, HHV]	0.010	0.008	0.008	0.008	0.020	0.020
PM/PM_{10} [lb/hr]	4.40	6.70	7.40	7.40	1.70	3.30

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3						
PROJECT TYPE	1x Aeroderivative SCGT - Natural Gas	1x Aeroderivative SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion	Reciprocating Engine (9MW Engines)	Reciprocating Engine (18 MW Engines)

Notes:

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available. Recip engine start times assume the engines are kept warm when not operational.
Note 2: OEM specific frame turbine option (7E.03 LLI) does not include a fast start package.
Note 3: MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate.
Note 4: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2007 or later. Reporting period is 2011-2016. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.
Note 5: EFOR data from GADS may not accurately represent the benefits of a reciprocating plant, depending on how events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so the plant would not be completely offline as it may be during an event at 1x gas turbine plant.
Note 6: Performance estimates were developed with natural gas only at the conditions provided by Montana-Dakota Utilities.
Note 7: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage, land costs excluded.
Note 8: Natural gas interconnection includes an allowance for 5 mile pipeline, utility interconnect and metering station. R.M. Heskett interconnection cost excludes existing pipeline to site, and includes additional pressure regulation equipment.
Note 9: Water interconnection allowance includes on site wells and pipe for raw water supply.
Note 10: MISO Queue Fees Owner's Costs includes application fee and Study Funding Deposit. Milestone payments are not included as those would be expected to be utilized for down payment on Network Upgrades which are shown separately as provided by MDU.
Note 11: All Gas Turbine FOM costs assume 4 full time personnel for greenfield options. Brownfield options assume 2 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
Note 12: Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27.
Note 13: VOM assumes the use of temporarily trailers for demineralized water treatment, where applicable.
Note 14: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable. Estimates are not for use for permitting purposes.
Note 15: Performance ratings are based on elevation of 1690 ft above msl.
Note 16: Reciprocating Engine major maintenance cost assumes no major overhaul falls within 20 year service period.
Note 17: Land allowance includes 15 acres at $5000/acre.
Note 18: Switchyard allowance for the Heskett Expansion as provided by MDU.
Note 19: Transmission allowance for Heskett Expansion provided by MDU.
Note 20: Startup time to stack emissions compliance is not the same as the start time to MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst (which impacts VOC emissions) and the time required for the emissions monitoring equipment to measure values matching the unit emissions rates included in this table. Estimates are not for use for permitting purposes.
Note 21: Property tax rate provided by MDU.
Note 22: Property Insurance rate provided by MDU.
Note 23: Major maintenance per MWh assumes 75% of summer net capacity for operating hours.

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
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PROJECT TYPE	2x1 SGT-800 CCGT - Fired	1x1 F Class CCGT - Fired	2x1 E Class CCGT - Fired Heskett Expansion
BASE PLANT DESCRIPTION			OPTION 1
Number of Gas Turbines	2	1	1 Exist / 1 New
Number of Steam Turbines	1	1	1
Representative Class Gas Turbine	Siemens SGT-800	GE 7F.05	GE 7E.03
Steam Conditions (Main Steam / Reheat)	1000 °F	1050 °F / 1050 °F	1000 °F
Main Steam Pressure, psia	1400	2400	1500
Steam Cycle Type	Subcritical	Subcritical	Subcritical
Capacity Factor (%)	70%	70%	70%
Startup Time, minutes (Cold Start to Unfired Base Load) (Note 1)	170	180	180
Startup Time, minutes (Cold Start to Stack Emissions Compliance) (Notes 1, 2)	50	60	25
Maximum Ramp Rate (Online, MW/min)	14	34	26
Forced Outage Factor (%) (Note 3)	2.2%	2.2%	2.2%
Equivalent Forced Outage Rate (%) (Note 3)	3.6%	3.6%	3.6%
Availability Factor (%) (Note 3)	87.8%	87.8%	87.8%
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only
Heat Rejection	Wet Cooling	Wet Cooling	Wet Cooling
NO_x Control	DLN & SCR	DLN & SCR	DLN
CO Control	Oxidation Catalyst	Oxidation Catalyst	Good Combustion Practice
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel	Low Sulfur Fuel
CO_2 Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice

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PROJECT TYPE	2x1 SGT-800 CCGT - Fired	1x1 F Class CCGT - Fired	2x1 E Class CCGT - Fired Heskett Expansion
ESTIMATED PERFORMANCE (Note 4)			
WINTER AMBIENT			**OPTION 1**
Base Load Performance @ 6.8°F / 70% RH (MDU Winter)			
Gross Plant Output, kW	154,700	347,150	289,110
Net Plant Output, kW	150,160	338,510	279,070
Net Plant Heat Rate, Btu/kWh (HHV)	7,060	6,570	7,710
Heat Input, MMBtu/h (HHV)	1,060	2,224	2,153
			7,713
Incremental Duct Fired Performance @ 6.8°F / 70% RH (MDU Winter)			
Gross Incremental Duct Fired Output, kW	36,290	95,870	88,400
Incremental Duct Fired Output, kW	35,290	95,380	86,300
Incremental Heat Rate, Btu/kWh (HHV)	9,120	8,270	10,210
Incremental Heat Input, MMBtu/h (HHV)	322	789	881
Minimum Load Performance @ 6.8°F / 70% RH (MDU Winter)			
Gross Plant Output, kW	40,620	198,150	115,730
Net Plant Output, kW	37,250	191,160	108,750
Net Plant Heat Rate, Btu/kWh (HHV)	8,920	7,150	8,300
Heat Input, MMBtu/h (HHV)	332	1,368	903
SUMMER AMBIENT (Note 5)			
Base Load Performance @ 84.5°F / 40% RH (MDU Summer)			
Gross Plant Output, kW	136,140	337,830	250,200
Net Plant Output, kW	131,100	329,180	239,320
Net Plant Heat Rate, Btu/kWh (HHV)	7,180	6,530	7,700
Heat Input, MMBtu/h (HHV)	942	2,150	1,843
Incremental Duct Fired Performance @ 84.5°F / 40% RH (MDU Summer)			
Gross Incremental Duct Fired Output, kW	43,630	91,960	91,350
Incremental Duct Fired Output, kW	42,850	91,210	90,450
Incremental Heat Rate, Btu/kWh (HHV)	9,040	8,020	9,990
Incremental Heat Input, MMBtu/h (HHV)	387	731	903
Minimum Load Performance @ 84.5°F / 40% RH (MDU Summer)			
Gross Plant Output, kW	34,540	183,090	94,190
Net Plant Output, kW	30,680	175,220	86,460
Net Plant Heat Rate, Btu/kWh (HHV)	9,360	7,210	8,460
Heat Input, MMBtu/h (HHV)	287	1,263	731

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**
ESTIMATED CAPITAL AND O&M COSTS			
Project Capital Cost, 2019 MM$ (w/o Owner's Costs) (NOTE 9)	**$246**	**$343**	**$274**
Project Cost Per UNFIRED Summer kW, 2019 $/kW	**$1,870**	**$1,040**	**$1,150**
Owner's Costs, 2019 MM$	**$119**	**$159**	**$68**
Owner's Project Development	$3.5	$3.5	$0.7
Owner's Operational Personnel Prior to COD	$1.8	$1.8	$1.8
Owner's Engineer	$0.0	$0.0	$0.0
Owner's Project Management	$4.5	$5.9	$2.0
Owner's Legal Costs	$1.0	$1.0	$0.8
Owner's Start-up Engineering and Training	$0.6	$0.5	$0.4
Temporary Utilities	$1.4	$1.6	$0.1
Permitting and Licensing Fees	$1.0	$1.0	$1.0
Switchyard	$7.4	$6.5	$3.0
Land (Note 11)	$0.4	$0.4	N/A
Transmission Interconnection (Note 12)	$30.0	$30.0	$1.7
Gas Interconnection (Note 13)	$10.0	$10.0	$1.3
Water Interconnection (Note 14)	$1.3	$1.3	Existing
MISO Queue Fees (Note 10)	$0.3	$0.4	$0.3
Network Upgrades	$20.9	$48.9	$21.1
Political Concessions & Area Development Fees	$0.5	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$2.0	$2.0	$2.0
Site Security	$0.5	$0.8	$0.4
Operating Spare Parts	$5.0	$6.0	$1.0
Permanent Plant Equipment and Furnishings	$1.3	$1.3	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.1	$1.5	$1.2
Owner's Contingency (10% for Screening Purposes)	$24.6	$34.3	$27.4
Total Project Cost, 2019 MM$ (Unloaded)	**$365**	**$502**	**$342**
Total Cost Per UNFIRED Summer kW, 2019 $/kW (Unloaded)	**$2,780**	**$1,520**	**$1,430**
Loaded Costs			
Interest During Construction, MM$	$29	$40	$27
Total Project Cost, UNFIRED, 2019 MM$ (Loaded)	**$394**	**$542**	**$369**
Total Cost Per UNFIRED Summer kW, 2019 $/kW (Loaded)	**$3,000**	**$1,650**	**$1,540**

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**
DUCT FIRING ADD-ON COST			
Capital Costs, 2019 $MM	$12.8	$8.7	$9.9
Owner's Costs, 2019 $MM	$1.3	$0.9	$1.0
Loaded Costs, Interest During Construction, 2019 MM$	$1.1	$0.8	$0.9
Total Project Cost, FIRED, 2019 $MM (Unloaded)	**$379**	**$512**	**$353**
Total Cost Per FIRED Summer kW, 2019 $/kW (Unloaded)	**$2,180**	**$1,220**	**$1,070**
Total Project Cost, FIRED, 2019 $MM (Loaded)	$409	$552	$381
Total Cost Per FIRED Summer kW, 2019 $/kW (Loaded)	$2,350	$1,310	$1,160
SCR ADD-ON COSTS			
Capital Costs, 2019 $MM	Included	Included	$5.1
Owner's Costs, 2019 $MM	Included	Included	$0.5
Loaded Costs, Interest During Construction, 2019 MM$	Included	Included	$0.4
FIXED O&M COSTS			
Fixed O&M Cost, 2019$/kW-mo (unfired kW) (Note 6)	$2.90	$1.10	$1.40
Property Tax, 2019 $/kW-mo (Note 15)	$1.00	$0.50	$0.50
Property Insurance, 2019 $/kW-mo (Note 16)	$0.40	$0.20	$0.20
MAJOR MAINTENANCE COSTS			
Major Maintenance Cost, 2019$/MWh	$2.35	$1.20	$2.24
Major Maintenance Cost, 2019$/GT-hr	$190	$400	$330
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)			
Total Variable O&M Cost, 2019$/MWh (Note 7)	$2.30	$1.80	$2.00
Incremental Duct Fired Variable O&M, 2019$/MWh	$1.70	$1.20	$2.10

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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PROJECT TYPE	2x1 SGT-800 CCGT - Fired	1x1 F Class CCGT - Fired	2x1 E Class CCGT - Fired Heskett Expansion
ESTIMATED BASE LOAD OPERATING EMISSIONS, (ISO) (Note 8)			
Unfired			
Gross Carbon Intensity (lb/MWh)	870	810	940
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.020
NO_X [ppmvd @ 15% O_2]	2.0	2.0	5.0
NO_X [lb/hr]	29.0	78.0	19.0
CO [lb/MMBtu, HHV]	0.004	0.004	0.050
CO [ppmvd @ 15% O_2]	5.0	10.0	10.0
CO [lb/hr]	2.30	11.0	55.0
CO_2 [lb/MMBtu, HHV]	120	120	120
CO_2 [ppmvd @ 15% O_2]	34,300	34,300	34,700
CO_2 [lb/hr]	61,600	280,200	121,000
PM/PM_{10} [lb/MMBtu, HHV]	0.006	0.006	0.004
PM/PM_{10} [lb/hr]	3.00	13.5	4.2
Fired			
Gross Carbon Intensity (lb/MWh)	920	860	1,030
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.060
NO_X [ppmvd @ 15% O_2]	2.0	2.0	10.0
NO_X [lb/hr]	41.0	78.0	58.0
CO [lb/MMBtu, HHV]	0.006	0.006	0.090
CO [ppmvd @ 15% O_2]	2.0	2.0	28.0
CO [lb/hr]	3.00	10.6	94.1
CO_2 [lb/MMBtu, HHV]	120	120	120
CO_2 [ppmvd @ 15% O_2]	34,300	34,300	34,700
CO_2 [lb/hr]	79,900	374,600	178,700
PM/PM_{10} [lb/MMBtu, HHV]	0.006	0.006	0.004
PM/PM_{10} [lb/hr]	3.00	13.5	11.1

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	2x1 SGT-800 CCGT - Fired	1x1 F Class CCGT - Fired	2x1 E Class CCGT - Fired Heskett Expansion

Notes:

Note 1: Cold start is >72 hours after shutdown. Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls.

Note 2: Startup time to stack emissions compliance with SCR/CO Catalyst is not the same as the start time for gas turbine MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.

Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined Cycle data is based on North American units that came online in 2007 or later. Reporting period is 2011-2016.

Note 4: Performance estimates assumed new and clean condition were developed with natural gas only at the conditions provided by Montana-Dakota Utilities.

Note 5: Summer ambient performances include incremental performance for evaporative cooling.

Note 6: Fixed O&M assumes 22 FTE for 1x1 and 25 FTE for 2x1 configurations (except for Heskett Expansion Option which assumes 20 FTEs).

Note 7: Variable O&M costs assume onsite demin treatment system.

Note 8: Emissions estimates are shown for steady state operation at ISO. Estimates account for the impacts of SCR and CO catalysts. Estimates are not for use for permitting purposes.

Note 9: Combined cycle base costs are for unfired plants. Add-on costs for duct firing provided.

Note 10: MISO Queue Fees Owner's Costs includes application fee and Study Funding Deposit. Milestone payments are not included as those would be expected to be utilized for Network Upgrades which are shown separately as provided by MDU.

Note 11: Land allowance includes 85 acres at $5000/acre.

Note 12: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage, land costs excluded.

Note 13: Natural gas interconnection includes an allowance for 5 mile pipeline, utility interconnect and metering station.

Note 14: Water interconnection allowance includes on site wells and pipe for raw water supply.

Note 15: Property tax rate provided by MDU.

Note 16: Property insurance rate provided by MDU.

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COAL AND BIOMASS TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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PROJECT TYPE	Coal w/o CC (Note 1)	Coal w/90% CC (Note 1)	Biomass
BASE PLANT DESCRIPTION			
Representative Technology	Circulating Fluidized Bed	Circulating Fluidized Bed	Bubbling Fluidized Bed (BFB)
Number of Steam Turbines	1	1	1
Capacity Factor (%)	90%	85%	85%
Startup Time (Cold Start)	4-18 hours	4-18 hours	12 hours
Equivalent Availability Factor (%)	90%	85%	85%
Fuel Design	100% Raw ND Lignite	100% Raw ND Lignite	Grasses
Heat Rejection	50% Wet-Cooled / 50% Air-Cooled	50% Wet-Cooled / 50% Air-Cooled	Wet Cooling
NO_x Control	SNCR	SNCR	SNCR
CO Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
SO_2 Control	Limestone Injection in Bed	Limestone Injection in Bed	Dry Sorbent Injection
Particulate Control	Baghouse	Baghouse	Baghouse
ESTIMATED PERFORMANCE			
Base Load Performance			
Gross Plant Output, kW	185,000	145,000	30,100
Net Plant Output, kW	168,000	122,000	25,000
Net Plant Heat Rate, Btu/kWh (HHV)	10,000	13,800	12,300
Heat Input, MMBtu/h (HHV)	1,680	1,680	310

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COAL AND BIOMASS TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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PROJECT TYPE	Coal w/o CC (Note 1)	Coal w/90% CC (Note 1)	Biomass
ESTIMATED CAPITAL AND O&M COSTS			
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$764**	**$1,023**	**$119**
Project Cost Per kW, 2019 $/kW	**$4,550**	**$8,390**	**$4,760**
Owner's Costs, 2019 MM$	**$224**	**$246**	**$80**
Owner's Project Development	$5.0	$5.0	$3.0
Owner's Operational Personnel Prior to COD	$12	$12	$1.3
Owner's Engineer	$0	$0	$0.0
Owner's Project Management	$9.3	$9.3	$2.0
Owner's Legal Costs	$5.0	$5.0	$1.0
Owner's Start-up Engineering	$0.9	$0.9	$0.2
Land (Note 2)	$2.3	$2.3	$1.5
Temporary Utilities	$2.1	$2.1	$1.3
Permitting and Licensing Fees	$3.0	$3.0	$1.0
Switchyard	$5.5	$5.5	$5.5
Transmission Interconnection (Note 8)	$30.0	$30.0	$30.0
Gas Interconnection (Note 9)	$7.4	$7.4	$7.4
Water Interconnection (Note 10)	$1.3	$1.3	$1.3
MISO Queue Fees (Note 4)	$0.3	$0.3	$0.2
Network Upgrades	$20.9	$16.3	$2.8
Political Concessions & Area Development Fees	$7.0	$7.0	$0.5
Startup/Testing (Fuel & Consumables)	$7.0	$7.0	$1.4
Site Security	$1.6	$1.6	$0.6
Operating Spare Parts	$5.3	$5.3	$0.8
Permanent Plant Equipment and Furnishings	$4.8	$4.8	$0.3
Builder's Risk Insurance (0.45% Project Cost)	$3.4	$4.6	$0.3
Owner's Contingency (10% for Screening Purposes)	$89.8	$115.4	$18.1
Total Project Costs, 2019 MM$ (Unloaded)	**$988**	**$1,269**	**$200**
Total Cost Per kW, 2019 $/kW (Unloaded)	**$5,880**	**$10,400**	**$7,980**
Loaded Costs			
Interest During Construction, MM$	$138	$177	$14
Total Project Costs, 2019 MM$ (Loaded)	**$1,125**	**$1,446**	**$213**
Total Cost Per kW, 2019 $/kW (Loaded)	**$6,700**	**$11,850**	**$8,530**

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COAL AND BIOMASS TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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PROJECT TYPE	Coal w/o CC (Note 1)	Coal w/90% CC (Note 1)	Biomass
FIXED O&M COSTS			
Fixed O&M Cost, 2019$/kW-mo	$21.00	$29.00	$21.00
Property Tax, 2019 $/kW-mo (Note 5)	$2.30	$4.10	$3.00
Property Insurance, 2019 $/kW-mo (Note 6)	$0.80	$1.50	$1.10
NON-FUEL VARIABLE & MAINTENANCE COSTS			
Major Maintenance Cost, 2019$/MWh	Included in VOM	Included in VOM	$3.10
Variable O&M Cost, 2019$/MWh	$14.06	$22.29	$5.60
ESTIMATED BASE LOAD OPERATING EMISSIONS (Note 3)			
Gross Carbon Intensity (lb/MWh)	2000	300	2,600
NO_X [lb/MMBtu, HHV]	0.06	0.06	0.120
NO_X [ppmvd @ 15% O_2]	14.40	14.40	N/A
NO_X [lb/hr]	101	101	37
CO [lb/MMBtu, HHV]	0.10	0.10	0.10
CO [ppmvd @ 15% O_2]	39.40	39.40	N/A
CO [lb/hr]	168	168	33
CO_2 [lb/MMBtu, HHV]	215	22	210
CO_2 [ppmvd @ 15% O_2]	Not specified in report	N/A	N/A
CO_2 [lb/hr]	361,200	37,000	65,700
PM/PM_{10} [lb/MMBtu, HHV]	< 0.0008	< 0.0008	0.020
PM/PM_{10} [lb/hr]	1.3	1.3	4.9

Notes:
Note 1: Coal technology option information provided by MDU, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council. Their assumptions govern the information presented.
Note 2: Land allowance is 450 acres for the coal options and 300 acres for the biomass option at $5,000/acre.
Note 3: Emissions estimates are not for use for permitting purposes.
Note 4: MISO Queue Fees Owner's Costs includes application fee and Study Funding Deposit. Milestone payments are not included as those would be expected to be utilized for down payment on Network Upgrades which are shown separately as provided by MDU.
Note 5: Property tax rate provided by MDU.
Note 6: Property Insurance rate provided by MDU.
Note 7: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage, land costs excluded.
Note 8: Natural gas interconnection includes an allowance for 5 mile pipeline, utility interconnect and metering station.
Note 9: Water interconnection allowance includes on site wells and pipe for raw water supply.

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
BASE PLANT DESCRIPTION				
Nominal Output, MW	20	50	50 MW PV Opt: 10 MW / 40 MWh Storage	5 MW PV Opt: 1 MW / 4 MWh Storage
Representative Technology	GE 2.72-116	GE 2.72-116	PV: Single Axis Tracking Storage: Li-Ion Batteries	PV: Single Axis Tracking Storage: Li-Ion Batteries
Number of Turbines	9 x 2.7 MW	23 x 2.7 MW	N/A	N/A
Capacity Factor (%) (Notes 1, 2)	43%	43%	26%	26%
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	1.32	1.32
PV Degradation (%/yr) (Note 3)	N/A	N/A	First year: 2% After 1st Year: 0.5% per year	First year: 2% After 1st Year: 0.5% per year
Startup Time (Cold Start)	N/A	N/A	N/A	N/A
Equivalent Availability Factor (%) (Note 4)	95%	95%	99%	97%
ESTIMATED PERFORMANCE				
Base Load Performance				
Net Plant Output, kW	20,000	50,000	50,000	5,000
Net Plant Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	N/A
Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	N/A

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
ESTIMATED CAPITAL AND O&M COSTS (Note 6)				
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$26**	**$62**	**$71**	**$7**
Project Cost Per kW, 2019 $/kW	**$1,280**	**$1,240**	**$1,430**	**$1,370**
Owner's Costs, 2019 MM$	**$7**	**$18**	**$19**	**$5**
Owner's Project Development	Included	Included	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$0	$0	$0	$0
Owner's Engineer	$0	$0	$0	$0
Owner's Project Management	Included	Included	$0.2	$0.1
Owner's Legal Costs	Included	Included	$0.3	$0.3
Owner's Start-up Engineering	$0	$0	$0.0	$0.0
Land (Note 5)	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Temporary Utilities	Included	Included	$0.3	$0.1
Permitting and Licensing Fees	Included	Included	$0.5	$0.4
Switchyard / Interconnection (Notes 7, 8)	Included	Included	$2.0	$2.0
MISO Queue Fees (Note 9)	$0.1	$0.2	$0.2	$0.1
Network Upgrades	$2.3	$5.6	$5.6	$0.6
Site Security	Included	Included	$0.1	$0.1
Operating Spare Parts	Included	Included	$0.4	$0.1
Permanent Plant Equipment and Furnishings (Note 10)	Included	Included	$0.3	$0.3
Political Concessions & Area Development Fees	$0	$0	$0.0	$0.0
Builder's Risk Insurance (0.45% Project Cost)	Included	Included	$0.3	$0.0
Owner's Contingency (10% for Screening Purposes)	$2.8	$6.8	$8.2	$1.1
Total Project Costs, 2019 MM$ (Unloaded)	**$33**	**$80**	**$90**	**$12**
Total Cost Per kW, 2019 $/kW (Unloaded)	**$1,640**	**$1,600**	**$1,800**	**$2,440**
Loaded Costs				
Interest During Construction, 2019 MM$	$2.8	$6.3	$4.0	$0.9
Total Project Costs, 2019 MM$ (Loaded)	**$36**	**$86**	**$94**	**$13**
Total Cost Per kW, 2019 $/kW (Loaded)	**$1,780**	**$1,720**	**$1,880**	**$2,610**

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
December 2018 - Revision 3

PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
FIXED O&M COST				
Fixed O&M Cost, 2019$/kW-mo (Note 10)	$4.30	$4.30	$2.90	$3.00
Property Tax, 2019 $/kW-mo (Note 11)	$0.60	$0.60	$0.70	$0.90
Property Insurance, 2019 $/kW-mo (Note 12)	$0.20	$0.20	$0.20	$0.30
NON-FUEL VARIABLE & MAINTENANCE COST				
Major Maintenance Cost, 2019$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Variable O&M Cost, 2019$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Co-Located Energy Storage			**10 MW | 40 MWh**	**1 MW | 4 MWh**
Add-On Costs				
Capital Costs, 2019 MM$	N/A	N/A	$17.6	$2.6
Owner's Costs, 2019 MM$	N/A	N/A	$1.50	$0.40
Incremental O&M Cost, 2019 MM$/Yr	N/A	N/A	$0.35	$0.06
Loaded Costs, Interest During Construction, 2019 MM$	N/A	N/A	$1.19	$0.49

Notes:

Note 1: Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on GE 2.72-116 turbines with 80 meter hub height and 8.5 m/s average wind speed.

Note 2: Solar capacity factor accounts for typical losses. Fixed tilt systems assumes 42 degree tilt.

Note 3: PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each remaining year.

Note 4: NERC GADS performance statistics are not available for PV, battery storage, and wind technologies. Availability estimates are based on vendor correspondence and industry publications.

Note 5: Wind and PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Land lease and property tax allowances are included in the Fixed O&M. Onshore wind assumes one acre per turbine. PV assumes seven acres per MW for fixed tilt and eight acres per MW for tracking options.

Note 6: Estimated Costs exclude decommissioning costs and salvage values.

Note 7: EPC costs for wind include 34.5 kV collection system and GSU to 115 kV. Owner's costs include 3 position ring bus switchyard for interconnection at 115 kV.

Note 8: PV scope for EPC includes 34.5 kV collector bus and circuit breaker. Owner costs include allowance for interconnection at 115 kV.

Note 9: MISO Queue Fees Owner's Costs includes application fee and Study Funding Deposit. Milestone payments are not included as those would be expected to be utilized for Network Upgrades which are shown separately as provided by MDU.

Note 10: Renewable options include an administrative building for storage and monitoring functions.

Note 11: Property tax rate provided by MDU.

Note 12: Property Insurance rate provided by MDU.

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HESKETT 4 ANALYSIS

INTRODUCTION

As part of the 2019 Integrated Resource Plan (IRP) development, Montana-Dakota retained Burns & McDonnell Engineering Company (BMcD) to prepare a 2019 IRP Technology Assessment (Assessment) to evaluate various power generation technologies as self-build supply-side resource options for Montana-Dakota's Electric Generation Expansion Analysis System (EGEAS) modeling. As further detailed in the Assessment, BMcD stated that the information provided was screening-level in nature and for comparative purposes only (not to be used for construction purposes). BMcD recommended that any self-build supply-side resource options of interest to Montana-Dakota should be followed by additional detailed studies.

In the preliminary EGEAS modeling results of feasible supply-side and demand-side resource options, the natural gas fired large frame General Electric (GE) 7E.03 simple cycle combustion turbine (SCCT) Heskett Expansion (Heskett 4) was selected in the base case model to economically and reliably meet future customer generation requirements beginning in the 2022-2023 timeframe, and therefore became a self-build supply-side resource option of interest to Montana-Dakota. As an interim step prior to hiring a consultant to perform additional detailed studies of Heskett 4, Montana-Dakota used its extensive knowledge obtained from the construction of the R.M. Heskett Station Unit 3 (Heskett 3) GE 7EA combustion turbine to perform a more detailed internal cost investigation of Heskett 4. This investigation would provide a more refined cost estimate for inclusion in the final EGEAS modeling.

Presented below are details on Heskett 3 & Heskett 4 plant synergies, assumptions, methodology, and results of Montana-Dakota's cost investigation.

HESKETT 3

Commissioned in 2014, Heskett 3 is a Montana-Dakota self-built GE 7EA large frame SCCT with a nameplate rating of 88MW. Heskett 3 is equipped with evaporative cooling for power augmentation, a Dry Low NOx (DLN) combustion system for emissions control, a closed cooling water system for cooling the generator and other systems, and a service building with an electrical room, control room, offices, and shop area. Heskett 3 shares portions of the water treatment and fire protection systems with R.M. Heskett Unit 1 (Heskett 1) & Unit 2 (Heskett 2) and is operated by the main plant control room located at the Heskett 1 & Heskett 2 building. Heskett 3 can also be operated remotely from other locations. During the design and construction of Heskett 3, the possibility of future expansion of the site by adding an additional SCCT combustion turbine or the conversion to a 2x1 combined cycle combustion turbine was taken into consideration. Included in these considerations were the sizing and location of the natural gas supply pipeline, underground fire protection loop, storm water drainage, electrical equipment room, and underground electrical conduit, among others. It is expected that Heskett 4 will take advantage of this existing infrastructure, reducing the overall capital cost of the project as compared to a greenfield site.

HESKETT 4

Heskett 4 will be located adjacent to Heskett 3. It is expected that the unit will be a near mirror image of Heskett 3, with the major equipment being nearly identical. Heskett 4 will consist of a new GE 7E.03 SCCT connected to a GE supplied generator, nominally rated at approximately 88MW, but capable of producing over 100MW under certain ambient conditions. It is planned to be equipped with an evaporative cooler at the air intake for power augmentation, DLN combustion system, and a closed cooling water system for cooling the generator and other systems.

The existing Heskett 3 service building will be used to house equipment associated with Heskett 4 and five to seven full-time employees. To accommodate these needs, the building will likely need to be expanded. Expansion of the existing service building is expected to cost significantly less than a new service building for a greenfield project. The 24-mile natural gas supply pipeline connecting the facility to Northern Border Pipeline is sized to provide enough fuel capacity to operate both Heskett 3 & Heskett 4 at full load continuously. Existing Heskett 3 on-hand spare parts will reduce the need to purchase additional spare parts for Heskett 4. The underground fire loop, oily drains tank, storm water drainage, underground electrical conduit and other systems are expected to be used with only minor modifications required.

Heskett 3 water supply is currently sourced from the existing Heskett 1 & Heskett 2 Missouri River water intake. Montana-Dakota's analysis assumed the intake would be shuttered during the decommissioning of Heskett 1 & Heskett 2, with future water being sourced from the local rural water supply. However, Montana-Dakota will further evaluate whether reuse of the water intake for Heskett 3 and Heskett 4 would better suit the plant from a cost and operability standpoint. Possible future expansion of the site to a 2x1 combined cycle power plant will be taken into consideration during the detailed design phase of the project.

Montana-Dakota expects to use the existing construction parking, equipment laydown area, and overall site layout for Heskett 4 with minimal modifications. This will reduce the amount of pre-construction work to be completed and support an overall shorter construction schedule and reduced project cost as compared to a greenfield site.

Montana-Dakota is expecting that decommissioning of Heskett 1 & 2 will allow for emissions netting of Heskett 4. Emissions netting will help maximize the number of permitted operating hours of the unit and eliminate the need for emissions control equipment such as Selective Catalytic Reduction for NOx emissions control and Catalytic Oxidation for CO & VOC emissions control. Decommissioning of Heskett 1 & 2 will allow Montana-Dakota to eliminate the Midcontinent Independent System Operator (MISO) transmission interconnect network upgrade costs, which can cost in excess of $400 to $1,000 per kW for new generator interconnections.

Heskett 4 is currently expected to be in service in the 2022-2023 timeframe to meet the capacity requirements of Montana-Dakota's electric service customers served by its integrated electric system. Under the assumption that Heskett 4 would be nearly identical to the existing Heskett 3, the actual costs incurred during permitting, design, and construction of Heskett 3 were used as the basis of Montana-Dakota's capital cost estimate of Heskett 4. The next step is to obtain an Engineering Consultant to verify Montana-Dakota's assumptions and provide a detailed Class 3 cost estimate. The engineering cost estimate is expected to be completed fall of 2019.

Montana-Dakota has hired BMcD to perform additional detailed studies to create the final cost estimate for Heskett 4. This work was still on-going at time of printing for the 2019 IRP.

CAPITAL COST ASSUMPTIONS

At the end of 2018, Montana-Dakota received an indictive quotation from GE for the supply of the prime mover and associated equipment. The scope of supply was requested to be the same as provided for Heskett 3. Equipment in this scope of supply included the gas turbine package, air inlet system, exhaust diffuser, generator, electronic electrical control cabinet, turbine package fire protection, cooling system, generator circuit breaker, as well as transportation of equipment, technical advisory services, O&M manuals and training. The estimates for the remaining equipment not provided in the prime mover contract, consisting of the generator step-up transformer and substation, auxiliary transformer, distributed control system, 480V transformer, continuous emissions monitoring equipment, exhaust stack, medium voltage equipment, fuel gas conditioning skid and regulation, and spare parts were based on the costs incurred in the Heskett 3 project and escalated to 2019 dollars.

Engineering, construction, construction management support, permitting support, internal Montana-Dakota labor, legal support, commissioning, first fills and commissioning fuel, and various testing requirements were estimated based on Heskett 3 actual costs and escalated to 2019 dollars. In addition, estimates for expansion of the existing service building office, fire protection upgrades, water storage tanks and an emergency generator were included based on Montana-Dakota experience and publicly available equipment costs.

To account for potential cost increases related to project risks, Montana-Dakota reviewed the scope of work and included a contingency to the capital cost estimate. The contingency is intended to cover pricing accuracy and productivity assumptions but does not cover any major scope of work changes. Possible risks considered in the contingency estimate included, but were not limited to: equipment delivery delay, craft labor availability, labor productivity, labor market volatility, safety, force majeure, procurement delay, delay in startup/commissioning, environmental permitting delay, and generator interconnect agreement delay.

Montana-Dakota assumed the existing 30 MW Heskett 1 and 73.1 MW Heskett 2 of MISO Network Resource Interconnection Service (NRIS) would no longer be in service at the time of commercial operation of the new combustion turbine. However, the in-service date of Heskett 4 would be timed so that the existing 103.1 MW of MISO NRIS rights for Heskett 1 and Heskett 2 would be retained for use by Heskett 4. By maintaining the NRIS of Heskett 1 and Heskett 2, Montana-Dakota assumed that the new combustion turbine would not incur additional transmission system network upgrade requirements and their associated costs.

Assuming emissions netting from the retirement of Heskett 1 and Heskett 2, no Selective Catalytic Reduction or Catalytic Oxidizer are assumed to be required for emissions control and are excluded from the estimate. The capital cost estimate for Heskett 4 is provided in the Summary Table.

OPERATIONS AND MAINTENANCE COST ASSUMPTIONS

Operations and maintenance (O&M) costs were estimated based on previous consultant support and Montana-Dakota's experience. O&M cost estimates are provided in the Summary Table.

Fixed O&M costs assume five Montana-Dakota personnel supporting the operation and maintenance of both Heskett 3 and Heskett 4, as well as costs associated with maintenance, administration, property taxes, and insurance. Major maintenance and variable O&M costs were sourced from the BMcD Assessment.

EXPLANATION OF REFINED R.M. HESKETT STATION 7EA SCCT EXPANSION COST ESTIMATE PERFORMED BY MONTANA-DAKOTA

Summary Table:

Base Load Performance @ 84.5°F / 40% RH (MDU Summer, Incl. Evap Cooler)	1x GE 7E.03 SCGT - Natural Gas Heskett 4
Gross Plant Output, kW	80,290
Net Plant Output, kW	78,280
Net Plant Heat Rate, Btu/kWh (HHV)	11,770
Heat Input, MMBtu/h (HHV)	922
Total Project Costs, 2019 MM$	$68.7
Total Cost Per Summer kW, 2019 $/kW	$878
Total Project Costs, 2019 MM$ (Loaded)	$73.0
Total Cost Per Summer kW, 2019 $/kW (Loaded)	$933
Fixed O&M Cost, 2019$/kW-mo	$1.52
Major Maintenance Cost, 2019$/MWh	$5.60
Non-Fuel Variable O&M Cost, 2019$/MWh	$0.90
Gross Carbon Intensity (lb/MWh)	1,460
NO_X [lb/MMBtu, HHV]	0.020
CO [lb/MMBtu, HHV]	0.50
PM/PM_{10} [lb/hr]	4.20

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Case Nos. PU-19-___ and PU-19-___

Direct Testimony
of
Darcy J. Neigum

Q. Please state your name and business address.

A. My name is Darcy J. Neigum and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Director of System Operations and Planning for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have managerial responsibility for overseeing the day-to-day operations of the Company's electric control center and system operations and planning department. The system operations and planning department is responsible for electric resource planning and expansion studies for the Company.

Q. Please outline your educational and professional background.

A. I hold a bachelor's degree in Electrical and Electronics Engineering from North Dakota State University as well as a master's degree in Business Administration from the University of Mary. My work experience includes four years as a nuclear plant engineer; three years of experience as a coal-fired power plant engineer; eleven years of generation development and operational responsibilities for coal-fired, gas-fired, and renewable generation sources; and eleven years of experience managing the system operations and planning department for Montana-Dakota.

Q. What is the purpose of your testimony in this proceeding?

A. I provide support for the Company's request for an Advance Determination of Prudency for the Heskett 4 simple cycle natural gas-fired combustion turbine (Heskett 4 or Project) as a generation resource for the Company's integrated electric system. I will provide support for the Company's request for a determination that public convenience and necessity will be served by the construction and operation of the Project, that Montana-Dakota is fit, willing and able to provide such service and that the Project is a prudent and reasonable resource for Montana-Dakota's North Dakota electric customers.

Q. How will Montana-Dakota utilize Heskett 4 to meet customer needs?

A. Heskett 4 is a least cost resource that will be used to meet customer peak demand requirements following the retirement of Lewis & Clark 1, Heskett 1, and Heskett 2 coal-fired generating stations.

Q. What are the plant closure dates for Lewis & Clark 1, Heskett 1, and Heskett 2?

A. Montana-Dakota announced on February 15, 2019, that it will be closing the Lewis & Clark 1 coal-fired station at the end of its coal supply agreement at the end of 2020; and the Heskett 1 and 2 coal-fired generation units at the end of their coal supply agreement at the end of 2021. As explained by Mr. Welte, the final closure dates are now expected to occur at the end of March 2021 and 2022. These plant closure dates are supported in the Company's 2019 Integrated Resource Plan (2019 IRP) filed with the North Dakota Public Service Commission on July 1, 2019 in Case No. PU-19-221.

Q. What is the reason for the plant closures of Lewis & Clark 1, Heskett 1, and Heskett 2?

A. As shown in the 2019 IRP; these units are no longer economical to run as compared to other alternatives available to the Company and the units should be shut down at the end of their current coal supply agreements.

The costs of fuel, transportation, labor, and maintenance continue to rise at these facilities, as shown in the 2019 IRP[1] , while the cost of natural gas and renewables in the area has changed the dispatch characteristic of the plants so that in 2018 the units idled at their minimum output level between 80 and 90 percent of all online hours[2].

Q. How does Montana-Dakota offer its coal-fired generation into the MISO energy market.

A. Because of the Company's obligations under its coal-supply agreements, if the units are available to run the generators are entered

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[1] Volume IV, Attachment I, Pages 7 and 8 of the 2019 IRP.
[2] Volume IV, Attachment I, Page 4, Figure 2 of the 2019 IRP.

into the MISO market as a must run unit at their minimum output level and the units are dispatched economically above minimum load.

If the MISO market price is lower than the Company's marginal cost of fuel and variable operations and maintenance (O&M), these incremental marginal costs are not recovered from the MISO market and are an additional cost to Montana-Dakota's customers over what the Company could have bought the same power for from the market. The impact of this is demonstrated in the 2019 IRP[3].

Q. Does the IRP model tell the Company when to retire a generating unit?

A. The IRP model will not indicate when to retire but can be a tool to evaluate alternatives to help develop a least cost plan including the determination of a unit retirement date.

Q. What analysis did the Company perform to determine the customer benefits and least cost alternatives associated with the retirement of Lewis & Clark 1, Heskett 1, and Heskett 2?

A. As part of the 2019 IRP, the Company analyzed three separate scenarios to help determine a best retirement date for Lewis & Clark 1, Heskett 1, and Heskett 2.

First, the Company varied the retirement dates of the units from 2029 to 2025 to 2021 in the 2019 IRP model. This analysis showed the earlier the retirement date, the greater the customer savings.

[3] Volume IV, Attachment I, page 5, Figure 3.

Second, the Company retired the units in 2021 and then allowed the 2019 IRP model to select each of the units for an additional 5-year life at the current O&M and fuel cost for the unit with no additional capital investment. No units were selected to run after 2021.

Finally, the Company developed a specific revenue requirement financial model to determine the actual projected customer impact associated with a retirement and replacement scenario. This analysis is described in Mr. Jacobson's testimony and shows significant customer savings over the option of continuing to run the Lewis & Clark 1, Heskett 1, and Heskett 2 units.

Q. What resources did the Company evaluate the Heskett 4 project against?

A. As part of the 2019 IRP, the Company developed an internal portfolio of future units including: coal, gas, wind, solar, and battery; and issued a Request for Proposals of Capacity and Energy Resources on August 1, 2018 (2018 RFP).

A copy of the 2018 RFP and summary of analysis of bids received is included in the 2019 IRP report [4].

Nineteen proposals from ten companies were received in response to the 2018 RFP. The majority of proposals received did not have signed generator interconnections agreements with the Midcontinent Independent System Operator (MISO) and therefore the magnitude of associated

[4] Volume IV, Attachment F of the 2019 IRP.

network upgrade costs associated with the proposals were unknown at the time of the 2018 RFP and 2019 IRP analysis. No proposals were shortlisted from the 2018 RFP because of the uncertainty with potential network upgrade costs and the impacts to final pricing to the proposals. Most of the 2018 RFP proposals were included as future supply options in the 2019 IRP model to help guide the Company in potential additional resource selections when these proposals become more definitive.

Q. What did the results of the 2019 IRP reveal about the Company's least cost supply plan?

A. The Heskett 4 unit was selected as a least cost unit in the base case model run and all sensitivities which included: low/high load, low/high natural gas, low/high MISO energy, high combustion turbine costs, $30 per ton carbon cost, higher MISO capacity requirement, and a high natural gas / MISO energy model run[5].

Q. What other resources did the 2019 IRP model select as a least cost plan?

A. In addition to the Heskett 4 unit, the model also selected future wind, solar, storage, and natural gas-fired combined cycle as part of the Company's least cost plan[6].

Q. Why didn't the Company enter into contract negotiations with the wind and solar resources identified in 2022 and 2023?

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[5] Volume IV, Attachment C, Page 14, Table 3-1 of the 2019 IRP.
[6] Id.

A. These units did not have a final interconnection agreement and the costs for their network upgrades were still unknown. Based upon potential network upgrade costs for other projects coming out of MISO's generator interconnection queue, a cost adder of up to $25 per MWh could be applicable to these projects. The Company will issue another RFP prior to its next IRP to see if any of these projects or others have final interconnection costs and better price certainty.

These projects were selected in addition to Heskett 4, which is a least cost resource in all modeling scenarios.

Q. What are the impacts of replacing baseload coal with a natural gas-fired peaking turbine?

A. The 2019 IRP model is selecting the peaking turbine for capacity requirements and the Company will rely on the MISO market for more energy without the addition of energy resources like renewables.

The 2018 economic comparison in the 2019 IRP shows that fuel and variable O&M costs of Lewis & Clark 1, Heskett 1, and Heskett 2 are $9.75 per MWh to $29.62 per MWh over the MISO market energy purchases [7]. MISO purchase prices are expected to remain low with abundant low-cost natural gas and additional renewables being added to the MISO market.

Market prices would have to rise significantly for Lewis & Clark 1, Heskett 1, or Heskett 2 to be economically competitive again. If market

[7] Volume IV, Attachment I, Page 12, Figure 11 of the 2019 IRP.

energy prices rise significantly, the Company could always look to combine cycle Heskett 3 and Heskett 4, and/or add additional renewable generation.

Q. Is the addition of Heskett 4 the best alternative for the Company?

A. Yes, the addition of Heskett 4; coupled with the retirement of Lewis & Clark 1, Heskett 1, and Heskett 2; provides significant customer savings versus continuing to run these coal units or implementing another future electric supply plan. The Heskett 4 addition is a least cost resource in the 2019 IRP base case and all sensitivity cases.

Q. Is Montana-Dakota fit, willing and able to construct, operate and maintain the Project?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Case Nos. PU-19-___ and PU-19-___

Direct Testimony
of
Alan L. Welte

Q. Please state your name and business address.

A. My name is Alan L. Welte and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Director of Generation in the power production department of Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have overall responsibility for the day-to-day operation of Montana-Dakota's electric generation facilities, represent Montana-Dakota's interests in jointly owned generation facilities operated by other companies, and I am also responsible for new generation development.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Mechanical Engineering from North Dakota State University. My work experience includes eight years of experience as a plant engineer, twelve years of experience as a plant manager, and fifteen years of generation development and operational responsibilities in my current position which includes coal-fired, gas-fired, and renewable generation.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the Heskett 4 combustion turbine project (Project) identified as part of the Montana-Dakota's 2019 least cost generation expansion plan. I will also discuss the benefits in locating Heskett 4 on the existing Heskett 3 site, of selecting similar major equipment to those used in Heskett Unit 3, and to build Heskett 4 in conjunction with the retirement of the existing Heskett 1 and 2 coal-fired units.

Q. Please describe Montana-Dakota's Heskett Unit 4 Project?

A. The Project includes a simple cycle combustion turbine (SCCT) and generator interconnected to Montana-Dakota's existing electric transmission and natural gas systems. The Project will be located near Mandan, North Dakota on Montana-Dakota's R.M. Heskett Station property and on the existing Heskett 3 site. The timeline for construction and commercial operation will be coordinated with the retirement of the Heskett 1 and 2 coal-fired units to utilize the existing MISO transmission system interconnection rights and to use the emissions reductions in the air permitting for Heskett 4. Heskett 4 will be operated and maintained with existing trained and experienced employees.

Q. What is a SCCT electric generating facility?

A. The purpose of a SCCT electric generating facility is to start up quickly to serve peak capacity needs under higher electric market price conditions or when there are transmission system reliability concerns. In the SCCT, air is drawn in and is compressed using rows of rotating blades. The compressed air is then sent to a combustion chamber where it is mixed with fuel and the mixture is ignited. The hot combustion gas is then expanded through rotating turbine blades delivering power through a shaft connected to the generator where electricity is produced.

Q. Please describe the major equipment that will comprise Montana-Dakota's Project.

A. The Project will include a nominal rated 88 MW heavy-duty frame type combustion turbine and a totally enclosed water to air cooled generator similar to those used in Heskett Unit 3. The SCCT will be natural gas-fired, have a dry low NOx combustion system, and include evaporative inlet air cooling for power augmentation. The generator will connect to Montana-Dakota's 115kV transmission system through a 13.8kV to 115kV generator step up transformer. Station power will be provided by a 13.8 kV to 4160 kV unit auxiliary transformer. Natural gas equipment will include a pressure regulation station, a natural gas-fired fuel gas heater and a final filtration skid. A closed cooling water system will be included for cooling the turbine and generator lubricating oil, the generator windings, and other smaller turbine support systems. A continuous emissions monitoring system will be installed to measure NOx, CO and O_2.

Q. What Heskett Unit 3 design considerations, facilities and equipment are anticipated to be utilized for the Heskett Unit 4 Project?

A. Heskett 4 will benefit from Heskett 3 design considerations relating to natural gas pipeline capacity and site layout. The existing natural gas pipeline has enough capacity and will not require any additional pipeline equipment to serve Heskett 4. The existing site, including the natural gas yard and the construction parking and lay down area, were laid out to accommodate the new Heskett 4 equipment. Additionally, Heskett 4 will share the existing Heskett 3 fire protection loop, the storm water and waste water systems, the oily drains tank, and the turbine water wash system. Portions of the Heskett 3 service building, the underground electric conduit, the control system, and spare parts will also be utilized for Heskett 4. Exhibit No. __(ALW-1) depicts a conceptual arrangement of Heskett 4 on the existing site.

Q. What potential savings and benefits can be realized by building the Project at the Heskett site over a greenfield location?

A. The full savings to be realized from site design considerations and shared equipment are not available at this point in the preliminary design. Three substantial cost savings that are anticipated relate to MISO transmission system network upgrades, the electric transmission interconnection, and the natural gas interconnection. If a greenfield location required 15 miles of additional electric transmission and five miles of additional natural gas pipeline, the added cost would be around $14.5 million and $7.4 million respectively. Assuming an average cost of approximately $113 per kW required for MISO transmission system network upgrades for new generator interconnections in MISO's West region, the savings realized by utilizing the existing Heskett 1 and 2 transmission interconnection rights through the MISO Generator Replacement process would be $11.0 million. Additionally, there are also benefits to be achieved by netting the emission reductions from Heskett 1 and 2 against the Heskett 4 emissions in the air permitting process.

Q. Please provide the estimated Project capital cost.

A. The Heskett 4 Project capital cost is estimated to be $73.0 million. North Dakota's allocated share is approximately $52 million.

Q. Please describe Montana-Dakota's Project contracting approach.

A. Montana-Dakota intends to hire an engineering consultant to perform the detailed design, assist with the procurement process from bid phase through administration of contracts after award, and manage on-site construction, commissioning, and startup activities for Heskett 4. This contracting approach is commonly referred to as an Engineer, procurement support, and Construction Management (EpCM) contracting approach, and is very similar to the multiple contracts approach used for Heskett 3. Montana-Dakota expects that there will be at least seven major equipment contracts, one or more major construction contracts, and several smaller contracts for specialized equipment, construction, and services for Heskett 4. Major contracts for equipment, construction, and services will be directly between Montana-Dakota and the associated vendor.

Q. Please describe the Project activities undertaken at the time of the Advance Determination of Prudence filing.

A. Project activities include preliminary design and cost estimate development, review of proposals for the air permit consultant, and filing of the MISO Generator Replacement Process application.

Q. What is the schedule for ceasing operation of Heskett Units 1 and 2?

A. It is anticipated Heskett 1 and 2 operation will cease around March 31, 2022, following the end of the term of the existing coal supply agreement and the cold winter months.

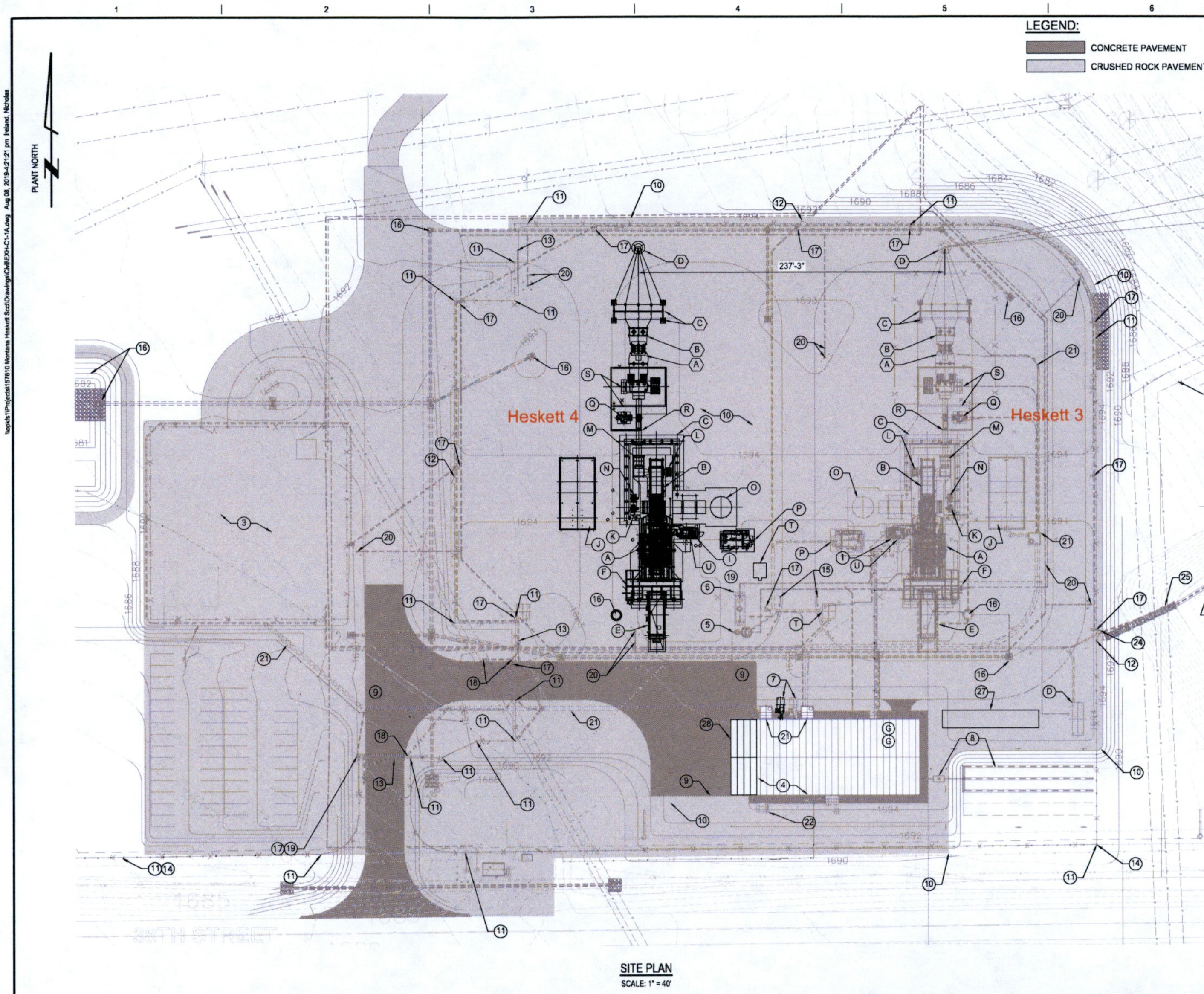
Q. What is the anticipated schedule for commercial operation of the SCCT?

A. Project permit work began in 2019. Detailed engineering work is anticipated to begin in January of 2021 and construction in March of 2022. The unit is projected to be available for commercial operation in February of 2023.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit No. ____ (ALW-1)
Page 1 of 1



SITE PLAN
SCALE: 1" = 40'

LEGEND:

- CONCRETE PAVEMENT
- CRUSHED ROCK PAVEMENT

KEYNOTES:

1. CT (COMBUSTION TURBINE) GROUP
   - A. CT
   - B. GENERATOR
   - C. GENERATOR ROTOR REMOVAL
   - D. WATER WASH SKID
   - E. PEECC (PACKAGED ELECTRICAL AND ELECTRONIC CONTROL COMPARTMENT)
   - F. INLET AIR FILTER AND EVAPORATIVE COOLING MODULE
   - G. WMFP (WATER MIST FIRE PROTECTION) SKID (INSIDE SERVICE BUILDING)
   - H. NOT USED
   - I. CT FUEL GAS VALVE MODULE
   - J. CLOSED COOLING WATER MODULE
   - K. CT EXHAUST FRAME BLOWERS
   - L. GNAC (GENERATOR NEUTRAL ACCESSORY COMPARTMENT)
   - M. GCBC (GENERATOR CIRCUIT BREAKER COMPARTMENT)
   - N. ACOUSTIC BARRIER WALL
   - O. EXHAUST SYSTEM AND ACOUSTIC PACKAGE-(CONTRACT 140089)
   - P. CEMS (CONTINUES EMISSION MONITORING SYSTEM) BUILDING-(CONTRACT 140093)
   - Q. UAT (UNIT AUX. TRANSFORMER)-(CONTRACT 140088)
   - R. NON-SEG BUS & BUS SUPPORT STANDS-(CONTRACT 140092)
   - S. GSU (GENERATOR STEP-UP) TRANSFORMER AND FIREWALL-(CONTRACT 140087)
   - T. FINAL GAS COALESCING FILTER SKID-(CONTRACT 140090)
   - U. OIL MIST ELIMINATOR
2. SWITCHYARD KEYNOTES
   - A. 115-KV CIRCUIT BREAKER
   - B. 115-KV DISCONNECT SWITCH
   - C. A-FRAME AND 115-KV METERING EQUIPMENT
   - D. TRANSMISSION POLE
3. FUEL GAS YARD FOUNDATION, GROUNDING, FENCE, GATE, ROCK, AND EQUIPMENT.
4. SERVICE BUILDING FOUNDATIONS AND METAL BUILDING. REF. SERVICE BUILDING DRAWINGS.
5. WASTEWATER LIFT STATION AND FORCE MAIN.
6. UNDERGROUND EMERGENCY OILY DRAIN TANK.
7. STATION SERVICE TRANSFORMER (CONTRACT 140092).
8. ONSITE WASTEWATER TREATMENT SYSTEM.
9. CONCRETE PAVEMENT, REF. PAVEMENT PLAN AND DETAILS. INSTALLED AS PART OF CN140096.
10. CRUSHED ROCK SURFACING, 5' MINIMUM OUTSIDE PAVEMENT. REF. PAVEMENT PLAN AND DETAILS.
11. SITE SECURITY FENCE, REF. FENCE DETAILS. EXTEND FENCE WEST ALONG 38TH STREET TO PROPERTY CORNER.
12. SITE SECURITY MAN GATE, 3 PLACES, REF. FENCE DETAILS.
13. SITE SECURITY CANTILEVER SLIDE GATE, 3 PLACES, REF. SITE DETAILS. INSTALLED AS PART OF CN140096.
14. FENCE ISOLATION REFERENCE FENCE DETAILS.
15. GUARDRAIL BARRIER, 6 PLACES, REF. SITE DETAILS.
16. STORMWATER MANAGEMENT SYSTEM.
17. SITE LIGHTING (12 PLACES), REFERENCE LIGHTING DETAILS.
18. GATE OPERATOR, AND GATE ACTUATOR. INSTALLED AS PART OF CN140096.
19. CLOSED CIRCUIT CAMERA, REF. SPECIFICATIONS (BY OTHERS).
20. SITE FIRE PROTECTION SYSTEM, REFERENCE MECHANICAL PLANS AND DETAILS.
21. ELECTRICAL MANHOLES AND DUCTBANK, REFERENCE ELECTRICAL PLANS AND DETAILS.
22. CONSTRUCTION POWER SUPPLY (SERVICE BUILDING ALTERNATE SUPPLY) TRANSFORMER. CONCRETE PAD FOR OWNER SUPPLIED AND INSTALLED ALTERNATE SUPPLY PAD MOUNT TRANSFORMER.
23. MANHOLES FOR MECHANICAL PIPING SERVICES, REFERENCE UNDERGROUND DRAWINGS.
24. KEY CARD READER.
25. STAIRCASE
26. SIDEWALK
27. EMERGENCY GENERATOR
28. 20' BUILDING EXTENSION

0 20 40 80 120 FEET
1" = 40'

PRELIMINARY, NOT FOR CONSTRUC[TION,] RECORDING PURPO[SES] OR IMPLEMENTATI[ON]

SEALING_ENGIN[EER]

PROJECT LOCATION:
2025 38TH ST
MANDAN, MORTON CO., NORTH DAK[OTA]

EXH-C1-1A.DWG

THIS DRAWING WAS PREPARED BY POWER ENGINEERS, INC. FOR A SPECIFIC PROJECT, TAKING INTO CONSIDERATION THE SPECIFIC AND UNIQUE REQUIREMENTS OF THE PROJECT. REUSE OF THIS DRAWING OR ANY INFORMATION CONTAINED IN THIS DRAWING FOR ANY PURPOSE IS PROHIBITED UNLESS WRITTEN PERMISSION FROM BOTH POWER AND POWER'S CLIENT IS GRANTED.

INTER-DISCIPLINE REVIEW						
DISC	ARCH	CIVIL	ELECT	I&C	MECH	STRUCT
DATE	•	•	•	•	•	•
INIT	•	•	•	•	•	•

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
C	ISSUED WITH SCCT STUDY	08/12/19	NLI	BHR	SMT	CMD
B	ISSUED WITH SCCT STUDY	07/19/19	NLI	BHR	SMT	CMD
A	ISSUED WITH SCCT STUDY	06/17/19	BLW	BHR	SMT	CMD

DSGN	BHR	06/17/19
DRN	BRG	06/17/19
CKD	SMT	06/17/19
SCALE:	1" = 40'	

FOR 22x34 DWG ONLY

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

POWER ENGINEERS
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(913) 681-2881 www.powereng.com
CERTIFICATE OF REGISTRATION NO. X-0000

MONTANA-DAKOTA UTILITIES CO.

MONTANA-DAKOTA UTILITIES CO.
HESKETT UNIT 4

OVERALL SITE PLAN

JOB NUMBER
157610

DRAWING NU[MBER]
EXH-C1

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case Nos. PU-19-___ and PU-19-___

Direct Testimony
of
Travis R. Jacobson

Q. Please state your name and business address.

A. My name is Travis R. Jacobson and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Analysis Manager for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

Q. Would you please describe your duties as Regulatory Analysis Manager?

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments, and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. Would you please describe your education and professional background?

A. I graduated from Minot State University with a Bachelor of Science degree in Accounting and I am a Certified Public Accountant (CPA). I started my career with Montana-Dakota in 1999 as a financial analyst in the Financial Reporting Department and during my tenure with the Company have held positions of increasing responsibility, including Supervisor, Financial Reporting and Planning and Manager, Financial Reporting and Planning before attaining my current position.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana and Wyoming and the Public Utilities Commissions of Minnesota and South Dakota.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide information supporting the revenue requirement analysis presented in Attachment I of the Integrated Resource Plan (IRP).

Q. What exhibit are you sponsoring?

A. I am sponsoring Exhibit No.___(TRJ-1), the revenue requirement analysis described above.

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes, it was.

Q. Why was the revenue requirement analysis performed?

A. As discussed in the testimony of Mr. Darcy Neigum, Montana-Dakota identified the Heskett and Lewis & Clark coal units for retirement and selected the Heskett 4 combustion turbine during the IRP process. While the modeling indicated these decisions were the most economic choices over the modeling period, the annual revenue requirement associated with the retirements and replacement were not known.

Typically, a revenue requirement is performed during a general rate case; however, a general rate case is all inclusive and considers all revenue, expense and rate base components so the impact of any one activity is not identified.

In this Docket, the Company has prepared a revenue requirement to specifically identify the projected impact of the decision to retire and replace these units at the customer level.

Q. Please provide an overview of the revenue requirement analysis?

A. Figure 14, shown on page 17 of Attachment I in the 2019 IRP, provides a comparison of the revenue requirement to maintain continued operations versus the revenue impact related to the retirement of Heskett Units 1 & 2 and the Lewis & Clark 1 coal fired generating facilities along with the addition of the planned Heskett 4 combustion turbine. This analysis was performed on an integrated electric system basis and shows a net benefit to customers of $20.1 million in 2023.

The Company prepared an analysis in several steps. The first step was to determine the ongoing costs to continue current operations of Heskett and Lewis & Clark. Next, an analysis of the deferred costs and the revenue requirement of the replacement was prepared to show ongoing costs once the units are retired and the new unit is in service. Finally, a comparison of the fuel and purchased power costs was prepared to determine the net cost to customers.

Q. Please describe each step in detail.

A. As noted above, there were three sets of analyses prepared as follows:

<u>Ongoing costs to continue current operations</u> – Montana-Dakota analyzed its operations and maintenance expenses with twelve months ended December 2018 for a base period. Costs associated with Heskett 3 and the RICE Units located at the Lewis & Clark Station were excluded from the analysis as those costs will continue upon retirement of the coal units. The cost of labor, the largest operating cost, was increased by 3.0 percent annually. Premium time was held constant throughout the projected period. All other costs were reviewed for abnormal expenses and were

escalated at 2.6 percent. Reagents and coal severance taxes were adjusted to reflect projected generation levels.

To determine the level of rate base, projected capital additions to enable the coal units to remain in service was established. The approved depreciation rates were applied to the plant balances to determine the depreciation expense as well as the balance in the accumulated reserve accounts. Changes in the level of deferred income taxes were included to provide the net rate base upon which the authorized return is applied to determine return on rate base. The authorized return on equity established in Case No. PU-16-666, along with the Company's capital structure and updated cost of debt, was used to develop the authorized return. The total costs to continue operations were projected to be $33.5 million during 2023.

<u>Ongoing costs for the recovery of deferred costs and Heskett 4 combustion turbine operations</u> – Montana-Dakota began accelerating depreciation expense of the retiring coal units upon the announcement of the closures in February 2019 in accordance with Generally Accepted Accounting Principles (GAAP). GAAP requires that the net book value must be $0 at the time of the plant closures. However, Montana-Dakota has not changed the level of depreciation recovered in rates charged to

customers and, therefore, began deferring the portion of depreciation that is in excess of the amount collected in rates.

Projected decommissioning costs to be incurred upon the plant closures have been estimated and are being amortized and will become a part of the costs to be recovered in the future.

The Company has established an employee retention package to ensure the plants will continue to operate until the closure dates. The package includes severance, retraining and job search assistance costs. Certain costs are required to be amortized upon the announcement under GAAP accounting rules.

The revenue requirement reflects the recovery of the deferred depreciation expense and decommissioning costs over a 15-year period, including a return on the unamortized balance, and a recovery of the employee retention package over a 5-year period.

The revenue requirement of the Heskett 4 combustion turbine was prepared and was based on the initial capital cost to be placed in service and was assumed to be in service for the full calendar year 2023. The revenue requirement included a return on the rate base as well as the operating costs necessary to operate the new combustion turbine. Those costs include the incremental labor, benefits and other operating costs as well as the depreciation and property taxes.

The total projected costs associated with the recovery of deferred plant and employee costs and the revenue requirement of the combustion turbine are approximately $22.3 million.

Fuel and purchased power costs – Montana-Dakota prepared two scenarios using its power generation dispatch software. The first scenario assumed operations as usual and Heskett and Lewis & Clark were included and expected to generate in a manner similar to that recently experienced. The second scenario did not include the Heskett and Lewis & Clark coal units and did include the Heskett combustion turbine. All other parameters were applied consistently.

The results of the two scenarios showed a reduction in fuel and purchased power costs under the retirement scenario and providing approximately $8.8 million annual savings to Montana-Dakota's customers.

Q. Please summarize the results of the revenue requirement analysis.

A. Continuing to operate the Heskett 1 and 2 and Lewis & Clark coal units is projected to cost Montana-Dakota's customers approximately $33.5 million annually. Retirement of these units and replacement with a combustion turbine is expected to require $22.2 million in annual revenue. This results in a savings to customers in excess of $11 million annually. The fuel and purchased power savings that is expected to be passed to customers through the Fuel and Purchased Power Adjustment Mechanism is estimated to add another $8.8 million in revenue reductions for a total customer savings in excess of $20 million annually.

Q. The analyses performed included a number of assumptions. Will Montana-Dakota continue to review and update the assumptions throughout the retirement and replacement process?

A. Yes. Montana-Dakota relied on the best information available at the time the IRP was prepared to make the decision to retire and replace the generating units. Each cost estimate was thoroughly investigated and the Company believes the estimates are still reasonable at this time and will be reviewing and updating the costs when more information is available.

The revenue requirement included assumptions regarding an amortization of deferred depreciation and decommissioning costs over a 15-year period and the employee retention package over a 5-year period. The amortization period selected for each category was chosen for the purpose of this analysis; however, the Company is analyzing alternative amortization periods that may be presented in future proceedings.

Q. Does this complete your direct testimony?

A. Yes, it does.

Montana-Dakota Utilities Co.
Integrated System Costs

Estimated Cost - Continued Operations (000's)	**2023**	
Lewis & Clark Non-Fuel Revenue Requirement	$13,959	
Heskett Non-Fuel Revenue Requirement	19,561	
Subtotal Non-Fuel Revenue Requirement Without Retirements	**$33,520**	
Estimated Cost - Discontinued Operations (000's)		
Lewis & Clark Retire 12/2020 - Revenue Requirement	$0	1/
Heskett Retire 12/2021 - Revenue Requirement	0	2/
Employee Retention Package Amortized over 5 years	1,413	3/
Net Book Value of Assets at Time of Retirement Amortized over 15 Years	8,815	4/
Plant Decommissioning Revenue Requirement	1,416	5/
Heskett IV Non-Fuel Revenue Requirement	10,642	6/
Subtotal Retirement & Heskett 4	**$22,286**	
Estimated Cost - Fuel & Purchased Power (000's)		
Fuel & Purchased Power - Without Retirements	$79,773	
Fuel & Purchased Power Redispatch after Retirements	68,076	
Capacity Replacement - Retirement	2,867	7/
Change in Fuel/Purchased Power	**($8,830)**	
Net Total Change	**($20,064)**	

1/ End of operation 12/31/2020 - End of coal contract 12/31/2020. Remaining plant balance - $38.3 M.

2/ End of operation 12/31/2021 - End of coal contract 12/31/2021. Remaining plant balance - $32.4 M.

3/ Employee retention package costs assumed to be amortized over 5 years from retirement date of each plant.

4/ Assumes a 15-year amortization of remaining balance, including the return on unamortized balance.

5/ Assumes 25% decommissioning completed year 1, 75% year 2 and 100% year 3 at a 15-year amorization, including a return on the unamortized balance.

6/ Assumes plant in service on 1/1/2023 plus incremental Heskett 4 non-fuel O&M costs.

7/ Capacity purchase at $4 per KW month for capacity needs not met by Heskett 4.