Integrated Resource Plan 2024

Submitted to the
Montana Public Service Commission
September 30, 2024

Volume IV: Attachments C-J

Montana-Dakota Utilities Co.

2024 Integrated Resource Plan

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

In the Community to Serve®

Attachment C

SUPPLY-SIDE AND INTEGRATION ANALYSIS DOCUMENTATION

Supply Side and Integration Analysis

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Supply-Side

Overview

To determine the most cost-effective plan, a supply-side analysis was conducted to identify the feasible supply-side resources to be added to Montana-Dakota's generating system. Potential new planning resources consisting of both capacity resources (generation or external resources) and load modifying resources must be proven technology and be able to provide the same system reliability that Montana-Dakota's customers have come to expect over the years. The integration process considers the potential planning resources and integrates those resources into a single least-cost plan. The analysis also considers possible future economic and social issues.

The least-cost resource plan, developed through the integration process, provides the basis for evaluating and determining the most cost-effective, long-term plan for future supply. Criteria other than simply least cost must be considered in the ultimate future resource selection.

Capacity Needs

The resource expansion analysis considers all planning resource options available to Montana-Dakota and produces a least-cost plan which satisfies the energy and capacity requirements to reliably serve Montana-Dakota's customers. Montana-Dakota is a member of MISO, which currently requires a planning reserve margin (PRM) of 9 percent on an unforced capacity (UCAP) basis for the summer peak and 27.4 percent for the winter. The PRM is adjusted annually through MISO's Loss of Load Expectation (LOLE) study. To meet the planning reserve margin requirement (PRMR), enough planning resources are needed to cover the projected yearly MISO coincident summer and winter peak demand with an adder for MISO losses, plus the PRM.

Montana-Dakota is required to meet a PRMR based on an 82.6 percent coincident factor in the summer and 92 percent coincident factor in the winter for the 2024-2025 Planning Year in MISO based on MDU's analysis of Montana-Dakota's peak at the time of the MISO system-wide peak.

MISO implemented a four-season resource adequacy requirement beginning with the 2023-2024 MISO Planning Year. The impacts of the four-season resource adequacy requirement have not had a large impact on the generation requirements for Montana-Dakota's fleet.

MISO is developing another change to Resource Adequacy that currently is expected to go into effect for the 2028-2029 Planning Year called the Direct Loss of Load (DLOL) method of calculating each Load Serving entities requirement and will develop each resources capacity credit. Montana-Dakota did receive numbers based on the 2022-2023 Planning Year and was able to manipulate those results to provide a look at how the DLOL method would affect Montana-Dakota.

Load and Capability

To further understand Montana-Dakota's capacity needs, a comparison of its zonal resource credits (ZRC) in MISO and the planning reserve margin requirement (PRMR) for summer and winter is shown in Figures 1-1 and 1-2, and Figures 1-3 and 1-4 showing the future summer and winter DLOL comparison. The ZRC is established by MISO annually through a Generator Verification Test Capability (GVTC) process. The GVTC is run annually by all Montana-Dakota's steam units and combustion turbines, as required by MISO for all generation resources, greater than 10 MW. All planning resources are corrected to MISO's seasonal peak to develop an Installed Capacity (ICAP) value to be used for each season. MISO then converts the ICAP value to a Seasonal Accredited Capacity (SAC) based on each unit's availability during the periods of highest risk and greatest need during each of the four seasons. The SAC values are then directly converted to a ZRC to be used to meet PRMR.

Figure 1-1 shows that, under the current summer system forecast, Montana-Dakota has adequate capacity to meet its PRMR through 2030. The capacity deficit in 2031 will be 2.2 ZRC and grow to 87.2 ZRC by 2043. As shown in Figure 1-2, under the current winter system forecast, a capacity deficit occurs in 2034 at 18.6 ZRC and grows to 150.9 ZRC by 2043. With the summer DLOL, as shown in Figure 1-3, a capacity deficit of 7.4 ZRC will occur in 2027 and grow to 92.2 ZRC by 2043. The winter DLOL, as shown in Figure 1-4, has a capacity deficit that shows up in 2026 at 0.5 ZRC and by 2043 will be 139.9 ZRC.

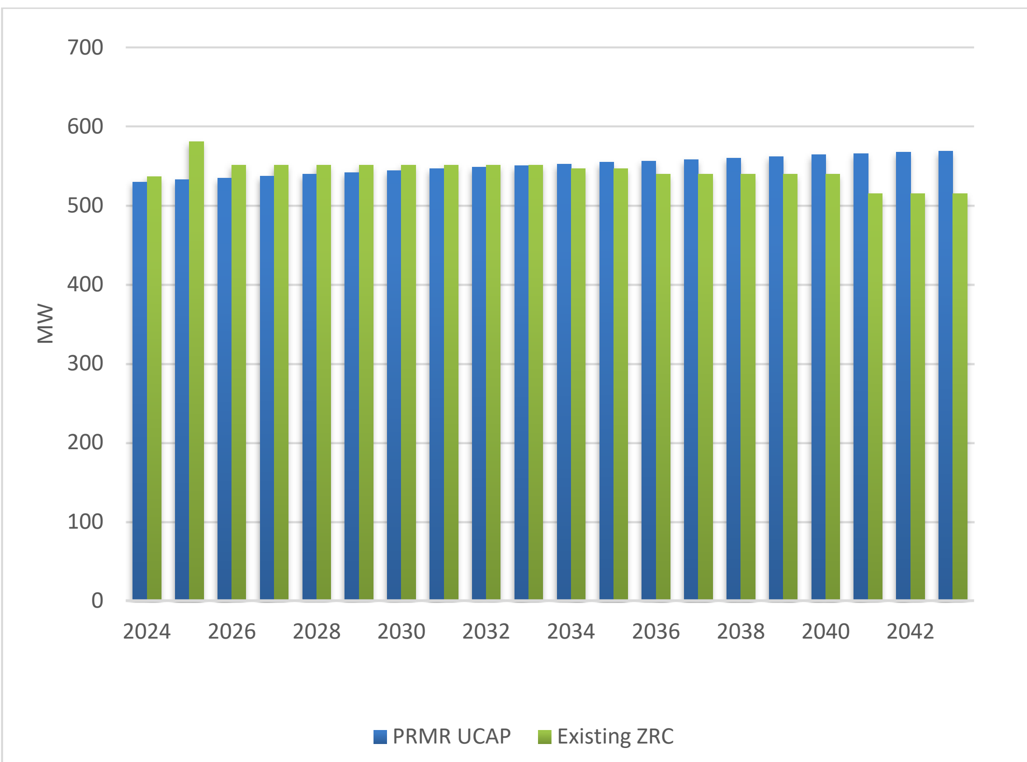


Figure 1-1: Zonal Resource Credit and Planning Reserve Margin Requirement Summer

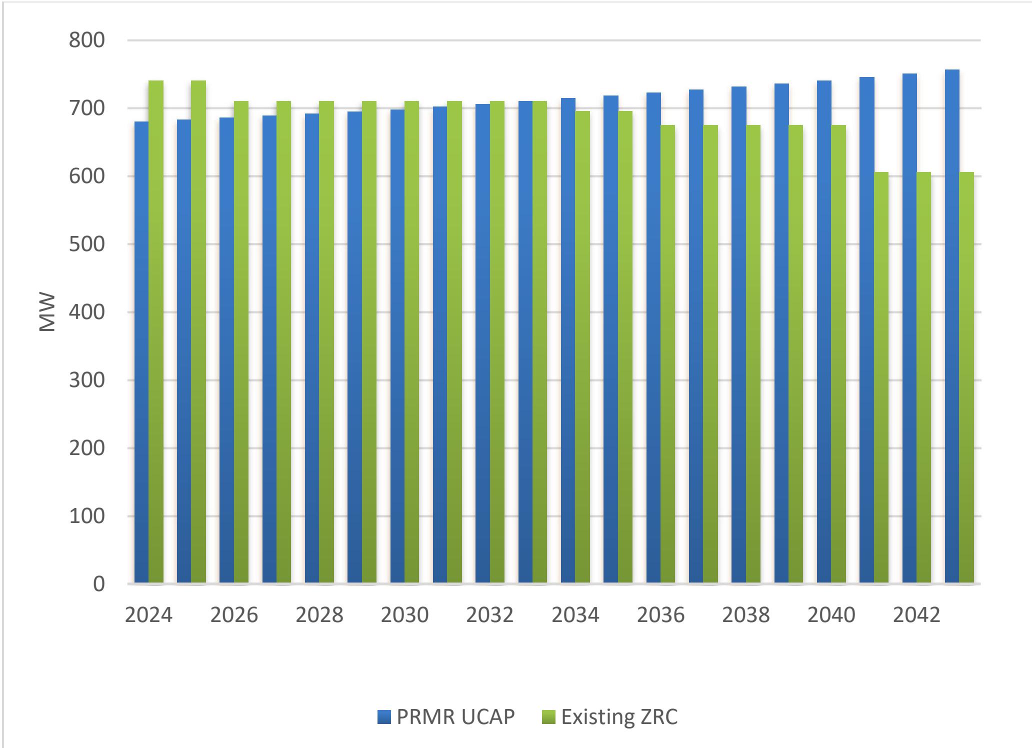


Figure 1-2: Zonal Resource Credit and Planning Reserve Margin Requirement Winter

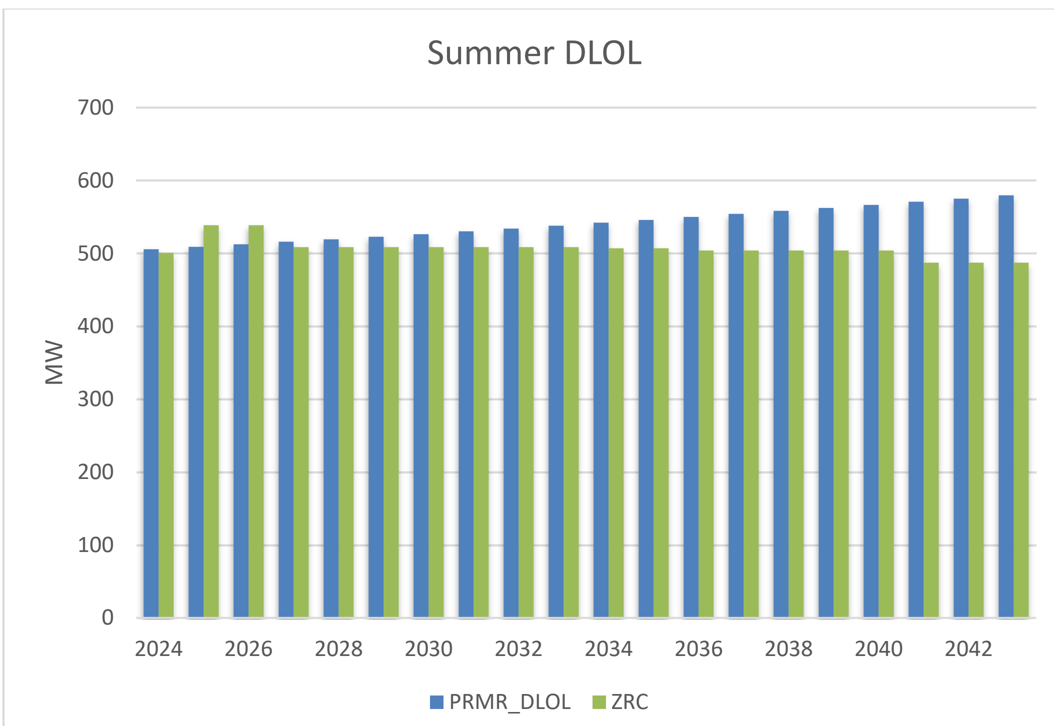


Figure 1-3: Zonal Resource Credit and Summer DLOL requirements

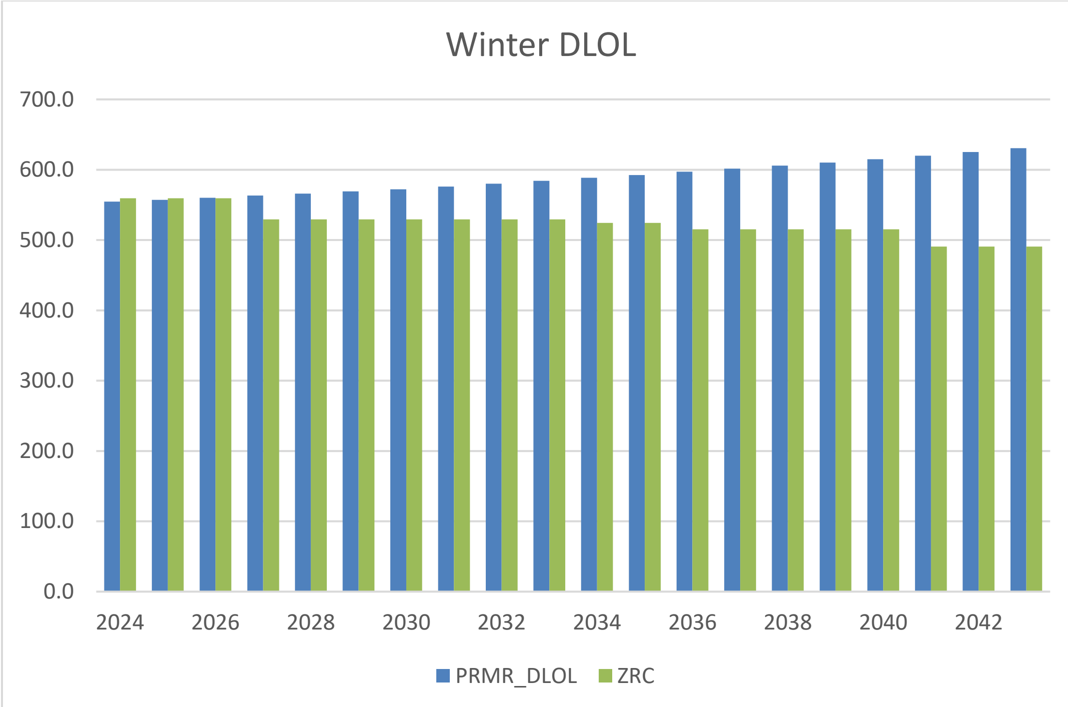


Figure 1-4: Zonal Resource Credit and Winter DLOL requirements

1. Analysis Method

The Electric Generation Expansion Analysis System (EGEAS) version 13, a computer model developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis, and develop the least-cost integrated resource expansion plan. The analysis was performed on various scenarios based on the load forecasts, availability of resources, and economic variables. Each of the scenarios constitutes a resource expansion plan unique to the assumptions used in that scenario. The resource expansion analysis minimizes the present worth, or the net present value (NPV), of the total revenue requirement over fifty years by using an algorithm called “dynamic programming”. The dynamic programming utilized in EGEAS calculates each scenario one year at a time to satisfy the reliability constraints and to fulfill the forecasted energy and capacity requirements. This process identifies all possible states that satisfy the reliability requirements for each year. Finally, the annual results are combined to determine the least-cost plan.

The base year used in the resource expansion analysis was 2023 with the study period starting in 2024. Costs indicated in this report are in 2023 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2024-2043) in which new resources can be added to meet the forecasted load growth and to compensate for unit retirements. To model the remaining life of capital investments installed during the study period, an additional 30 years, called the extension period, was added. During this extension period, loads stayed the same as the final year of the study period. All associated operational and fuel costs continue to be escalated at specified rates through the extension period.

2. Resources

Montana-Dakota's existing generation portfolio includes coal, natural gas, diesel, waste heat and wind. The resource expansion analysis considered other potential available alternative resources to expand the generation portfolio to meet forecasted energy and capacity requirements. All resources were modeled with applicable ZRC amounts, fixed and variable O&M costs, and fuel costs that are shown in Tables 2-1 through 2-5 below.

For resource capacity accreditation, MISO considers wind generation resources differently than thermal resources. The ZRC for wind generation resources is only available if the wind resources have been designated as a network resource in MISO or if the wind resource has been granted a transmission service request and has been designated an energy only resource. The ZRC value for wind resources is based on an effective load carrying capability (ELCC) study performed annually by MISO. This study examines MISO's top eight annual summer peaks for the last five years to determine how much wind is generated during summer peak conditions and compares the amount of wind generated to MISO's peak load. This study is done on a MISO system-wide basis and on all single commercial pricing nodes (CPNode). On a system-wide basis for the 2024-2025 planning year, the ELCC study concluded that 18.1 percent in summer and 53.1 percent in winter of nameplate wind capacity could be converted into a ZRC value if the wind resource is a network resource or has a transmission service request (TSR) for the nameplate value. Based upon production data collected at Montana-Dakota's wind farms' CPNodes, Diamond Willow was determined to contribute up to 19.85 percent in summer and 72.35 percent in winter of its nameplate capacity to ZRCs, Cedar Hills was allowed up to 26.65 percent in summer and 68.02 percent in winter of its nameplate capacity to ZRCs, and Thunder Spirit was allowed up to 24.4 percent in summer and 69.67 percent in winter of its nameplate capacity to ZRCs. Diamond Willow, Cedar Hills, and Thunder Spirit are all designated network resources and have been granted a TSR from MISO.

2.1. Current Resources

The existing resource portfolio is broken down into five groups: coal, natural gas/oil, renewable, contract, and Demand Side Management ("DSM"). Figure 2-1 shows Montana-Dakota's 2024 summer resource mix by zonal resource credits. Thirty nine percent of Montana-Dakota's ZRCs comes from coal generation, thirty two percent from gas-fired generation, twelve percent from capacity contract, ten percent from renewable resources and seven percent from DSM. Figure 2-2 shows Montana-Dakota's 2024 winter resource mix by zonal resource credits. Twenty nine percent of Montana-Dakota's ZRCs comes from coal generation, thirty eight percent from gas-fired generation, twenty two percent from renewable resources, six percent from DSM, and five percent from capacity contract.

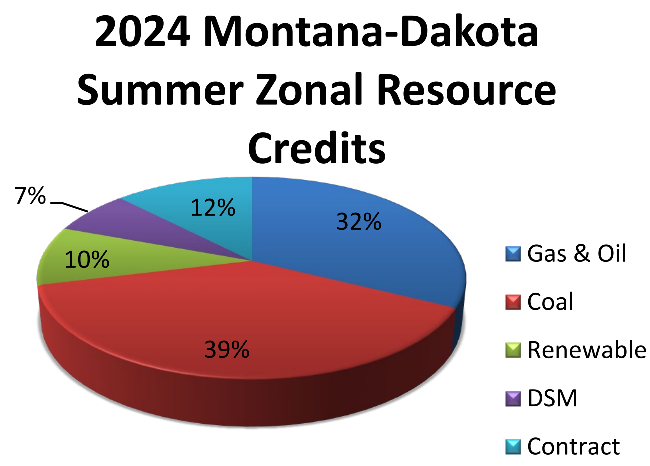


Figure 2-1: Montana-Dakota's Current Summer Generation Mix by Zonal Resource Credits

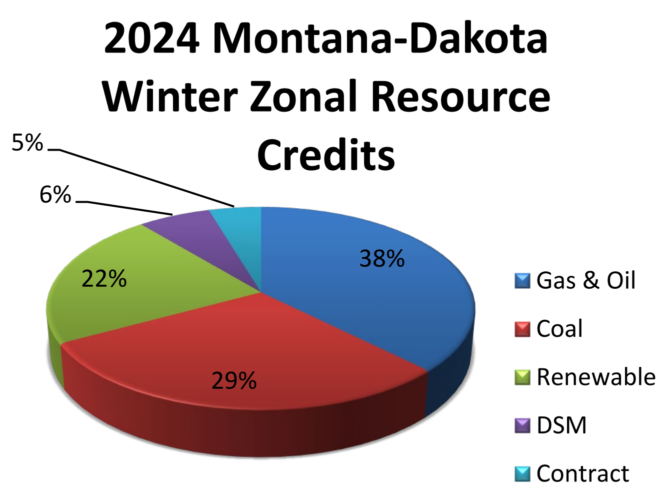


Figure 2-2: Montana-Dakota's Current Winter Generation Mix by Zonal Resource Credits

2.1.1. Coal

Montana-Dakota currently jointly owns two coal-fired units with other regional utilities as part of its integrated system. Coal-fired units currently account for 39 percent in summer and 29 percent in winter of the zonal resource credits on Montana-Dakota's system. Table 2-1 shows the capacity in MW established by the MISO Generator Verification Test Capability (GVTC) process, number of zonal resource credits, and various costs for each coal-fired plant serving Montana-Dakota's customers.

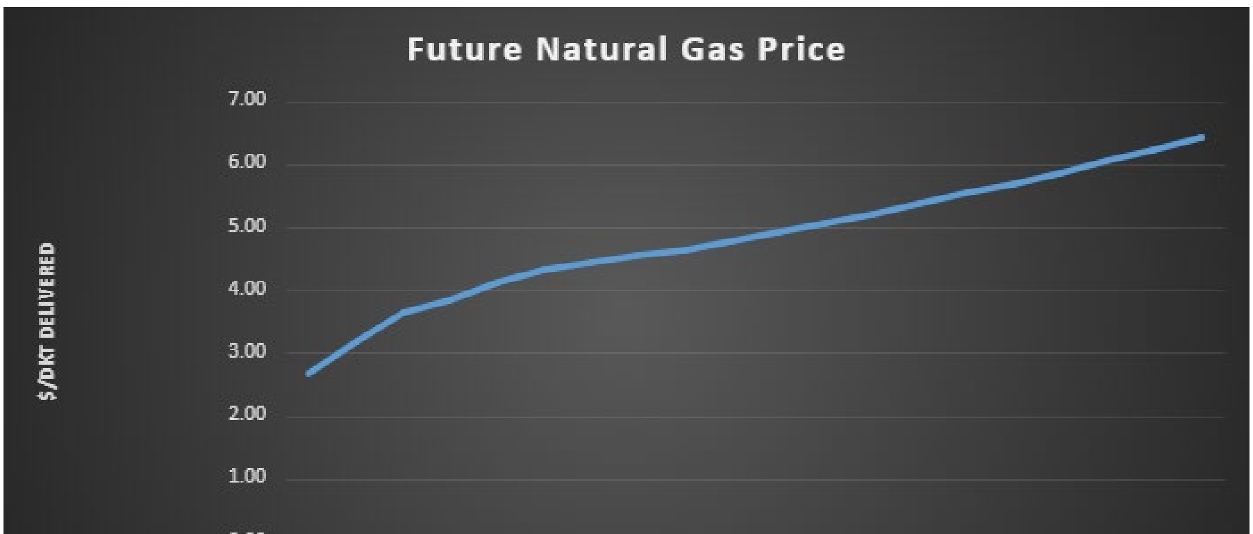
Table 2-1: Montana-Dakota's Coal-Fired Units

Unit	Summer GVTC (MW)	Summer Zonal Resource Credit [1]	Winter GVTC (MW)	Winter Zonal Resource Credit [1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	106.6	99.7	108.3	109.3	33.83	5.20	2.19
Big Stone[3]	108.3	108.7	111.5	83.7	27.79	3.80	2.10

1. Based on MISO 2024-25 Planning Year
2. Montana-Dakota's 25 percent ownership share
3. Montana-Dakota's 22.7 percent ownership share

2.1.2. Natural Gas and Diesel

Simple cycle combustion turbines capable of firing natural gas or fuel oil, along with reciprocating internal combustion engines firing natural gas or diesel, are operated as peaking units and make up about 32 percent in summer and 38 percent in winter percent of Montana-Dakota's existing zonal resource credits. To determine the natural gas price, a combination of forward index prices at Henry Hub and Montana-Dakota's knowledge of natural gas pricing was used to produce a forward-looking natural gas price and escalates the prices by three percent which can be seen in Figure 2-3.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Natural Gas (Gas_new)	2.68	3.18	3.65	3.85	4.12	4.31	4.42	4.54	4.63	4.77	4.91	5.06	5.21	5.37	5.53	5.69	5.87	6.04	6.22	6.41

Figure 2-3: Future Natural Gas Prices of Future natural gas alternatives

The capacity in MW established by the MISO Generator Verification Test Capability (GVTC) process, number of zonal resource credits, and various costs for Montana-Dakota's existing combustion turbines and diesel generator are shown in Table 2-2.

Table 2-2: Montana-Dakota's Natural Gas Combustion Turbines and Diesel Generators

Unit	Summer GVTC (MW)	Summer Zonal Resource Credit[1]	Winter GVTC (MW)	Winter Zonal Resource Credit[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)[2]
Glendive 1	31.4	29	34	30.3	6.70	4.20	4.76
Glendive 2	41	24.9	41	38.6	7.41	4.20	4.76
Miles City	21.6	16.2	21.6	21	9.27	4.20	4.76
Heskett 3	83.1	85.7	99	70.9	40.28	0.90	3.30
Heskett 4[3]	83	80.1	99	70.9	40.28	0.90	3.30
Lewis & Clark 2	18.4	14.4	16.7	18.2	78.77	3.59	4.76
Diesel 2	2.1	1.8	1.6	1.8	19.26	4.20	21.59
Diesel 3	2	1.7	1.5	1.8	19.26	4.20	21.59

1. Based on MISO 2021-22 Planning Year ICAP and $XEFOR_d$
2. 2024 natural gas price
3. Estimated GVTC, ZRC, and O&M

2.1.3. Renewable

In addition to coal, diesel, and natural gas, Montana-Dakota owns four renewable resources, as shown in Table 2-3. The renewable resources make up about 10 percent in the summer and 22 percent in the winter of Montana-Dakota's existing zonal resource credits.

Table 2-3: Montana-Dakota's Renewable Generation

Unit	Summer Zonal Resource Credits[1]	Winter Zonal Resource Credits[1]	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow	6	21.7	0	-
Cedar Hills	5.2	13.3	0	-
Glen Ullin Station 6	2.9	4.4	8.13	-
Thunder Spirit[2]	36.7	104.5	-37.04	-

1. ZRC is based on MISO ELCC study.
2. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.

2.1.4. Demand Response

In addition to the supply side resources, two different demand response programs were included into the model. The totals below reflect the number of MWs and ZRCs contracted with the company in 2024.

- Montana-Dakota Interruptible loads
    - Summer – 12.2 ZRC
    - Winter – 11.8 ZRC

- Commercial DSM
    - Summer – 25.7 ZRC
    - Winter – 29.9 ZRC

2.1.5. MISO Energy Market

The MISO energy market provides a source of energy when prices are lower than Montana-Dakota's generating cost, or when energy is required due to planned maintenance or forced outages. Montana-Dakota used the Wood Mackenzie pricing for the off-peak and on-peak pricing based of the pricing they established for Montana-Dakota. The model included a 250 MW block of energy for off-peak and on-peak periods.

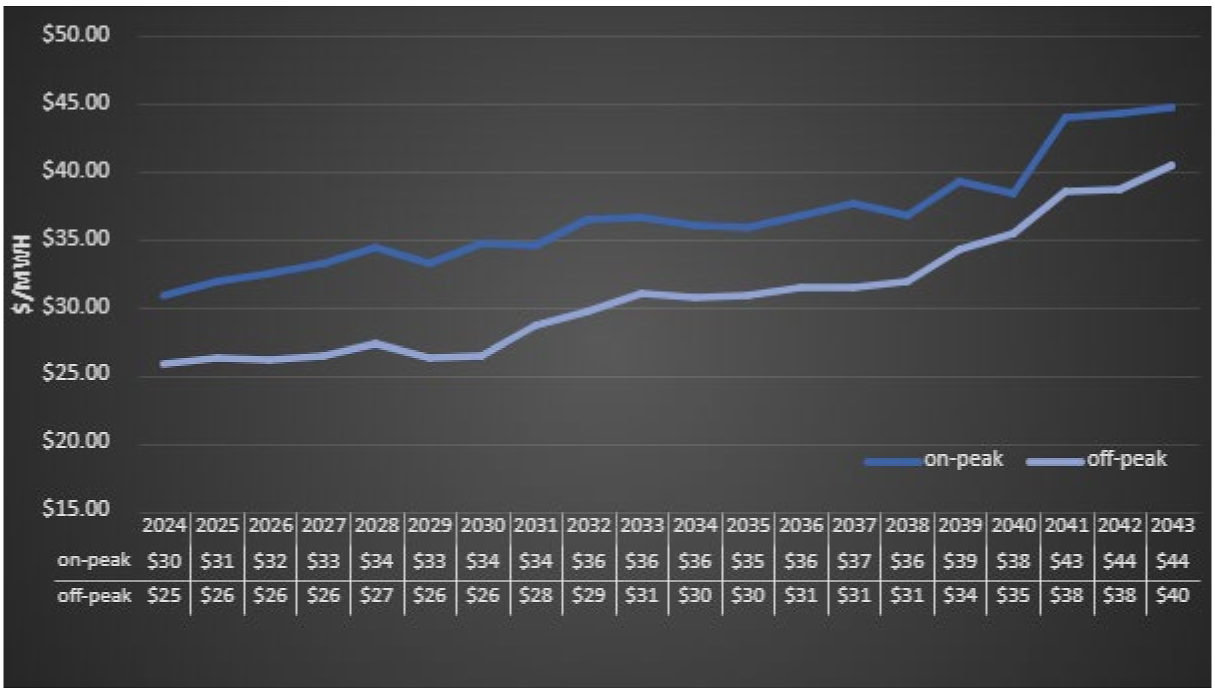


Figure 2-4: Forecasted On-Peak and Off-Peak MISO Market Prices developed by Wood Mackenzie

2.1.6. Minnkota Power Capacity and Energy Purchase

The Company has entered into a power purchase agreement with Minnkota Power Cooperative to purchase capacity and energy from June 2021 through May 2026. The timing of the Minnkota Power Purchase Agreement (PPA) came about during the evaluation of the 2020 RFP as the Company was out contacting its neighboring utilities to determine availability and pricing of capacity and energy as a bridge product to the in-service date for Heskett 4. The Minnkota PPA includes the following purchased capacity and firm energy amounts.

Table 2-4: Minnkota Capacity and Energy

Year	Capacity (MWs)	Energy (MWh)
2021-2022	75	30
2022-2023	90	75
2023-2024	30	75
2024-2025	30	75
2025-2026	30	75

2.2. Considered Supply-Side Resource Alternatives

Montana-Dakota analyzed the following supply-side alternatives that are described in more detail below:

- Simple Cycle Combustion Turbine,
- Simple Cycle Reciprocating Internal Combustion Engines,
- Combined Cycle Combustion Turbine,
- Wind Generation (self-built),
- Solar plus Storage,
- Battery Storage

Information regarding the resource alternatives available to Montana-Dakota is summarized in Table 2-5. Performance and cost estimates for the resource alternatives were developed by a consulting engineer using thermal engineering/costing software, budgetary quotations from original equipment manufacturers (OEMs), input from Montana-Dakota, published information, and engineering experience. More detail of the Supply-Side resource alternatives can be seen in Attachment E.

2.2.1. Simple Cycle Combustion Turbine

Simple cycle combustion turbines (SCCT) are primarily built to serve peaking capacity needs. SCCTs typically have one of the lower capital costs per MW compared to other generating types and can be installed with a shorter lead time than baseload and intermediate resources. Two basic types of SCCT exist: aeroderivative (Aero), and heavy-duty Frame (Frame). Aero SCCTs are adapted from jet and turboshaft jet engines and are usually smaller and more thermally efficient than similar sized Frame units. However, they generally have a higher capital cost, more expensive maintenance costs, are more susceptible to cold weather reliability issues, and do not normally exceed 100 MWs generating capability in a single unit size. Frame units are designed to drive stationary generation and process plant equipment. They are usually less expensive on a unit basis than an Aero, more robust, require less frequent inspection and maintenance intervals, and are available in over 500 MWs in a single unit size. Montana-Dakota has operating experience with six Frame units, and one Aero unit. Three options for the SCCT were analyzed in the resource expansion analysis and are shown in Table 2-5: 77.9 MW summer net large frame greenfield unit (dual fuel sub-option), a 99.9 MW summer net aero-hybrid unit, and a 45 MW summer net Aero unit (dual fuel sub-option).

Additional larger simple cycle combustion turbines were added to the model in the Coyote retirement sensitivity that are both over 400 MW in size with MDU taking a 25 percent ownership based on the current Coyote ownership.

2.2.2. Simple Cycle Reciprocating Internal Combustion Engine

Simple cycle reciprocating internal combustion engines (RICE) are primarily built to serve peaking capacity needs. These units require a shorter lead time than baseload and intermediate resources and are normally more thermally efficient and require lower fuel pressure compared to SCCTs of similar power output. Three RICE natural gas fired plants were analyzed in the resource expansion analysis and are shown in Table 2-5: a 36.5 MW (net) four-engine unit, a 55.0 MW (net) three-engine unit, and a 44.4 MW (net) four-engine unit (dual fuel sub-option).

2.2.3. Combined Cycle Combustion Turbine

A conventional combined cycle combustion turbine (CCCT) burns natural gas or fuel oil in one or more SCCTs. The hot exhaust gases from the SCCT passes through a heat recovery steam generator to produce additional power in a steam turbine. With some of the latest advanced CCCT technology configurations, CCCTs have one of the highest efficiencies of any alternative fossil fuel power plant that was modeled. These units are usually used as an intermediate unit today, but in the future could be used as more of a baseload unit to replace retired coal units. Three natural gas fired CCCTs were analyzed in the resource expansion analysis and are shown in Table 2-5: a 198.6 MW (summer net) 2x1 large frame unit (modeled in blocks of 100 MW), 329.7 MW (summer net) 2x1 large frame unit (Heskett Expansion includes Heskett 3 and 4 in the total MW), and a 409.6 MW (summer net) 1x1 large frame unit (modeled in blocks of 200 MW).

2.2.4. Wind Generation

A wind energy resource is characterized as being a clean, renewable resource with low operating and maintenance costs. The main disadvantage of wind generation is that, because of the variability of wind, it cannot be relied on as a firm capacity resource. Unlike the thermal resources such as coal-fired and gas-fired units, wind energy resources are allowed limited zonal resource credits (ZRC) by MISO. Therefore, the installation of additional wind generation on Montana-Dakota's system would require adding other capacity resources to meet the MISO planning reserve margin requirements.

This option represents Montana-Dakota's self-built wind generation. Two wind options were analyzed in the resource expansion analysis and are shown in Table 2-5: 50 MW and 100 MW (net) options. Both projects assume Federal Production Tax Credits (PTCs) are available for a future wind project.

Montana-Dakota also included in its analysis a potential off-take from a 150 MW wind project that recently became available to the company for consideration.

2.2.5. Solar PV plus Battery Storage

Solar PV resources are characterized as renewable, high capital cost, low operational and maintenance cost energy sources. Like wind generation, solar PV is a variable output energy resource that cannot be relied on as a firm capacity resource to meet Montana-Dakota's MISO planning reserve margin requirements. In MISO's four-season planning model for resource adequacy, solar PV capacity credit ranges from 50 percent in the summer, spring and fall seasons to 5 percent in the winter to meet peak seasonal demand forecast requirements. Two solar PV options were included in the resource expansion analysis and are shown in Table 2-5: a 50 MW with an option to add 10 MW battery storage and a 5 MW with an option to add 1 MW battery storage. Both projects assume Federal Earned Income Tax Credits (ITCs) are available for a future solar project.

2.2.6. Battery Storage

Battery Storage is a standalone resource that can store energy during times when there is excess energy on the grid, specifically from renewable resources, and when the load on the system is low. This unit can then dispatch for short durations when load increases or there is a shortage of generation on the system to serve the load. As of now in MISO, there is very little battery storage on the system and very little operating history to establish a resource accreditation number for battery storage units, so for now this technology is assumed to receive accreditation for close to nameplate of the facility. The model had one option of 50 MW of Battery Storage.

Table 2-5: Considered Resource Alternatives Available to Montana-Dakota

EGEAS Model Input Summary Summer, 2024 $	Plant Size (Summer MW,net)	Summer ZRC	Capital Cost Summer ($/kW)	Plant Size (Winter MW,net)	Winter ZRC	Capital Cost Winter ($/kW)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)	Reservation Fee ($/kW-yr)	Total Fixed O&M ($/kW-year)	Full Load Heat Rate (BTU/kWh)	Carbon Intensity (ton/GWh)	Fuel Cost ($/MBtu)
GE 7E.03 LLI no SCR	77.9	75.5	$2,077.00	94.8	74.9	$1,708.86	$3.02	$0.90	$2.62	$38.86	11800	675	$2.68
GE LMS 100 PB+	99.9	96.8	$2,485.00	109.9	86.8	$2,256.60	$2.69	$1.33	$1.65	$33.93	8970	525	$2.68
GE LM6000 PF+ no SCR	45	42.1	$3,252.00	53.1	41.9	$2,749.53	$5.04	$0.90	$2.10	$62.58	9730	565	$2.68
GE 7E.03 (2x1) Addition to existing w/duct firing	329.7	323.8	$1,201.00	365.4	321.7	$1,082.92	$2.09	$4.60	$3.23	$28.31	9990	450	$2.68
GE 7F.05 (1X1) w/duct firing	409.6	402.2	$1,618.00	425.4	413.5	$1,558.53	$2.12	$4.00	$2.58	$28.02	8030	420	$2.68
SIEMENS SGT-800 (2x1) w/duct firing	198.6	195.0	$2,464.00	225.1	216.5	$2,175.03	$3.94	$5.20	$2.44	$49.72	9590	500	$2.68
WARTSILA 20V34SG	36.5	34.1	$3,789.00	36.5	30.1	$3,789.00	$6.25	$5.11	$1.58	$76.58	8470	510	$2.68
WARTSILA 18V50SG	55	53.3	$3,425.00	55	45.4	$3,425.00	$4.60	$5.29	$1.56	$56.76	8330	500	$2.68
WARTSILA 31DF	44.4	41.5	$3,356.00	44.4	36.4	$3,356.00	$5.26	$5.76	$1.60	$64.72	8370	500	$2.68
PV SOLAR + Storage[1]	50+10	35.0	$2,280.00	50+10	3.0	$2,280.00	$2.90	$0.00	-	$34.80	-	-	$0.00
PV SOLAR + Storage[2]	5+1	3.5	$2,467.00	5+1	0.3	$2,467.00	$3.30	$0.00	-	$39.60	-	-	$0.00
Wind	50	9.1	$2,660.00	50	20.0	$2,660.00	$4.90	$0.00	-	$58.80	-	-	$0.00
Wind	100	18.1	$2,156.00	100	40.0	$2,156.00	$4.70	$0.00	-	$56.40	-	-	$0.00
Battery Storage	50	45.0	$2,070.00	50	45.5	$2,070.00	$3.74	$0.00	-	$44.88	-	-	$0.00

1 - Storage additional $19.4 million and $3.33MM/yr fixed O&M ($1940/kW and $333/kW/yr)

2 - Storage additional $3.2 million and $4.75MM/yr fixed O&M ($3200/kW and $4750/kW/yr)

2.3. Retirements

Montana-Dakota's Diamond Willow, Cedar Hills, and Thunder Spirit wind projects are assumed to be retired in the model after a 25-year operating life or by year 19 of the IRP study period as a conservative assumption. This would require the model to replace the wind projects within the initial 20-year study period.

2.4. Integration of Demand-Side and Supply-Side Resources

As indicated in Chapter 2 of the current Integrated Resource Plan, the energy efficiency programs reductions have been included into the load forecast while the Rate 38/39 Interruptible Loads and the Commercial Demand Response programs are modeled as resources in EGEAS.

2.5. Transmission Alternatives

Montana-Dakota did not identify any transmission issues that could be mitigated with local generation resources additions as part of the 2024 IRP Analysis.

3. Summaries of Results

Four base cases were established along with 22 sensitivity runs for each base case for a total of 92 scenarios. The least-cost resource plan and associated net present value (NPV) of the total revenue requirement for each scenario are shown in Tables 3-1 to 3-8.

Table 3-1: Least-Cost Resource Expansion Plans for the Summer Studied Scenarios

	Current Summer Base Case and Sensitivities											
	Base Case - Summer	High Gas +$2	High Gas +$5	High Gas +$7	Low Gas -$1	High Market +25%	High Market +50%	Low Market - 25%	Low Market -25% & Low Gas -$1	High Market +25% & High Gas +$5	High Market +50% & High Gas +$7	High CT
2024												
2025												
2026												
2027												
2028							Wind(100 MW)			Wind(100 MW)	Wind(100 MW)	
2029												
2030												
2031												
2032												
2033	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)		PP(10 MW)	PP(10 MW)			PP(10 MW)
2034	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)		PP(10 MW)	PP(10 MW)			PP(10 MW)
2035	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)		PP(20 MW)	PP(20 MW)			PP(20 MW)
2036	CT (77.9 MW)	Solar(50 MW)	Solar(50 MW)	Solar(50 MW)	CT (77.9 MW)	CT (77.9 MW)	PP(10 MW)	CT (77.9 MW)	CT (77.9 MW)	PP(10 MW)	PP(10 MW)	Solar(50 MW)
2037		PP(10 MW)	PP(10 MW)	PP(10 MW)			PP(20 MW)			PP(20 MW)	PP(20 MW)	PP(10 MW)
2038		PP(10 MW)	PP(10 MW)	PP(10 MW)			PP(20 MW)			PP(20 MW)	PP(20 MW)	PP(10 MW)
2039		PP(20 MW)	PP(20 MW)	PP(20 MW)			PP(20 MW)			PP(20 MW)	PP(20 MW)	PP(20 MW)
2040		PP(20 MW)	PP(20 MW)	PP(20 MW)			Solar(50 MW)			Solar(50 MW)	Solar(50 MW)	PP(20 MW)
2041		Storage(50 MW)	Storage(50 MW)	Storage(50 MW)			Solar(50 MW), PP(10 MW)			Solar(50 MW), PP(10 MW)	Solar(50 MW), PP(10 MW)	Storage(50 MW)
2042	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)
2043	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	Solar(5 MW), PP(20 MW)	PP(20 MW)	PP(20 MW)	Solar(5 MW), PP(20 MW)	Solar(5 MW), PP(20 MW)	PP(20 MW)
NPV ($M)	$2,644.41	$2,649.55	$2,652.00	$2,653.52	$2,599.53	$2,877.51	$3,007.54	$2,361.88	$2,334.45	$2,875.88	$3,031.05	$2,646.89
Difference	0.00%	0.19%	0.29%	0.34%	-1.70%	8.81%	13.73%	-10.68%	-11.72%	8.75%	14.62%	0.09%

Alternative Resources:

PP(XX MW) - Purchase Capacity
CT (77.9 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (107.3 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
Solar(50 MW) - Self built 50 MW solar
Solar(5 MW) - Self built 5 MW solar
Wind(100 MW) - Self built 100 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-2: Additional Least-Cost Resource Expansion Plans for the Summer Studied Scenarios

	Current Summer Base Case and Sensitivities Continued											
	Base Case - Summer	Limit Energy 5 years	Limit Energy 10 years	High Growth	Low Growth	Carbon Tax	Coyote Retire 2032	Greenhouse Gas Rule	Lower RA - 10%	Renewable +25% Demand Response +5%	Renewable +50% Demand Response +10%	New Wind Opportunity
2024												
2025									PP(10 MW)			
2026				PP(20 MW)					PP(10 MW)			New Wind(150 MW)
2027				CT (77.9 MW)					CT (77.9 MW)			
2028		CC(200 MW), Wind(100 MW)	CC(200 MW), Wind(100 MW)	PP(10 MW), Wind(100 MW)		Wind(100 MW)		Wind(100 MW)		Wind(50 MW)	Wind(100 MW)	
2029				CC(200 MW)								
2030												
2031												
2032							CT(107.3 MW)	CC(200 MW)				
2033	PP(10 MW)											
2034	PP(10 MW)			PP(20 MW)				PP(10 MW)				
2035	PP(20 MW)			CC(200 MW)				PP(10 MW)	PP(10 MW)	PP(10 MW)		
2036	CT (77.9 MW)				PP(10 MW)	Wind(100 MW)	PP(20 MW)	Wind(100 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)
2037					PP(10 MW)		PP(20 MW)	PP(10 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)
2038					PP(20 MW)		PP(20 MW)	PP(10 MW)	PP(20 MW)	CT (77.9 MW)	PP(10 MW)	PP(20 MW)
2039				CT (77.9 MW)	PP(20 MW)	PP(10 MW)	Wind(100 MW), PP(10 MW)	PP(20 MW)	CT (77.9 MW)		PP(20 MW)	CT (77.9 MW)
2040				PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)			PP(20 MW)	
2041		Storage(50 MW)	Storage(50 MW)	CC(200 MW)	Storage(50 MW)	Wind(100 MW), PP(20 MW)	Storage(50 MW)	Storage(50 MW)			Storage(50 MW)	
2042	PP(20 MW)				PP(10 MW)	Solar(50 MW), PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(10 MW)		PP(20 MW)	
2043	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)	Solar(5 MW), PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(20 MW)
NPV ($M)	$2,644.41	$3,479.91	$3,366.94	$6,093.14	$2,474.99	$4,649.72	$2,729.15	$3,103.55	$2,899.12	$2,706.62	$2,642.32	$2,624.19
Difference	0.00%	31.60%	27.32%	130.42%	-6.41%	75.83%	3.20%	17.36%	9.63%	2.35%	-0.08%	-0.76%

Alternative Resources:
PP(XX MW) - Purchase Capacity
CT (77.9 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (107.3 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
Solar(50 MW) - Self built 50 MW solar
Solar(5 MW) - Self built 5 MW solar
Wind(100 MW) - Self built 100 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-3: Least-Cost Resource Expansion Plans for the Winter Studied Scenarios

	Current Winter Base Case and Sensitivities											
	Base Case - Winter	High Gas +$2	High Gas +$5	High Gas +$7	Low Gas -$1	High Market +25%	High Market +50%	Low Market -25%	Low Market - 25% & Low Gas -$1	High Market +25% & High Gas +$5	High Market +50% & High Gas +$7	High CT
2024												
2025												
2026												
2027												
2028						Wind(100 MW)	Wind(100 MW)	Wind(100 MW)		Wind(100 MW)	Wind(100 MW)	
2029												
2030												
2031												
2032												
2033												
2034												
2035	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)				PP(10 MW)			PP(10 MW)
2036	Wind(100 MW)	Wind(100 MW)	Wind(100 MW)	Wind(100 MW)	CC(200 MW)				CC(200 MW)			Wind(100 MW)
2037												
2038												
2039												
2040												
2041	PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)		PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)		PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)
2042	PP(10 MW), Storage(50 MW)	PP(10 MW), Storage(50 MW)	PP(10 MW), Storage(50 MW)	PP(10 MW), Storage(50 MW)		Wind(100 MW), PP(10 MW)	Wind(100 MW), PP(10 MW)	Storage(50 MW), PP(10 MW)		Wind(100 MW), PP(10 MW)	Wind(100 MW), PP(10 MW)	PP(10 MW), Storage(50 MW)
2043	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)		PP(10 MW)	PP(10 MW)	PP(20 MW)		PP(10 MW)	PP(10 MW)	PP(20 MW)
NPV ($M)	$2,713.27	$2,713.56	$2,713.86	$2,714.01	$2,630.97	$2,886.75	$2,998.27	$2,455.07	$2,425.56	$2,884.26	$3,014.80	$2,713.27
Difference	0.00%	0.01%	0.02%	0.03%	-3.03%	6.39%	10.50%	-9.52%	-10.60%	6.30%	11.11%	0.00%

<u>Alternative Resources:</u>
PP(XX MW) - Purchase Capacity
CT (94.8 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (116.6 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
Solar(50 MW) - Self built 50 MW solar
Solar(5 MW) - Self built 5 MW solar
Wind(100 MW) - Self built 100 MW wind
Wind(50 MW) - Self built 50 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-4: Additional Least-Cost Resource Expansion Plans for the Winter Studied Scenarios

	Current Winter Base Case and Sensitivities Continued											
	Base Case - Winter	Limit Energy 5 years	Limit Energy 10 years	High Growth	Low Growth	Carbon Tax	Coyote Retire 2032	Greenhouse Gas Rule	Lower RA -10%	Renewable +25% Demand Response +5%	Renewable +50% Demand Response +10%	New Wind Opportunity
2024									PP(10 MW)			
2025									PP(10 MW)			
2026				PP(30 MW)					PP(10 MW)			New Wind(150 MW)
2027				PP(10 MW), CT(94.8 MW)					CT(94.8 MW)			
2028		CC(200 MW)		Wind(100 MW)		Wind(100 MW)				Wind(50 MW)	Wind(100 MW)	
2029				CC(200 MW)								
2030		PP(10 MW)										
2031		PP(10 MW)	CC(200 MW)									
2032							CT(116.6 MW)	CC(200 MW), Wind(100 MW)				
2033		PP(10 MW)		PP(20 MW)								
2034		PP(10 MW)	PP(10 MW)	CC(200 MW)					PP(10 MW)			
2035	PP(10 MW)	Wind(100 MW)	Wind(100 MW)						PP(10 MW)			
2036	Wind(100 MW)			PP(10 MW)	Wind(100 MW)	Wind(100 MW)	Wind(100 MW)		Wind(100 MW)			
2037				CC(200 MW)						PP(10 MW)		
2038										PP(10 MW)		
2039										PP(20 MW)		
2040		PP(10 MW)	PP(10 MW)	Wind(100 MW)					Wind(100 MW)	PP(20 MW)		
2041	PP(20 MW), Wind(100 MW)	Storage(50 MW)	Storage(50 MW)	CC(200 MW)	Wind(100 MW)	Wind(100 MW)	PP(20 MW), Wind(100 MW)	PP(20 MW), Wind(100 MW)	Wind(100 MW)	PP(20 MW), CT (94.8 MW)	PP(10 MW), Wind(100 MW)	Wind(100 MW)
2042	PP(10 MW), Storage(50 MW)			Wind(100 MW)	PP(10 MW), Wind(50 MW)	PP(10 MW)	Wind(100 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW), Storage(50 MW)	Wind(100 MW)
2043	PP(20 MW)	PP(10 MW), Solar(5 MW)	PP(10 MW), Solar(5 MW)	PP(10 MW), Wind(100 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW), Storage(50 MW)
NPV ($M)	$2,713.27	$3,553.70	$3,437.88	$6,423.93	$2,608.05	$4,664.46	$2,769.63	$3,028.02	$3,017.51	$2,771.23	$2,725.27	$2,702.13
Difference	0.00%	30.97%	26.71%	136.76%	-3.88%	71.91%	2.08%	11.60%	11.21%	2.14%	0.44%	-0.41%

Alternative Resources:
PP(XX MW) - Purchase Capacity
CT (94.8 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (116.6 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
Solar(50 MW) - Self built 50 MW solar
Solar(5 MW) - Self built 5 MW solar
Wind(100 MW) - Self built 100 MW wind
Wind(50 MW) - Self built 50 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-5: Least-Cost Resource Expansion Plans for the Summer DLOL Studied Scenarios

	Summer DLOL Base Case and Sensitivities											
	Base Case - Summer DLOL	High Gas +$2	High Gas +$5	High Gas +$7	Low Gas -$1	High Market +25%	High Market +50%	Low Market -25%	Low Market -25% & Low Gas -$1	High Market +25% & High Gas +$5	High Market +50% & High Gas +$7	High CT
2024												
2025												
2026												
2027												
2028	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	Wind (100 MW)	Wind (100 MW)	PP(10 MW)	PP(10 MW)	Wind (100 MW)	Wind (100 MW)	PP(10 MW)
2029	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)			PP(10 MW)	PP(10 MW)			PP(10 MW)
2030	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)			PP(10 MW)	PP(10 MW)			PP(10 MW)
2031	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)
2032	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)
2033	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	CC(200 MW)	PP(10 MW)	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	PP(10 MW)	Storage(50 MW)	Storage(50 MW)
2034						PP(20 MW)				PP(20 MW)		
2035						PP(20 MW)				PP(20 MW)		
2036						CT (77.9 MW)				CT (77.9 MW)		
2037												
2038												
2039	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)				PP(10 MW)	PP(10 MW)			PP(10 MW)
2040	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)				PP(10 MW)	PP(10 MW)			PP(10 MW)
2041	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)			PP(20 MW)	Storage(50 MW)	Storage(50 MW)		PP(20 MW)	Storage(50 MW)
2042						PP(10 MW)	Solar(50 MW), PP(20 MW)			PP(10 MW)	Wind(100 MW), PP(20 MW)	
2043						PP(20 MW)	PP(20 MW)			PP(20 MW)	Wind(50 MW), PP(20 MW)	
NPV ($M)	$2,684.72	$2,685.95	$2,687.09	$2,687.79	$2,647.01	$2,926.23	$3,058.98	$2,401.14	$2,402.75	$2,923.36	$3,088.47	$2,684.72
Difference	0.00%	0.05%	0.09%	0.11%	-1.40%	9.00%	13.94%	-10.56%	-10.50%	8.89%	15.04%	0.00%

<u>Alternative Resources:</u>
PP(XX MW) - Purchase Capacity
CT (77.9 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (107.3 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
Solar(50 MW) - Self built 50 MW solar
Solar(5 MW) - Self built 5 MW solar
Wind(100 MW) - Self built 100 MW wind
Wind(50 MW) - Self built 50 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
CC(329.7 MW) - Heskett 3 & 4 Expansion to Combined Cycle
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-6: Additional Least-Cost Resource Expansion Plans for the Summer DLOL Studied

	Summer DLOL Base Case and Sensitivities Continued											
	Base Case - Summer DLOL	Limit Energy 5 years	Limit Energy 10 years	High Growth	Low Growth	Carbon Tax	Coyote Retire 2032	Greenhouse Gas Rule	Lower RA - 10%	Renewable +25% Demand Response +5%	Renewable +50% Demand Response +10%	New Wind Opportunity
2024									PP(20 MW)			
2025				PP(20 MW)					PP(20 MW)			
2026				PP(40 MW)					PP(20 MW)			New Wind(150 MW)
2027				CC(329.7 MW)					CT (77.9 MW)			
2028	PP(10 MW)	CC(200 MW), Wind(100 MW)	Wind(100 MW)	Wind(100 MW)		Wind(100 MW)	PP(10 MW)	PP(10 MW)		Wind(50 MW)	Wind(100 MW)	
2029	PP(10 MW)				PP(10 MW)		PP(10 MW)	PP(10 MW)				
2030	PP(10 MW)			Storage(50 MW)	PP(10 MW)		PP(10 MW)	PP(10 MW)		PP(10 MW)		
2031	PP(20 MW)		PP(10 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(10 MW)		
2032	PP(20 MW)		CC(200 MW)	CC(200 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW), CT(107.3 MW)	CC(200 MW), Storage(50 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)
2033	Storage(50 MW)				Storage(50 MW)	Storage(50 MW)	Storage(50 MW)		PP(20 MW)	Storage(50 MW)	PP(10 MW)	Storage(50 MW)
2034									PP(20 MW)		PP(20 MW)	
2035								PP(10 MW)	CT (77.9 MW)		PP(20 MW)	
2036				CC(200 MW)				PP(10 MW)			CT (77.9 MW)	
2037				PP(20 MW)				PP(20 MW)				
2038				PP(20 MW)				PP(20 MW)				
2039	PP(10 MW)			PP(20 MW)		Wind(100 MW)		PP(20 MW)				
2040	PP(10 MW)	PP(10 MW)	PP(10 MW)	Solar(50 MW), PP(20 MW)				Storage(50 MW)				
2041	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	CC(200 MW)		Wind(100 MW)	PP(20 MW)		PP(10 MW)	PP(20 MW)		PP(20 MW)
2042					PP(10 MW)	PP(10 MW)	PP(20 MW), Solar (50 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW), Solar(50 MW)	PP(10 MW)	Storage(50 MW)
2043		Solar(5 MW), PP(10 MW)	Solar(5 MW), PP(10 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	
NPV ($M)	$2,684.72	$3,500.42	$3,387.92	$6,333.57	$2,499.25	$4,755.60	$3,056.21	$3,141.19	$2,929.89	$2,730.05	$2,721.64	$2,678.12
Difference	0.00%	30.38%	26.19%	135.91%	-6.91%	77.14%	13.84%	17.00%	9.13%	1.69%	1.38%	-0.25%

Alternative Resources:

PP(XX MW) - Purchase Capacity

CT (77.9 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)

CT (107.3 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)

Solar(50 MW) - Self built 50 MW solar

Solar(5 MW) - Self built 5 MW solar

Wind(100 MW) - Self built 100 MW wind

Wind(50 MW) - Self built 50 MW wind

Storage(50 MW) - Self built 50 MW Battery Storage

CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)

CC(329.7 MW) - Heskett 3 & 4 Expansion to Combined Cycle

New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-7: Least-Cost Resource Expansion Plans for the Winter DLOL Studied Scenarios

	Current Winter DLOL Base Case and Sensitivities											
	Base Case - Winter DLOL	High Gas +$2	High Gas +$5	High Gas +$7	Low Gas -$1	High Market +25%	High Market +50%	Low Market -25%	Low Market -25% & Low Gas -$1	High Market +25% & High Gas +$5	High Market +50% & High Gas +$7	High CT
2024												
2025												
2026												
2027	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)	CT(94.8 MW)
2028											Wind(100 MW)	
2029												
2030												
2031												
2032												
2033												
2034												
2035												
2036	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)		PP(10 MW)
2037	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)		PP(20 MW)
2038	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)
2039	PP(10 MW), Wind(100 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW), Wind(100 MW)	CT(94.8 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW), Wind(100 MW)	CT(94.8 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW)	PP(10 MW), Wind(100 MW)
2040	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)		PP(20 MW)	PP(20 MW)	PP(20 MW)		PP20(MW)	PP(20 MW)	PP(20 MW)
2041	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)		Storage(50 MW)	Storage(50 MW)	Storage(50 MW)	PP(10 MW)	Storage(50 MW)	Storage(50 MW)	Storage(50 MW)
2042	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)
2043	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)
NPV ($M)	$2,934.87	$2,937.84	$2,941.96	$2,944.12	$2,825.25	$3,158.68	$3,282.67	$2,661.10	$2,591.92	$3,154.86	$3,336.09	$2,984.70
Difference	0.00%	0.10%	0.24%	0.32%	-3.73%	7.63%	11.85%	-9.33%	-11.69%	7.50%	13.67%	1.70%

Alternative Resources:

PP(XX MW) - Purchase Capacity
CT (53.1 MW) - Simple Cycle Combustion Aeroderivative Unit(GE LM 6000 PF+)
CT (94.8 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (109.9 MW) - Simple Cycle Combustion Aeroderivative Unit(GE LMS 100 PB+)
CT (116.6 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
RICE(44.4 MW) - Reciprocating Engine (4 x 11 MW Wartsila 31DF)
Wind(100 MW) - Self built 100 MW wind
Wind(50 MW) - Self built 50 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
CC(365.4 MW) - Heskett 3 & 4 Expansion to Combined Cycle
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

Table 3-8: Additional Least-Cost Resource Expansion Plans for the Winter DLOL Studied

	Winter DLOL Base Case and Sensitivities Continued											
	Base Case - Winter DLOL	Limit Energy 5 years	Limit Energy 10 years	High Growth	Low Growth	Carbon Tax	Coyote Retire 2032	Greenhouse Gas Rule	Lower RA -10%	Renewable +25% Demand Response +5%	Renewable +50% Demand Response +10%	New Wind Opportunity
2024				PP(30 MW)					PP(50 MW)			
2025				PP(60 MW)					PP(50 MW)			
2026				PP(90 MW)					PP(50 MW)			New Wind(150 MW)
2027	CT(94.8 MW)	CC(365.4 MW)	RICE(44.4 MW)	CT(109.9 MW), CT(94.8 MW), PP(20 MW)	CT(94.8 MW)	CT(53.1 MW)	CT(94.8 MW)	PP(10 MW), CT(53.1 MW)	CT(109.9 MW), PP(20 MW)	CT(94.8 MW)	CT(94.8 MW)	PP(10 MW)
2028		Wind(100 MW)		CC(200 MW)		Wind(100 MW)			PP(20 MW)	Wind(50 MW)	Wind(100 MW)	PP(10 MW)
2029			PP(10 MW)						PP(20 MW)			PP(10 MW)
2030			PP(10 MW)						Wind(100 MW), PP(10 MW)			PP(10 MW)
2031			Wind(100 MW)	CC(200 MW)				PP(10 MW)	PP(20 MW)			PP(20 MW)
2032			CC(200 MW)				CT(116.6 MW)	CC(200 MW), Wind(100 MW)	PP(20 MW)			PP(20 MW)
2033								Storage(50 MW)	Storage(50 MW)			Storage(50 MW)
2034				CC(200 MW)		PP(10 MW)						
2035						PP(10 MW)						
2036	PP(10 MW)				PP(10 MW)	PP(10 MW)			PP(10 MW)			PP(10 MW)
2037	PP(20 MW)			CC(200 MW)	CT(94.8 MW)	PP(10 MW)			PP(10 MW)	PP(10 MW)		PP(10 MW)
2038	PP(20 MW)					PP(20 MW)			PP(20 MW)	PP(10 MW)		PP(20 MW)
2039	PP(10 MW), Wind(100 MW)			PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)		PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)
2040	PP(20 MW)		PP(10 MW)	CC(200 MW)	PP(20 MW)	Storage(50 MW)	PP(10 MW)	PP(10 MW)	CT(94.8 MW)	PP(20 MW)	PP(10 MW)	Storage(50 MW)
2041	Storage(50 MW)	Wind(100 MW)	Storage(50 MW)	PP(20 MW)	Storage(50 MW)	PP(10 MW)	Storage(50 MW)	Storage(50 MW)		CT(94.8 MW)	Storage(50 MW)	PP(10 MW)
2042	PP(20 MW)	PP(10 MW)		CC(200 MW)	PP(20 MW)	PP(10 MW), Wind(100 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	PP(10 MW)	Storage(50 MW)
2043	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)	PP(10 MW)	PP(20 MW)	PP(10 MW)
NPV ($M)	$2,934.87	$3,748.51	$3,662.38	$7,376.70	$2,786.06	$5,021.10	$2,990.08	$3,446.40	$3,258.35	$3,004.83	$2,959.90	$2,823.33
Difference	0.00%	27.72%	24.79%	151.35%	-5.07%	71.08%	1.88%	17.43%	11.02%	2.38%	0.85%	-3.80%

Alternative Resources:

PP(XX MW) - Purchase Capacity
CT (53.1 MW) - Simple Cycle Combustion Aeroderivative Unit(GE LM 6000 PF+)
CT (94.8 MW) - Simple Cycle Combustion Turbine Frame Unit(GE 7E.03 LLI)
CT (109.9 MW) - Simple Cycle Combustion Aeroderivative Unit(GE LMS 100 PB+)
CT (116.6 MW) - Simple Cycle Combustion Turbine Frame Unit(2xGE 7F.05 - MDU 25% of 429 MW Total)
RICE(44.4 MW) - Reciprocating Engine (4 x 11 MW Wartsila 31DF)
Wind(100 MW) - Self built 100 MW wind
Wind(50 MW) - Self built 50 MW wind
Storage(50 MW) - Self built 50 MW Battery Storage
CC(200 MW) - Combined Cycle Combustion Turbine(1x1 GE 75.05)
CC(365.4 MW) - Heskett 3 & 4 Expansion to Combined Cycle
New Wind(150 MW) - New wind opportunity of 150 MW recently made available to the company

3.1. Base Case Plan Results

The Summer and Winter Base Cases least-cost plan consists of the following resource additions for 2024-2029:

- Complete commissioning of Heskett 4 an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in 2024.
- Continue to grow the Commercial Demand Response program to a total of 45 MW.
- Inclusion of the Minnkota Power capacity and energy purchase agreement through May 2026.

The Summer DLOL Base Case least-cost plan consists of the following resource additions for 2024-2029:

- Complete commissioning of Heskett 4 an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in 2024.
- Continue to grow the Commercial Demand Response program to a total of 45 MW.
- Inclusion of the Minnkota Power capacity and energy purchase agreement.
- In 2028 and 2029 purchase 10 MW of capacity.

The Winter DLOL Base Case least-cost plan consists of the following resource additions for 2024-2029:

- Complete commissioning of Heskett 4 an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in 2024.
- Continue to grow the Commercial Demand Response program to a total of 45 MW.
- Inclusion of the Minnkota Power capacity and energy purchase agreement.
- In 2027 the model selected another simple cycle combustion turbine similar to Heskett 3 and 4.

3.2. Sensitivity Analysis

The 22 sensitivity scenarios consist of various assumptions regarding low and high natural gas prices, high and low market prices, combination of gas and market prices, high environmental cost on combustion turbine alternatives, limiting energy, low and high load growth, carbon tax, Coyote retirement, greenhouse gas rule, lower resource accreditation, higher renewable and demand response, and new wind opportunity.

3.2.1. High and Low Gas Price

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, future combustion turbines, and future combined cycle plants were developed in-house for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. Due to potential fluctuations of natural gas prices, there is a need to consider what impact both higher and lower gas prices would have on the Base Case. Therefore, high, and low gas price scenarios were also developed, whereby the gas price used in the Base Case was increased by \$2/MMBtu, \$5/MMBtu, and \$7/MMBtu and decreased by \$1/MMBtu from the Base Case, respectively. The results can be seen in Tables 3-1, 3-3, 3-5 and 3-7.

3.2.2. High and Low Market Prices

These scenarios were used to look at the effects the MISO market could have on the resource plan if the market prices went higher or lower than the Base Case. The high market price cases increased the on-peak and off-peak market prices of the Base Case by 25% and 50%. The lower market price case decreased the base year on- and off-peak prices by 25%. The results can be seen in Tables 3-1, 3-3, 3-5 and 3-7.

3.2.3. Gas and Market Price Combinations

These sensitivities were looking at a combination of both natural gas prices and the energy market were both increasing or decreasing. Two combinations of a high gas price and market price (+\$5 Gas and +25% market and +\$7 and +50% market) and one sensitivity of lower natural gas prices and energy market prices (-\$1 Gas and –25% market). The results can be seen in Tables 3-1, 3-3, 3-5 and 3-7.

3.2.4. Higher Environmental Costs on Combustion Turbine Alternatives

This sensitivity looked at adding environmental controls on combustion turbine resources, which adds capital cost and O&M costs to some of the simple and combined cycle combustion turbine options. This scenario was done in part to show if the additional costs were added if it would still pick the same resources as the Base Cases. The results can be seen in Tables 3-1, 3-3, 3-5 and 3-7 under High CT.

3.2.5. Limiting Market Energy

The on-peak and off-peak markets were set at 250 MW in the Base Case. These two scenarios limited the amount of market energy that could be selected to zero MW either over five or ten years. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.6. High Growth

A high-growth scenario evaluated the effects of a continued long-term average load growth rate of 4.4 percent per year starting in 2024. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.7. Low Growth

This scenario was used to evaluate the load growth potential at less than the optimal resource case with an average growth rate of 0.5 percent per year during the 20-year forecast. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.8. Carbon Tax

With the potential of a future carbon penalty applied to all fossil fuel units and MISO energy purchases, a carbon tax was modeled to assess the impact on the resource expansion plan. The assumed carbon tax was applied to all carbon emissions from Montana-Dakota's existing fossil fueled resources, energy purchases from the MISO market, and new fossil fuel generating units added to the resource plan starting in 2028. While no carbon tax was modeled in the Base Case, Montana-Dakota modeled a carbon tax of $50 per ton for a sensitivity analysis. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.9. Coyote Retire 2032

This scenario looked at retiring Coyote at the end of 2031 with the option to select it to run at sixty percent coal and forty percent natural gas along with twenty-five million capital cost to add a natural gas pipeline (twenty-five percent of estimated total $100 million). The model also included two larger additional simple cycle combustion turbines; 2 – GE F Class Frame Unit (429 MW Summer MDU 25 percent) and 1 – GE J-Class Frame Unit (392.6 MW Summer MDU 25 percent) that were used as part of Coyote replacement analysis. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.10. Greenhouse Gas Rule

With the recent new Greenhouse Gas Rule by the EPA (Chapter 2 of the Main Report), this option was put together to look at all coal retirements (Coyote and Big Stone) at the end of 2031. The new combustion turbine options were also limited on run times if selected. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.11. Lower Resource Accreditation

As part of the new rules in North Dakota, a new sensitivity was developed to look at what effects a lower resource accreditation would have on existing and new alternatives. The case was set up lowering all thermal and renewable resources reserve capacity by ten percent from all the Base Cases. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8 under Lower RA - 10%.

3.2.12. Higher Renewables and Demand Response

As part of the new rules in Montana, a couple new sensitivities were included as part of the IRP that includes higher renewables and higher demand response. The first case increased renewables by twenty five percent (50 MW wind added in 2028) and demand response by five percent (increased the CPower by an additional 5%). The other case increased renewables by fifty percent (100 MW wind added in 2028) and demand response by ten percent (increased CPower by an additional 10%). The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.2.13. New Wind Opportunity

A final sensitivity was added with a late addition of a possible new wind opportunity that presented itself in the later stages of the IRP process. This option was included as a 150 MW wind farm option that is available in that 2025-2026 timeframe. The project has made it through the MISO queue process and has a final GIA signed with minimal network upgrades. With the delays in the MISO Queue, potential high network upgrade cost and future JTIQ cost adders this project is going to be further analyzed. The results can be seen in Tables 3-2, 3-4, 3-6, and 3-8.

3.3. Additional Modeling

Additional modeling was conducted using the Winter DLOL base case results as the Winter DLOL base case was the most restrictive scenario for needing new resources. The additional models forced in the future resources selected from the Winter DLOL base case.

3.3.1. Extreme Weather vs Normal Weather

In this scenario, the model was set up in EGEAS to reduce the amount of available on-peak and off-peak MISO purchases by one-third what is assumed to normally be available in the first quarter of the year to show the effects of having less energy available from the market under an extreme weather event. Table 3-9 shows the difference in annual costs and unserved energy for years 5, 10, and 20 of the study periods.

Table 3-9: Winter DLOL Extreme Weather vs Normal Weather

	Normal Weather annual costs ($M)	Extreme Weather annual costs ($M)	Normal Weather unserved energy (GWh)	Extreme Weather unserved energy (GWh)
5th year	137.37	137.88	0.00	0.09
10th year	159.13	160.61	0.00	0.64
20th year	267.43	271.46	0.06	0.61

3.3.2. Natural Gas Fuel Delivery Outages

In this scenario, the model was set up in EGEAS to reduce the amount of available on-peak and off-peak MISO purchases by one-third of what is assumed to normally be available in the first quarter of the year to show the effects of having potentially less energy available from the market in a natural gas fuel delivery outage event, along with increasing the forced outage rate on the MDU owned combustion turbines to show the effect increased outages associated with natural gas supply. Table 3-10 shows the difference in unserved energy for years 5, 10, and 20 of the study periods.

Table 3-10: Winter DLOL Base Case vs Natural Gas fuel delivery outages

	Base Case unserved energy (GWh)	NG Shortage unserved energy (GWh)
5th year	0.00	0.58
10th year	0.00	3.43
20th year	0.06	3.09

4. Conclusions

Based on the current results of the supply-side and integration analysis, the current summer and winter Base Cases are the least-cost plan. The future summer and winter DLOL Base Cases show a need for capacity sooner, but more time is needed to see potential impacts as DLOL is not going into effect until 2028 in MISO. In both the current summer and winter plans, the following resources are selected as the least-cost options in meeting the forecasted capacity and energy requirements:

- Complete commissioning of the Heskett 4 an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in 2024.
- Continue to grow the Commercial Demand Response program to a total of 45 MW.
- Continue the evaluation of the new 150 MW wind opportunity.

Figures 4-1 and 4-2 show a comparison of the summer resource mix that Montana-Dakota has available to serve its customers' needs in 2024 which includes a new simple cycle combustion turbine online in 2024, as compared to the least cost plan in 2029. Figures 4-3 and 4-4 show the comparison of the winter mix. Note a Zonal Resource Credit (ZRC) represents one megawatt of accredited generating capacity under the MISO resource adequacy rules.

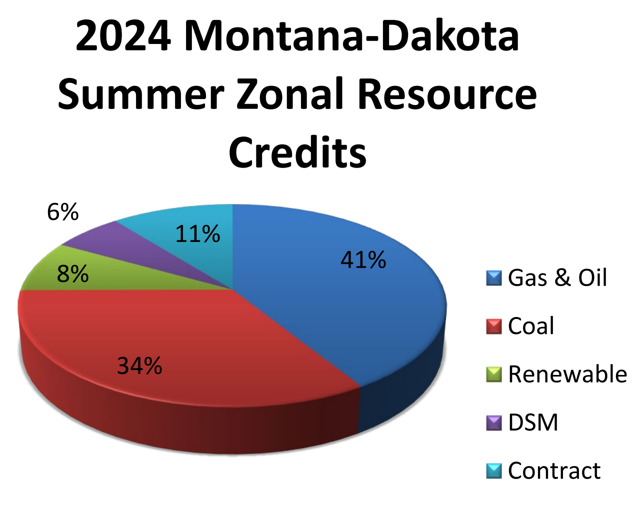


Figure 4-1: 2024 Montana-Dakota Summer Zonal Resource Credits

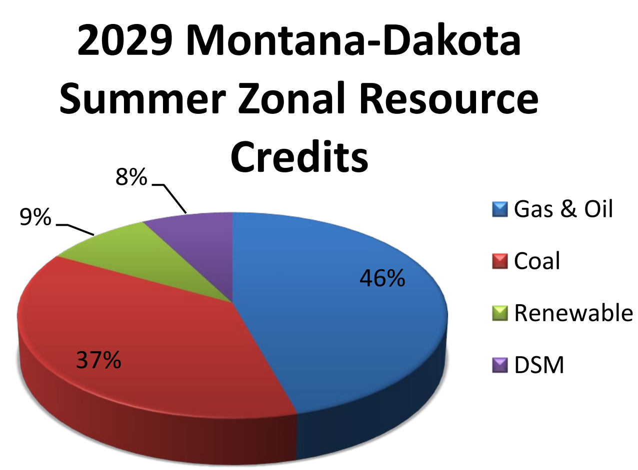


Figure 4-2: 2029 Montana-Dakota Summer Zonal Resource Credits

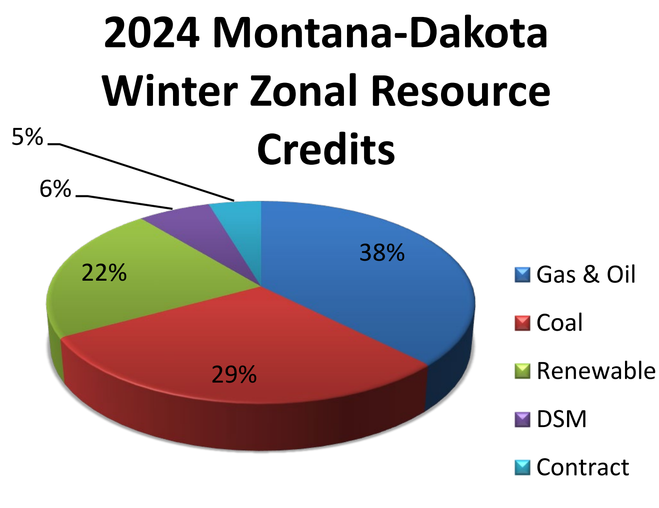


Figure 4-3: 2024 Montana-Dakota Winter Zonal Resource Credits

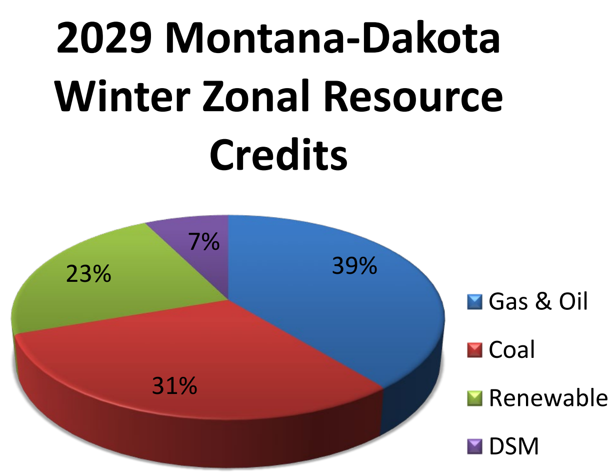


Figure 4-4: 2029 Montana-Dakota Summer Zonal Resource Credits

As shown in Figures 4-1 and 4-2; in 2024 approximately 34 percent of Montana-Dakota's resource capacity comes from natural gas and oil-fired combustion turbines and reciprocating internal combustion engines while in 2029, based on the Base Case plan, approximately 46 percent of the Company's resource capacity would be made up by natural gas and oil-fired combustion turbines and reciprocating internal combustion engines. In the winter with the expiration of the Minnkota capacity and energy contract on May 31, 2026, there is slight difference in the ZRCs from 2024 to 2029 as shown in Figures 4-3 and 4-4. It should be noted that while natural gas makes up a sizable portion of the capacity, these are peaking resources that, while critical to the system, contribute little to the actual energy usage.

Figures 6-6 and 6-7 shows the percentage of energy on a yearly basis in 2024 and in 2029. In 2024, 30 percent of Montana-Dakota's energy will come from coal, 26 percent from MISO energy market, 24 percent from renewable, and 20 percent from energy contract. In 2029, 32 percent of energy will come from coal, 45 percent will come from MISO energy market, and 23 percent will come from renewable based upon forecasted fuel and MISO energy prices. If MISO energy prices increase higher than forecasted, Montana-Dakota's natural gas-fired units could be dispatched to offset forecasted MISO energy purchases and provide pricing protection for customers.

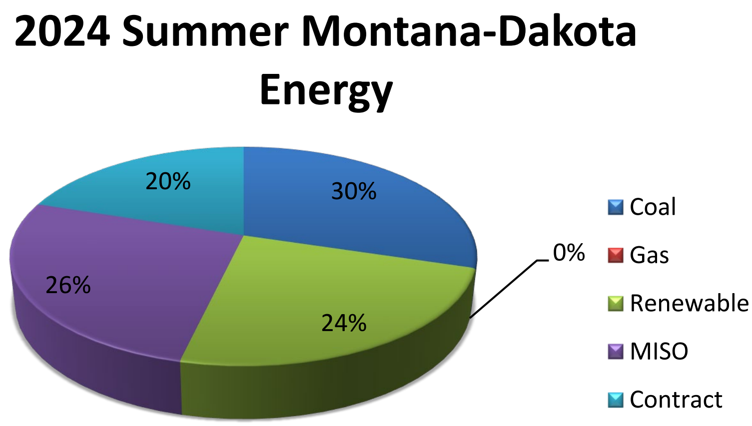


Figure 6-6: 2024 Montana-Dakota Energy by Resource Type

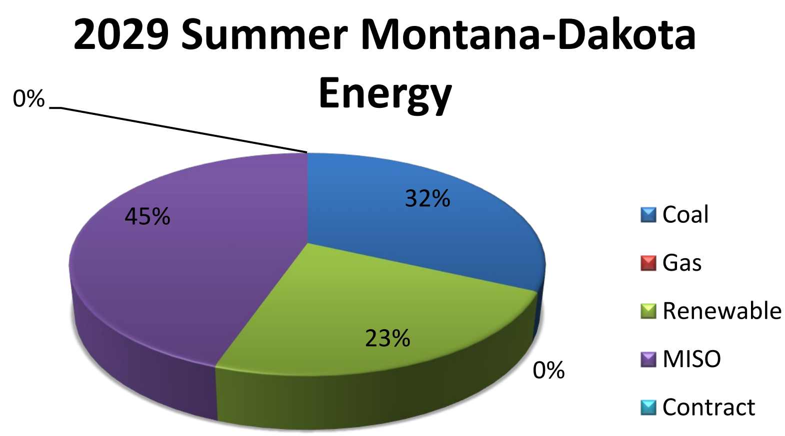


Figure 6-7: 2029 Montana-Dakota Energy by Resource Type

The sensitivity scenarios show that the largest variations in NPV of supply plans reflect potential carbon tax, high load growth scenarios, limiting MISO energy market, and the Greenhouse Gas Rule.

5. Future Resource Plan

Based on the analysis of the resource expansion models and the consideration of customer impacts, market availability of capacity and energy, and other factors such as environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan is to pursue the following resource changes to meet the requirements identified for the 2024-2029 period:

- Continue to grow the Commercial Demand Response program to a total of 45 MW with a goal of reaching 60 MW.
- Complete the commissioning of the Heskett 4 natural gas-fired simple cycle combustion turbine resource, to be online in 2024.
- Issue a new request for proposal prior to the next IRP.
- Continue the evaluation of the new 150 MW wind opportunity.

Montana-Dakota's recommended resource plan satisfies future customer requirements through the current MISO Resource Adequacy process for both capacity and energy. With the unknowns of the new MISO DLOL process, the current plan will allow Montana-Dakota to continue to evaluate the DLOL process within MISO and react once more information is provided by MISO. Montana-Dakota will continue its reliance on Big Stone and Coyote to provide base load energy as well as having nearly 300 MW of natural gas-fired peaking capacity with the Heskett 4 addition to provide energy when it is needed. In addition, Montana-Dakota has the Minnkota contract for capacity and energy that goes through May 2026, the use of the MISO energy market to meet customer demands, and 200 MW of renewables.

A new request for proposals will be issued prior to the next IRP to see what impacts the uncertainties with final project pricing, network upgrade costs, delays in the MISO queue process and potential JTIQ price adder will have on potential projects that could potentially be future options to Montana-Dakota.

6. References

MISO Resource Adequacy Business Practice Manual-11-r29 Resource Adequacy. (October 1, 2023)
EGEAS User's Guide Version 13. EPRI, Palo Alto, CA, November 2018.
MISO Planning Year 2024-2025 Loss of load Expectation Study Report. (April 18, 2024)
MISO Planning Year 2024-2025 Wind & Solar Capacity Credit. (March 28, 2024)

Appendix A

EGEAS INPUT DATA FOR THE SUMMER BASE CASE

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ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

Montana-Dakota Utilities Co.
2024 Model
Base Case Run
-- Data updated for the 2024 Model

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3420 HILLVIEW AVENUE
PALO ALTO, CALIFORNIA 94304

NUMBER OF LOAD AREAS 1

LOAD MODIFICATION OPTION 1

NUMBER OF LOAD COMPONENTS 1

COST ANALYSIS FORMAT 1 - NO CONSTRUCTION COSTS, LEVELIZED FIXED CHARGES

REPORT FILE OPTION 0 - STANDARD

REPORT OPTIONS

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MIRROR IMAGE	1	- GENERATE
ERROR	3	- ALL MESSAGES
DATA BASE CONTENTS	1	- GENERATE WITHOUT ORTHOG DATA

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HOURLY NDT							
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TECHNOLOGY 2	windCHcf	1	0				
TECHNOLOGY 3	windTScf	1	0				
TECHNOLOGY 4	wind46cf	1	0				
TECHNOLOGY 5	slr16cf	1	0				
TECHNOLOGY 6	slr20cf	1	0				

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                    *                                                                                                68
                    *            RATED --CAPACITY MULT.--  EQV. HEAT  ENRGY STOR      CAP.MULT.                      69
                    *             CAP.  OPER. EMER. CHRG.  FOR  RATE  LIMIT EFF.       RESERVE                       70
                    *BP B        ------++++++------++++++------++++++----------++++++      ------                    71
                    *                                                                                                72
                    *             INSTALL.  INSTALL. LEVEL. FIXED  VAR. AFUDC  DEBT M CAP                            73
                    *              COST 1    COST 2  CARRY.  O+M   O+M   PCT. AFUDC U STR                            74
                    *BP C        ----------++++++++++------++++++------++++++------+----                             75
                    *                                                                                                76
                    *             INST  FIX  VAR  FOR           OPER                                                 77
                    *             COST  O+M  O+M  OUT  MNT FUEL  CAP ENRG  CAP ENRG WEEK LOAD                        78
                    *               TJ   TJ   TJ   TJ  CYC TYPE   TJ   TJ   SM   SM ENRG  BLK                        79
                    *BP D      1 -----+++++-----+++++-----+++++-----+++++-----+++++-----+++++                        80
                    *                                                                                                81
                    *                             RES HEAT     RATED                                                 82
                    *                   ENV  GEN  CAP RATE  TAX  CAP                                                 83
                    *              NDT PLNT SITE   TJ   TJ DEPR   TJ                                                 84
                    *BP D      2 -----+++++-----+++++-----+++++-----                                                 85
                    *                                                                                                86
                    *             M S       DISPATCH    2ND HT RT MUST-RUN  SPINNING  MUST                           87
                    *             R P       MODIF TJ   FUEL  MULT YR 1 LAST YR 1 LAST  SM                            88
                    *BP E         - +      -----+++++-----++++++ ---- ++++ ---- ++++ -----                           89
                    *                                                                                                90
                    *              CONSTRUC  CONSTRUC       EXP   PCT                                                91

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                            DATA FIELDS                                                      NUM
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                    *                COST 1    COST 2   TJ PATT  CWIP                                                          92
                    *BP F        ----------+++++++++-----+++++------                                                           93
                    *                                                                                                          94
                    *              STARTING   EQUITY     DEBT                                                                  95
                    *               CWIP       AFUDC    AFUDC                                                                  96
                    *BP G        ----------+++++++++----------                                                                 97
                    *-- ----- -- ----------------------------------------------------------                                    98
                    *                                                                                                          99
 BASIC PLANT TYPE   BPA     1    STORAGE1         STOR P G STRG MDU  NDAK 100.0    1      30 25                               100
                    BPB     1     1.0001.00001.00001.00000.0010        0.33 95.00       0.9500                                101
                    BPC     1      2240.000          11.1304750.00.0000             2  1                                      102
                    BPD     1  1    51   22         0    0         0    0    0    0    0    0                                 103
                    BPD     1  2     0    0    0    0    0    0    0                                                         104
                    *                                                                                                         105
 BASIC PLANT TYPE   BPA     2    ENERGY           THRM B E PURC MDU  MISO 100.0    1 2021  6  6                               106
                    BPB     2    75.0001.00001.0000      0.0000 10500                   0.0000                                107
                    BPC     2                              0.000023.000             2  0                                      108
                    BPD     2  1             42    0    7    8    0    0    0    0    0    6                                 109
                    BPD     2  2     0    0    0    0    0    0   28                                                         110
                    *                                                                                                         111
 BASIC PLANT TYPE   BPA     3    CAPACITY         THRM P E PURC MDU  MISO 100.0    1 2021  6  6                               112
                    BPB     3    30.0001.00001.0000      0.0000     1                   1.0000                                113
                    BPC     3         0.000                24.0001000.0             2  0                                      114
                    BPD     3  1        21   23    0    7    8    0    0    0    0    0    0                                 115
                    BPD     3  2     0    0    0    0    0    0   45                                                         116
                    BPF     3         0.000                   00.0000                                                         117
                    BPG     3    0.000000000.000000000.00000000                                                               118
                    *                                                                                                         119
 BASIC PLANT TYPE   BPA     4    WRTSLA 31DF      THRM P G GAS  MDU  NDAK 100.0    1      40 35                               120
                    BPB     4    44.4001.00001.0000      0.5000  8370                   0.9348                                121
                    BPC     4      3356.000          10.04064.7205.7600             1  1                                      122
                    BPD     4  1    30   22   56    0    5    3    0    0    0    0    0    9                                 123
                    BPD     4  2     0    0    0    0    0   20    0                                                         124
                    BPF     4       857.000             30   370.0000                                                         125
                    BPG     4    0.000000000.000000000.00000000                                                               126
                    *                                                                                                         127
 BASIC PLANT TYPE   BPA    24    STORAGE10        STOR P G STRG MDU  NDAK 100.0    1      30 25                               128
                    BPB    24    10.0001.00001.00001.00000.0010       13.14 95.00       0.9500                                129
                    BPC    24      1358.000          11.130333.000.0000             2  1                                      130
                    BPD    24  1    51   22         0    0         0    0    0    0    0    0                                 131
                    BPD    24  2     0    0    0    0    0    0    0                                                         132
                    *                                                                                                         133
 BASIC PLANT TYPE   BPA    27    STORAGE50        STOR P G STRG MDU  NDAK 100.0    1      30 25                               134
                    BPB    27    50.0001.00001.00001.00000.0010       65.70 95.00       0.9500                                135
                    BPC    27      1449.000          11.13044.8800.0000             2  1                                      136
                    BPD    27  1    51   22         0    0         0    0    0    0    0    0                                 137
                    BPD    27  2     0    0    0    0    0    0    0                                                         138

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                              MIRROR IMAGE REPORT                                      PAGE      5
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 RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                                    NUM
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                    *                                                                                                     139
 BASIC PLANT TYPE   BPA    80    MISO - On peak   HYDR P E PURC MDU  MISO 100.0    1 2014 50 50                           140
                    BPB    80     250.01.00001.0000      0.0000 105001095.0           0.0000                              141
                    BPC    80                              0.000025.890             2  0                                  142
                    BPD    80  1             29    0    0    8    0    0    0    0    0    7                              143
                    BPD    80  2     0    0    0    0    0    0    0                                                     144
                    *                                                                                                     145
 BASIC PLANT TYPE   BPA    90    MISO - Off peak  HYDR P E PURC MDU  MISO 100.0    1 2014 50 50                           146
                    BPB    90     250.01.00001.0000      0.0000 105001095.0           0.0000                              147
                    BPC    90                              0.000023.230             2  0                                  148
                    BPD    90  1             46    0    0    8    0    0    0    0    0    7                              149
                    BPD    90  2     0    0    0    0    0    0    0                                                     150
                    *                                                                                                     151
 BASIC PLANT TYPE   BPA   100    INTERRUPTIBLES   DTHR1P E DSM  MDU  MISO 100.0    1 2012 50 30                           152
                    BPB   100    15.2001.00001.0000      0.0000     1                 0.8026                              153
                    BPC   100        0.000                 50.040300.00             1  1                                  154
                    BPD   100  1        48   49    0   14    4    0    0    0    0    0    0                              155
                    BPD   100  2     0    0    0    0    0    0   16                                                     156
                    BPF   100        0.000                    00.0000                                                     157
                    BPG   100    0.000000000.000000000.00000000                                                           158
                    *                                                                                                     159
 BASIC PLANT TYPE   BPA   110    COMMERCIAL DSM   DTHR1P E DSM  MDU  MISO 100.0    1 2013 50 30                           160
                    BPB   110    25.0001.00001.0000      0.0000     1                 1.0280                              161
                    BPC   110        0.000                 50.040300.00             2  0                                  162
                    BPD   110  1        48   49    0   14    4    0    0    0    0    0    0                              163
                    BPD   110  2     0    0    0    0    0    0    4                                                     164
                    BPF   110        0.000                    00.0000                                                     165
                    BPG   110    0.000000000.000000000.00000000                                                           166
                    *                                                                                                     167
 BASIC PLANT TYPE   BPA   120    MILES CITY C.T.  THRM P E GAS  MDU  MONT 100.0    1 1972 99 30                           168
                    BPB   120    20.7000.85711.0000      0.5000 16266                 0.7826                              169
                    BPC   120                              9.27004.2000             2  0                                  170
                    BPD   120  1         3    5    0    2    1    0    0    0    0    0   12                              171
                    BPD   120  2     0    0    0    0    0    0    0                                                     172
                    *                                                                                                     173
 BASIC PLANT TYPE   BPA   130    GLENDIVE CT #1   THRM P E GAS  MDU  MONT 100.0    1 1979 99 30                           174
                    BPB   130    31.3000.84511.0000      0.5000 13010                 0.9265                              175
                    BPC   130                              6.70004.2000             2  0                                  176
                    BPD   130  1         3    6    0    3    1    0    0    0    0    0    5                              177
                    BPD   130  2     0    0    0    0    0    0    0                                                     178
                    *                                                                                                     179
 BASIC PLANT TYPE   BPA   132    GLENDIVE CT #2   THRM P E GAS  MDU  MONT 100.0    1 2003 99 30                           180
                    BPB   132    43.3000.92381.0000      0.5000  9322                 0.5751                              181
                    BPC   132                              7.41004.2000             2  0                                  182
                    BPD   132  1         3    7    0    4    1    0    0    0    0    0   13                              183
                    BPD   132  2     0    0    0    0    0    0    0                                                     184
                    *                                                                                                     185

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                                   NUM
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 BASIC PLANT TYPE   BPA   136    DIESEL 2         THRM P E GAS  MDU  NDAK 100.0    1 2012 99 30                          186
                    BPB   136     2.0001.00001.0000      0.5000  8687                 0.9048                              187
                    BPC   136                              19.2604.2000            2  0                                 188
                    BPD   136  1          3    8    0   23    2    0    0    0    0    0    0                             189
                    BPD   136  2     0    0    0    0    0    0    0                                                     190
                    *                                                                                                    191
 BASIC PLANT TYPE   BPA   138    DIESEL 3         THRM P E GAS  MDU  NDAK 100.0    1 2012 99 30                          192
                    BPB   138     2.0001.00001.0000      0.5000  8687                 0.8500                              193
                    BPC   138                              19.2604.2000            2  0                                 194
                    BPD   138  1          3    8    0   23    2    0    0    0    0    0    0                             195
                    BPD   138  2     0    0    0    0    0    0    0                                                     196
                    *                                                                                                    197
 BASIC PLANT TYPE   BPA   152    HESKETT #3       THRM P E GAS  MDU  NDAK 100.0    1 2014 40 25                          198
                    BPB   152    84.5000.95451.0000      0.5000 11482                 1.0142                              199
                    BPC   152                              40.2800.9000            1  1                                 200
                    BPD   152  1          3   15    0   17   13    0    0    0    0    0    2                             201
                    BPD   152  2     0    0    0    0    0    0    0                                                     202
                    *                                                                                                    203
 BASIC PLANT TYPE   BPA   154    HESKETT #4       THRM P E GAS  MDU  NDAK 100.0    1 2023 40 35                          204
                    BPB   154    88.0000.88641.0000      0.5000 11770                 0.9102                              205
                    BPC   154      878.000          8.729040.2800.9000            1  1                                 206
                    BPD   154  1    30   22   60    0   37   13    0    0    0    0    0    8                             207
                    BPD   154  2     0    0    0    0    0   20    0                                                     208
                    BPF   154      857.000             30   370.0000                                                     209
                    BPG   154    0.000000000.000000000.00000000                                                          210
                    *                                                                                                    211
 BASIC PLANT TYPE   BPA   162    LEWIS & CLARK2   THRM P E GAS  MDU  MONT 100.0    1 2015 40 25                          212
                    BPB   162    18.5001.00001.0000      0.5000  8643                 0.7784                              213
                    BPC   162                              78.7703.5900            1  1                                 214
                    BPD   162  1          3   20    0   19   11    0    0    0    0    0   11                             215
                    BPD   162  2     0    0    0    0    0    0    0                                                     216
                    *                                                                                                    217
 BASIC PLANT TYPE   BPA   170    BIG STONE        THRM B E COAL MDU  SDAK 100.0    1 1975 99 30                          218
                    BPB   170     107.81.00001.0000      0.0375 10197                 1.0083                              219
                    BPC   170                              27.7903.8000            2  0                                 220
                    BPD   170  1          3   12    0    8    6    0    0    0    0    0   17                             221
                    BPD   170  2     0    0    0    0    0    0    0                                                     222
                    BPE   170     M        0.0000    0    0       1980 2080              0                               223
                    *                                                                                                    224
 BASIC PLANT TYPE   BPA   180    COYOTE           THRM B E COAL MDU  NDAK 100.0    1 1981 99 30                          225
                    BPB   180     106.81.00001.0000      0.1633 11011                 0.9335                              226
                    BPC   180                              33.8305.2000            2  0                                 227
                    BPD   180  1          3   13    0   22    7    0    0    0    0    0   18                             228
                    BPD   180  2     0    0    0    0    0    0    0                                                     229
                    BPE   180     M        0.0000    0    0       1980 2080              0                               230
                    *                                                                                                    231
 BASIC PLANT TYPE   BPA   190    DIAMOND WILLOW   NDT  B E WIND MDU  MONT 100.0    1 2008 28 25                          232

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 RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                               NUM
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 BASIC PLANT TYPE   BPB  190      30.0001.00000.3810      0.0000                        0.2000                         233
                    BPC  190                                21.7700.0000              2  1                             234
                    BPD  190    1          3         0   10         0    0    0    0    0    0                         235
                    BPD  190    2     1    0    0    0    0    0   40                                                  236
                    *                                                                                                  237
 BASIC PLANT TYPE   BPA  200      GLEN ULLIN ORMAT THRM B E WH   MDU  NDAK 100.0    1 2009 35 20                       238
                    BPB  200       7.5000.66670.6667      0.0500     1                   0.3867                         239
                    BPC  200                                122.088.1300              2  1                             240
                    BPD  200    1         44   18    0   15    5    0    0    0    0    0    0                         241
                    BPD  200    2     0    0    0    0    0    0    0                                                  242
                    BPE  200       M        0.0000    0    0       1980 2080               0                           243
                    *                                                                                                  244
 BASIC PLANT TYPE   BPA  210      CEDAR HILLS      NDT  B E WIND MDU  NDAK 100.0    1 2010 26 25                       245
                    BPB  210      19.5001.00000.3810      0.0000                        0.2667                         246
                    BPC  210                                28.7700.0000              2  1                             247
                    BPD  210    1          3         0   10         0    0    0    0    0    0                         248
                    BPD  210    2     2    0    0    0    0    0    0                                                  249
                    *                                                                                                  250
 BASIC PLANT TYPE   BPA  220      THUNDER SPIRIT   NDT  B E WIND MDU  NDAK 100.0    1 2015 27 25                       251
                    BPB  220       150.01.00000.4186      0.0000                        0.2447                         252
                    BPC  220                                29.470-37.04              2  1                             253
                    BPD  220    1          3   32    0   13         0    0    0    0    0    0                         254
                    BPD  220    2     3    0    0    0    0    0    9                                                  255
                    *                                                                                                  256
 BASIC PLANT TYPE   BPA  230      WAPA PUR-FT PECK HYDR B E HYDR MDU  NDAK 100.0    1 2001 50 30                       257
                    BPB  230       2.8000.89291.0000      0.0000       14.35            0.0000                         258
                    BPC  230           0.000                0.000024.000              2  0                             259
                    BPD  230    1              14    0    0         0    0    0    0    0    0                         260
                    BPD  230    2     0    0    0    0    0    0    0                                                  261
                    BPE  230       M        0.0000    0    0       1980 2080               0                           262
                    *                                                                                                  263
 BASIC PLANT TYPE   BPA  310      PURCHASE POWER   THRM P G PURC MDU  MISO 100.0    1       1  1                       264
                    BPB  310      10.0001.00001.0000      0.0000     1                   1.0000                         265
                    BPC  310           0.000                12.0001000.0              2  0                             266
                    BPD  310    1         10   23    0    0    8    0    0    0    0    0    0                         267
                    BPD  310    2     0    0    0    0    0    0    0                                                  268
                    BPF  310           0.000                   00.0000                                                 269
                    BPG  310      0.000000000.000000000.00000000                                                       270
                    *                                                                                                  271
 BASIC PLANT TYPE   BPA  320      GE 7EA           THRM P G GAS  MDU  NDAK 100.0    1      40 35                       272
                    BPB  320      77.9000.91951.0000      0.5000 11800                   0.9694                         273
                    BPC  320        2077.000          10.04038.8600.9000              1  1                             274
                    BPD  320    1    30   22   60    0   28    3    0    0    0    0    0    2                         275
                    BPD  320    2     0    0    0    0    0   20    0                                                  276
                    BPF  320         857.000             30   370.0000                                                 277
                    BPG  320      0.000000000.000000000.00000000                                                       278
                    *                                                                                                  279

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 RECORD DESCRIPTION TYP  REF  SQ                            DATA FIELDS                                                     NUM
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 BASIC PLANT TYPE   BPA   330    GE LMS100PB      THRM P G GAS  MDU  NDAK 100.0    1      40 35                             280
                    BPB   330    99.9000.90411.0000      0.5000  8970                   0.9694                               281
                    BPC   330      2485.000          10.04033.9301.3300              1  1                                    282
                    BPD   330  1    30   22   24    0   28    3    0    0    0    0    0   13                              283
                    BPD   330  2     0    0    0    0    0   20    0                                                       284
                    BPF   330       857.000            30   370.0000                                                       285
                    BPG   330    0.000000000.000000000.00000000                                                            286
                    *                                                                                                      287
 BASIC PLANT TYPE   BPA   340    GE LM6000PH      THRM P G GAS  MDU  NDAK 100.0    1      40 35                             288
                    BPB   340    45.0000.92721.0000      0.5000  9730                   0.9349                               289
                    BPC   340      3252.000          10.04062.5800.9000              1  1                                    290
                    BPD   340  1    30   22   62    0   28    3    0    0    0    0    0   13                              291
                    BPD   340  2     0    0    0    0    0   20    0                                                       292
                    BPF   340       850.000            30   370.0000                                                       293
                    BPG   340    0.000000000.000000000.00000000                                                            294
                    *                                                                                                      295
 BASIC PLANT TYPE   BPA   370    GE 7EA 2x1 ADD   THRM I G GAS  MDU  NDAK 100.0    1      50 35                             296
                    BPB   370     329.70.90961.0000      0.0166  9990                   0.9820                               297
                    BPC   370      1201.000          10.04028.3104.6000              1  1                                    298
                    BPD   370  1    59   59   59    0   21    3    0    0    0    0    0    4                              299
                    BPD   370  2     0    0    0    0    0   20    0                                                       300
                    BPF   370       750.000            30   370.0000                                                       301
                    BPG   370    0.000000000.000000000.00000000                                                            302
                    *                                                                                                      303
 BASIC PLANT TYPE   BPA   380    GE 7FA.05 1x1    THRM I G GAS  MDU  NDAK 100.0    1      50 35                             304
                    BPB   380     200.00.85711.0000      0.0166  8030                   0.9820                               305
                    BPC   380      1618.000          10.04028.0204.0000              1  1                                    306
                    BPD   380  1    30   22   54    0   24    3    0    0    0    0    0    2                              307
                    BPD   380  2     0    0    0    0    0   20    0                                                       308
                    BPF   380       750.000            30   370.0000                                                       309
                    BPG   380    0.000000000.000000000.00000000                                                            310
                    *                                                                                                      311
 BASIC PLANT TYPE   BPA   400    SMN SGT-800 2x1  THRM I G GAS  MDU  NDAK 100.0    1      50 35                             312
                    BPB   400     100.00.85711.0000      0.0166  9589                   0.9820                               313
                    BPC   400      2464.000          10.04049.7205.2000              1  1                                    314
                    BPD   400  1    30   22   69    0   25    3    0    0    0    0    0    3                              315
                    BPD   400  2     0    0    0    0    0   20    0                                                       316
                    BPF   400       750.000            30   370.0000                                                       317
                    BPG   400    0.000000000.000000000.00000000                                                            318
                    *                                                                                                      319
 BASIC PLANT TYPE   BPA   410    WRTSLA 18V50SG   THRM P G GAS  MDU  NDAK 100.0    1      40 35                             320
                    BPB   410    55.0001.00001.0000      0.5000  8330                   0.9695                               321
                    BPC   410      3425.000          10.04056.7605.2900              1  1                                    322
                    BPD   410  1    30   22   56    0    1    3    0    0    0    0    0    1                              323
                    BPD   410  2     0    0    0    0    0   20    0                                                       324
                    BPF   410       857.000            30   370.0000                                                       325
                    BPG   410    0.000000000.000000000.00000000                                                            326

                                  1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                      NUM
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          COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

                    *                                                                                                      327
 BASIC PLANT TYPE   BPA   420    WRTSLA 20V34SG   THRM P G GAS  MDU  NDAK 100.0    1      40 35                            328
                    BPB   420    36.5001.00001.0000      0.5000  8470                  0.9348                              329
                    BPC   420      3789.000          10.04076.5805.1100            1  1                                    330
                    BPD   420  1    30   22   56    0   28    3    0    0    0    0    0   10                              331
                    BPD   420  2     0    0    0    0    0   20    0                                                       332
                    BPF   420       857.000             30   370.0000                                                      333
                    BPG   420    0.000000000.000000000.00000000                                                            334
                    *                                                                                                      335
 BASIC PLANT TYPE   BPA   430    BIOMASS          THRM B G BMP  MDU  NDAK 100.0    1      40 25                            336
                    BPB   430    25.0001.00001.0000      0.0928 12300                  0.9072                              337
                    BPC   430      7980.000          10.040252.005.6000            1  1                                    338
                    BPD   430  1    30   22   58    0   28   10    0    0    0    0    0   19                              339
                    BPD   430  2     0    0    0    0    0   20    0                                                       340
                    BPF   430       857.000             30   370.0000                                                      341
                    BPG   430    0.000000000.000000000.00000000                                                            342
                    *                                                                                                      343
 BASIC PLANT TYPE   BPA   450    PV SOLAR50       NDT  B G SOLR MDU  NDAK 100.0    1      30 25                            344
                    BPB   450    50.0001.00001.0000      0.0000                        0.5000                              345
                    BPC   450      2280.000          11.13034.800-37.04            1  1                                    346
                    BPD   450  1    30   22   17    0   10         0    0    0    0    0    0                              347
                    BPD   450  2     6    0    0    0    0    0    0                                                       348
                    BPF   450      2558.000             30   380.0000                                                      349
                    BPG   450    0.000000000.000000000.00000000                                                            350
                    *                                                                                                      351
 BASIC PLANT TYPE   BPA   460    PV SOLAR5        NDT  B G SOLR MDU  NDAK 100.0    1      30 25                            352
                    BPB   460     5.0001.00001.0000      0.0000                        0.5000                              353
                    BPC   460      2467.000          11.13039.600-37.04            1  1                                    354
                    BPD   460  1    30   22   17    0   10         0    0    0    0    0    0                              355
                    BPD   460  2     6    0    0    0    0    0    0                                                       356
                    BPF   460      2558.000             30   380.0000                                                      357
                    BPG   460    0.000000000.000000000.00000000                                                            358
                    *                                                                                                      359
 BASIC PLANT TYPE   BPA   490    CFBC             THRM B G LIGN MDU  NDAK 100.0    1      50 50                            360
                    BPB   490    30.0000.95001.0000      0.0936 10000                  0.9143                              361
                    BPC   490      5880.000          9.4200168.7214.060            1  1                                    362
                    BPD   490  1    30   22   61    0   33   12    0    0    0    0    0    0                              363
                    BPD   490  2     0    0    0    0    0   20    0                                                       364
                    BPE   490     M        0.0000    0    0       1980 2080               0                                365
                    BPF   490      3900.000             30   310.0000                                                      366
                    BPG   490    0.000000000.000000000.00000000                                                            367
                    *                                                                                                      368
 BASIC PLANT TYPE   BPA   500    CFBC CO2         THRM B G COAL MDU  NDAK 100.0    1      50 50                            369
                    BPB   500    30.0000.95001.0000      0.0936 13800                  0.9143                              370
                    BPC   500     10400.000          9.4200267.4822.290            1  1                                    371
                    BPD   500  1    30   22   25    0   33   12    0    0    0    0    0    0                              372
                    BPD   500  2     0    0    0    0    0   20    0                                                       373

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                              NUM
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          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0

 BASIC PLANT TYPE   BPE   500     M        0.0000    0    0       1980 2080              0                          374
                    BPF   500      3900.000             30   310.0000                                               375
                    BPG   500    0.000000000.000000000.00000000                                                     376
                    *                                                                                               377
 BASIC PLANT TYPE   BPA   510    WIND50          NDT  B G WIND MDU  NDAK 100.0    1      25 25                      378
                    BPB   510    50.0001.00000.3810      0.0000                       0.1810                        379
                    BPC   510      2660.000         11.13058.800-37.04             1  1                             380
                    BPD   510  1    30   22   17    0   10         0    0    0    0    0    0                       381
                    BPD   510  2     4    0    0    0    0   21    0                                                382
                    BPF   510      2400.000             30   380.0000                                               383
                    BPG   510    0.000000000.000000000.00000000                                                     384
                    *                                                                                               385
 BASIC PLANT TYPE   BPA   520    WIND100         NDT  B G WIND MDU  NDAK 100.0    1      25 25                      386
                    BPB   520     100.01.00000.3810      0.0000                       0.1810                        387
                    BPC   520      2156.000         11.13056.400-37.04             1  1                             388
                    BPD   520  1    30   22   17    0   10         0    0    0    0    0    0                       389
                    BPD   520  2     4    0    0    0    0   21    0                                                390
                    BPF   520      2400.000             30   380.0000                                               391
                    BPG   520    0.000000000.000000000.00000000                                                     392
                    *                                                                                               393
                    *            == MAINTENANCE CYCLES ==                                                           394
                    *             Y YBO ----NUMBER OF WEEKS (W) AND STARTING WEEK (S)----                           395
                    *             I RAP   1    2    3    4    5    6    7    8    9   10                             396
                    *             N PST  W S  W S  W S  W S  W S  W S  W S  W S  W S  W S                           397
                    *            ++--+- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++--                           398
                    *                                                                                               399
 MAINTENANCE CYCLE  MC      1  1  1 110  2                                                                          400
                    *                                                                                               401
 MAINTENANCE CYCLE  MC      2  1 101011  0    0    0    0    0    0    0    237  0    0                            402
                    *                                                                                               403
 MAINTENANCE CYCLE  MC      3  1 101011  0    216  0    0    0    0    216  0    0    0                            404
                    *                                                                                               405
 MAINTENANCE CYCLE  MC      4  1 101011  0    0    238  0    221  0    0    238  0    221                          406
                    *                                                                                               407
 MAINTENANCE CYCLE  MC      5  1  1 110  2                                                                          408
                    *                                                                                               409
 MAINTENANCE CYCLE  MC      7  1  6 101 23 1  0    0    0    0   2923                                               410
                    *                                                                                               411
 MAINTENANCE CYCLE  MC      8  1 101011  340  341  814  340  340  340  341  814  340  340                          412
                    *                                                                                               413
 MAINTENANCE CYCLE  MC     10  1  1 110  1                                                                          414
                    *                                                                                               415
 MAINTENANCE CYCLE  MC     13  1  1 110  1                                                                          416
                    *                                                                                               417
 MAINTENANCE CYCLE  MC     14  1  1 100  1                                                                          418
                    *                                                                                               419
 MAINTENANCE CYCLE  MC     15  1  1 120  1                                                                          420

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
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RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                   NUM
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         COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

                   *                                                                                                   421
MAINTENANCE CYCLE  MC     17  1 101011  0    239  0    0    0    0    239  0    0    0                                 422
                   *                                                                                                   423
MAINTENANCE CYCLE  MC     19  1 101011  0    241  220  0    0    0    241  220  0    0                                 424
                   *                                                                                                   425
MAINTENANCE CYCLE  MC     21  1  1 110  2                                                                              426
                   *                                                                                                   427
MAINTENANCE CYCLE  MC     22  1 101012  122  714  122  123  714  122  714  122  123  714                               428
                   MC     22  2         138  139  138  138  138  138  139  138  138  138                               429
                   *                                                                                                   430
MAINTENANCE CYCLE  MC     23  1  1 110  2                                                                              431
                   *                                                                                                   432
MAINTENANCE CYCLE  MC     24  1  1 110  2                                                                              433
                   *                                                                                                   434
MAINTENANCE CYCLE  MC     25  1  1 110  2                                                                              435
                   *                                                                                                   436
MAINTENANCE CYCLE  MC     28  1  1 110  2                                                                              437
                   *                                                                                                   438
MAINTENANCE CYCLE  MC     33  1  1 110  3                                                                              439
                   *                                                                                                   440
MAINTENANCE CYCLE  MC     37  1  1 110  2                                                                              441
                   *                                                                                                   442
                   *-- ----- -- --------------------------------------------------------------------                   443
                   *            == FUEL TYPES ==                                                                       444
                   *                 MASS    HEAT    AVAILABLE   FUEL      AV   CS   AV   CS  LONG                     445
                   *            NAME UNIT   CONTENT    FUEL      COST      TJ   TJ   SM   SM  NAME                     446
                   *FL A        ---- ++++ ----------++++++++++----------+++++-----+++++-----++++++++                   447
                   *            MIN. FUEL    TJ   SM                                                                   448
                   *FL B        ----------+++++-----                                                                   449
                   *-- ----- -- --------------------------------------------------------------------                   450
                   *                                                                                                   451
FUEL TYPE          FLA     1    GAS  DKT      1.1400 -1.000000  5.370000    0   33    0    0GAS                        452
                   *                                                                                                   453
FUEL TYPE          FLA     2    OIL2 GAL     39.1700 -1.000000 19.000000    0   34    0    0OIL2                       454
                   *                                                                                                   455
FUEL TYPE          FLA     3    GAS  DKT      1.1400 -1.000000  5.060000    0   11    0    0GAS                        456
                   *                                                                                                   457
FUEL TYPE          FLA     4    DSM  NONE     0.0100 -1.000000  0.000000    0         0    0DSM                        458
                   *                                                                                                   459
FUEL TYPE          FLA     5    WH   NONE     0.0100 -1.000000  0.000000    0         0    0WH                         460
                   *                                                                                                   461
FUEL TYPE          FLA     6    COAL TON     16.4400 -1.000000  2.100000    0   38    0    0COAL                       462
                   *                                                                                                   463
FUEL TYPE          FLA     7    COAL TON     14.1300 -1.000000  2.190000    0   39    0    0COAL                       464
                   *                                                                                                   465
FUEL TYPE          FLA     8    PURC NONE     0.0100 -1.000000  0.000000    0         0    0PURC                       466
                   *                                                                                                   467

                                1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                                          NUM
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                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 FUEL TYPE          FLA    10    BMP  TON     14.9000 -1.000000  6.750000    0   63    0    0BMP                             468
                    *                                                                                                        469
 FUEL TYPE          FLA    11    GAS  DKT      1.1400 -1.000000  5.080000    0   47    0    0GAS                             470
                    *                                                                                                        471
 FUEL TYPE          FLA    12    COAL TON     14.0700 -1.000000  2.880000    0   43    0    0COAL                            472
                    *                                                                                                        473
 FUEL TYPE          FLA    13    GAS  DKT      1.1400 -1.000000  5.060000    0   50    0    0GAS                             474
                    *                                                                                                        475
                    *            == PLANNING ALTERNATIVES ==                                                                 476
                    *                                  1ST LAST T EXIST ---PREREQ ALT---                                     477
                    *            NAME             BP   YEAR YEAR Y   RET   PA   NfR L L R                                    478
                    *            ----------------+++++ ---- ++++ - +++++-----  ++-+ -++ +                                    479
                    *                                                                                                        480
 PLANNING ALTERN    PA      1  1 GE 7EA            320 2027 2043 0     0    0    00 0-1 0                                    481
                    *                                                                                                        482
 PLANNING ALTERN    PA      2  1 WRTSLA 18V50SG    410 2027 2043 0     0    0    00 0-1 0                                    483
                    *                                                                                                        484
 PLANNING ALTERN    PA      3  1 STORAGE1            1 2028 2043 0     0   12   100 0-1 0                                    485
                    *                                                                                                        486
 PLANNING ALTERN    PA      4  1 WRTSLA 31DF         4 2027 2043 0     0    0    00 0-1 0                                    487
                    *                                                                                                        488
 PLANNING ALTERN    PA      5  1 CFBC              490 2030 2043 0     0    0    00 0-1 0                                    489
                    *                                                                                                        490
 PLANNING ALTERN    PA      6  1 GE LM6000PH       340 2027 2043 0     0    0    00 0-1 0                                    491
                    *                                                                                                        492
 PLANNING ALTERN    PA      7  1 PURCHASE POWER    310 2024 2043 1     0    0    00 0-1 0                                    493
                    *                                                                                                        494
 PLANNING ALTERN    PA      8  1 GE 7EA 2x1 ADD    370 2027 2043 0   152    0    00 0-1 0                                    495
                    PA      8  2                                     154    0    00 0-1 0                                    496
                    *                                                                                                        497
 PLANNING ALTERN    PA      9  1 GE 7FA.05 1x1     380 2028 2043 0     0    0    00 0-1 0                                    498
                    *                                                                                                        499
 PLANNING ALTERN    PA     10  1 BIOMASS           430 2028 2043 0     0    0    00 0-1 0                                    500
                    *                                                                                                        501
 PLANNING ALTERN    PA     11  1 CFBC CO2          500 2030 2043 0     0    0    00 0-1 0                                    502
                    *                                                                                                        503
 PLANNING ALTERN    PA     12  1 PV SOLAR5         460 2028 2043 0     0    0    00 0-1 0                                    504
                    *                                                                                                        505
 PLANNING ALTERN    PA     13  1 WIND100           520 2028 2043 0     0    0    00 0-1 0                                    506
                    *                                                                                                        507
 PLANNING ALTERN    PA     14  1 GE LMS100PB       330 2027 2043 0     0    0    00 0-1 0                                    508
                    *                                                                                                        509
 PLANNING ALTERN    PA     16  1 PV SOLAR50        450 2028 2043 0     0    0    00 0-1 0                                    510
                    *                                                                                                        511
 PLANNING ALTERN    PA     19  1 SMN SGT-800 2x1   400 2028 2043 0     0    0    00 0-1 0                                    512
                    *                                                                                                        513
 PLANNING ALTERN    PA     22  1 WIND50            510 2026 2043 0     0    0    00 0-1 0                                    514

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                                              NUM
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         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

                   *                                                                                                                515
 PLANNING ALTERN    PA     23  1 WRTSLA 20V34SG    420 2027 2043 0     0    0    00 0-1 0                                           516
                   *                                                                                                                517
 PLANNING ALTERN    PA     40  1 STORAGE10          24 2028 2043 0     0   16   100 0-1 0                                           518
                   *                                                                                                                519
 PLANNING ALTERN    PA     43  1 STORAGE50          27 2028 2043 0     0    0    00 0-1 0                                           520
                   *                                                                                                                521
                   *           == TRAJECTORIES ==                                                                                   522
                   *            T B                                                                                                 523
                   *            Y A  N YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE                                        524
                   *            - + -- ++++------ ++++------ ++++------ ++++------ ++++------                                       525
                   *                                                                                                                526
 TRAJECTORY         TJ      1  1  1 1 21 2023-2.708 2024.59794 2025.65588 2026.65160 2027.62715                                     527
                    TJ      1  2         2028.62324 2029.65933 2030.71458 2031.70950 2032.70449                                     528
                    TJ      1  3         2033.69958 2034.69470 2035.70908 2036.72312 2037.71793                                     529
                    TJ      1  4         2038.71282 2039.68914 2040.73992 2041.73448 2042.74736                                     530
                    TJ      1  5         2043.70000                                                                                 531
                   *                                                                                                                532
 TRAJECTORY         TJ      2  1  1 1 21 2023-0.708 2024.36604 2025.41374 2026.45477 2027.39498                                     533
                    TJ      2  2         2028.45698 2029.40971 2030.55805 2031.56987 2032.56665                                     534
                    TJ      2  3         2033.56345 2034.56616 2035.60382 2036.60600 2037.58793                                     535
                    TJ      2  4         2038.60169 2039.59808 2040.67663 2041.67489 2042.67595                                     536
                    TJ      2  5         2043.70000                                                                                 537
                   *                                                                                                                538
 TRAJECTORY         TJ      3  1  1 1  1 20233.0000                                                                                 539
                   *                                                                                                                540
 TRAJECTORY         TJ      4  1  1 1  6 2023.00000 20246.6680 20256.2474 20265.8836 2027.00000                                     541
                    TJ      4  2         2028.00000                                                                                 542
                   *                                                                                                                543
 TRAJECTORY         TJ      5  1  1 1  1 20233.0000                                                                                 544
                   *                                                                                                                545
 TRAJECTORY         TJ      6  1  1 1  1 20233.0000                                                                                 546
                   *                                                                                                                547
 TRAJECTORY         TJ      7  1  1 1  1 20233.0000                                                                                 548
                   *                                                                                                                549
 TRAJECTORY         TJ      8  1  1 1  1 20233.0000                                                                                 550
                   *                                                                                                                551
 TRAJECTORY         TJ      9  1  1 1 20 2023.00000 2024.00000 2025.00000 2026.00000 2027.00000                                     552
                    TJ      9  2         2028.00000 2029.00000 2030.00000 2031.00000 2032.00000                                     553
                    TJ      9  3         2033.00000 2034.00000 2035.00000 2036.00000 2037.00000                                     554
                    TJ      9  4         2038.00000 2039.00000 2040-66.66 2041.00000 2042.00000                                     555
                   *                                                                                                                556
 TRAJECTORY         TJ     10  1  1 1  1 20233.0000                                                                                 557
                   *                                                                                                                558
 TRAJECTORY         TJ     11  1  1 1  6 2023-47.03 202418.656 202514.779 20265.4794 20277.0129                                     559
                    TJ     11  2         20283.0000                                                                                 560
                   *                                                                                                                561

                                1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                                     MIRROR IMAGE REPORT                                 PAGE     14
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                  NUM
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                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

 TRAJECTORY         TJ     12  1  1 1  1 20233.0000                                                                    562
                    *                                                                                                  563
 TRAJECTORY         TJ     13  1  1 1  1 20233.0000                                                                    564
                    *                                                                                                  565
 TRAJECTORY         TJ     14  1  1 1  1 2023.00000                                                                    566
                    *                                                                                                  567
 TRAJECTORY         TJ     15  1  1 1  1 20233.0000                                                                    568
                    *                                                                                                  569
 TRAJECTORY         TJ     16  1  1 1  6 2023.00000 2024.00000 2025.00000 2026.00000 2027.00000                        570
                    TJ     16  2         2028.00000                                                                    571
                    *                                                                                                  572
 TRAJECTORY         TJ     17  1  1 1  4 2023.00000 2024.00000 2025.00000 2026.00000                                   573
                    *                                                                                                  574
 TRAJECTORY         TJ     18  1  1 1  6 20231.4760 20241.4545 20251.5531 20261.5294 20271.5063                        575
                    TJ     18  2         20281.5000                                                                    576
                    *                                                                                                  577
 TRAJECTORY         TJ     20  1  1 1  1 20233.0000                                                                    578
                    *                                                                                                  579
 TRAJECTORY         TJ     21  1  1 1  3 202325.000 202420.000 2025.00000                                              580
                    *                                                                                                  581
 TRAJECTORY         TJ     22  1  1 1  1 20243.0000                                                                    582
                    *                                                                                                  583
 TRAJECTORY         TJ     23  1  1 1  1 20233.0000                                                                    584
                    *                                                                                                  585
 TRAJECTORY         TJ     24  1  1 1  1 20243.0000                                                                    586
                    *                                                                                                  587
 TRAJECTORY         TJ     25  1  1 1  1 20243.0000                                                                    588
                    *                                                                                                  589
 TRAJECTORY         TJ     28  1  1 1  3 2023.00000 2024.00000 2025.00000                                              590
                    *                                                                                                  591
 TRAJECTORY         TJ     29  1  1 1 28 202319.466 20243.2654 20251.5967 20262.3728 20273.7928                        592
                    TJ     29  2         2028-3.828 20294.5838 2030-0.144 20315.3133 2032.24678                        593
                    TJ     29  3         2033-1.477 2034-0.222 20352.1146 20362.4795 2037-2.100                        594
                    TJ     29  4         20386.5182 2039-2.141 204014.590 2041.63665 2042.92634                        595
                    TJ     29  5         20438.2382 2044-5.315 204521.996 2046-3.581 20477.2794                        596
                    TJ     29  6         20483.8601 20493.0833 20503.0000                                              597
                    *                                                                                                  598
 TRAJECTORY         TJ     30  1  1 1  1 20243.0000                                                                    599
                    *                                                                                                  600
 TRAJECTORY         TJ     31  1  1 1  1 20233.0000                                                                    601
                    *                                                                                                  602
 TRAJECTORY         TJ     32  1  1 1  6 2023.00000 2024.00000 2025-66.70 2026.00000 2027-100.0                        603
                    TJ     32  2         2028.00000                                                                    604
                    *                                                                                                  605
 TRAJECTORY         TJ     33  1  1 1  6 2023-11.35 20241.0504 2025-1.871 2026-0.423 2027.21278                        606
                    TJ     33  2         20283.0000                                                                    607
                    *                                                                                                  608

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
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RECORD DESCRIPTION TYP  REF  SQ                              DATA FIELDS                                             NUM
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                              1         2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

TRAJECTORY         TJ     34  1  1 1  6 202313.631 2024-33.99 20251.0526 20263.9583 2027.00000                     609
                   TJ     34  2         20283.0000                                                                 610
                   *                                                                                               611
TRAJECTORY         TJ     38  1  1 1  6 20237.1428 20241.7777 20253.0567 20262.9661 20272.8806                     612
                   TJ     38  2         20283.0000                                                                 613
                   *                                                                                               614
TRAJECTORY         TJ     39  1  1 1  6 20237.3059 2024.85106 2025-6.751 2026-0.904 202736.073                     615
                   TJ     39  2         20283.0000                                                                 616
                   *                                                                                               617
TRAJECTORY         TJ     40  1  1 1 15 2023.00000 2024.00000 2025.00000 2026.00000 2027.00000                     618
                   TJ     40  2         2028.00000 2029.00000 2030.00000 2031.00000 2032.00000                     619
                   TJ     40  3         2033-65.00 2034.00000 2035.00000 2036.00000 2037.00000                     620
                   *                                                                                               621
TRAJECTORY         TJ     42  1  1 1  3 20234.3478 20244.1666 2025.00000                                           622
                   *                                                                                               623
TRAJECTORY         TJ     43  1  1 1  1 20243.0000                                                                 624
                   *                                                                                               625
TRAJECTORY         TJ     44  1  1 1  1 20233.0000                                                                 626
                   *                                                                                               627
TRAJECTORY         TJ     45  1  1 1  3 2023.00000 2024.00000 2025.00000                                           628
                   *                                                                                               629
TRAJECTORY         TJ     46  1  1 1 28 202311.622 20241.4654 2025-0.874 20261.6871 20272.9411                     630
                   TJ     46  2         2028-3.626 2029.76017 20307.9215 20313.9846 20324.2016                     631
                   TJ     46  3         2033-1.096 2034.61970 20351.9449 2036.03179 20371.3032                     632
                   TJ     46  4         20387.6247 20393.2944 20408.6085 2041.59772 20424.4691                     633
                   TJ     46  5         2043-0.840 204412.568 20454.1648 20461.3398 20473.0430                     634
                   TJ     46  6         20489.1446 20499.8525 20503.0000                                           635
                   *                                                                                               636
TRAJECTORY         TJ     47  1  1 1  6 2023-6.299 20241.0504 2025-1.871 2026-0.423 2027.21278                     637
                   TJ     47  2         20283.0000                                                                 638
                   *                                                                                               639
TRAJECTORY         TJ     48  1  1 1  1 20233.0000                                                                 640
                   *                                                                                               641
TRAJECTORY         TJ     49  1  1 1  1 2023.00000                                                                 642
                   *                                                                                               643
TRAJECTORY         TJ     50  1  1 1  6 2023-34.78 20248.1818 2025-9.243 20269.2592 2027-6.497                     644
                   TJ     50  2         20283.0000                                                                 645
                   *                                                                                               646
TRAJECTORY         TJ     51  1  1 1 20 20243.0000 20253.0000 20263.0000 20273.0000 20283.0000                     647
                   TJ     51  2         20293.0000 20303.0000 20313.0000 20323.0000 203314.035                     648
                   TJ     51  3         203412.967 203521.176 20363.0000 20373.0000 20383.0000                     649
                   TJ     51  4         20393.0000 20403.0000 20413.0000 20423.0000 20433.0000                     650
                   *                                                                                               651
TRAJECTORY         TJ     54  1  1 1  1 20243.0000                                                                 652
                   *                                                                                               653
TRAJECTORY         TJ     56  1  1 1  1 20243.0000                                                                 654
                   *                                                                                               655

                              1         2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
```

```
 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                    NUM
 ---------------------- ----- -- ---------------------------------------------------------------------------------------   ----
                                1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 TRAJECTORY         TJ     58  1  1 1  1 20243.0000                                                                      656
                    *                                                                                                    657
 TRAJECTORY         TJ     59  1  1 1  1 20243.0000                                                                      658
                    *                                                                                                    659
 TRAJECTORY         TJ     60  1  1 1  1 20243.0000                                                                      660
                    *                                                                                                    661
 TRAJECTORY         TJ     61  1  1 1  1 20243.0000                                                                      662
                    *                                                                                                    663
 TRAJECTORY         TJ     62  1  1 1  1 20243.0000                                                                      664
                    *                                                                                                    665
 TRAJECTORY         TJ     63  1  1 1  1 20243.0000                                                                      666
                    *                                                                                                    667
 TRAJECTORY         TJ     69  1  1 1  1 20243.0000                                                                      668
                    *                                                                                                    669
                    *           == LOADING BLOCKS ==                                                                     670
                    *             -A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-                                             671
                    *           N     1       2       3       4       5                                                  672
                    *           - ++++++++-------++++++++-------++++++++                                                 673
                    *                                                                                                    674
 LOADING BLOCK      LBA     1   5 0.2325580.2093020.1860470.1860470.186047                                               675
                    LBB     1     1.8436370.7766110.6303580.7719000.794509                                               676
                    LBC     1     1.0000000.0000000.0000000.0000000.000000                                               677
                    *                                                                                                    678
 LOADING BLOCK      LBA     2   5 0.0946750.2130180.2011830.3076920.183432                                               679
                    LBB     2     3.2613650.8753020.6785150.6585090.903074                                               680
                    LBC     2     1.0000000.0000000.0000000.0000000.000000                                               681
                    *                                                                                                    682
 LOADING BLOCK      LBA     3   5 0.0873940.1966630.1857260.2841110.246106                                               683
                    LBB     3     3.0460290.8174930.6337540.6219811.132241                                               684
                    LBC     3     1.0000000.0000000.0000000.0000000.000000                                               685
                    *                                                                                                    686
 LOADING BLOCK      LBA     4   5 0.0946330.2129470.2011220.2171920.274106                                               687
                    LBB     4     2.9498470.7916370.6136950.6402401.057082                                               688
                    LBC     4     1.0000000.0000000.0000000.0000000.000000                                               689
                    *                                                                                                    690
 LOADING BLOCK      LBA     5   5 0.2875400.1916930.1597440.1916930.169329                                               691
                    LBB     5     1.6009220.7367790.7009220.7632850.827680                                               692
                    LBC     5     1.0000000.0000000.0000000.0000000.000000                                               693
                    *                                                                                                    694
 LOADING BLOCK      LBA     6   5 0.2000000.2000000.2000000.2000000.200000                                               695
                    LBB     6     1.0000001.0000001.0000001.0000001.000000                                               696
                    LBC     6     1.0000000.0000000.0000000.0000000.000000                                               697
                    *                                                                                                    698
 LOADING BLOCK      LBA     7   5 0.2000000.2000000.2000000.2000000.200000                                               699
                    LBB     7     1.0000001.0000001.0000001.0000001.000000                                               700
                    LBC     7     1.0000000.0000000.0000000.0000000.000000                                               701
                    *                                                                                                    702

                                1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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RECORD DESCRIPTION TYP  REF  SQ                            DATA FIELDS                                                         NUM
---------------------- ----- -- --------------------------------------------------------------------------------------------  ----
                                1          2         3         4         5         6         7         8         9
         COLUMNS       123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 LOADING BLOCK         LBA     8    5 0.0953370.2145080.2025910.3098450.177720                                                  703
                       LBB     8      3.2591500.8747070.6780540.6580620.902461                                                  704
                       LBC     8      1.0000000.0000000.0000000.0000000.000000                                                  705
                       *                                                                                                        706
 LOADING BLOCK         LBA     9    5 0.2325580.2093020.1860470.1860470.186047                                                  707
                       LBB     9      1.8436370.7766110.6303580.7719000.794509                                                  708
                       LBC     9      1.0000000.0000000.0000000.0000000.000000                                                  709
                       *                                                                                                        710
 LOADING BLOCK         LBA    10    5 0.2325580.2093020.1860470.1860470.186047                                                  711
                       LBB    10      1.8436370.7766110.6303580.7719000.794509                                                  712
                       LBC    10      1.0000000.0000000.0000000.0000000.000000                                                  713
                       *                                                                                                        714
 LOADING BLOCK         LBA    11    5 0.1891890.2432430.2162160.2162160.135135                                                  715
                       LBB    11      1.2000461.1529430.8809440.8645150.851903                                                  716
                       LBC    11      1.0000000.0000000.0000000.0000000.000000                                                  717
                       *                                                                                                        718
 LOADING BLOCK         LBA    12    5 0.3381640.1449270.1932370.1449270.178744                                                  719
                       LBB    12      1.5721750.6487760.7008480.7372640.738719                                                  720
                       LBC    12      0.8019250.0856190.1114440.1309420.231734                                                  721
                       *                                                                                                        722
 LOADING BLOCK         LBA    13    5 0.2309470.2078520.1847570.1847570.191686                                                  723
                       LBB    13      1.8148470.7642730.6209910.7594000.871078                                                  724
                       LBC    13      1.0000000.0000000.0000000.0000000.000000                                                  725
                       *                                                                                                        726
 LOADING BLOCK         LBA    17    5 0.2631680.1642250.1642250.2462910.162092                                                  727
                       LBB    17      1.2424240.7960430.8631700.9475121.031431                                                  728
                       LBC    17      1.0000000.0000000.0000000.0000000.000000                                                  729
                       *                                                                                                        730
 LOADING BLOCK         LBA    18    5 0.3512880.1405150.1405150.1405150.227166                                                  731
                       LBB    18      1.1612020.8910180.9029610.9154030.930482                                                  732
                       LBC    18      1.0000000.0000000.0000000.0000000.000000                                                  733
                       *                                                                                                        734
 LOADING BLOCK         LBA    19    5 0.2325580.2093020.1860470.1860470.186047                                                  735
                       LBB    19      1.8436370.7766110.6303580.7719000.794509                                                  736
                       LBC    19      1.0000000.0000000.0000000.0000000.000000                                                  737
                       *                                                                                                        738
                       *            == ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ==                                          739
                       *            YEAR OPT   RATE                                                                             740
                       *            ---- +    ------                                                                            741
 A. F. U. D. C.        ZA      1    2024 1    10.500                                                                            742
                       *                                                                                                        743
                       *-- ----- -- -------------------------------------------------------------------                         744
                       *            == EXPENDITURE PATTERNS - CONSTRUCTION COST AND CAPITAL EXPENSES ==                         745
                       *                          COST PERCENTAGES FOR YEARS BEFORE ON-LINE                                     746
                       *            YR          1    2    3    4    5    6    7    8    9   10                                  747
                       *ZC A        --        +++++-----+++++-----+++++-----+++++-----+++++-----                                748
                       *                      ANNUAL EXPENDITURES FOR YEARS OF OPERATING LIFE                                   749

                                1          2         3         4         5         6         7         8         9
         COLUMNS       123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                                    MIRROR IMAGE REPORT                                PAGE     18
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                     NUM
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                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

                    *            YR F   TJ      1         2         3         4         5                                  750
                    *ZC B        -- +----- ++++++++++----------++++++++++----------++++++++++                              751
                    *-- ----- -- -------------------------------------------------------------------                       752
                    *                                                                                                      753
 CONSTRUCTION EXPEN ZCA    31  1  4        13.7035.1034.8016.50                                                            754
                    *                                                                                                      755
 CONSTRUCTION EXPEN ZCA    37  1  3        69.0027.004.000                                                                 756
                    *                                                                                                      757
 CONSTRUCTION EXPEN ZCA    38  1  1        100.0                                                                           758
                    *                                                                                                      759
                    *            == RETURN ON RATE BASE ==                                                                 760
                    *                --CAPITAL STRUC-- -RATES OF RETURN- INCOME  PROP                                      761
                    *            YEAR COMM  PREF  DEBT  COMM  PREF  DEBT  TAX    TAX                                       762
                    *            ----+++++-----+++++-----+++++-----+++++------                                             763
 RETURN ON RATEBASE ZR      1  1 202450.0000.000050.0009.7500        4.6524.4001.2650                                      764
                    *                                                                                                      765
                    *            == TAX DEPRECIATION TABLES ==                                                             766
                    *                              DEPRECIATION PERCENTAGES FOR YEARS                                          767
                    *            YR          1    2    3    4    5    6    7    8    9   10                                 768
                    *            --        +++++-----+++++-----+++++-----+++++-----+++++-----                              769
                    *                                                                                                      770
 TAX DEPRECIATION   ZT     20  1 21        3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464                              771
                    ZT     20  2           4.4624.4624.4624.4624.4624.4624.4624.4624.4624.462                              772
                    ZT     20  3           2.224                                                                           773
                    *                                                                                                      774
 TAX DEPRECIATION   ZT     21  1 20        3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464                              775
                    ZT     21  2           4.4624.4624.4624.4624.4624.4624.4624.4624.4626.686                              776
                    *                                                                                                      777

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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****************************************************
****************************************************
**                                                **
**                                                **
**              DIAGNOSTIC SUMMARY                **
**                                                **
**                                                **
**         TERMINAL ERRORS            0           **
**         FATAL ERRORS               0           **
**         WARNING MESSAGES           0           **
**         DEFAULTS                   0           **
**                                                **
**                                                **
**     HIGHEST ERROR LEVEL FOUND IS WARNING       **
**                                                **
**                                                **
**     DATA BASE HAS BEEN SUCCESSFULLY CREATED    **
**                                                **
**                                                **
****************************************************
****************************************************
```

SOURCE FILE HEADERS	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
	2024	1	0	6/28/24	12: 8: 0	2024 IRP	1300

FILE CONTENTS

LOAD FORMAT	2	SUBPERIOD
COST ANALYSIS FORMAT	1	NO CONSTRUCTION COSTS, LEVELIZED FIXED CHARGES
NUMBER OF LOAD AREAS	1	
LOAD MODIFICATION OPTION	1	
NUMBER OF LOAD COMPONENTS	1	
NUMBER OF NON-DISPATCHABLE TECHNOLOGIES	6	
NUMBER OF YEARS	21	
FIRST CALENDAR YEAR	2023	
LAST CALENDAR YEAR	2043	
NUMBER OF DAYS PER YEAR	364	
NUMBER OF CUMULANTS	8	
NUMBER OF SEGMENTS PER YEAR	4	
NUMBER OF SUBWEEKS PER SEGMENT	3	
NUMBER OF CONTRACTS	0	
DAY OF WEEK OPTION	0	- DETERMINED BY CALENDAR YEAR IN COLUMNS 5-6
TIME INTERVAL OPTION	0	ONE HOUR

SOURCE FILE HEADERS	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
ORTHOGONALIZED LOAD	2024	1	0	6/28/24	12: 7:57	2024 IRP	1300
HOURLY LOADS							
SYSTEM A	HOURLOAD	1	0				
HOURLY NDT							
TECHNOLOGY 1	windDWcf	1	0				
TECHNOLOGY 2	windCHcf	1	0				
TECHNOLOGY 3	windTScf	1	0				
TECHNOLOGY 4	wind46cf	1	0				
TECHNOLOGY 5	slr16cf	1	0				
TECHNOLOGY 6	slr20cf	1	0				

ADDITIONAL HOURLY FILE PARAMETERS

SOURCE FILE	HEADER RECORD OPTION	DUPLICATE RECORD OPTION	FILE YEARS 1 / 21	2 / 22	3 / 23	4 / 24	5 / 25	6 / 26	7 / 27	8 / 28	9 / 29	10 / 30	11	12	13	14	15	16	17	18	19	20
HOURLY LOADS																						
SYSTEM A	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			
HOURLY NDT																						
TECHNOLOGY 1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			
TECHNOLOGY 2	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			
TECHNOLOGY 3	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			
TECHNOLOGY 4	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			
TECHNOLOGY 5	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			
TECHNOLOGY 6	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			1																			

GENERAL DATA

BASE YEAR 2023
ALL DATA BASE COSTS
ARE IN 2023 DOLLARS

NUMBER OF DAYS PER YEAR 364
NUMBER OF HOURS PER YEAR 8736
STORAGE GENERATION SUBWEEK 1

UNSERVED ENERGY COST . . . . . 130.00 $/MWH
YEARLY ESCALATION TRAJECTORY 31
CAPITAL STRUCTURE FOR NON-EGEAS ASSETS . 1

SYSTEM DISCOUNT RATE (PERCENT) 6.63
CUSTOMER DISCOUNT RATE (PERCENT) 6.63
INFLATION RATE (PERCENT) 3.00

NUMBER OF CUMULANTS 8
USED IN REPRESENTING PLANT
OUTAGES AND LOAD CURVES

BENCHMARK YEAR 2023
BENCHMARK PEAK . . . . . 498. MW

SERVICE AREAS AND NAMES IDENTIFYING SYSTEMS

SYSTEM A - SYSA SYSA

GENERATING COMPANIES

SYSTEM	COMPANY	CODE	NAME
A	1	NDAK	NDAK
	2	MONT	MONT
	3	SDAK	SDAK
	4	MISO	MISO

SYSTEM DEMAND

IN BASE YEAR 2023 -
PEAK LOAD . . . . 498.5 MW
ENERGY . . . . 3274.2 GWH

YEARLY ESCALATION TRAJECTORIES
PEAK LOAD 1
ENERGY 2

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
1	2023	INITIAL LOAD	498.5	299.5	3274.2	0.75184344	0.60070605	SUNDAY
		LOAD AFTER CONTRACTS	498.5	299.5	3274.2	0.75184344	0.60070605	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.985450059117323	0.931353080277899	0.862025012835275	0.796049051842321	0.718873591215110
0.618417619716474	0.514026920932942	0.415831186673586	0.341865057394288	0.269154525988559
0.210255571192081	0.151927342701771	0.107753126604412	0.072596386144499	0.048511736024234
0.029791913181943	0.012784269258154	0.004451665188109	0.001141452612338	0.000000000000000

CUMULANTS

0.751843444629574D+00	0.639333026136678D-02	0.213731425384362D-03	-0.176545548123336D-04
-0.461110897290212D-05	-0.873174365973736D-07	0.186493728507732D-06	0.365043544613861D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
2	2024	INITIAL LOAD	485.0	303.4	3251.0	0.76729544	0.62556895	SUNDAY
		LOAD AFTER CONTRACTS	485.0	303.4	3251.0	0.76729544	0.62556895	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	0.991774136130578	0.938761235400579	0.865461238815337	0.797656368140123
0.713045873572744	0.603479627102962	0.490209917205143	0.394315145609839	0.317712521781177
0.246361344593525	0.182887337367391	0.126948014452272	0.084936441324183	0.055368513497621
0.034362726933576	0.015526016156036	0.004908960990514	0.001141618835006	0.000000000000000

CUMULANTS

0.767295435822661D+00	0.562193006764228D-02	0.176240545196878D-03	-0.136512805098868D-04
-0.334349854720935D-05	-0.593711800903649D-07	0.118909975104312D-06	0.218261866297033D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
3	2025	INITIAL LOAD	487.9	303.8	3262.9	0.76552668	0.62272289	SUNDAY
		LOAD AFTER CONTRACTS	487.9	303.8	3262.9	0.76552668	0.62272289	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	0.986911902289302	0.930129363611818	0.857327332757150	0.789637262075861
0.700965368818836	0.591831609076083	0.481851134259952	0.389472573608932	0.313060677761792
0.238587591212267	0.179282836226427	0.124539985470267	0.082456418951469	0.054514755544679
0.034328329328345	0.015510474380915	0.004904047046909	0.001140476057423	0.000000000000000

CUMULANTS

0.765526676541266D+00	0.570771900629581D-02	0.180289960069608D-03	-0.140710864025213D-04
-0.347251360661033D-05	-0.621308559290343D-07	0.125382865966392D-06	0.231892411961186D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
4	2026	INITIAL LOAD	491.1	304.4	3276.4	0.76368513	0.61975974	SUNDAY
		LOAD AFTER CONTRACTS	491.1	304.4	3276.4	0.76368513	0.61975974	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.997375020875455	0.982478721589999	0.920918409906301	0.848785851796532	0.783656033050014
0.689069796581908	0.581575358182532	0.472201743510592	0.380524277350292	0.308369658902832
0.235986703055223	0.173079749313846	0.121932171680204	0.079918090052569	0.054572638635898
0.033337260421931	0.014499424909540	0.004909254103232	0.001141687000754	0.000000000000000

CUMULANTS

0.763685127254037D+00	0.579772524279304D-02	0.184571274211489D-03	-0.145183655610364D-04
-0.361103391534234D-05	-0.651166892303471D-07	0.132440531539490D-06	0.246868885262832D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
5	2027	INITIAL LOAD	494.3	305.2	3291.3	0.76219177	0.61735691	SUNDAY
		LOAD AFTER CONTRACTS	494.3	305.2	3291.3	0.76219177	0.61735691	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.996808260985793	0.976195286715936	0.913827896341757	0.843382509152870	0.773179799716078
0.680091970579233	0.570204627010811	0.465452206039043	0.376675099812426	0.303302761375774
0.231299735631564	0.172989836811767	0.119244313633442	0.079876573725752	0.053289085614181
0.033319942182744	0.014491892661675	0.004906703814585	0.001141093910371	0.000000000000000

CUMULANTS

0.762191768157039D+00	0.587123328438413D-02	0.188092585948354D-03	-0.148888501729070D-04
-0.372658347704686D-05	-0.676250101307112D-07	0.138411405245291D-06	0.259629190304449D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
6	2028	INITIAL LOAD	497.4	305.7	3304.3	0.76043320	0.61452734	SUNDAY
		LOAD AFTER CONTRACTS	497.4	305.7	3304.3	0.76043320	0.61452734	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.997404860833362	0.969431750772230	0.907844276132064	0.837122690308775	0.762661026723329
0.669221040716301	0.559214322473794	0.454991306505528	0.372536727938232	0.295562554231804
0.226354320899319	0.169708638171741	0.116717515620135	0.078801453794417	0.051849072496618
0.031748991528767	0.014504035698395	0.004910815236467	0.001142050054995	0.000000000000000

CUMULANTS

0.760433196524448D+00	0.595838768278093D-02	0.192296233990724D-03	-0.153341625861621D-04
-0.386642316800694D-05	-0.706813416043668D-07	0.145737016961918D-06	0.275391781705624D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
7	2029	INITIAL LOAD	500.5	306.6	3319.4	0.75917671	0.61250554	SUNDAY
		LOAD AFTER CONTRACTS	500.5	306.6	3319.4	0.75917671	0.61250554	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.997007030167845	0.963462907273200	0.898406298612263	0.830825008226694	0.759389258173282
0.663403776328367	0.550799864560461	0.447560578314835	0.368760680627355	0.291788026944223
0.224294201533642	0.166393407145885	0.116715210777691	0.076972653683136	0.051848048623360
0.031748364575539	0.013475924532065	0.004910718261687	0.001142027502720	0.000000000000000

CUMULANTS

0.759176705548413D+00	0.602105469357785D-02	0.195337913014178D-03	-0.156584087935501D-04
-0.396888917005913D-05	-0.729352433834940D-07	0.151172656353486D-06	0.287161603729087D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
8	2030	INITIAL LOAD	503.8	307.1	3333.0	0.75729404	0.60947627	SUNDAY
		LOAD AFTER CONTRACTS	503.8	307.1	3333.0	0.75729404	0.60947627	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.995830350315625	0.956164097497814	0.890199600376943	0.823802875482635	0.746264456789440
0.649541274708239	0.545052831255701	0.435996586996495	0.359942703565467	0.286515305598274
0.221081559042750	0.162727903737562	0.115108580328045	0.076053883431031	0.050588393933855
0.030375875364348	0.013475012379675	0.004910385867172	0.001141950201670	0.000000000000000

CUMULANTS

0.757294042538043D+00	0.611556324180848D-02	0.199955037034727D-03	-0.161538270615899D-04
-0.412646957129563D-05	-0.764237848249182D-07	0.159641866061318D-06	0.305620083436303D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
9	2031	INITIAL LOAD	507.4	308.3	3351.6	0.75611719	0.60758267	SUNDAY
		LOAD AFTER CONTRACTS	507.4	308.3	3351.6	0.75611719	0.60758267	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.995556780684735	0.951660478304713	0.883640717688907	0.820425540860710	0.741549461273990
0.642782892052359	0.532356380630951	0.430960608756429	0.356885681840205	0.282950363166873
0.218338133348749	0.159466856555763	0.112598461439016	0.076132563775011	0.050640729357854
0.030407300246478	0.013488952740921	0.004915465829321	0.001143131588217	0.000000000000000

CUMULANTS

0.756117191156485D+00	0.617501397456692D-02	0.202877826786801D-03	-0.164694243279004D-04
-0.422748796971814D-05	-0.786742892029703D-07	0.165139914472625D-06	0.317678425435161D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
10	2032	INITIAL LOAD	511.0	309.6	3370.7	0.75506886	0.60589588	SUNDAY
		LOAD AFTER CONTRACTS	511.0	309.6	3370.7	0.75506886	0.60589588	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.990545825396714	0.943438497428517	0.876822850865630	0.813256896496003	0.733742494793495
0.634292533924885	0.530513708780207	0.429468903178308	0.355650375523258	0.281034425501563
0.217582388612885	0.158914885924071	0.112208718734919	0.075869042312139	0.050465444060478
0.030302049932478	0.013442262752003	0.004898451680817	0.001139174809495	0.000000000000000

CUMULANTS

0.755068860506882D+00	0.622821337709493D-02	0.205505238361093D-03	-0.167544246234342D-04
-0.431912932577012D-05	-0.807251854450220D-07	0.170173286021215D-06	0.328768161362423D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
11	2033	INITIAL LOAD	514.6	310.9	3389.8	0.75403534	0.60423289	SUNDAY
		LOAD AFTER CONTRACTS	514.6	310.9	3389.8	0.75403534	0.60423289	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.989060724202748	0.938859514165799	0.870514332130142	0.809383863945405	0.731255455635552
0.632235442378710	0.524771868882321	0.424945558971157	0.350987482336059	0.278282932423591
0.214694940493877	0.155209399656402	0.110310351591335	0.073844119660316	0.049457327056448
0.029742770418741	0.012763181175860	0.004444322016596	0.001139569747848	0.000000000000000

CUMULANTS

0.754035336976229D+00	0.628088801149283D-02	0.208117796561618D-03	-0.170390217701356D-04
-0.441103124875120D-05	-0.827907425613776D-07	0.175264089905160D-06	0.340032301412971D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
12	2034	INITIAL LOAD	518.2	312.3	3408.9	0.75301599	0.60259271	SUNDAY
		LOAD AFTER CONTRACTS	518.2	312.3	3408.9	0.75301599	0.60259271	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.988384788721530	0.935580180075643	0.865778366293620	0.805463070348840	0.725992695536696
0.626753590475624	0.519291542550307	0.420454954451722	0.346156318363755	0.272770722350603
0.210227477225863	0.151907042447136	0.110477849052464	0.073956246059915	0.049532424058648
0.029787932440801	0.012782561047395	0.004451070364720	0.001141300093521	0.000000000000000

CUMULANTS

0.753015986720159D+00	0.633305362306173D-02	0.210715952558285D-03	-0.173232290100062D-04
-0.450319175630693D-05	-0.848708614526449D-07	0.180411975819457D-06	0.351470253306801D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
13	2035	INITIAL LOAD	521.8	313.6	3428.2	0.75205480	0.60104607	SUNDAY
		LOAD AFTER CONTRACTS	521.8	313.6	3428.2	0.75205480	0.60104607	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.986484831320641	0.930904271211106	0.862396218991725	0.799665534425673	0.721968792625425
0.621080312980342	0.513532282416022	0.416010252355253	0.342012271700243	0.269270429605734
0.210346111676745	0.151992765820711	0.107799527373969	0.072627647679921	0.048532626201206
0.029804742208271	0.012789774434203	0.004453582169055	0.001141944145914	0.000000000000000

CUMULANTS

0.752054798890927D+00	0.638244721481031D-02	0.213185925459589D-03	-0.175945023040776D-04
-0.459151082975305D-05	-0.868721952100220D-07	0.185384986304839D-06	0.362564230822009D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
14	2036	INITIAL LOAD	525.5	315.2	3448.9	0.75126861	0.59978110	SUNDAY
		LOAD AFTER CONTRACTS	525.5	315.2	3448.9	0.75126861	0.59978110	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.998115904599398
0.984774267149904	0.927743680759726	0.858614905942036	0.798741374618216	0.719182350143477
0.613198429832457	0.507067091050486	0.410855515870602	0.343142616091906	0.269409707014150
0.207141560142772	0.149573037244337	0.107855285590061	0.072665213596694	0.048557729211629
0.028449116643991	0.012796389815773	0.004455885739423	0.001142534804983	0.000000000000000

CUMULANTS

0.751268613902810D+00	0.642298289642150D-02	0.215220087330055D-03	-0.178187012633776D-04
-0.466476161019968D-05	-0.885379642233313D-07	0.189538734393341D-06	0.371863006938468D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
15	2037	INITIAL LOAD	529.3	316.7	3469.8	0.75039501	0.59837540	SUNDAY
		LOAD AFTER CONTRACTS	529.3	316.7	3469.8	0.75039501	0.59837540	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.997361716837398
0.981221636097884	0.926281400774697	0.854787366067859	0.792624158916343	0.712850834271503
0.607504697649270	0.504177122623074	0.410553675488184	0.337827676799093	0.265558356280734
0.206989380884339	0.148762914115993	0.105378487896441	0.072611829146411	0.048522055640292
0.028428216128078	0.012786988780503	0.004452612164642	0.001141695426834	0.000000000000000

CUMULANTS

0.750395006912355D+00	0.646817988808877D-02	0.217495766323406D-03	-0.180703543899391D-04
-0.474725654196302D-05	-0.904201578385764D-07	0.194247973961006D-06	0.382440731240439D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
16	2038	INITIAL LOAD	533.1	318.2	3490.2	0.74942644	0.59681698	SUNDAY
		LOAD AFTER CONTRACTS	533.1	318.2	3490.2	0.74942644	0.59681698	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.997487278228225
0.977659238417433	0.921554306091210	0.851621549282706	0.786772391355952	0.707668028057240
0.601742896266899	0.500832946521046	0.406056077936353	0.333203497024263	0.265603610033735
0.204169928951126	0.145476783827593	0.105396445426114	0.071025556939376	0.048530324275298
0.028433060575411	0.012560789812433	0.004453370933501	0.001141889982951	0.000000000000000

CUMULANTS

0.749426436772990D+00	0.651847473973581D-02	0.220037502099961D-03	-0.183524705977042D-04
-0.484008029344303D-05	-0.925459530209609D-07	0.199586104184947D-06	0.394475607486315D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
17	2039	INITIAL LOAD	536.9	319.7	3511.2	0.74859947	0.59548631	SUNDAY
		LOAD AFTER CONTRACTS	536.9	319.7	3511.2	0.74859947	0.59548631	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.997380526913215
0.974475764000446	0.918000461795501	0.847949987635941	0.784123982197246	0.698994868078822
0.597694614287940	0.495909853687802	0.402850465442986	0.333196615125464	0.261829965209969
0.204165712078250	0.145473779187747	0.102882162518180	0.071024089995903	0.047501642183756
0.028432473326336	0.012560530385130	0.004453278954730	0.001141866398651	0.000000000000000

CUMULANTS

0.748599472316957D+00	0.656157277072799D-02	0.222223287175436D-03	-0.185959481257110D-04
-0.492047793009835D-05	-0.943937347806704D-07	0.204242837525659D-06	0.405011972600324D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
18	2040	INITIAL LOAD	540.6	321.3	3532.2	0.74792256	0.59439721	SUNDAY
		LOAD AFTER CONTRACTS	540.6	321.3	3532.2	0.74792256	0.59439721	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.996880115121422
0.971497068832687	0.915028004414411	0.844468449137221	0.783222129915428	0.694834093550451
0.595012009911988	0.488229333581047	0.402700786462711	0.329534345384878	0.261732682357994
0.199752374237458	0.145419728444870	0.102843936678830	0.070997701014687	0.047483992961593
0.028421909248647	0.012555863523501	0.004451624340152	0.001141442138503	0.000000000000000

CUMULANTS

0.747922557790190D+00	0.659695544175906D-02	0.224023188986495D-03	-0.187970468394151D-04
-0.498708031708717D-05	-0.959289130221919D-07	0.208123749668172D-06	0.413818638360477D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
19	2041	INITIAL LOAD	544.6	323.3	3556.1	0.74745274	0.59364123	SUNDAY
		LOAD AFTER CONTRACTS	544.6	323.3	3556.1	0.74745274	0.59364123	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.997439086078500
0.970250166584435	0.911793766087885	0.844459102389871	0.779744680502749	0.694268916451799
0.590061189321682	0.489120861397081	0.399204191999659	0.329757511388560	0.258483286550853
0.199887649785239	0.143005335732069	0.102913584260859	0.068989794554450	0.047516149891808
0.027755827941610	0.012564366557932	0.004340417538197	0.001142215141633	0.000000000000000

CUMULANTS

0.747452744297387D+00	0.662156945495480D-02	0.225278127608299D-03	-0.189375792881596D-04
-0.503372902323241D-05	-0.970065777693191D-07	0.210854339058521D-06	0.420029194521150D-07

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
20	2042	INITIAL LOAD	548.6	325.3	3580.1	0.74701057	0.59292976	SUNDAY
		LOAD AFTER CONTRACTS	548.6	325.3	3580.1	0.74701057	0.59292976	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.996512054779568
0.967191143586846	0.909782222710525	0.839944312367691	0.779422351430170	0.689031599931299
0.590513858054040	0.483931611262215	0.398884628574685	0.329493540113052	0.258276370376114
0.199727639486611	0.142890859792708	0.102831201815680	0.068934568142810	0.047478113157963
0.027733609368715	0.012554308767733	0.004336943028855	0.001141300797070	0.000000000000000

CUMULANTS

0.747010572746985D+00	0.664477380088119D-02	0.226463382267645D-03	-0.190705342084855D-04
-0.507794527614890D-05	-0.980302852296766D-07	0.213451845420316D-06	0.425948139498044D-07

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
21	2043	INITIAL LOAD	552.7	327.2	3604.3	0.74648113	0.59207789	SUNDAY
		LOAD AFTER CONTRACTS	552.7	327.2	3604.3	0.74648113	0.59207789	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.996686400388106
0.965194096681686	0.905652220383957	0.839727046635939	0.774412239171496	0.687603287340387
0.584820760352794	0.485227636120908	0.399027332153993	0.325615436710498	0.258368770433331
0.196259795128103	0.142941979930417	0.100356230318561	0.068959229934484	0.047495098762825
0.027743531248478	0.012558800153634	0.004338494598530	0.001141709104879	0.000000000000000

CUMULANTS

0.746481127007751D+00	0.667261564372998D-02	0.227888176250935D-03	-0.192306877862858D-04
-0.513130445031530D-05	-0.992673977952783D-07	0.216598615072828D-06	0.433131993836233D-07

BASIC PLANT TYPES - 1

DATA SET REF. NO.	1	2	3	4	24
NAME	STORAGE1	ENERGY	CAPACITY	WRTSLA 31DF	STORAGE10
TYPE / LOADING / STATUS /AVD	STOR P G	THRM B E	THRM P E	THRM P G	STOR P G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	PURC MDU MISO	PURC MDU MISO	GAS MDU NDAK	STRG MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE		1/ 1/2021	1/ 1/2021		
OPERATING/BOOK LIVES, YEARS	30 25	6 6	6 6	40 35	30 25
RATED CAPACITY, MW	1.000	75.000	30.000	44.400	10.000
- RESERVE	0.9500	0.0000	1.0000	0.9348	0.9500
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	1.0000	0.0000	0.0000	0.0000	1.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0000	0.0000	0.5000	0.0010
FULL LOAD HEAT RATE, BTU/KWH	0.	10500.	1.	8370.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.330000	0.000000	0.000000	0.000000	13.140000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	0.00	0.00	95.00
INSTALLATION COST 1, $/KW	2240.00	0.00	0.00	3356.00	1358.00
INSTALLATION COST 2, $/KW	2240.00	0.00	0.00	3356.00	1358.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	1	2
LEVEL. CARRYING CHARGE, PCT	11.13	0.00	0.00	10.04	11.13
FIXED O+M COST, $/KW-YR	4750.00	0.00	24.00	64.72	333.00
VARIABLE O+M COST, $/MWH	0.00	23.00	1000.00	5.76	0.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	0	0	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	51 22 0	0 0 42	0 21 23	30 22 56	51 22 0
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	28	45	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	1	2	3	4	24
MAINTENANCE REQUIREMENTS	0	7	7	5	0
FUEL 1 / FUEL 2	0 0	8 0	8 0	3 0	0 0
LOADING BLOCKS / NDT NO.	0 0	6 0	0 0	9 0	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 20	0 0 0
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00	857.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	857.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	30 37	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	27	80	90	100	110
NAME	STORAGE50	MISO - On peak	MISO - Off peak	INTERRUPTIBLES	COMMERCIAL DSM
TYPE / LOADING / STATUS /AVD	STOR P G	HYDR P E	HYDR P E	DTHR P E	DTHR P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	PURC MDU MISO	PURC MDU MISO	DSM MDU MISO	DSM MDU MISO
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE		1/ 1/2014	1/ 1/2014	1/ 1/2012	1/ 1/2013
OPERATING/BOOK LIVES, YEARS	30 25	50 50	50 50	50 30	50 30
RATED CAPACITY, MW	50.000	250.000	250.000	15.200	25.000
- RESERVE	0.9500	0.0000	0.0000	0.8026	1.0280
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	1.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0000	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	10500.	10500.	1.	1.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	65.699997	1095.000000	1095.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	1449.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	1449.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	1	2
LEVEL. CARRYING CHARGE, PCT	11.13	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	44.88	0.00	0.00	50.04	50.04
VARIABLE O+M COST, $/MWH	0.00	25.89	23.23	300.00	300.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	0	0	1	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	51 22 0	0 0 29	0 0 46	0 48 49	0 48 49
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	16	4
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
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BASIC PLANT TYPES - 2

DATA SET REF. NO.	27	80	90	100	110
MAINTENANCE REQUIREMENTS	0	0	0	14	14
FUEL 1 / FUEL 2	0 0	8 0	8 0	4 0	4 0
LOADING BLOCKS / NDT NO.	0 0	7 0	7 0	0 0	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	120	130	132	136	138
NAME	MILES CITY C.T.	GLENDIVE CT #1	GLENDIVE CT #2	DIESEL 2	DIESEL 3
TYPE / LOADING / STATUS /AVD	THRM P E	THRM P E	THRM P E	THRM P E	THRM P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU MONT	GAS MDU MONT	GAS MDU MONT	GAS MDU NDAK	GAS MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/1972	1/ 1/1979	1/ 1/2003	1/ 1/2012	1/ 1/2012
OPERATING/BOOK LIVES, YEARS	99 30	99 30	99 30	99 30	99 30
RATED CAPACITY, MW	20.700	31.300	43.300	2.000	2.000
- RESERVE	0.7826	0.9265	0.5751	0.9048	0.8500
CAPACITY - OPERATING	0.8571	0.8451	0.9238	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.5000	0.5000	0.5000	0.5000	0.5000
FULL LOAD HEAT RATE, BTU/KWH	16266.	13010.	9322.	8687.	8687.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	2
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	9.27	6.70	7.41	19.26	19.26
VARIABLE O+M COST, $/MWH	4.20	4.20	4.20	4.20	4.20
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	0	0	0	0	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 5	0 3 6	0 3 7	0 3 8	0 3 8
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	120	130	132	136	138
MAINTENANCE REQUIREMENTS	2	3	4	23	23
FUEL 1 / FUEL 2	1 0	1 0	1 0	2 0	2 0
LOADING BLOCKS / NDT NO.	12 0	5 0	13 0	0 0	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	152	154	162	170	180
NAME	HESKETT #3	HESKETT #4	LEWIS & CLARK2	BIG STONE	COYOTE
TYPE / LOADING / STATUS /AVD	THRM P E	THRM P E	THRM P E	THRM B E	THRM B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	GAS MDU NDAK	GAS MDU MONT	COAL MDU SDAK	COAL MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2014	1/ 1/2023	1/ 1/2015	1/ 1/1975	1/ 1/1981
OPERATING/BOOK LIVES, YEARS	40 25	40 35	40 25	99 30	99 30
RATED CAPACITY, MW	84.500	88.000	18.500	107.800	106.800
- RESERVE	1.0142	0.9102	0.7784	1.0083	0.9335
CAPACITY - OPERATING	0.9545	0.8864	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.5000	0.5000	0.5000	0.0375	0.1633
FULL LOAD HEAT RATE, BTU/KWH	11482.	11770.	8643.	10197.	11011.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	878.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	878.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	2	2
LEVEL. CARRYING CHARGE, PCT	0.00	8.73	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	40.28	40.28	78.77	27.79	33.83
VARIABLE O+M COST, $/MWH	0.90	0.90	3.59	3.80	5.20
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	0	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 15	30 22 60	0 3 20	0 3 12	0 3 13
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	152	154	162	170	180
MAINTENANCE REQUIREMENTS	17	37	19	8	22
FUEL 1 / FUEL 2	13 0	13 0	11 0	6 0	7 0
LOADING BLOCKS / NDT NO.	2 0	8 0	11 0	17 0	18 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 20	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR				M 1980 2080	M 1980 2080
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	857.00	0.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	857.00	0.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	30 37	0 0	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	190	200	210	220	230
NAME	DIAMOND WILLOW	GLEN ULLIN ORMAT	CEDAR HILLS	THUNDER SPIRIT	WAPA PUR-FT PECK
TYPE / LOADING / STATUS /AVD	NDT B E	THRM B E	NDT B E	NDT B E	HYDR B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	WIND MDU MONT	WH MDU NDAK	WIND MDU NDAK	WIND MDU NDAK	HYDR MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2008	1/ 1/2009	1/ 1/2010	1/ 1/2015	1/ 1/2001
OPERATING/BOOK LIVES, YEARS	28 25	35 20	26 25	27 25	50 30
RATED CAPACITY, MW	30.000	7.500	19.500	150.000	2.800
- RESERVE	0.2000	0.3867	0.2667	0.2447	0.0000
CAPACITY - OPERATING	1.0000	0.6667	1.0000	1.0000	0.8929
MULTIPLIERS - EMERGENCY	0.3810	0.6667	0.3810	0.4186	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.0500	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	1.	0.	0.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	14.350000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	2
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	21.77	122.08	28.77	29.47	0.00
VARIABLE O+M COST, $/MWH	0.00	8.13	0.00	-37.04	24.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 0	0 44 18	0 3 0	0 3 32	0 0 14
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	40	0	0	9	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	190	200	210	220	230
MAINTENANCE REQUIREMENTS	10	15	10	13	0
FUEL 1 / FUEL 2	0 0	5 0	0 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 1	0 0	0 2	0 3	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR		M 1980 2080			M 1980 2080
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	310	320	330	340	370
NAME	PURCHASE POWER	GE 7EA	GE LMS100PB	GE LM6000PH	GE 7EA 2x1 ADD
TYPE / LOADING / STATUS /AVD	THRM P G	THRM P G	THRM P G	THRM P G	THRM I G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MDU MISO	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE					
OPERATING/BOOK LIVES, YEARS	1 1	40 35	40 35	40 35	50 35
RATED CAPACITY, MW	10.000	77.900	99.900	45.000	329.700
- RESERVE	1.0000	0.9694	0.9694	0.9349	0.9820
CAPACITY - OPERATING	1.0000	0.9195	0.9041	0.9272	0.9096
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.5000	0.5000	0.5000	0.0166
FULL LOAD HEAT RATE, BTU/KWH	1.	11800.	8970.	9730.	9990.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	2077.00	2485.00	3252.00	1201.00
INSTALLATION COST 2, $/KW	0.00	2077.00	2485.00	3252.00	1201.00
MULTI-UNIT CAPITAL COST OPT.	2	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	0.00	10.04	10.04	10.04	10.04
FIXED O+M COST, $/KW-YR	12.00	38.86	33.93	62.58	28.31
VARIABLE O+M COST, $/MWH	1000.00	0.90	1.33	0.90	4.60
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	0	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 10 23	30 22 60	30 22 24	30 22 62	59 59 59
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	310	320	330	340	370
MAINTENANCE REQUIREMENTS	0	28	28	28	21
FUEL 1 / FUEL 2	8 0	3 0	3 0	3 0	3 0
LOADING BLOCKS / NDT NO.	0 0	2 0	13 0	13 0	4 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 20	0 0 20	0 0 20	0 0 20
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	857.00	857.00	850.00	750.00
CONSTRUCTION COST 2, $/KW	0.00	857.00	857.00	850.00	750.00
TRAJECTORY / EXPEND. PATTERN	0 0	30 37	30 37	30 37	30 37
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	380	400	410	420	430
NAME	GE 7FA.05 1x1	SMN SGT-800 2x1	WRTSLA 18V50SG	WRTSLA 20V34SG	BIOMASS
TYPE / LOADING / STATUS /AVD	THRM I G	THRM I G	THRM P G	THRM P G	THRM B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK	BMP MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE					
OPERATING/BOOK LIVES, YEARS	50 35	50 35	40 35	40 35	40 25
RATED CAPACITY, MW	200.000	100.000	55.000	36.500	25.000
- RESERVE	0.9820	0.9820	0.9695	0.9348	0.9072
CAPACITY - OPERATING	0.8571	0.8571	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0166	0.0166	0.5000	0.5000	0.0928
FULL LOAD HEAT RATE, BTU/KWH	8030.	9589.	8330.	8470.	12300.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	1618.00	2464.00	3425.00	3789.00	7980.00
INSTALLATION COST 2, $/KW	1618.00	2464.00	3425.00	3789.00	7980.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	10.04	10.04	10.04	10.04	10.04
FIXED O+M COST, $/KW-YR	28.02	49.72	56.76	76.58	252.00
VARIABLE O+M COST, $/MWH	4.00	5.20	5.29	5.11	5.60
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 54	30 22 69	30 22 56	30 22 56	30 22 58
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	380	400	410	420	430
MAINTENANCE REQUIREMENTS	24	25	1	28	28
FUEL 1 / FUEL 2	3 0	3 0	3 0	3 0	10 0
LOADING BLOCKS / NDT NO.	2 0	3 0	1 0	10 0	19 0
EMISSIONS / SITE / TAX DEPR.	0 0 20	0 0 20	0 0 20	0 0 20	0 0 20
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	750.00	750.00	857.00	857.00	857.00
CONSTRUCTION COST 2, $/KW	750.00	750.00	857.00	857.00	857.00
TRAJECTORY / EXPEND. PATTERN	30 37	30 37	30 37	30 37	30 37
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	450	460	490	500	510
NAME	PV SOLAR50	PV SOLAR5	CFBC	CFBC CO2	WIND50
TYPE / LOADING / STATUS /AVD	NDT B G	NDT B G	THRM B G	THRM B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	SOLR MDU NDAK	SOLR MDU NDAK	LIGN MDU NDAK	COAL MDU NDAK	WIND MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE					
OPERATING/BOOK LIVES, YEARS	30 25	30 25	50 50	50 50	25 25
RATED CAPACITY, MW	50.000	5.000	30.000	30.000	50.000
- RESERVE	0.5000	0.5000	0.9143	0.9143	0.1810
CAPACITY - OPERATING	1.0000	1.0000	0.9500	0.9500	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	0.3810
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.0000	0.0936	0.0936	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	10000.	13800.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	2280.00	2467.00	5880.00	10400.00	2660.00
INSTALLATION COST 2, $/KW	2280.00	2467.00	5880.00	10400.00	2660.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	11.13	11.13	9.42	9.42	11.13
FIXED O+M COST, $/KW-YR	34.80	39.60	168.72	267.48	58.80
VARIABLE O+M COST, $/MWH	-37.04	-37.04	14.06	22.29	-37.04
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 17	30 22 17	30 22 61	30 22 25	30 22 17
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

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DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
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RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	450	460	490	500	510
MAINTENANCE REQUIREMENTS	10	10	33	33	10
FUEL 1 / FUEL 2	0 0	0 0	12 0	12 0	0 0
LOADING BLOCKS / NDT NO.	0 6	0 6	0 0	0 0	0 4
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 20	0 0 20	0 0 21
MUST RUN / 1ST YR / LAST YR			M 1980 2080	M 1980 2080	
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	2558.00	2558.00	3900.00	3900.00	2400.00
CONSTRUCTION COST 2, $/KW	2558.00	2558.00	3900.00	3900.00	2400.00
TRAJECTORY / EXPEND. PATTERN	30 38	30 38	30 31	30 31	30 38
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	520		
NAME	WIND100		
TYPE / LOADING / STATUS /AVD	NDT	B	G
LOAD COMPONENT FOR DSM			
CLASS / AREA / GENERATING CO.	WIND	MDU	NDAK
OWNERSHIP PCT. / NO. UNITS	100.0		1
INSTALLATION DATE			
OPERATING/BOOK LIVES, YEARS		25	25
RATED CAPACITY, MW	100.000		
- RESERVE	0.1810		
CAPACITY - OPERATING	1.0000		
MULTIPLIERS - EMERGENCY	0.3810		
- CHARGING	0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0000		
FULL LOAD HEAT RATE, BTU/KWH	0.		
HEAT RATE MULT. - 2ND FUEL	0.0000		
ANNUAL ENERGY LIMIT, GWH	0.000000		
STORAGE EFFICIENCY, PERCENT	0.00		
INSTALLATION COST 1, $/KW	2156.00		
INSTALLATION COST 2, $/KW	2156.00		
MULTI-UNIT CAPITAL COST OPT.	1		
LEVEL. CARRYING CHARGE, PCT	11.13		
FIXED O+M COST, $/KW-YR	56.40		
VARIABLE O+M COST, $/MWH	-37.04		
DEFAULT AFUDC, PCT. OF GBV	0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00		
CAPITAL STRUCTURE	1		
YEARLY TRAJECTORIES			
COSTS-CAPITAL/FIX OM/VAR OM	30	22	17
F.O.R./RESERVE CAP/OPER CAP	0	0	0
ENERGY / HEAT RATE		0	0
RATED CAPACITY		0	
SEGMENT MULT. - CAP / ENERGY		0	0
SUBWEEK ENERGY ALLOCATION		0	

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DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

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                                                   BASIC PLANT TYPES - 2
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DATA SET REF. NO.                        520
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MAINTENANCE REQUIREMENTS                10
FUEL 1 / FUEL 2                    0     0
LOADING BLOCKS / NDT NO.                 0    4
EMISSIONS / SITE / TAX DEPR.       0     0   21

MUST RUN  / 1ST YR / LAST YR
SPIN RSV  / 1ST YR / LAST YR
DISPATCH MODIFIER, $/MWH                 0.00
TJ-DISP MODIF / SM-MUST-RUN              0    0

CONSTRUCTION COST 1, $/KW              2400.00
CONSTRUCTION COST 2, $/KW              2400.00
TRAJECTORY / EXPEND. PATTERN            30   38
PERCENT CWIP IN RATE BASE                0.00

STARTING VALUE OF CWIP, $/KW             0.00
  EQUITY AFUDC, $/KW                     0.00
  DEBT AFUDC, $/KW                       0.00

DSM CUSTOMER COST / OPT / TJ           0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR      0     0    0
  LEV.CARRYING CHARGE, PCT              0.00
  EXPENDITURE PATTERN                    0
REBOUND BENEFITS  / OPT / TJ           0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR      0     0    0
  LEV.CARRYING CHARGE, PCT              0.00
  EXPENDITURE PATTERN                    0
CUSTOMER BENEFITS / OPT / TJ           0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR      0     0    0
  LEV.CARRYING CHARGE, PCT              0.00
  EXPENDITURE PATTERN                    0
TRANS/DISTR COSTS / OPT / TJ           0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR      0     0    0
  LEV.CARRYING CHARGE, PCT              0.00
  EXPENDITURE PATTERN                    0
OTHER COSTS       / OPT / TJ           0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR      0     0    0
  LEV.CARRYING CHARGE, PCT              0.00
  EXPENDITURE PATTERN                    0

PERCENTAGE FOR 2ND FUEL
  MINIMUM / TRAJ / SEG MULT     0.00      0    0
  MAXIMUM / TRAJ / SEG MULT   100.00      0    0
  TARGET  / TRAJ / SEG MULT     0.00      0    0

BID MULTIPLIERS                      1.00
  TRAJECTORY / SEG MULT                   0    0
NDT REVENUES                             0.00
  TRAJECTORY                                   0
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MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	..FIRST PERIOD.. START WEEK	..SECOND PERIOD.. NO. OF WEEKS	..SECOND PERIOD.. START WEEK
1	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
2	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	0	0		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	0	0		
					7	0	0		
					8	2	37		
					9	0	0		
					10	0	0		
3	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	0	0		
					2	2	16		
					3	0	0		
					4	0	0		
					5	0	0		
					6	0	0		
					7	2	16		
					8	0	0		
					9	0	0		
					10	0	0		
4	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	0	0		
					2	0	0		
					3	2	38		
					4	0	0		
					5	2	21		
					6	0	0		
					7	0	0		
					8	2	38		
					9	0	0		
					10	2	21		
5	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
7	6	1	0 - INSTALLATION	1 - START WEEKS	1	23	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	29	23		

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	START WEEK	..SECOND PERIOD.. NO. OF WEEKS	START WEEK
8	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	3	40		
					2	3	41		
					3	8	14		
					4	3	40		
					5	3	40		
					6	3	40		
					7	3	41		
					8	8	14		
					9	3	40		
					10	3	40		
10	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
13	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
14	1	1	0 - INSTALLATION	0 - NO. WEEKS ONLY	1	1			
15	1	1	2 - BASE YEAR=1	0 - NO. WEEKS ONLY	1	1			
17	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	0	0		
					2	2	39		
					3	0	0		
					4	0	0		
					5	0	0		
					6	0	0		
					7	2	39		
					8	0	0		
					9	0	0		
					10	0	0		
19	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	0	0		
					2	2	41		
					3	2	20		
					4	0	0		
					5	0	0		
					6	0	0		
					7	2	41		
					8	2	20		
					9	0	0		
					10	0	0		
21	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	FIRST PERIOD NO. OF WEEKS	FIRST PERIOD START WEEK	SECOND PERIOD NO. OF WEEKS	SECOND PERIOD START WEEK
22	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	22	1	38
					2	7	14	1	39
					3	1	22	1	38
					4	1	23	1	38
					5	7	14	1	38
					6	1	22	1	38
					7	7	14	1	39
					8	1	22	1	38
					9	1	23	1	38
					10	7	14	1	38
23	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
24	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
25	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
28	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
33	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	3			
37	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			

FUEL TYPES

DATA SET REF. NO.	NAME	MASS UNIT	HEAT CONTENT MBTU/MASS UNIT	..MASS UNITS AVAILABLE.. MAXIMUM	MINIMUM	FUEL COST $/MBTU	..TRAJECTORIES.. MAX.	MIN.	COST	..SEGMENT MULT.. MAX.	MIN.	COST
1	GAS	DKT	1.14	-1.00	0.00	5.370000	0	0	33	0	0	0
2	OIL2	GAL	39.17	-1.00	0.00	19.000000	0	0	34	0	0	0
3	GAS	DKT	1.14	-1.00	0.00	5.060000	0	0	11	0	0	0
4	DSM	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
5	WH	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
6	COAL	TON	16.44	-1.00	0.00	2.100000	0	0	38	0	0	0
7	COAL	TON	14.13	-1.00	0.00	2.190000	0	0	39	0	0	0
8	PURC	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
10	BMP	TON	14.90	-1.00	0.00	6.750000	0	0	63	0	0	0
11	GAS	DKT	1.14	-1.00	0.00	5.080000	0	0	47	0	0	0
12	COAL	TON	14.07	-1.00	0.00	2.880000	0	0	43	0	0	0
13	GAS	DKT	1.14	-1.00	0.00	5.060000	0	0	50	0	0	0

CAPACITY PLANNING ALTERNATIVES

DATA SET REF. NO.	NAME	BASIC PLANT INSTALLED	GENERIC SITE	-AVAILABLE- FIRST YEAR	LAST YEAR	TYPE	BASIC PLANT RETIRED	------PREREQUISITE PLANNING ALTERNATIVE------ PLAN. ALT.	DEPENDENCY MULTIPLIER NO.	FLAG	RETIRE. OPTION	LAG YEAR MIN	MAX	REQUIRED OPTION
1	GE 7EA	320	0	2027	2043	0	0	0	0	0	0 - NO	0	-1	0
2	WRTSLA 18V50SG	410	0	2027	2043	0	0	0	0	0	0 - NO	0	-1	0
3	STORAGE1	1	0	2028	2043	0	0	12	1	0	0 - NO	0	-1	0
4	WRTSLA 31DF	4	0	2027	2043	0	0	0	0	0	0 - NO	0	-1	0
5	CFBC	490	0	2030	2043	0	0	0	0	0	0 - NO	0	-1	0
6	GE LM6000PH	340	0	2027	2043	0	0	0	0	0	0 - NO	0	-1	0
7	PURCHASE POWER	310	0	2024	2043	1	0	0	0	0	0 - NO	0	-1	0
8	GE 7EA 2x1 ADD	370	0	2027	2043	0	152	0	0	0	0 - NO	0	-1	0
							154	0	0	0	0 - NO	0	-1	0
9	GE 7FA.05 1x1	380	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0
10	BIOMASS	430	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0
11	CFBC CO2	500	0	2030	2043	0	0	0	0	0	0 - NO	0	-1	0
12	PV SOLAR5	460	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0
13	WIND100	520	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0
14	GE LMS100PB	330	0	2027	2043	0	0	0	0	0	0 - NO	0	-1	0
16	PV SOLAR50	450	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0
19	SMN SGT-800 2x1	400	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0
22	WIND50	510	0	2026	2043	0	0	0	0	0	0 - NO	0	-1	0
23	WRTSLA 20V34SG	420	0	2027	2043	0	0	0	0	0	0 - NO	0	-1	0
40	STORAGE10	24	0	2028	2043	0	0	16	1	0	0 - NO	0	-1	0
43	STORAGE50	27	0	2028	2043	0	0	0	0	0	0 - NO	0	-1	0

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
1	1 - RATE	2023	-2.71	2024	0.60	2025	0.66	2026	0.65	2027	0.63
		2028	0.62	2029	0.66	2030	0.71	2031	0.71	2032	0.70
		2033	0.70	2034	0.69	2035	0.71	2036	0.72	2037	0.72
		2038	0.71	2039	0.69	2040	0.74	2041	0.73	2042	0.75
		2043	0.70								
2	1 - RATE	2023	-0.71	2024	0.37	2025	0.41	2026	0.45	2027	0.39
		2028	0.46	2029	0.41	2030	0.56	2031	0.57	2032	0.57
		2033	0.56	2034	0.57	2035	0.60	2036	0.61	2037	0.59
		2038	0.60	2039	0.60	2040	0.68	2041	0.67	2042	0.68
		2043	0.70								
3	1 - RATE	2023	3.00								
4	1 - RATE	2023	0.00	2024	6.67	2025	6.25	2026	5.88	2027	0.00
		2028	0.00								
5	1 - RATE	2023	3.00								
6	1 - RATE	2023	3.00								
7	1 - RATE	2023	3.00								
8	1 - RATE	2023	3.00								
9	1 - RATE	2023	0.00	2024	0.00	2025	0.00	2026	0.00	2027	0.00
		2028	0.00	2029	0.00	2030	0.00	2031	0.00	2032	0.00
		2033	0.00	2034	0.00	2035	0.00	2036	0.00	2037	0.00
		2038	0.00	2039	0.00	2040	-66.66	2041	0.00	2042	0.00
10	1 - RATE	2023	3.00								
11	1 - RATE	2023	-47.03	2024	18.66	2025	14.78	2026	5.48	2027	7.01
		2028	3.00								
12	1 - RATE	2023	3.00								
13	1 - RATE	2023	3.00								
14	1 - RATE	2023	0.00								
15	1 - RATE	2023	3.00								
16	1 - RATE	2023	0.00	2024	0.00	2025	0.00	2026	0.00	2027	0.00
		2028	0.00								
17	1 - RATE	2023	0.00	2024	0.00	2025	0.00	2026	0.00		

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
18	1 - RATE	2023	1.48	2024	1.45	2025	1.55	2026	1.53	2027	1.51
		2028	1.50								
20	1 - RATE	2023	3.00								
21	1 - RATE	2023	25.00	2024	20.00	2025	0.00				
22	1 - RATE	2024	3.00								
23	1 - RATE	2023	3.00								
24	1 - RATE	2024	3.00								
25	1 - RATE	2024	3.00								
28	1 - RATE	2023	0.00	2024	0.00	2025	0.00				
29	1 - RATE	2023	19.47	2024	3.27	2025	1.60	2026	2.37	2027	3.79
		2028	-3.83	2029	4.58	2030	-0.14	2031	5.31	2032	0.25
		2033	-1.48	2034	-0.22	2035	2.11	2036	2.48	2037	-2.10
		2038	6.52	2039	-2.14	2040	14.59	2041	0.64	2042	0.93
		2043	8.24	2044	-5.32	2045	22.00	2046	-3.58	2047	7.28
		2048	3.86	2049	3.08	2050	3.00				
30	1 - RATE	2024	3.00								
31	1 - RATE	2023	3.00								
32	1 - RATE	2023	0.00	2024	0.00	2025	-66.70	2026	0.00	2027	-100.00
		2028	0.00								
33	1 - RATE	2023	-11.35	2024	1.05	2025	-1.87	2026	-0.42	2027	0.21
		2028	3.00								
34	1 - RATE	2023	13.63	2024	-33.99	2025	1.05	2026	3.96	2027	0.00
		2028	3.00								
38	1 - RATE	2023	7.14	2024	1.78	2025	3.06	2026	2.97	2027	2.88
		2028	3.00								
39	1 - RATE	2023	7.31	2024	0.85	2025	-6.75	2026	-0.90	2027	36.07
		2028	3.00								
40	1 - RATE	2023	0.00	2024	0.00	2025	0.00	2026	0.00	2027	0.00
		2028	0.00	2029	0.00	2030	0.00	2031	0.00	2032	0.00
		2033	-65.00	2034	0.00	2035	0.00	2036	0.00	2037	0.00
42	1 - RATE	2023	4.35	2024	4.17	2025	0.00				

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
43	1 - RATE	2024	3.00								
44	1 - RATE	2023	3.00								
45	1 - RATE	2023	0.00	2024	0.00	2025	0.00				
46	1 - RATE	2023	11.62	2024	1.47	2025	-0.87	2026	1.69	2027	2.94
		2028	-3.63	2029	0.76	2030	7.92	2031	3.98	2032	4.20
		2033	-1.10	2034	0.62	2035	1.94	2036	0.03	2037	1.30
		2038	7.62	2039	3.29	2040	8.61	2041	0.60	2042	4.47
		2043	-0.84	2044	12.57	2045	4.16	2046	1.34	2047	3.04
		2048	9.14	2049	9.85	2050	3.00				
47	1 - RATE	2023	-6.30	2024	1.05	2025	-1.87	2026	-0.42	2027	0.21
		2028	3.00								
48	1 - RATE	2023	3.00								
49	1 - RATE	2023	0.00								
50	1 - RATE	2023	-34.78	2024	8.18	2025	-9.24	2026	9.26	2027	-6.50
		2028	3.00								
51	1 - RATE	2024	3.00	2025	3.00	2026	3.00	2027	3.00	2028	3.00
		2029	3.00	2030	3.00	2031	3.00	2032	3.00	2033	14.03
		2034	12.97	2035	21.18	2036	3.00	2037	3.00	2038	3.00
		2039	3.00	2040	3.00	2041	3.00	2042	3.00	2043	3.00
54	1 - RATE	2024	3.00								
56	1 - RATE	2024	3.00								
58	1 - RATE	2024	3.00								
59	1 - RATE	2024	3.00								
60	1 - RATE	2024	3.00								
61	1 - RATE	2024	3.00								
62	1 - RATE	2024	3.00								
63	1 - RATE	2024	3.00								
69	1 - RATE	2024	3.00								

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
1	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000
2	5	1	0.094675	3.261365	1.000000
		2	0.213018	0.875302	0.000000
		3	0.201183	0.678515	0.000000
		4	0.307692	0.658509	0.000000
		5	0.183432	0.903074	0.000000
3	5	1	0.087394	3.046029	1.000000
		2	0.196663	0.817493	0.000000
		3	0.185726	0.633754	0.000000
		4	0.284111	0.621981	0.000000
		5	0.246106	1.132241	0.000000
4	5	1	0.094633	2.949847	1.000000
		2	0.212947	0.791637	0.000000
		3	0.201122	0.613695	0.000000
		4	0.217192	0.640240	0.000000
		5	0.274106	1.057082	0.000000
5	5	1	0.287540	1.600922	1.000000
		2	0.191693	0.736779	0.000000
		3	0.159744	0.700922	0.000000
		4	0.191693	0.763285	0.000000
		5	0.169329	0.827680	0.000000
6	5	1	0.200000	1.000000	1.000000
		2	0.200000	1.000000	0.000000
		3	0.200000	1.000000	0.000000
		4	0.200000	1.000000	0.000000
		5	0.200000	1.000000	0.000000
7	5	1	0.200000	1.000000	1.000000
		2	0.200000	1.000000	0.000000
		3	0.200000	1.000000	0.000000
		4	0.200000	1.000000	0.000000
		5	0.200000	1.000000	0.000000
8	5	1	0.095337	3.259150	1.000000
		2	0.214508	0.874707	0.000000
		3	0.202591	0.678054	0.000000
		4	0.309845	0.658062	0.000000
		5	0.177720	0.902461	0.000000

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
9	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000
10	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000
11	5	1	0.189189	1.200046	1.000000
		2	0.243243	1.152943	0.000000
		3	0.216216	0.880944	0.000000
		4	0.216216	0.864515	0.000000
		5	0.135135	0.851903	0.000000
12	5	1	0.338164	1.572175	0.801925
		2	0.144927	0.648776	0.085619
		3	0.193237	0.700848	0.111444
		4	0.144927	0.737264	0.130942
		5	0.178744	0.738719	0.231734
13	5	1	0.230947	1.814847	1.000000
		2	0.207852	0.764273	0.000000
		3	0.184757	0.620991	0.000000
		4	0.184757	0.759400	0.000000
		5	0.191686	0.871078	0.000000
17	5	1	0.263168	1.242424	1.000000
		2	0.164225	0.796043	0.000000
		3	0.164225	0.863170	0.000000
		4	0.246291	0.947512	0.000000
		5	0.162092	1.031431	0.000000
18	5	1	0.351288	1.161202	1.000000
		2	0.140515	0.891018	0.000000
		3	0.140515	0.902961	0.000000
		4	0.140515	0.915403	0.000000
		5	0.227166	0.930482	0.000000
19	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

DATA SET REF. NO.	CALENDAR YEAR	COMPOUNDING OPTION	AFUDC RATE
1	2024	1 - COMPOUND	10.50

CONSTRUCTION COST EXPENDITURE PATTERN

DATA SET REF. NO.	NUMBER OF YEARS	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST
31	4	1	13.70	2	35.10	3	34.80	4	16.50		
37	3	1	69.00	2	27.00	3	4.00				
38	1	1	100.00								

RETURN ON RATE BASE

DATA SET REFERENCE NUMBER 1 (DEFAULT)

	-----CAPITAL STRUCTURE-----								
CALENDAR YEAR	COMMON STOCK PERCENT	PREFERRED STOCK PERCENT	DEBT PERCENT	RETURN ALLOWED ON EQUITY PERCENT	COST OF PREFERRED STOCK PERCENT	DEBT INTEREST RATE PERCENT	ANNUAL INCOME TAX RATE PERCENT	PROPERTY TAX RATE PERCENT	CALCULATED RETURN ON RATE BASE PERCENT
2024	50.00	0.00	50.00	9.75	0.00	4.65	24.40	1.26	8.77

TAX DEPRECIATION TABLE

DATA SET REF. NO.	TAX LIFE YEARS	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT
20	21	1	3.75	2	7.22	3	6.68	4	6.18	5	5.71
		6	5.28	7	4.89	8	4.52	9	4.46	10	4.46
		11	4.46	12	4.46	13	4.46	14	4.46	15	4.46
		16	4.46	17	4.46	18	4.46	19	4.46	20	4.46
		21	2.22								
21	20	1	3.75	2	7.22	3	6.68	4	6.18	5	5.71
		6	5.28	7	4.89	8	4.52	9	4.46	10	4.46
		11	4.46	12	4.46	13	4.46	14	4.46	15	4.46
		16	4.46	17	4.46	18	4.46	19	4.46	20	6.69

SUBPERIOD DEFINITION

SEGMENT	WEEKS	HOURS
1	13	2184
2	13	2184
3	13	2184
4	13	2184
	52	8736

SEGMENT	SUBWEEK	HOURS	TIME FRAME	HOURS
ALL	1	60	1	60
	2	60	2	60
	3	48	3	48

SUBWEEK DEFINITION

DAY	HOUR-- 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SUNDAY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
MONDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
TUESDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
WEDNESDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
THURSDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
FRIDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
SATURDAY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Appendix B

EGEAS OUTPUT REPORT FOR THE SUMMER BASE CASE

```
EEEEEEEE    GGGGGG    EEEEEEEE    AAAAAA     SSSSSS
EEEEEEEE   GGGGGGGG   EEEEEEEE   AAAAAAAA   SSSSSSSS
EE         GG    GG   EE         AA    AA   SS
EEEEEEE    GG         EEEEEEE    AAAAAAAA   SSSSSSS
EEEEEEE    GG   GGG   EEEEEEE    AAAAAAAA    SSSSSSS
EE         GG    GG   EE         AA    AA         SS
EEEEEEEE   GGGGGGGG   EEEEEEEE   AA    AA   SSSSSSSS
EEEEEEEE    GGGGGG    EEEEEEEE   AA    AA    SSSSSS
```

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

REPORT PROGRAM

Montana-Dakota Utilities Co.
2024 Model
Base Case Run
-- Data updated for the 2024 Model

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3420 HILLVIEW AVENUE
PALO ALTO, CALIFORNIA 94304

REPORT FILE OPTION 0 - STANDARD

REPORT OPTIONS

CONTROL	1 - GENERATE
MIRROR IMAGE	1 - GENERATE
ERROR	3 - ALL MESSAGES
REPORT SELECTION	1 - GENERATE

INPUT FILES	NAME	VERSION	UPDATE	RUN	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
EGEAS DATA BASE	2024	1	0		4/ 1/24	14:39:59	2024 IRP	1300
EXPANSION PLAN	2024	1	0	1	4/ 1/24	14:40: 2	2024 IRP	1300
SUBPERIOD REPORT	2024	1	0	1	4/ 1/24	14:40: 2	2024 IRP	1300
UNIT REPORT	2024	1	0	1	4/ 1/24	14:40: 2	2024 IRP	1300
UNIT CAPITAL COST REPORT	2024	1	0	1	4/ 1/24	14:40: 2	2024 IRP	1300

```
 -------------------------------------------------------------------------------------------------------------------------
 EGEAS   REPORT                                              MIRROR IMAGE REPORT                                   PAGE      2
 **************************************************************************************************************************

 HEADER RECORD        PROGRAM   VERSION   DATE & TIME MODIFIED                                                          NUM
                      REPORT    13        03/15/24  13:14:37                                                              1


 RECORD DESCRIPTION   TYP  REF  SQ                          DATA FIELDS                                                NUM
 -------------------- --- ----- -- -------------------------------------------------------------------------------- ----
                                 1          2         3         4         5         6         7         8         9
           COLUMNS    123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
                      *            Montana-Dakota Utilities Co.                                                          2
                      *            2024 Model                                                                            3
                      *            Base Case Run                                                                         4
                      *              -- Data updated for the 2024 Model                                                  5
                      *                                                                                                  6
                      *            CONTROL RECORD                                                                        7
                      *             SbUnUcc                                                                              8
                      *                                                                                                  9
                      *                       C M E S   F                                                               10
                      *                       T I R E   I                                                               11
                      *                       L R R L   L        DESCRIPTIVE INFORMATION                                12
                      *                       + - + -   +        --------------------------------                       13
 CONTROL RECORD       CC                      1 1 3 1   0        2024 IRP                                               14
                      *                                                                                                 15
                      *            --INPUT FILES---                                                                     16
                      *            NAME     V U RUN                                                                     17
                      *            --------++--++++                                                                     18
 FILE IDENTIFICATION  FF           2024     1 0   1                                                                     19
                      *                                                                                                 20
                      *            == PLAN SELECTION ==                                                                 21
                      *               PLANS C O   C E M                                                                 22
                      *            DR  1  L P M   S N O                    --AREAS TO INCLUDE--                         23
                      *             -+++--- + -   + - +                    --++--++--++--++--++                         24
 PLAN SELECTION       RA            1  1  1 0 1   3 2 0                                                                 25
                      *                                                                                                 26
                      *            == TIME PERIODS ==                                                                   27
                      *            --YEARS-- -SG- -SW-                                                                  28
                      *             1ST LAST  1 L 1 L                                                                   29
                      *            ---- ++++ --++ - +                                                                   30
 TIME PERIOD          RB           2024 2043  113 1 3                                                                   31
                      *                                                                                                 32
                      *            == REPORT SELECTION ==                                                               33
                      *                 -PROD-  MNT -STORAGE--   -FL -EM-    -ECON INT- -COST -EM RED  CAP              34
                      *             S S S  UOBRRSU DOSPD  -PJ-     SU SSU GCF TSTU  CUT  UCTCA RR    I   TU N         35
                      *             Y U YAFNRLEEYN EPWRS C 1 L    YN YIN E+M RYIN  OFF  NOOOS AU    N   ON D         36

                                 1          2         3         4         5         6         7         8         9
           COLUMNS    123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
```

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 -------------------------------------------------------------------------------------------------------------------------
 EGEAS   REPORT                                              MIRROR IMAGE REPORT                                  PAGE      3
 *************************************************************************************************************************

 RECORD DESCRIPTION   TYP  REF  SQ                          DATA FIELDS                                              NUM
 -------------------- --- ----- -- -------------------------------------------------------------------------------- ----
                                 1          2         3         4         5         6         7         8         9
           COLUMNS    123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

                      *                S M SRLTDKLSST TRKDP E 1 L    ST STT NRT NSET  PCT. TNTVT TN    C   TI U          37
                      *                - + -+-+-+-+-+ +-+-+ -++--    +- +-+ -+- +-+-++++++ -+-+- +-    +   -+ -          38
 REPORT SELECTION     RC               1 2 0111101100 00000 0        10 000 001 00000.0000 00000 00    0   00 0          39
                      *                                                                                                  40

                                 1          2         3         4         5         6         7         8         9
           COLUMNS    123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
```

```
*****************************************************
*****************************************************
**                                                 **
**                                                 **
**               DIAGNOSTIC SUMMARY                **
**                                                 **
**                                                 **
**          TERMINAL ERRORS            0           **
**          FATAL ERRORS               0           **
**          WARNING MESSAGES           0           **
**          DEFAULTS                   0           **
**                                                 **
**                                                 **
**      HIGHEST ERROR LEVEL FOUND IS NONE          **
**                                                 **
**                                                 **
**      REPORT PROGRAM INPUT SUCCEEDED             **
**                                                 **
**                                                 **
*****************************************************
*****************************************************
```

```
RA      EXPANSION PLAN DIRECTORY      =  1 - YES

        FIRST EXPANSION PLAN          =  1                  CAPACITY OPTION  =  0 - RATED
        LAST  EXPANSION PLAN          =  1                  FIXED O+M OPTION =  1 - SEPARATE ITEM IN PRODUCTION COST

        COST SCALING OPTION           =  3 - 0.001 M$
        ENERGY SCALING OPTION         =  2 - 0.010 GWH
        MONTHLY OUTPUT OPTION         =  0 - NO

RB      FIRST YEAR = 2024         FIRST SEGMENT =  1        FIRST SUBWEEK =  1
        LAST  YEAR = 2043         LAST  SEGMENT = 13        LAST  SUBWEEK =  3

RC      SYSTEM/DISPATCH OPTION        =  1 - SYSTEM A,  INDEPENDENT DISPATCH

        EXPANSION PLAN SUMMARY        =  2 - YES, WITH RESERVE CAPACITY

        PRODUCTION COST REPORTS
           SYSTEM                     =  0 - NO             UNIT ORDER OPTION    =  1 - CAPACITY FACTOR
           SERVICE AREAS              =  1 - ANNUAL         LOADING BLOCK OPTION =  0 - UNIT
           FUEL CLASSES               =  1 - ANNUAL
           UNITS                      =  1 - ANNUAL
           DETAILED COSTS BY UNITS    =  0 - NO
           NDT UTILIZTION             =  0 - NO

        RELIABILITY REPORTS
           RELIABILITY                =  1 - ANNUAL
           RESERVE                    =  1 - ANNUAL

        FUEL USAGE REPORTS
           SYSTEM                     =  1 - ANNUAL
           UNITS                      =  0 - NO
```

PLAN 1

NEW UNITS ADDED

YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2024	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2025	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2026	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2027	0	0	0	0	0	0.	0.	0.	0.	0.	0.	0	0	0.	0.
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	1+	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0+	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0+	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0+	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0+	0	0	0	0	0	0	0	0	0	0	0	0
2041	0	0	0+	0	0	0	0	0	0	0	0	0	0	0	0
2042	2+	0	0+	0	0	0	0	0	0	0	0	0	0	0	0
2043	2+	0	0+	0	0	0	0	0	0	0	0	0	0	0	0

PLAN 1

NEW UNITS ADDED

YEAR	16
2024	0.
2025	0.
2026	0.
2027	0
2028	0
2029	0
2030	0
2031	0
2032	0
2033	0
2034	0
2035	0
2036	0
2037	0
2038	0
2039	0
2040	0
2041	0
2042	0
2043	0

TOTAL COST, M$
--W/O EXT 1425.822
--WITH EXT 2644.407

UNIT TYPES

1 PA	7 PURCHASE POWER	10.000 MW	2 PA	8 GE 7EA 2x1 ADD	329.700 MW	3 PA	1 GE 7EA	77.900 MW
4 PA	6 GE LM6000PH	45.000 MW	5 PA	14 GE LMS100PB	99.900 MW	6 PA	9 GE 7FA.05 1x1	200.000 MW
7 PA	16 PV SOLAR50	50.000 MW	8 PA	12 PV SOLAR5	5.000 MW	9 PA	3 STORAGE1	1.000 MW
10 PA	40 STORAGE10	10.000 MW	11 PA	22 WIND50	50.000 MW	12 PA	2 WRTSLA 18V50SG	55.000 MW
13 PA	23 WRTSLA 20V34SG	36.500 MW	14 PA	43 STORAGE50	50.000 MW	15 PA	13 WIND100	100.000 MW
16 PA	4 WRTSLA 31DF	44.400 MW						

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2023.
W/O EXT = COST FOR STUDY PERIOD ONLY.
WITH EXT = TOTAL COST FOR STUDY AND EXTENSION PERIODS.
\+ MEANS CUMULATIVE NUMBER OF UNITS IS AT AN UPPER BOUND.
. MEANS LOWER AND UPPER BOUNDS ARE EQUAL.

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	1	2	3	4	5	6	7	8	9	10
2024	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2025	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2026	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2027	0.00	0.00	0.00	0.00	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	1.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	2.00 +	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	2.00 +	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	8.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

NOTE: + MEANS CUMULATIVE NUMBER OF UNITS IS AT AN UPPER BOUND
. MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1 PA	7 PURCHASE POWER	10.000 MW	2 PA	8 GE 7EA 2x1 ADD	329.700 MW	3 PA	1 GE 7EA	77.900 MW
4 PA	6 GE LM6000PH	45.000 MW	5 PA	14 GE LMS100PB	99.900 MW	6 PA	9 GE 7FA.05 1x1	200.000 MW
7 PA	16 PV SOLAR50	50.000 MW	8 PA	12 PV SOLAR5	5.000 MW	9 PA	3 STORAGE1	1.000 MW
10 PA	40 STORAGE10	10.000 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14	15	16
2024	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2025	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2026	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2027	0.00 .	0.00	0.00	0.00 .	0.00 .	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	0.00	0.00	0.00	0.00	0.00	0.00

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

11 PA	22 WIND50	50.000 MW	12 PA	2 WRTSLA 18V50SG	55.000 MW	13 PA	23 WRTSLA 20V34SG	36.500 MW
14 PA	43 STORAGE50	50.000 MW	15 PA	13 WIND100	100.000 MW	16 PA	4 WRTSLA 31DF	44.400 MW

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2033	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	77.900	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2041	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2042	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2043	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	80.000	0.000	77.900	0.000	0.000	0.000	0.000	0.000	0.000	0.000

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1 PA	7	PURCHASE POWER	10.000 MW
2 PA	8	GE 7EA 2x1 ADD	329.700 MW
3 PA	1	GE 7EA	77.900 MW
4 PA	6	GE LM6000PH	45.000 MW
5 PA	14	GE LMS100PB	99.900 MW
6 PA	9	GE 7FA.05 1x1	200.000 MW
7 PA	16	PV SOLAR50	50.000 MW
8 PA	12	PV SOLAR5	5.000 MW
9 PA	3	STORAGE1	1.000 MW
10 PA	40	STORAGE10	10.000 MW

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14	15	16
2024	0.000	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000	0.000
2031	0.000	0.000	0.000	0.000	0.000	0.000
2032	0.000	0.000	0.000	0.000	0.000	0.000
2033	0.000	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000
2041	0.000	0.000	0.000	0.000	0.000	0.000
2042	0.000	0.000	0.000	0.000	0.000	0.000
2043	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000

UNIT TYPES

11 PA	22 WIND50	50.000 MW	
12 PA	2 WRTSLA 18V50SG	55.000 MW	
13 PA	23 WRTSLA 20V34SG	36.500 MW	
14 PA	43 STORAGE50	50.000 MW	
15 PA	13 WIND100	100.000 MW	
16 PA	4 WRTSLA 31DF	44.400 MW	

PLAN 1

YEAR	PEAK LOAD,MW	ENERGY GWH	RATED CAPACITY, MW INSTALLED	RETIRED	CHANGED	TOTAL	RESERVE CAPACITY	RESERVE PERCENT	RELATIVE RELIABILITY	CAPITAL COSTS, M$ NEW UNITS	CHANGES
BENCH	498.5	3274.20				1359.9	580.9	17.89	1.0000		
2024	485.0	3251.00	0.0	0.0	0.0	1359.9	580.9	21.45	1.0000	0.000	0.000
2025	487.9	3262.90	0.0	0.0	1.7	1361.6	582.6	21.13	1.0000	0.000	0.000
2026	491.1	3276.40	0.0	0.0	1.7	1363.2	584.3	20.73	1.0000	0.000	0.000
2027	494.3	3291.30	0.0	105.0	1.7	1259.9	556.0	13.68	1.0000	0.000	0.000
2028	497.4	3304.30	0.0	0.0	0.0	1259.9	556.0	12.91	1.0000	0.000	0.000
2029	500.5	3319.40	0.0	0.0	0.0	1259.9	556.0	12.14	1.0000	0.000	0.000
2030	503.8	3333.00	0.0	0.0	0.0	1259.9	556.0	11.34	1.0000	0.000	0.000
2031	507.4	3351.60	0.0	0.0	0.0	1259.9	556.0	10.48	1.0000	0.000	0.000
2032	511.0	3370.70	0.0	0.0	0.0	1259.9	556.0	9.63	1.0000	0.000	0.000
2033	514.6	3389.80	10.0	0.0	0.0	1269.9	566.0	10.91	1.0000	0.000	0.000
2034	518.2	3408.90	10.0	10.0	-19.5	1250.4	562.1	9.25	1.0000	0.000	0.000
2035	521.8	3428.20	20.0	10.0	0.0	1260.4	572.1	10.52	1.0000	0.000	0.000
2036	525.5	3448.90	77.9	50.0	0.0	1288.3	620.4	19.66	1.0000	230.686	0.000
2037	529.3	3469.80	0.0	0.0	0.0	1288.3	620.4	18.73	1.0000	0.000	0.000
2038	533.1	3490.20	0.0	0.0	0.0	1288.3	620.4	17.81	1.0000	0.000	0.000
2039	536.9	3511.20	0.0	0.0	0.0	1288.3	620.4	16.90	1.0000	0.000	0.000
2040	540.6	3532.20	0.0	0.0	0.0	1288.3	620.4	16.03	1.0000	0.000	0.000
2041	544.6	3556.10	0.0	0.0	-100.0	1188.3	595.9	10.23	1.0000	0.000	0.000
2042	548.6	3580.10	20.0	50.0	0.0	1158.3	603.7	10.89	1.0000	0.000	0.000
2043	552.7	3604.30	20.0	20.0	0.0	1158.3	603.7	10.00	1.0000	0.000	0.000

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	COST SUMMARY ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2024	70.446	6.744	77.190	77.190	72.390	72.390
2025	72.927	6.744	79.671	156.861	70.072	142.462
2026	89.903	6.744	96.647	253.509	79.717	222.179
2027	92.320	6.744	99.064	352.573	76.630	298.809
2028	106.459	6.744	113.204	465.776	82.123	380.932
2029	107.716	6.744	114.461	580.237	77.872	458.804
2030	110.539	6.744	117.284	697.521	74.831	533.635
2031	116.063	6.744	122.808	820.329	73.484	607.118
2032	120.632	6.744	127.377	947.705	71.479	678.597
2033	124.598	6.744	131.342	1079.047	69.121	747.718
2034	128.897	6.744	135.641	1214.689	66.945	814.663
2035	131.509	6.744	138.254	1352.942	63.992	878.654
2036	142.279	29.905	172.184	1525.126	74.741	953.396
2037	146.230	29.905	176.135	1701.261	71.702	1025.098
2038	148.306	29.905	178.211	1879.473	68.037	1093.135
2039	157.186	29.905	187.091	2066.564	66.986	1160.121
2040	160.113	29.905	190.018	2256.582	63.804	1223.924
2041	187.179	29.905	217.084	2473.666	68.359	1292.284
2042	200.195	29.905	230.100	2703.767	67.953	1360.237
2043	206.903	29.905	236.808	2940.574	65.585	1425.822
EXT.	1108.882	109.703			1218.585	2644.407

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS. PRESENT WORTH COSTS ARE SHOWN FOR THE EXTENSION PERIOD.
- PRESENT WORTH COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2023.
- CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES. SEE RESERVE REPORT FOR DETAILS.

PLAN 1

	......TOTAL SYSTEM.....		..SERVICE AREA - MDU ..	
YEAR	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$
2024	3251.00	70.446	3251.00	70.446
2025	3262.90	72.927	3262.90	72.927
2026	3276.40	89.903	3276.40	89.903
2027	3291.30	92.320	3291.30	92.320
2028	3304.30	106.459	3304.30	106.459
2029	3319.40	107.716	3319.40	107.716
2030	3333.00	110.539	3333.00	110.539
2031	3351.60	116.063	3351.60	116.063
2032	3370.70	120.632	3370.70	120.632
2033	3389.80	124.598	3389.80	124.598
2034	3408.90	128.897	3408.90	128.897
2035	3428.20	131.509	3428.20	131.509
2036	3448.90	142.279	3448.90	142.279
2037	3469.80	146.230	3469.80	146.230
2038	3490.20	148.306	3490.20	148.306
2039	3511.20	157.185	3511.20	157.185
2040	3532.20	160.111	3532.20	160.111
2041	3555.86	187.125	3555.86	187.125
2042	3579.90	200.148	3579.90	200.148
2043	3604.03	206.839	3604.03	206.839
EXT.	3604.03	1108.559	3604.03	1108.559

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2023.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1

YEAR	......TOTAL SYSTEM..... ENERGY, GWH	COST, M$	..FUEL CLASS - STRG.. ENERGY, GWH	COST, M$	..FUEL CLASS - PURC.. ENERGY, GWH	COST, M$	..FUEL CLASS - GAS .. ENERGY, GWH	COST, M$
2024	3251.00	70.446	0.00	0.000	1492.55	38.358	0.00	9.375
2025	3262.90	72.927	0.00	0.000	1533.31	40.578	0.00	9.656
2026	3276.40	89.903	0.00	0.000	1469.40	39.629	0.04	9.948
2027	3291.30	92.320	0.00	0.000	1227.08	33.427	0.08	10.249
2028	3304.30	106.459	0.00	0.000	1474.17	42.967	0.09	10.557
2029	3319.40	107.716	0.00	0.000	1469.69	41.234	0.10	10.874
2030	3333.00	110.539	0.00	0.000	1506.88	43.312	0.12	11.201
2031	3351.60	116.063	0.00	0.000	1581.16	48.163	0.12	11.538
2032	3370.70	120.632	0.00	0.000	1506.00	47.565	0.15	11.886
2033	3389.80	124.598	0.00	0.000	1550.04	50.742	0.18	12.244
2034	3408.90	128.897	0.00	0.000	1714.71	56.061	0.19	12.612
2035	3428.20	131.509	0.00	0.000	1761.40	58.074	0.22	12.993
2036	3448.90	142.279	0.00	0.000	1906.25	64.210	0.26	17.702
2037	3469.80	146.230	0.00	0.000	1854.66	63.019	0.30	18.235
2038	3490.20	148.306	0.00	0.000	2107.20	72.167	0.75	18.816
2039	3511.20	157.185	0.00	0.000	2090.12	76.587	0.83	19.386
2040	3532.20	160.111	0.00	0.000	2130.39	78.535	1.74	20.037
2041	3555.86	187.125	0.00	0.000	2190.00	90.294	25.60	22.469
2042	3579.90	200.148	0.00	0.000	2190.23	91.672	38.69	24.121
2043	3604.03	206.839	0.00	0.000	2190.29	94.152	46.28	25.434
EXT.	3604.03	1108.559	0.00	0.000	2190.29	538.091	46.28	129.162

YEAR	..FUEL CLASS - DSM .. ENERGY, GWH	COST, M$	..FUEL CLASS - COAL.. ENERGY, GWH	COST, M$	..FUEL CLASS - WIND.. ENERGY, GWH	COST, M$	..FUEL CLASS - WH .. ENERGY, GWH	COST, M$
2024	0.00	2.072	966.71	34.944	736.70	-15.926	40.70	1.279
2025	0.00	2.223	937.85	34.565	736.70	-15.752	40.70	1.312
2026	0.00	2.381	1015.21	37.333	736.70	-1.079	40.70	1.346
2027	0.00	2.546	1272.39	45.265	736.70	-0.894	40.70	1.382
2028	0.00	2.623	1038.29	42.018	736.70	6.532	40.70	1.418
2029	0.00	2.702	1057.86	44.379	736.70	6.728	40.70	1.455
2030	0.00	2.783	1034.26	44.475	736.70	6.930	40.70	1.493
2031	0.00	2.866	978.57	44.481	736.70	7.138	40.70	1.533
2032	0.00	2.953	1072.80	48.960	736.70	7.352	40.70	1.573
2033	0.01	3.041	1047.84	49.039	736.70	7.572	40.70	1.615
2034	0.01	3.133	961.91	47.877	677.04	7.212	40.70	1.657
2035	0.01	3.227	934.49	47.741	677.04	7.428	40.70	1.701
2036	0.00	3.323	900.69	48.461	586.65	6.492	40.70	1.746
2037	0.01	3.423	973.14	52.729	586.65	6.686	40.70	1.793
2038	0.02	3.530	740.54	44.722	586.65	6.887	40.70	1.840
2039	0.02	3.635	778.53	48.250	586.65	7.094	40.70	1.889
2040	0.05	3.755	758.30	48.195	586.65	7.306	40.70	1.940
2041	0.94	4.131	1088.68	65.386	195.59	2.509	40.70	1.991
2042	1.47	4.406	1294.46	77.560	0.00	0.000	40.70	2.045
2043	1.82	4.632	1310.59	80.177	0.00	0.000	40.70	2.099
EXT.	1.82	22.699	1310.59	407.095	0.00	0.000	40.70	10.284

PLAN 1

	..FUEL CLASS - HYDR..		..FUEL CLASS - SOLR..	
YEAR	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$
2024	14.35	0.344	0.00	0.000
2025	14.35	0.344	0.00	0.000
2026	14.35	0.344	0.00	0.000
2027	14.35	0.344	0.00	0.000
2028	14.35	0.344	0.00	0.000
2029	14.35	0.344	0.00	0.000
2030	14.35	0.344	0.00	0.000
2031	14.35	0.344	0.00	0.000
2032	14.35	0.344	0.00	0.000
2033	14.35	0.344	0.00	0.000
2034	14.35	0.344	0.00	0.000
2035	14.35	0.344	0.00	0.000
2036	14.35	0.344	0.00	0.000
2037	14.35	0.344	0.00	0.000
2038	14.35	0.344	0.00	0.000
2039	14.35	0.344	0.00	0.000
2040	14.35	0.344	0.00	0.000
2041	14.35	0.344	0.00	0.000
2042	14.35	0.344	0.00	0.000
2043	14.35	0.344	0.00	0.000
EXT.	14.35	1.229	0.00	0.000

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2023.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1 YEAR 2024 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	673.	673.	7.33
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	578.	578.	9.92
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-21730.	4553.	-17176.	-29.28
ENERGY			75.000	10500.	0.000	98.90	647.98	0.	15552.	0.	15552.	24.00
BIG STONE		MUST	107.800	10145.	2.250	74.53	701.84	16021.	2747.	3086.	21853.	31.14
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	336.	943.	1279.	31.42
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	38.61	843.25	0.	21865.	0.	21865.	25.93
COYOTE		MUST	106.800	12773.	2.350	28.39	264.87	7951.	1419.	3721.	13091.	49.42
MISO - On peak		HYDR	250.000	10500.	0.000	0.06	1.32	0.	41.	0.	41.	30.93
GLENDIVE CT #1			31.300	0.	0.000	0.00	0.00	0.	0.	216.	216.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	330.	330.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	40.	40.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	40.	40.	0.00
HESKETT #3			84.500	0.	0.000	0.00	0.00	0.	0.	3506.	3506.	0.00
HESKETT #4			88.000	0.	0.000	0.00	0.00	0.	0.	3545.	3545.	0.00
LEWIS & CLARK2			18.500	0.	0.000	0.00	0.00	0.	0.	1501.	1501.	0.00
CAPACITY			30.000	0.	0.000	0.00	0.00	0.	0.	900.	900.	0.00
INTERRUPTIBLES		D	15.200	0.	0.000	0.00	0.00	0.	0.	783.	783.	0.00
COMMERCIAL DSM		D	25.000	0.	0.000	0.00	0.00	0.	0.	1289.	1289.	0.00
MILES CITY C.T.			20.700	0.	0.000	0.00	0.00	0.	0.	198.	198.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2025 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	693.	693.	7.55
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	595.	595.	10.22
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-21730.	4690.	-17040.	-29.05
ENERGY			75.000	10500.	0.000	99.20	649.97	0.	16249.	0.	16249.	25.00
BIG STONE		MUST	107.800	10143.	2.290	74.81	704.55	16365.	2840.	3178.	22384.	31.77
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	341.	971.	1312.	32.24
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	40.38	881.81	0.	23200.	0.	23200.	26.31
COYOTE		MUST	106.800	12771.	2.370	25.01	233.30	7061.	1287.	3833.	12181.	52.21
MISO - On peak		HYDR	250.000	10500.	0.000	0.07	1.53	0.	49.	0.	49.	31.94
GLENDIVE CT #1			31.300	0.	0.000	0.00	0.00	0.	0.	222.	222.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	340.	340.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	41.	41.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	41.	41.	0.00
HESKETT #3			84.500	0.	0.000	0.00	0.00	0.	0.	3611.	3611.	0.00
HESKETT #4			88.000	0.	0.000	0.00	0.00	0.	0.	3651.	3651.	0.00
LEWIS & CLARK2			18.500	0.	0.000	0.00	0.00	0.	0.	1546.	1546.	0.00
CAPACITY			30.000	0.	0.000	0.00	0.00	0.	0.	1080.	1080.	0.00
INTERRUPTIBLES		D	15.200	0.	0.000	0.00	0.00	0.	0.	807.	807.	0.00
COMMERCIAL DSM		D	26.667	0.	0.000	0.00	0.00	0.	0.	1416.	1416.	0.00
MILES CITY C.T.			20.700	0.	0.000	0.00	0.00	0.	0.	204.	204.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2026 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	714.	714.	7.77
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	613.	613.	10.52
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-7236.	4830.	-2406.	-4.10
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	346.	1001.	1346.	33.08
BIG STONE		MUST	107.800	10216.	2.360	62.08	584.64	14096.	2428.	3274.	19797.	33.86
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	28557.	0.	28557.	26.08
COYOTE		MUST	106.800	11709.	2.210	46.15	430.57	11142.	2447.	3948.	17536.	40.73
ENERGY			75.000	10500.	0.000	44.20	289.62	0.	7241.	0.	7241.	25.00
MISO - On peak		HYDR	250.000	10500.	0.000	3.88	84.78	0.	2751.	0.	2751.	32.45
HESKETT #3			84.500	18553.	3.240	0.00	0.02	1.	0.	3719.	3720.	189471.88
LEWIS & CLARK2			18.500	8900.	4.720	0.00	0.00	0.	0.	1592.	1593.	513417.38
HESKETT #4			88.000	18088.	3.240	0.00	0.01	1.	0.	3761.	3761.	388491.69
GLENDIVE CT #2			43.300	11128.	4.721	0.00	0.00	0.	0.	351.	351.	122633.09
GLENDIVE CT #1			31.300	14522.	4.721	0.00	0.00	0.	0.	229.	229.	143715.80
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	0.	831.	831.	*********
DIESEL 2			2.000	8687.	14.401	0.00	0.00	0.	0.	42.	42.	585102.06
DIESEL 3			2.000	8687.	14.401	0.00	0.00	0.	0.	42.	42.	598814.56
MILES CITY C.T.			20.700	18471.	4.721	0.00	0.00	0.	0.	210.	210.	306876.03
COMMERCIAL DSM		D	28.333	1.	0.000	0.00	0.00	0.	0.	1549.	1549.	*********
CAPACITY			30.000	0.	0.000	0.00	0.00	0.	0.	1080.	1080.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2027 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	735.	735.	8.01
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	631.	631.	10.84
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-7236.	4975.	-2261.	-3.85
BIG STONE		MUST	107.800	10192.	2.430	74.71	703.58	17425.	3009.	3372.	23806.	33.84
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	351.	1031.	1382.	33.95
COYOTE		MUST	106.800	11290.	2.190	60.97	568.81	14064.	3329.	4067.	21459.	37.73
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	29039.	0.	29039.	26.52
MISO - On peak		HYDR	250.000	10500.	0.000	6.05	132.08	0.	4388.	0.	4388.	33.22
HESKETT #3			84.500	18176.	3.540	0.01	0.04	3.	0.	3831.	3834.	88968.80
LEWIS & CLARK2			18.500	8830.	4.700	0.00	0.01	0.	0.	1640.	1640.	278432.22
HESKETT #4			88.000	17472.	3.540	0.00	0.02	1.	0.	3873.	3875.	200707.48
GLENDIVE CT #2			43.300	11176.	4.701	0.00	0.01	0.	0.	361.	361.	56989.73
INTERRUPTIBLES	D		15.200	1.	0.000	0.00	0.00	0.	0.	856.	856.	600158.50
GLENDIVE CT #1			31.300	14639.	4.701	0.00	0.00	0.	0.	236.	236.	86689.02
DIESEL 2			2.000	8687.	14.972	0.00	0.00	0.	0.	43.	43.	295419.31
DIESEL 3			2.000	8687.	14.972	0.00	0.00	0.	0.	43.	43.	311087.50
MILES CITY C.T.			20.700	18478.	4.701	0.00	0.00	0.	0.	216.	216.	156822.53
COMMERCIAL DSM	D		30.000	1.	0.000	0.00	0.00	0.	0.	1690.	1690.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2028 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	757.	757.	8.25
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	650.	650.	11.16
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5125.	5125.	8.74
BIG STONE		MUST	107.800	10202.	2.500	85.60	806.12	20561.	3551.	3473.	27585.	34.22
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	357.	1061.	1418.	34.84
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	29893.	0.	29893.	27.30
COYOTE		MUST	106.800	12784.	2.980	24.88	232.17	8845.	1400.	4189.	14433.	62.17
MISO - On peak		HYDR	250.000	10500.	0.000	17.36	379.17	0.	13074.	0.	13074.	34.48
HESKETT #3			84.500	17989.	3.310	0.01	0.05	3.	0.	3946.	3949.	81257.55
LEWIS & CLARK2			18.500	8849.	4.710	0.00	0.01	0.	0.	1689.	1690.	246514.95
HESKETT #4			88.000	17271.	3.310	0.00	0.02	1.	0.	3990.	3991.	183604.66
GLENDIVE CT #2			43.300	11141.	4.711	0.00	0.01	0.	0.	372.	372.	51111.87
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	882.	882.	527328.06
GLENDIVE CT #1			31.300	14700.	4.711	0.00	0.00	0.	0.	243.	243.	74595.62
DIESEL 2			2.000	8687.	14.972	0.00	0.00	0.	0.	45.	45.	268251.50
DIESEL 3			2.000	8687.	14.972	0.00	0.00	0.	0.	45.	45.	285181.97
MILES CITY C.T.			20.700	18454.	4.711	0.00	0.00	0.	0.	222.	223.	143220.34
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	0.	1740.	1740.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2029 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	780.	780.	8.50
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	670.	670.	11.50
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5278.	5278.	9.00
BIG STONE		MUST	107.800	10219.	2.575	84.32	794.04	20894.	3603.	3577.	28074.	35.36
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	362.	1093.	1455.	35.75
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	28809.	0.	28809.	26.31
COYOTE		MUST	106.800	12784.	3.069	28.28	263.82	10353.	1638.	4314.	16305.	61.80
MISO - On peak		HYDR	250.000	10500.	0.000	17.16	374.69	0.	12424.	0.	12424.	33.16
HESKETT #3			84.500	17807.	3.409	0.01	0.05	3.	0.	4064.	4068.	74535.91
LEWIS & CLARK2			18.500	8851.	4.851	0.00	0.01	0.	0.	1740.	1740.	231801.11
HESKETT #4			88.000	16993.	3.409	0.00	0.03	1.	0.	4109.	4111.	164088.97
GLENDIVE CT #2			43.300	11077.	4.852	0.00	0.01	0.	0.	383.	384.	47521.41
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	908.	909.	476401.59
GLENDIVE CT #1			31.300	14515.	4.852	0.00	0.00	0.	0.	250.	251.	67144.26
DIESEL 2			2.000	8687.	15.421	0.00	0.00	0.	0.	46.	46.	247388.62
DIESEL 3			2.000	8687.	15.421	0.00	0.00	0.	0.	46.	46.	256395.91
MILES CITY C.T.			20.700	18435.	4.852	0.00	0.00	0.	0.	229.	229.	130575.54
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	0.	1793.	1793.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2030 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	803.	803.	8.75
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	690.	690.	11.84
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5437.	5437.	9.27
BIG STONE		MUST	107.800	10215.	2.652	85.17	802.06	21729.	3748.	3684.	29162.	36.36
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	367.	1126.	1493.	36.69
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	29028.	0.	29028.	26.51
COYOTE		MUST	106.800	12784.	3.162	24.89	232.20	9385.	1485.	4444.	15313.	65.95
MISO - On peak		HYDR	250.000	10500.	0.000	18.86	411.88	0.	14284.	0.	14284.	34.68
HESKETT #3			84.500	17784.	3.512	0.01	0.06	4.	0.	4186.	4190.	70230.46
LEWIS & CLARK2			18.500	8873.	4.997	0.01	0.01	0.	0.	1792.	1793.	207808.06
HESKETT #4			88.000	17030.	3.512	0.00	0.03	2.	0.	4232.	4234.	143019.52
GLENDIVE CT #2			43.300	11027.	4.997	0.00	0.01	1.	0.	395.	395.	39697.91
INTERRUPTIBLES	D		15.200	1.	0.000	0.00	0.00	0.	1.	935.	936.	395467.16
GLENDIVE CT #1			31.300	14434.	4.997	0.00	0.00	0.	0.	258.	258.	55384.96
DIESEL 2			2.000	8687.	15.883	0.00	0.00	0.	0.	47.	47.	207344.25
MILES CITY C.T.			20.700	18779.	4.997	0.00	0.00	0.	0.	236.	236.	103977.05
DIESEL 3			2.000	8687.	15.883	0.00	0.00	0.	0.	47.	47.	216020.38
COMMERCIAL DSM	D		30.000	1.	0.000	0.00	0.00	0.	0.	1846.	1847.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2031 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	827.	827.	9.01
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	711.	711.	12.20
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5600.	5600.	9.55
BIG STONE		MUST	107.800	10216.	2.732	75.89	714.69	19946.	3440.	3795.	27181.	38.03
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	373.	1160.	1533.	37.66
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	31328.	0.	31328.	28.61
COYOTE		MUST	106.800	12784.	3.256	28.28	263.88	10985.	1738.	4577.	17300.	65.56
MISO - On peak		HYDR	250.000	10500.	0.000	22.26	486.16	0.	16836.	0.	16836.	34.63
HESKETT #3			84.500	18844.	3.617	0.01	0.06	4.	0.	4312.	4316.	68305.81
LEWIS & CLARK2			18.500	8829.	5.147	0.01	0.01	0.	0.	1846.	1846.	198664.22
HESKETT #4			88.000	16420.	3.617	0.00	0.03	2.	0.	4359.	4361.	158992.67
GLENDIVE CT #2			43.300	11221.	5.147	0.00	0.01	1.	0.	406.	407.	42249.81
GLENDIVE CT #1			31.300	14596.	5.147	0.00	0.00	0.	0.	266.	266.	54207.53
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	964.	964.	487090.09
MILES CITY C.T.			20.700	18730.	5.147	0.00	0.00	0.	0.	243.	243.	104853.77
DIESEL 2			2.000	8687.	16.360	0.00	0.00	0.	0.	49.	49.	250837.89
DIESEL 3			2.000	8687.	16.360	0.00	0.00	0.	0.	49.	49.	256665.52
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	0.	1902.	1902.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2032 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	852.	852.	9.28
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	732.	732.	12.56
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5768.	5768.	9.83
BIG STONE		MUST	107.800	10202.	2.814	85.90	808.93	23221.	4011.	3909.	31141.	38.50
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	378.	1195.	1573.	38.65
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	32576.	0.	32576.	29.75
COYOTE		MUST	106.800	12784.	3.354	28.28	263.87	11314.	1790.	4714.	17819.	67.53
MISO - On peak		HYDR	250.000	10500.	0.000	18.82	411.00	0.	14989.	0.	14989.	36.47
HESKETT #3			84.500	17287.	3.726	0.01	0.08	5.	0.	4441.	4446.	55723.63
LEWIS & CLARK2			18.500	8873.	5.301	0.01	0.01	1.	0.	1901.	1902.	171698.97
HESKETT #4			88.000	17259.	3.726	0.00	0.04	2.	0.	4490.	4493.	117618.27
GLENDIVE CT #2			43.300	10961.	5.302	0.00	0.01	1.	0.	419.	419.	34692.95
INTERRUPTIBLES	D		15.200	1.	0.000	0.00	0.00	0.	1.	992.	993.	341624.84
GLENDIVE CT #1			31.300	14370.	5.302	0.00	0.01	0.	0.	274.	274.	48608.19
DIESEL 2			2.000	8687.	16.851	0.00	0.00	0.	0.	50.	50.	156098.92
MILES CITY C.T.			20.700	18419.	5.302	0.00	0.00	0.	0.	250.	251.	84438.75
DIESEL 3			2.000	8687.	16.851	0.00	0.00	0.	0.	50.	50.	188985.52
COMMERCIAL DSM	D		30.000	1.	0.000	0.00	0.00	0.	1.	1959.	1959.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2033 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	878.	878.	9.56
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	754.	754.	12.94
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5941.	5941.	10.13
BIG STONE		MUST	107.800	10201.	2.898	86.60	815.58	24112.	4165.	4026.	32303.	39.61
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	384.	1230.	1615.	39.67
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	33945.	0.	33945.	31.00
COYOTE		MUST	106.800	12783.	3.455	24.89	232.25	10257.	1623.	4856.	16736.	72.06
MISO - On peak		HYDR	250.000	10500.	0.000	20.83	455.04	0.	16636.	0.	16636.	36.56
HESKETT #3			84.500	17343.	3.837	0.01	0.09	6.	0.	4574.	4581.	48929.45
LEWIS & CLARK2			18.500	8865.	5.460	0.01	0.01	1.	0.	1958.	1959.	151930.45
HESKETT #4			88.000	17116.	3.837	0.01	0.04	3.	0.	4625.	4628.	107608.06
GLENDIVE CT #2			43.300	10939.	5.461	0.00	0.01	1.	0.	431.	432.	29917.45
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	1022.	1023.	279777.81
GLENDIVE CT #1			31.300	14364.	5.461	0.00	0.01	1.	0.	282.	282.	40960.97
DIESEL 2			2.000	8687.	17.356	0.00	0.00	0.	0.	52.	52.	136046.19
DIESEL 3			2.000	8687.	17.356	0.00	0.00	0.	0.	52.	52.	143252.34
MILES CITY C.T.			20.700	18420.	5.461	0.00	0.00	0.	0.	258.	258.	70983.16
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	1.	2017.	2018.	974553.88
PURCHASE POWER	2033		10.000	1.	0.000	0.00	0.00	0.	0.	161.	161.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2034 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	10.500	0.	0.000	35.02	32.13	0.	0.	316.	316.	9.85
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	777.	777.	13.33
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	6119.	6119.	10.43
BIG STONE		MUST	107.800	10152.	2.985	74.12	698.01	21153.	3672.	4147.	28972.	41.51
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	390.	1267.	1657.	40.72
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	33573.	0.	33573.	30.66
MISO - On peak		HYDR	250.000	10500.	0.000	28.38	619.71	0.	22322.	0.	22322.	36.02
COYOTE		MUST	106.800	12784.	3.558	28.29	263.90	12004.	1900.	5001.	18905.	71.64
HESKETT #3			84.500	17186.	3.953	0.01	0.10	7.	0.	4711.	4718.	48020.96
LEWIS & CLARK2			18.500	8884.	5.624	0.01	0.01	1.	0.	2017.	2018.	143073.69
HESKETT #4			88.000	17368.	3.953	0.01	0.05	3.	0.	4764.	4767.	98446.38
GLENDIVE CT #2			43.300	10929.	5.625	0.00	0.02	1.	0.	444.	445.	28997.79
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	1053.	1054.	260872.80
GLENDIVE CT #1			31.300	14348.	5.625	0.00	0.01	1.	0.	290.	291.	39911.14
DIESEL 2			2.000	8687.	17.877	0.00	0.00	0.	0.	53.	53.	131948.75
DIESEL 3			2.000	8687.	17.877	0.00	0.00	0.	0.	53.	53.	138138.36
MILES CITY C.T.			20.700	18382.	5.625	0.00	0.00	0.	0.	266.	266.	68899.09
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	1.	2078.	2079.	857339.94
PURCHASE POWER	2034		10.000	1.	0.000	0.00	0.00	0.	0.	166.	166.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2035 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	10.500	0.	0.000	35.02	32.13	0.	0.	326.	326.	10.14
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	800.	800.	13.73
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	6303.	6303.	10.74
BIG STONE		MUST	107.800	10148.	3.075	74.56	702.20	21909.	3804.	4271.	29985.	42.70
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	396.	1305.	1701.	41.80
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	33781.	0.	33781.	30.85
MISO - On peak		HYDR	250.000	10500.	0.000	30.51	666.40	0.	23950.	0.	23950.	35.94
COYOTE		MUST	106.800	12783.	3.665	24.90	232.29	10883.	1722.	5151.	17756.	76.44
HESKETT #3			84.500	17189.	4.071	0.01	0.11	8.	0.	4853.	4861.	44167.92
LEWIS & CLARK2			18.500	8869.	5.793	0.01	0.02	1.	0.	2078.	2079.	124971.95
HESKETT #4			88.000	16938.	4.071	0.01	0.06	4.	0.	4907.	4911.	85690.27
GLENDIVE CT #2			43.300	10900.	5.793	0.01	0.02	1.	0.	457.	459.	23423.37
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.01	0.	2.	1084.	1086.	198896.50
GLENDIVE CT #1			31.300	14313.	5.793	0.00	0.01	1.	0.	299.	300.	32308.05
DIESEL 2			2.000	8687.	18.413	0.00	0.00	0.	0.	55.	55.	105903.59
DIESEL 3			2.000	8687.	18.413	0.00	0.00	0.	0.	55.	55.	110917.64
MILES CITY C.T.			20.700	18365.	5.793	0.00	0.00	1.	0.	274.	274.	55202.23
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	1.	2140.	2141.	654677.94
PURCHASE POWER	2035		10.000	1.	0.000	0.00	0.00	0.	0.	171.	171.	854164.56
PURCHASE POWER	2035		10.000	1.	0.000	0.00	0.00	0.	0.	171.	171.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2036 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	6492.	6492.	11.07
BIG STONE		MUST	107.800	10141.	3.167	67.61	636.71	20448.	3553.	4399.	28401.	44.61
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	402.	1345.	1746.	42.90
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	34438.	0.	34438.	31.45
MISO - On peak		HYDR	250.000	10500.	0.000	37.15	811.25	0.	29773.	0.	29773.	36.70
COYOTE		MUST	106.800	12783.	3.775	28.29	263.98	12739.	2016.	5306.	20060.	75.99
HESKETT #3			84.500	17972.	4.193	0.02	0.13	10.	0.	4998.	5008.	38442.85
LEWIS & CLARK2			18.500	8877.	5.967	0.01	0.02	1.	0.	2140.	2141.	105465.65
HESKETT #4			88.000	17031.	4.193	0.01	0.06	5.	0.	5054.	5059.	78101.05
GLENDIVE CT #2			43.300	10985.	5.967	0.01	0.02	1.	0.	471.	473.	21775.58
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	1117.	1118.	343372.62
GE 7EA	2036		77.900	17864.	5.220	0.00	0.01	1.	0.	4316.	4317.	300283.06
GLENDIVE CT #1			31.300	14380.	5.967	0.00	0.01	0.	0.	308.	308.	53941.14
DIESEL 2			2.000	8687.	18.966	0.00	0.00	0.	0.	57.	57.	181144.47
DIESEL 3			2.000	8687.	18.966	0.00	0.00	0.	0.	57.	57.	186069.44
MILES CITY C.T.			20.700	18469.	5.967	0.00	0.00	0.	0.	282.	282.	93018.29
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	0.	2205.	2205.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2037 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	6686.	6686.	11.40
BIG STONE		MUST	107.800	10141.	3.262	75.30	709.14	23459.	4076.	4531.	32066.	45.22
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	408.	1385.	1793.	44.04
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	34449.	0.	34449.	31.46
MISO - On peak		HYDR	250.000	10500.	0.000	34.78	759.66	0.	28571.	0.	28571.	37.61
COYOTE		MUST	106.800	12783.	3.888	28.30	264.00	13121.	2076.	5465.	20663.	78.27
HESKETT #3			84.500	16892.	4.319	0.02	0.15	11.	0.	5148.	5159.	34495.16
LEWIS & CLARK2			18.500	8892.	6.146	0.01	0.02	1.	0.	2204.	2206.	101481.75
HESKETT #4			88.000	17213.	4.319	0.01	0.07	6.	0.	5205.	5211.	69520.39
GLENDIVE CT #2			43.300	10847.	6.146	0.01	0.02	2.	0.	485.	487.	20295.53
INTERRUPTIBLES		D	15.200	1.	0.000	0.00	0.00	0.	1.	1150.	1152.	329984.44
GE 7EA	2036		77.900	17271.	5.376	0.00	0.02	1.	0.	4446.	4447.	286272.22
GLENDIVE CT #1			31.300	14307.	6.146	0.00	0.01	1.	0.	317.	318.	54270.50
DIESEL 2			2.000	8687.	19.534	0.00	0.00	0.	0.	58.	58.	174822.14
DIESEL 3			2.000	8687.	19.534	0.00	0.00	0.	0.	58.	58.	185001.58
MILES CITY C.T.			20.700	18348.	6.146	0.00	0.00	0.	0.	290.	291.	93301.87
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.00	0.	1.	2271.	2271.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2038 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	6887.	6887.	11.74
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	414.	1426.	1840.	45.21
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
BIG STONE		MUST	107.800	10330.	3.360	53.92	507.83	17626.	3006.	4667.	25299.	49.82
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	34898.	0.	34898.	31.87
MISO - On peak		HYDR	250.000	10500.	0.000	46.35	1012.19	0.	37269.	0.	37269.	36.82
COYOTE		MUST	106.800	12778.	4.005	24.94	232.71	11909.	1885.	5629.	19423.	83.46
HESKETT #3			84.500	16199.	4.449	0.05	0.38	27.	1.	5303.	5331.	14093.18
LEWIS & CLARK2			18.500	8864.	6.330	0.03	0.06	3.	0.	2270.	2274.	40831.51
HESKETT #4			88.000	16380.	4.449	0.02	0.18	13.	0.	5362.	5375.	30108.29
GLENDIVE CT #2			43.300	10665.	6.331	0.02	0.07	4.	0.	500.	505.	7751.12
INTERRUPTIBLES		D	15.200	1.	0.000	0.01	0.01	0.	3.	1185.	1188.	107632.10
GLENDIVE CT #1			31.300	14157.	6.331	0.01	0.02	2.	0.	327.	328.	18728.05
GE 7EA	2036		77.900	16422.	5.537	0.01	0.04	4.	0.	4579.	4583.	108835.01
DIESEL 3			2.000	8687.	20.121	0.01	0.00	0.	0.	60.	60.	61174.12
DIESEL 2			2.000	8687.	20.121	0.01	0.00	0.	0.	60.	60.	61587.51
MILES CITY C.T.			20.700	18229.	6.331	0.01	0.01	1.	0.	299.	300.	31609.69
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.01	0.	3.	2339.	2341.	269409.62

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2039 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	7094.	7094.	12.09
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	420.	1469.	1889.	46.42
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
BIG STONE		MUST	107.800	10323.	3.461	54.59	514.12	18366.	3135.	4807.	26308.	51.17
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	37559.	0.	37559.	34.30
MISO - On peak		HYDR	250.000	10500.	0.000	45.56	995.12	0.	39029.	0.	39029.	39.22
COYOTE		MUST	106.800	12778.	4.125	28.34	264.42	13937.	2206.	5798.	21942.	82.98
HESKETT #3			84.500	16026.	4.582	0.06	0.42	31.	1.	5462.	5493.	13188.20
LEWIS & CLARK2			18.500	8863.	6.520	0.04	0.06	3.	0.	2338.	2342.	41088.93
HESKETT #4			88.000	16436.	4.582	0.03	0.21	16.	0.	5522.	5539.	26233.74
GLENDIVE CT #2			43.300	10642.	6.520	0.02	0.07	5.	0.	515.	520.	7719.76
INTERRUPTIBLES		D	15.200	1.	0.000	0.01	0.01	0.	3.	1221.	1224.	113089.81
GE 7EA	2036		77.900	16481.	5.704	0.01	0.05	4.	0.	4716.	4721.	99951.60
GLENDIVE CT #1			31.300	14142.	6.520	0.01	0.02	2.	0.	337.	338.	19886.76
DIESEL 2			2.000	8687.	20.724	0.01	0.00	0.	0.	62.	62.	62284.02
DIESEL 3			2.000	8687.	20.724	0.01	0.00	0.	0.	62.	62.	66194.67
MILES CITY C.T.			20.700	18202.	6.520	0.01	0.01	1.	0.	308.	309.	33587.34
COMMERCIAL DSM		D	30.000	1.	0.000	0.00	0.01	0.	3.	2409.	2412.	283116.50

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2040 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	7306.	7306.	12.45
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	426.	1513.	1940.	47.66
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
BIG STONE		MUST	107.800	10316.	3.564	55.68	524.40	19283.	3294.	4952.	27528.	52.49
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	38796.	0.	38796.	35.43
MISO - On peak		HYDR	250.000	10500.	0.000	47.41	1035.40	0.	39739.	0.	39739.	38.38
COYOTE		MUST	106.800	12763.	4.249	25.07	233.90	12684.	2010.	5972.	20666.	88.36
HESKETT #3			84.500	15523.	4.719	0.11	0.83	61.	1.	5626.	5688.	6878.47
LEWIS & CLARK2			18.500	8840.	6.715	0.08	0.12	7.	1.	2409.	2417.	19447.08
HESKETT #4			88.000	15793.	4.719	0.06	0.45	33.	1.	5688.	5722.	12762.59
GLENDIVE CT #2			43.300	10492.	6.716	0.04	0.16	11.	1.	530.	542.	3448.46
INTERRUPTIBLES		D	15.200	1.	0.000	0.02	0.03	0.	9.	1257.	1266.	44668.71
GE 7EA	2036		77.900	15798.	5.875	0.02	0.11	11.	0.	4858.	4868.	42770.32
GLENDIVE CT #1			31.300	14014.	6.716	0.02	0.04	4.	0.	347.	351.	8198.74
DIESEL 3			2.000	8687.	21.346	0.01	0.00	0.	0.	64.	64.	26071.75
DIESEL 2			2.000	8687.	21.346	0.01	0.00	0.	0.	64.	64.	26748.11
MILES CITY C.T.			20.700	18092.	6.716	0.01	0.02	3.	0.	317.	320.	13565.54
COMMERCIAL DSM		D	30.000	1.	0.000	0.01	0.03	0.	8.	2481.	2489.	95963.07

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2041 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	50.010	0.	0.000	44.77	195.59	0.	0.	2509.	2509.	12.83
BIG STONE		MUST	107.800	10176.	3.671	76.34	718.89	26856.	4651.	5100.	36607.	50.92
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	433.	1559.	1991.	48.93
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	42136.	0.	42136.	38.48
MISO - On peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	48158.	0.	48158.	43.98
COYOTE		MUST	106.800	11960.	4.376	39.64	369.80	19355.	3274.	6151.	28779.	77.82
HESKETT #3			84.500	14768.	4.861	1.74	12.82	921.	20.	5794.	6735.	525.14
LEWIS & CLARK2			18.500	8802.	6.917	0.94	1.53	93.	9.	2481.	2583.	1692.87
HESKETT #4			88.000	15096.	4.861	0.82	6.28	461.	9.	5859.	6329.	1008.07
GLENDIVE CT #2			43.300	10265.	6.918	0.56	2.12	150.	15.	546.	712.	336.11
INTERRUPTIBLES		D	15.200	1.	0.000	0.35	0.47	0.	140.	1295.	1434.	3082.67
GE 7EA	2036		77.900	15053.	6.051	0.26	1.79	163.	3.	5003.	5169.	2888.20
GLENDIVE CT #1			31.300	13845.	6.918	0.23	0.64	62.	5.	357.	423.	658.54
DIESEL 2			2.000	8687.	21.986	0.22	0.04	7.	0.	66.	73.	1922.89
DIESEL 3			2.000	8687.	21.986	0.21	0.04	7.	0.	66.	73.	1958.12
MILES CITY C.T.			20.700	17928.	6.918	0.19	0.35	43.	2.	327.	372.	1071.30
COMMERCIAL DSM		D	30.000	1.	0.000	0.18	0.47	0.	141.	2556.	2697.	5726.47

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2042 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
BIG STONE		MUST	107.800	10186.	3.781	87.79	826.73	31845.	5509.	5253.	42607.	51.54
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	439.	1606.	2045.	50.24
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	42387.	0.	42387.	38.71
MISO - On peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	48465.	0.	48465.	44.26
COYOTE		MUST	106.800	11550.	4.508	50.13	467.74	24352.	4265.	6335.	34953.	74.73
HESKETT #3			84.500	14309.	5.007	2.57	18.96	1358.	30.	5968.	7356.	388.09
LEWIS & CLARK2			18.500	8795.	7.124	1.46	2.37	148.	15.	2555.	2718.	1149.27
HESKETT #4			88.000	14814.	5.007	1.25	9.64	715.	15.	6035.	6764.	701.69
GLENDIVE CT #2			43.300	10206.	7.125	0.87	3.29	239.	24.	563.	826.	251.13
INTERRUPTIBLES		D	15.200	1.	0.000	0.54	0.71	0.	214.	1334.	1548.	2170.10
GE 7EA	2036		77.900	14813.	6.232	0.41	2.81	260.	4.	5154.	5417.	1927.24
GLENDIVE CT #1			31.300	13788.	7.125	0.35	0.96	95.	7.	368.	470.	486.87
DIESEL 2			2.000	8687.	22.646	0.33	0.06	11.	0.	68.	79.	1361.05
DIESEL 3			2.000	8687.	22.646	0.33	0.06	11.	0.	68.	79.	1388.12
MILES CITY C.T.			20.700	17881.	7.125	0.30	0.55	70.	4.	336.	410.	749.83
COMMERCIAL DSM		D	30.000	1.	0.000	0.29	0.75	0.	226.	2632.	2858.	3795.21
PURCHASE POWER	2042		10.000	1.	0.000	0.15	0.13	0.	232.	210.	443.	3343.25
PURCHASE POWER	2042		10.000	1.	0.000	0.11	0.10	0.	167.	210.	377.	3964.12

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1 YEAR 2043 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
BIG STONE		MUST	107.800	10196.	3.895	90.50	852.29	33848.	5849.	5411.	45108.	52.93
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	62.12	40.70	0.	446.	1654.	2099.	51.58
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
MISO - Off peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	44282.	0.	44282.	40.44
MISO - On peak		HYDR	250.000	10500.	0.000	50.14	1095.00	0.	48914.	0.	48914.	44.67
COYOTE		MUST	106.800	11392.	4.643	49.12	458.30	24239.	4304.	6526.	35069.	76.52
HESKETT #3			84.500	14188.	5.157	3.15	23.23	1700.	38.	6147.	7885.	339.42
LEWIS & CLARK2			18.500	8795.	7.338	1.75	2.83	183.	18.	2632.	2833.	1000.28
HESKETT #4			88.000	14773.	5.157	1.43	11.01	839.	17.	6216.	7072.	642.06
GLENDIVE CT #2			43.300	10192.	7.339	1.02	3.88	290.	29.	579.	899.	231.93
INTERRUPTIBLES		D	15.200	1.	0.000	0.66	0.88	0.	264.	1374.	1638.	1862.43
GE 7EA	2036		77.900	14764.	6.419	0.49	3.31	314.	5.	5308.	5627.	1700.31
GLENDIVE CT #1			31.300	13782.	7.339	0.44	1.20	121.	9.	379.	509.	425.33
DIESEL 2			2.000	8687.	23.325	0.41	0.07	14.	1.	70.	85.	1188.87
DIESEL 3			2.000	8687.	23.325	0.39	0.07	14.	1.	70.	84.	1230.39
MILES CITY C.T.			20.700	17881.	7.339	0.38	0.68	89.	5.	347.	441.	649.39
COMMERCIAL DSM		D	30.000	1.	0.000	0.36	0.95	0.	284.	2711.	2995.	3168.48
PURCHASE POWER	2043		10.000	1.	0.000	0.19	0.17	0.	304.	217.	521.	3094.09
PURCHASE POWER	2043		10.000	1.	0.000	0.14	0.12	0.	219.	217.	436.	3589.96

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2023.

PLAN 1

YEAR	PEAK LOAD MW	ENERGY GWH	RESERVE CAPACITY MW	RESERVE MARGIN PCT.	EMERGENCY CAPACITY MW	---LOSS OF LOAD--- HOURS	PROB.	OPERATING CAPACITY MW	--UNSERVED ENERGY-- GWH	PCT.
2024	485.0	3251.00	580.9	21.45	1357.4	0.00	0.000000	1332.2	0.00	0.00
2025	487.9	3262.90	582.6	21.13	1359.1	0.00	0.000000	1333.8	0.00	0.00
2026	491.1	3276.40	584.3	20.73	1360.7	0.00	0.000000	1335.5	0.00	0.00
2027	494.3	3291.30	556.0	13.68	1257.4	0.00	0.000000	1232.2	0.00	0.00
2028	497.4	3304.30	556.0	12.91	1257.4	0.00	0.000000	1232.2	0.00	0.00
2029	500.5	3319.40	556.0	12.14	1257.4	0.00	0.000000	1232.2	0.00	0.00
2030	503.8	3333.00	556.0	11.34	1257.4	0.00	0.000000	1232.2	0.00	0.00
2031	507.4	3351.60	556.0	10.48	1257.4	0.00	0.000000	1232.2	0.00	0.00
2032	511.0	3370.70	556.0	9.63	1257.4	0.00	0.000000	1232.2	0.00	0.00
2033	514.6	3389.80	566.0	10.91	1267.4	0.00	0.000000	1242.2	0.00	0.00
2034	518.2	3408.90	562.1	9.25	1247.9	0.00	0.000000	1222.7	0.00	0.00
2035	521.8	3428.20	572.1	10.52	1257.9	0.00	0.000000	1232.7	0.00	0.00
2036	525.5	3448.90	620.4	19.66	1285.8	0.00	0.000000	1254.3	0.00	0.00
2037	529.3	3469.80	620.4	18.73	1285.8	0.00	0.000000	1254.3	0.00	0.00
2038	533.1	3490.20	620.4	17.81	1285.8	0.00	0.000000	1254.3	0.00	0.00
2039	536.9	3511.20	620.4	16.90	1285.8	0.00	0.000000	1254.3	0.00	0.00
2040	540.6	3532.20	620.4	16.03	1285.8	0.00	0.000000	1254.3	0.01	0.00
2041	544.6	3556.10	595.9	10.23	1185.8	0.00	0.000000	1154.3	0.24	0.01
2042	548.6	3580.10	603.7	10.89	1155.8	0.00	0.000000	1124.3	0.21	0.01
2043	552.7	3604.30	603.7	10.00	1155.8	0.00	0.000000	1124.3	0.27	0.01
EXT.	552.7	3604.30	603.7	10.00	1155.8	0.00	0.000000	1124.3	0.27	0.01

NOTE - RESERVE MARGIN: ANNUAL CALCULATION, CAPACITIES NOT DERATED FOR MAINTENANCE. SEE RESERVE REPORT FOR DETAIL.
- LOSS OF LOAD: ANNUAL CALCULATION, CAPACITIES DERATED FOR MAINTENANCE.
- RESERVE, EMERGENCY AND OPERATING CAPACITIES SHOWN ABOVE ARE NOT DERATED FOR MAINTENANCE.
- CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES.

PLAN 1

YEAR	LOADS: PEAK LOAD MW	LOADS: PURCH./SALE CONTRACTS	LOADS: DEMAND-SIDE MANAGEMENT	LOADS: NET LOADS MW	RESOURCES: CAPACITY MW	RESOURCES: RESERVE SHARING	RESOURCES: PURCH./SALE CONTRACTS	RESOURCES: NET RESOURCES MW	RESERVE MARGIN PCT.
2024	485.0	0.0	-37.9	447.1	543.0	0.0	0.0	543.0	21.45
2025	487.9	0.0	-39.6	448.3	543.0	0.0	0.0	543.0	21.13
2026	491.1	0.0	-41.3	449.8	543.0	0.0	0.0	543.0	20.73
2027	494.3	0.0	-43.0	451.3	513.0	0.0	0.0	513.0	13.68
2028	497.4	0.0	-43.0	454.4	513.0	0.0	0.0	513.0	12.91
2029	500.5	0.0	-43.0	457.5	513.0	0.0	0.0	513.0	12.14
2030	503.8	0.0	-43.0	460.8	513.0	0.0	0.0	513.0	11.34
2031	507.4	0.0	-43.0	464.4	513.0	0.0	0.0	513.0	10.48
2032	511.0	0.0	-43.0	468.0	513.0	0.0	0.0	513.0	9.63
2033	514.6	0.0	-43.0	471.6	523.0	0.0	0.0	523.0	10.91
2034	518.2	0.0	-43.0	475.2	519.1	0.0	0.0	519.1	9.25
2035	521.8	0.0	-43.0	478.8	529.1	0.0	0.0	529.1	10.52
2036	525.5	0.0	-43.0	482.5	577.3	0.0	0.0	577.3	19.66
2037	529.3	0.0	-43.0	486.3	577.3	0.0	0.0	577.3	18.73
2038	533.1	0.0	-43.0	490.1	577.3	0.0	0.0	577.3	17.81
2039	536.9	0.0	-43.0	493.9	577.3	0.0	0.0	577.3	16.90
2040	540.6	0.0	-43.0	497.6	577.3	0.0	0.0	577.3	16.03
2041	544.6	0.0	-43.0	501.6	552.9	0.0	0.0	552.9	10.23
2042	548.6	0.0	-43.0	505.6	560.6	0.0	0.0	560.6	10.89
2043	552.7	0.0	-43.0	509.7	560.6	0.0	0.0	560.6	10.00
EXT.	552.7	0.0	-43.0	509.7	560.6	0.0	0.0	560.6	10.00

PLAN 1 YEAR 2024

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	701.84	10145.	TON	16.44	4.33106E+05				2.25	16021.	22.83
COAL	264.87	12773.	TON	14.13	2.39436E+05				2.35	7951.	30.02
PURC	1492.55	10500.	NONE	0.01	1.56718E+09				0.00	0.	0.00

PLAN 1 YEAR 2025

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	704.55	10143.	TON	16.44	4.34702E+05				2.29	16365.	23.23
COAL	233.30	12771.	TON	14.13	2.10856E+05				2.37	7061.	30.27
PURC	1533.31	10500.	NONE	0.01	1.60998E+09				0.00	0.	0.00

PLAN 1 YEAR 2026

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.01	13158.	DKT	1.14	5.93155E+01				4.72	0.	62.11
OIL2	0.00	8687.	GAL	39.17	3.15505E-02				14.40	0.	125.11
DSM	0.00	1.	NONE	0.01	1.19816E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	584.64	10216.	TON	16.44	3.63309E+05				2.36	14096.	24.11
COAL	430.57	11709.	TON	14.13	3.56787E+05				2.21	11142.	25.88
PURC	1469.40	10500.	NONE	0.01	1.54287E+09				0.00	0.	0.00
GAS	0.00	8900.	DKT	1.14	2.42165E+01				4.72	0.	42.01
GAS	0.03	18399.	DKT	1.14	4.73172E+02				3.24	2.	59.62

PLAN 1 YEAR 2027

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.01	13043.	DKT	1.14	1.19514E+02				4.70	1.	61.31
OIL2	0.00	8687.	GAL	39.17	6.34832E-02				14.97	0.	130.06
DSM	0.00	1.	NONE	0.01	1.92171E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	703.58	10192.	TON	16.44	4.36179E+05				2.43	17425.	24.77
COAL	568.81	11290.	TON	14.13	4.54479E+05				2.19	14064.	24.72
PURC	1227.08	10500.	NONE	0.01	1.28844E+09				0.00	0.	0.00
GAS	0.01	8830.	DKT	1.14	4.56322E+01				4.70	0.	41.50
GAS	0.06	17958.	DKT	1.14	9.82897E+02				3.54	4.	63.58

PLAN 1 YEAR 2028

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.01	13039.	DKT	1.14	1.38423E+02				4.71	1.	61.42
OIL2	0.00	8687.	GAL	39.17	7.16807E-02				14.97	0.	130.06
DSM	0.00	1.	NONE	0.01	2.28327E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	806.12	10202.	TON	16.44	5.00266E+05				2.50	20561.	25.51
COAL	232.17	12784.	TON	14.13	2.10063E+05				2.98	8845.	38.10
PURC	1474.17	10500.	NONE	0.01	1.54788E+09				0.00	0.	0.00
GAS	0.01	8849.	DKT	1.14	5.32062E+01				4.71	0.	41.68
GAS	0.07	17767.	DKT	1.14	1.09614E+03				3.31	4.	58.81

PLAN 1 YEAR 2029

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.01	12977.	DKT	1.14	1.54369E+02				4.85	1.	62.96
OIL2	0.00	8687.	GAL	39.17	8.10624E-02				15.42	0.	133.96
DSM	0.00	1.	NONE	0.01	2.71016E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	794.04	10219.	TON	16.44	4.93571E+05				2.57	20894.	26.31
COAL	263.82	12784.	TON	14.13	2.38701E+05				3.07	10353.	39.24
PURC	1469.69	10500.	NONE	0.01	1.54317E+09				0.00	0.	0.00
GAS	0.01	8851.	DKT	1.14	5.82952E+01				4.85	0.	42.94
GAS	0.08	17551.	DKT	1.14	1.22584E+03				3.41	5.	59.84

PLAN 1 YEAR 2030

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.02	13010.	DKT	1.14	1.92765E+02				5.00	1.	65.02
OIL2	0.00	8687.	GAL	39.17	9.93768E-02				15.88	0.	137.98
DSM	0.00	1.	NONE	0.01	3.51733E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	802.06	10215.	TON	16.44	4.98344E+05				2.65	21729.	27.09
COAL	232.20	12784.	TON	14.13	2.10081E+05				3.16	9385.	40.42
PURC	1506.88	10500.	NONE	0.01	1.58222E+09				0.00	0.	0.00
GAS	0.01	8873.	DKT	1.14	6.71428E+01				5.00	0.	44.34
GAS	0.09	17534.	DKT	1.14	1.37295E+03				3.51	5.	61.57

PLAN 1 YEAR 2031

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.02	13236.	DKT	1.14	1.95794E+02				5.15	1.	68.13
OIL2	0.00	8687.	GAL	39.17	8.53554E-02				16.36	0.	142.12
DSM	0.00	1.	NONE	0.01	3.04440E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	714.69	10216.	TON	16.44	4.44117E+05				2.73	19946.	27.91
COAL	263.88	12784.	TON	14.13	2.38744E+05				3.26	10985.	41.63
PURC	1581.16	10500.	NONE	0.01	1.66022E+09				0.00	0.	0.00
GAS	0.01	8829.	DKT	1.14	7.19839E+01				5.15	0.	45.44
GAS	0.09	18110.	DKT	1.14	1.43957E+03				3.62	6.	65.51

PLAN 1 YEAR 2032

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.02	12960.	DKT	1.14	2.35279E+02				5.30	1.	68.71
OIL2	0.00	8687.	GAL	39.17	1.30504E-01				16.85	0.	146.38
DSM	0.00	1.	NONE	0.01	4.58084E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	808.93	10202.	TON	16.44	5.01993E+05				2.81	23221.	28.71
COAL	263.87	12784.	TON	14.13	2.38733E+05				3.35	11314.	42.88
PURC	1506.00	10500.	NONE	0.01	1.58130E+09				0.00	0.	0.00
GAS	0.01	8873.	DKT	1.14	8.62168E+01				5.30	1.	47.04
GAS	0.12	17278.	DKT	1.14	1.78827E+03				3.73	8.	64.37

PLAN 1 YEAR 2033

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.02	12974.	DKT	1.14	2.84267E+02				5.46	2.	70.85
OIL2	0.00	8687.	GAL	39.17	1.64719E-01				17.36	0.	150.77
DSM	0.01	1.	NONE	0.01	5.72831E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	815.58	10201.	TON	16.44	5.06062E+05				2.90	24112.	29.56
COAL	232.25	12783.	TON	14.13	2.10120E+05				3.45	10257.	44.16
PURC	1550.04	10500.	NONE	0.01	1.62754E+09				0.00	0.	0.00
GAS	0.01	8865.	DKT	1.14	1.00275E+02				5.46	1.	48.41
GAS	0.14	17272.	DKT	1.14	2.06992E+03				3.84	9.	66.28

PLAN 1 YEAR 2034

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.03	12955.	DKT	1.14	3.01182E+02				5.62	2.	72.87
OIL2	0.00	8687.	GAL	39.17	1.75435E-01				17.88	0.	155.30
DSM	0.01	1.	NONE	0.01	6.46519E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	698.01	10152.	TON	16.44	4.31036E+05				2.99	21153.	30.31
COAL	263.90	12784.	TON	14.13	2.38758E+05				3.56	12004.	45.49
PURC	1714.71	10500.	NONE	0.01	1.80045E+09				0.00	0.	0.00
GAS	0.01	8884.	DKT	1.14	1.09919E+02				5.62	1.	49.97
GAS	0.15	17246.	DKT	1.14	2.21891E+03				3.95	10.	68.16

PLAN 1 YEAR 2035

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.03	12932.	DKT	1.14	3.83802E+02				5.79	3.	74.92
OIL2	0.00	8687.	GAL	39.17	2.25167E-01				18.41	0.	159.95
DSM	0.01	1.	NONE	0.01	8.73136E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	702.20	10148.	TON	16.44	4.33437E+05				3.07	21909.	31.20
COAL	232.29	12783.	TON	14.13	2.10147E+05				3.67	10883.	46.85
PURC	1761.40	10500.	NONE	0.01	1.84947E+09				0.00	0.	0.00
GAS	0.02	8869.	DKT	1.14	1.29397E+02				5.79	1.	51.38
GAS	0.17	17103.	DKT	1.14	2.51083E+03				4.07	12.	69.63

PLAN 1 YEAR 2036

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.03	12368.	DKT	1.14	3.30478E+02				5.97	2.	73.80
OIL2	0.00	8687.	GAL	39.17	1.36808E-01				18.97	0.	164.75
GAS	0.01	17864.	DKT	1.14	2.25306E+02				5.22	1.	93.24
DSM	0.00	1.	NONE	0.01	4.85927E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	636.71	10141.	TON	16.44	3.92751E+05				3.17	20448.	32.12
COAL	263.98	12783.	TON	14.13	2.38813E+05				3.78	12739.	48.26
PURC	1906.25	10500.	NONE	0.01	2.00156E+09				0.00	0.	0.00
GAS	0.02	8877.	DKT	1.14	1.58098E+02				5.97	1.	52.97
GAS	0.20	17659.	DKT	1.14	3.02146E+03				4.19	14.	74.05

PLAN 1 YEAR 2037

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.03	12170.	DKT	1.14	3.51968E+02				6.15	2.	74.80
OIL2	0.00	8687.	GAL	39.17	1.43902E-01				19.53	0.	169.70
GAS	0.02	17271.	DKT	1.14	2.35344E+02				5.38	1.	92.85
DSM	0.01	1.	NONE	0.01	5.70695E-01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	709.14	10141.	TON	16.44	4.37452E+05				3.26	23459.	33.08
COAL	264.00	12783.	TON	14.13	2.38824E+05				3.89	13121.	49.70
PURC	1854.66	10500.	NONE	0.01	1.94739E+09				0.00	0.	0.00
GAS	0.02	8892.	DKT	1.14	1.69517E+02				6.15	1.	54.65
GAS	0.22	16999.	DKT	1.14	3.34799E+03				4.32	16.	73.42

PLAN 1 YEAR 2038

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.09	12109.	DKT	1.14	9.78748E+02				6.33	7.	76.66
OIL2	0.00	8687.	GAL	39.17	4.34959E-01				20.12	0.	174.79
GAS	0.04	16422.	DKT	1.14	6.06586E+02				5.54	4.	90.94
DSM	0.02	1.	NONE	0.01	1.97315E+00				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	507.83	10330.	TON	16.44	3.19103E+05				3.36	17626.	34.71
COAL	232.71	12778.	TON	14.13	2.10439E+05				4.00	11909.	51.17
PURC	2107.20	10500.	NONE	0.01	2.21255E+09				0.00	0.	0.00
GAS	0.06	8864.	DKT	1.14	4.32969E+02				6.33	3.	56.11
GAS	0.56	16257.	DKT	1.14	7.93953E+03				4.45	40.	72.32

PLAN 1 YEAR 2039

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.09	12022.	DKT	1.14	9.86703E+02				6.52	7.	78.39
OIL2	0.00	8687.	GAL	39.17	4.28446E-01				20.72	0.	180.03
GAS	0.05	16481.	DKT	1.14	6.82802E+02				5.70	4.	94.00
DSM	0.02	1.	NONE	0.01	1.93393E+00				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	514.12	10323.	TON	16.44	3.22818E+05				3.46	18366.	35.72
COAL	264.42	12778.	TON	14.13	2.39117E+05				4.13	13937.	52.71
PURC	2090.12	10500.	NONE	0.01	2.19463E+09				0.00	0.	0.00
GAS	0.06	8863.	DKT	1.14	4.43152E+02				6.52	3.	57.79
GAS	0.63	16164.	DKT	1.14	8.89919E+03				4.58	46.	74.06

PLAN 1 YEAR 2040

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.22	11968.	DKT	1.14	2.34868E+03				6.72	18.	80.38
OIL2	0.00	8687.	GAL	39.17	1.07732E+00				21.35	1.	185.43
GAS	0.11	15798.	DKT	1.14	1.57740E+03				5.87	11.	92.81
DSM	0.05	1.	NONE	0.01	5.42720E+00				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	524.40	10316.	TON	16.44	3.29071E+05				3.56	19283.	36.77
COAL	233.90	12763.	TON	14.13	2.11279E+05				4.25	12684.	54.23
PURC	2130.40	10500.	NONE	0.01	2.23691E+09				0.00	0.	0.00
GAS	0.12	8840.	DKT	1.14	9.63627E+02				6.72	7.	59.36
GAS	1.28	15618.	DKT	1.14	1.74703E+04				4.72	94.	73.71

PLAN 1 YEAR 2041

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	3.11	11862.	DKT	1.14	3.23349E+04				6.92	255.	82.05
OIL2	0.08	8687.	GAL	39.17	1.66959E+01				21.99	14.	190.99
GAS	1.79	15053.	DKT	1.14	2.36324E+04				6.05	163.	91.08
DSM	0.94	1.	NONE	0.01	9.36305E+01				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	718.89	10176.	TON	16.44	4.44955E+05				3.67	26856.	37.36
COAL	369.80	11960.	TON	14.13	3.12997E+05				4.38	19355.	52.34
PURC	2190.00	10500.	NONE	0.01	2.29950E+09				0.00	0.	0.00
GAS	1.53	8802.	DKT	1.14	1.17815E+04				6.92	93.	60.88
GAS	19.10	14876.	DKT	1.14	2.49268E+05				4.86	1381.	72.31

PLAN 1 YEAR 2042

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	4.80	11800.	DKT	1.14	4.96937E+04				7.13	404.	84.08
OIL2	0.12	8687.	GAL	39.17	2.55993E+01				22.65	23.	196.72
GAS	2.81	14813.	DKT	1.14	3.65261E+04				6.23	260.	92.32
DSM	1.47	1.	NONE	0.01	1.46632E+02				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	826.73	10186.	TON	16.44	5.12247E+05				3.78	31845.	38.52
COAL	467.74	11550.	TON	14.13	3.82345E+05				4.51	24352.	52.06
PURC	2190.23	10499.	NONE	0.01	2.29950E+09				0.00	0.	0.00
GAS	2.37	8795.	DKT	1.14	1.82491E+04				7.12	148.	62.66
GAS	28.60	14479.	DKT	1.14	3.63194E+05				5.01	2073.	72.50

PLAN 1 YEAR 2043

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	5.75	11847.	DKT	1.14	5.97556E+04				7.34	500.	86.94
OIL2	0.14	8687.	GAL	39.17	3.08899E+01				23.33	28.	202.63
GAS	3.31	14764.	DKT	1.14	4.28595E+04				6.42	314.	94.77
DSM	1.82	1.	NONE	0.01	1.82445E+02				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	852.29	10196.	TON	16.44	5.28602E+05				3.89	33848.	39.71
COAL	458.30	11392.	TON	14.13	3.69487E+05				4.64	24239.	52.89
PURC	2190.29	10499.	NONE	0.01	2.29950E+09				0.00	0.	0.00
GAS	2.83	8795.	DKT	1.14	2.18511E+04				7.34	183.	64.54
GAS	34.24	14376.	DKT	1.14	4.31835E+05				5.16	2539.	74.14

PLAN 1 EXTENSION PERIOD

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	5.75	11847.	DKT	1.14	5.97556E+04				37.27	2539.	441.52
OIL2	0.14	8687.	GAL	39.17	3.08899E+01				118.45	143.	1029.00
GAS	3.31	14764.	DKT	1.14	4.28595E+04				32.60	1593.	481.30
DSM	1.82	1.	NONE	0.01	1.82445E+02				0.00	0.	0.00
WH	40.70	1.	NONE	0.01	4.07000E+03				0.00	0.	0.00
COAL	854.13	10197.	TON	16.44	5.29780E+05				19.78	172273.	201.69
COAL	456.46	11398.	TON	14.13	3.68197E+05				23.58	122665.	268.73
PURC	2190.29	10499.	NONE	0.01	2.29950E+09				0.00	0.	0.00
GAS	2.83	8795.	DKT	1.14	2.18511E+04				37.27	928.	327.75
GAS	34.24	14376.	DKT	1.14	4.31835E+05				26.19	12893.	376.49

Attachment D

PUBLIC ADVISORY GROUP DOCUMENTATION

ATTACHMENT D
PUBLIC ADVISORY GROUP DOCUMENTATION

This Attachment is comprised of the official Public Advisory Group roster as well as the description of the meetings and the topics discussed at each meeting. No minutes of the meetings were taken.

MONTANA-DAKOTA UTILITIES CO. INTEGRATED RESOURCE PLANNING
2023-2024 PUBLIC ADVISORY GROUP ROSTER

NORTH DAKOTA

Darin Scherr
Bismarck Public School
Bismarck, North Dakota

Dr. Patrick O'Neill
Department of Economics
University of North Dakota
Grand Forks, North Dakota

Rich Garman
ND Department of Commerce
Bismarck, North Dakota

Rich Wardner
Former ND State Senate
Dickinson, North Dakota

Martin Fritz
Kadrmas Lee & Jackson
Bismarck, North Dakota

Adam Renfandt *
North Dakota Public Service Commission
Bismarck, North Dakota
** Invited as an observer*

MONTANA

Kevin Thompson
Action for Eastern Montana
Glendive, Montana

Kyla Maki
Montana Department of Environmental Quality
Helena, Montana

Jeff Blend – Replaced Kyla
Montana Department of Environmental Quality
Helena, Montana

Stephen Schreibeis
Glendive Public Schools
Glendive, Montana

SOUTH DAKOTA

Patrick Steffensen
South Dakota Public Utilities Commission
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In addition to the PAG members and Montana-Dakota personnel included on the roster, the following Montana-Dakota personnel and invited guests participated in one or more of the Public Advisory Group meetings as presenters:

Abbie Krebsbach	Director of Environmental
Jacob Hein	Engineer – Power Production
Jay Skabo	VP Electric Supply
Joe Geiger	Director Generation
Andy McDonald	Manager Environmental Compliance
Shawn Nieuwsma	Director Gas Supply

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

November 2, 2023 Meeting Agenda

2021 IRP Action Plan Updates	Brian Giggee
Heskett plant closures/Heskett 4	Joe Geiger
Environmental Update	Andy McDonald
MISO Resource Adequacy	Brian Giggee
Gas Supply Update	Shawn Nieuwsma
MISO Transmission/Generation	Darcy Neigum
Wrap-up Meeting Logistics Discussion Topics for Future Meetings	Group Discussion

March 12, 2024 Meeting Agenda

Load Forecast	Joanne Mahrer

Potential Study Results	Larry Oswald/ Kathy Baerlocher
Resource Alternatives	Jake Hein
Base Case Results & Next Steps	Brian Giggee

Wrap-up

- Meeting Logistics
- Discussion Topics for Future Meetings

May 29, 2024 Meeting Agenda

MISO LRTP & GI Queue Update	Brian Giggee
MT Select Committee Resource Planning	Darcy Neigum
Demand Side Recap	Kathy Baerlocher
Environmental Update	Andy McDonald
Supply-Side Analysis	Brian Giggee
2024 IRP Action Plan	Darcy Neigum

Wrap-up

- IRP Filing Timeline
- Feedback from the PAG members
- Future PAG membership for 2027 IRP

Attachment E

SUPPLY-SIDE RESOURCES STUDY

1898 & CO.
PART OF BURNS & McDONNELL

2024 TECHNOLOGY ASSESSMENT REPORT

MONTANA-DAKOTA UTILITIES CO.
2024 TECHNOLOGY ASSESSMENT
PROJECT NO. 163084

FINAL DRAFT
February 6, 2024

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CONTENTS

TABLES

1.0 Introduction

Montana-Dakota Utilities Co. ("MDU") retained 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. ("1898 & Co,") to evaluate various power generation technologies in support of its power supply planning efforts. The 2024 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.

It is the understanding of 1898 & Co. that this Assessment will be used for preliminary information in support of MDU's long-term power supply planning process. Any technologies of interest to MDU should be followed by additional detailed studies to further investigate each technology and its direct application within MDU's long-term plans.

1.1 Evaluated Technologies

The following technologies were considered as part of this Assessment:

- Simple Cycle Gas Turbines ("SCGT")
    - GE LM6000 PF+ Aeroderivative
        - Option for Selective Catalytic Reduction ("SCR").
        - Option for Dual Fuel.
        - Evaporative cooler installed.
    - GE LMS 100 PB+ Aeroderivative
        - SCR and carbon monoxide ("CO") oxidation catalyst included.
        - Evaporative cooler installed.
    - GE 7E.03 LLI SCGT
        - Option for SCR.
        - Option for Dual Fuel.
        - Evaporative cooler installed.
- Reciprocating Internal Combustion Engines ("RICE")
    - 4 x Wärtsilä 20V34SG (9 megawatt ("MW")) engine plant
        - SCR and CO catalyst included.
        - Natural gas operation only.
    - 3 x Wärtsilä 18V50SG (18 MW) engine plant
        - SCR and CO catalyst included.
        - Natural gas operation only.
    - 4 x Wärtsilä 31DF (11 MW) engine plant
        - SCR and CO catalyst included.
        - Dual fuel included (requires natural gas and fuel oil for operation). Additional dual fuel costs broken out as an option to support fuel oil only operation.
- Combined Cycle Gas Turbines ("CCGT")

- 2 x 1 GE SGT-800
  - SCR and CO oxidation catalyst included.
  - Option for duct firing capability.
  - Evaporative coolers installed.
- 1 x 1 GE 7F.05
  - SCR and CO oxidation catalyst included.
  - Option for duct firing capability.
  - Evaporative cooler installed.
- 2 x 1 GE 7E.03 LLI Heskett expansion
  - Option for SCR.
  - Option for duct firing capability.
  - Evaporative coolers installed.

- Wind Generation
  - 50 MW
  - 100 MW
- Solar Photovoltaic ("PV") Systems
  - 5 MWac
    - Single axis tracking
    - Add-on cost for 1 MW / 4 megawatt-hour ("MWh") lithium-ion energy storage co-location
  - 50 MWac
    - Single axis tracking
    - Add-on cost for 10 MW / 40 MWh lithium-ion energy storage co-location
- Battery Storage
  - 50 MW / 200 MWh
    - Standalone lithium-ion energy storage co-location

1.2 Assessment Approach

This report compiles the assumptions and methodologies used by 1898 & Co. during the Assessment. Its purpose is to articulate that the delivered information is in alignment with MDU's intent to advance its resource planning initiatives. A detailed summary of the cost, performance, and emissions information developed for each technology is included in Appendix B ("Summary Table"). A scope assumptions matrix is provided in Appendix C to document the basis for the information provided in the Summary Table.

1.3 Conclusions & Recommendations

This Assessment provides information to support MDU's power supply planning efforts for further evaluation within their long-term power supply planning. The information provided in this assessment is preliminary in nature and is intended to highlight indicative, differential costs associated between each technology. After identifying the preferred combination of resources within the Study, MDU should pursue additional engineering studies to define specific items such as project scope, design, and equipment, budgets, and implementation timeline for the preferred technologies of interest.

1.4 Statement of Limitations

Estimates and projections prepared by 1898 & Co. relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. 1898 & Co. 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 is included in Appendix C.

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 operations and maintenance ("O&M") estimates are stated in 2024 US dollars ("USD"). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct ("EPC") fixed price contract for project execution.
- 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.
- Technologies were evaluated for Bismarck, North Dakota.
- Ambient conditions are based on MDU requests for integrated resource plan ("IRP") studies:
  - Elevation: 1,695 feet ("ft")
  - Winter Conditions: 6.8 degrees Fahrenheit ("°F") and 70% relative humidity ("RH")
  - Summer Conditions: 84.5 °F and 40% RH
  - Generator Power Factor ("PF"): 0.85
- The primary fuel for the SCGT, CCGT, and RICE options is pipeline quality natural gas. The assumed gas constituency is provided below. Several options include options to operate on fuel oil as a backup fuel. All performances are based on natural gas operation.
  - Methane: 68.90 %mol
  - Ethane: 22.30 %mol
  - Propane: 3.83 %mol
  - Iso-Butane: 0.10 %mol
  - n-Butane: 0.20 %mol
  - Iso-Pentane: 0.01 %mol
  - n-Pentane: 0.01 %mol
  - Carbon Dioxide ("CO_2"): 0.95 %mol
  - Nitrogen: 3.70 %mol
  - Fuel Gas Temperature: 80 °F
  - Fuel Gas Pressure: 900 pounds per square inch gauge ("psig")

- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- Fuel oil add-on costs are broken out in the Summary Table.
- Natural gas pipeline interconnection costs are included in Owner's Costs. Natural gas assumed to be delivered to site at sufficient pressure. Gas compression is not included for all options.
- Duct firing costs and performance information is included as a broken-out option for combined cycle options.
- Fuel and power consumed during construction, startup, and/or testing are included in the Owners' Costs section of the Summary Table.
- Piling is included under heavily loaded foundations.
- Water interconnection costs are included in Owner's Costs. Costs assume on-site wells and pipe for raw water supply.
- Wastewater is assumed to be delivered to site boundary. Treatment facilities are excluded.
- Electrical scope is assumed to end at the high side of the generator step up unit ("GSU"). Unless otherwise stated, GSU costs assume 115 kilovolts ("kV") transmission voltage.
- Demolition or removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of Best Available Control Technology ("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 winter conditions.

2.3 EPC Project Indirect Costs

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

- Performance Testing and Continuous Emissions Monitoring System ("CEMS")/Stack Emissions Testing (where applicable)
- Construction/Startup Technical Service
- Engineering and Construction Management
- EPC Fees & Contingency

2.4 Owner Costs

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

- Project Development
- Owner's Operational Personnel
- Owner's Engineering
- Owner's Project Management
- Startup and Commissioning
- Land Allowance, as applicable
  - $5,000/acre was assumed for the purpose of this Assessment based on a high-level analysis of land costs in the area surrounding Bismarck, ND.
  - Exceptions:

  - Wind, PV, and battery storage projects assume leased land and cost is included in O&M costs.
- Legal Fees
- Permitting/Licensing
- Construction Power, Temporary Utilities, Startup Consumables
- Initial Fuel Inventory, as applicable
- Site Security
- Operating Spare Parts
- Switchyard (assumes 115 kV for transmission voltage)
- Political Concessions / area development fees
- Permanent plant equipment and furnishings
- Builder's risk insurance at 0.45% of construction cost
- Owner project contingency at 5% of total costs for screening purposes
- Property Tax Value, provided by MDU (0.44%)
- Network Upgrade Costs, provided by MDU ($150/kW)
- Transmission Interconnection Cost was included and assumes of 15 miles of transmission line at 115 kV. Land cost for transmission lines was excluded.
- Natural Gas Interconnection Cost was included and assumes five miles of interconnection, an easement allowance, and associated piping.

2.5 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing Fees
- Interest During Construction ("IDC")
- Escalation
- Sales Tax
- Water Rights
- Off-Site Infrastructure
- Utility Demand Costs
- Decommissioning Costs
- Salvage Values

2.6 Operating and Maintenance Assumptions

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 2024 USD.
- O&M estimates exclude emissions credit costs and property insurance.
- Property taxes allowance included for PV and onshore wind options. Allowance assumption provided by MDU.

- Land lease allowance included for PV and onshore wind options. Allowance assumption provided by MDU.
- 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 C.
- Where applicable, variable O&M costs include routine maintenance, makeup water, water treatment, water disposal, ammonia, 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 ("GT") 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 in winter conditions unless otherwise stated.

3.0 Simple Cycle Gas Turbine Technology

This Assessment includes three SCGT options, including two aeroderivative unit types and one frame unit type.

3.1 Simple Cycle Gas Turbine Technology Description

A SCGT plant utilizes natural gas to produce power in a GT generator (“GTG”). The GT (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Simple cycle GTs 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 GT generation is a widely used, mature technology.

Evaporative coolers or inlet foggers are often used to cool the air entering the GT by evaporating additional water vapor into the air, which increases the mass flow through the turbine and therefore increases the output. Evaporative coolers are included 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 synced 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 GT 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 traditional frame units.

A desirable attribute of aeroderivative turbines is the ability to start and ramp 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 starts are generally not affected by cold, warm, or hot conditions. However, all GTs start times in this Assessment assume that all start permissives are met, which can include purge credits, lube oil temperature checks, fuel pressure, etc. Available aeroderivative GTs models include both dry low NOx (“DLN”) and water injection methods to control emissions during natural gas operation. The LM6000 PF+ utilized in this Assessment utilizes a DLN system and therefore does not consume water for NOx control. Additionally, the LMS-100 PB+ includes an intercooler that would 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 PF+ and LMS100 PB+ options, which are well-established in the marketplace.

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 British thermal units per kilowatt-hour ("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 (~500 psig). Most available frame GT models utilize DLN to control emissions during natural gas operation. This can result in decreased water usage in comparison to aeroderivative GTs, which reduces variable O&M costs.

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. Fast start times are shown in the Summary Table.

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, and Mitsubishi. Commercially available frame units range in size from approximately 50 MW to 400 MW and advancements in turbine control systems and further testing has led equipment manufacturers to tout capacities greater than 420 MW. Continued development by GT manufacturers has resulted in the separation of GTs 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 an E class SCGT option based on the GE 7E.03 LLI.

3.2 Simple Cycle Gas Turbine Emissions Controls

Emissions levels and required oxides of nitrogen ("NOx") 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 GT 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 NOx emissions measured in parts per million ("ppm"), independent of operating hours. Per NSPS, units with heat inputs below 850 million British thermal units per hour ("MMBtu/hr") have a NOx 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 NOx emissions, SCR may be required or the number of operating hours available for the facility may be limited.

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 E class GT in this evaluation uses DLN combustors to achieve NOx emissions of 5 ppm at 15 percent oxygen ("O_2") at full load and ISO conditions while operating on natural gas fuel. Since these units emit less than 15 ppm NOx, it is assumed that SCR is not required. SCR systems are included as optional costs for E class simple cycle options in this Assessment.

Units operating on fuel oil require water injection for NOx control. It should be noted that OEMs may offer to tune the turbines to balance output and emissions targets depending on site specific needs.

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 a DLN system to achieve NOx emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel without the use of water injection. An SCR system is included as an optional cost. The LMS 100 PB+ uses SCR to control NOx emissions to approximately 2.5 ppm.

The LM6000 PF+ and 7E.03LLI are capable of dual fuel operation and will control NOx through water injection to 42 ppm when operating on fuel oil.

Oxidation catalysts can be used to control CO emissions to 2-2.5 ppm at 15 percent O_2 while operating on natural gas fuel. It is assumed that CO controls are not required on the base E class and aeroderivative options, but the costs of the CO catalyst are included in the SCR option costs.

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 GTs.

Emissions estimates are shown in the Summary Tables for full load operation at ISO. Emissions are shown for the bare turbine operating on natural gas fuel and 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 files provided to MDU. Estimated performance results are based on data requested from GE at nominal performance points across winter and summer ambient conditions adjusted for small differences between these nominal performance conditions and those in the assessment. Full load and minimum load performance estimates are shown for winter and summer conditions. Summer ratings include a separate, incremental performance with evaporative coolers.

Minimum load is defined as the minimum emissions compliant load ("MECL"), as reflected in the OEM ratings. 1898 & Co. provided 50% load as the standard MECL.

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

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

The Summary Tables include startup time and ramp rate estimates for SCGT options. SCGT start times assume that purge credits and other permissives are achieved prior to start.

Outage and availability statistics, collected using the North American Electric Reliability Corporation ("NERC") Generating Availability Data System ("GADS"), are also shown in the Summary Tables. Simple cycle GADS data are based on the 2013 to 2022 operating statistics for applicable North American units that are no more than 10 years old. The GADS data delivered was changed from weighted rates which correct for derating or dependable plant capacity impacts by weighting each term in the calculation by the Net Maximum Capacity, to unweighted time-based calculation methods. The outage statistics included in the analysis are now Scheduled Outage Factor ("SOF"), Forced Outage Factor ("FOF"), and Availability Factor ("AF") which are additive to 100% of the potential uptime for the generating facility.

3.4 Simple Cycle Gas Turbine Cost Estimates

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

Additional cost clarifications and assumptions are shown below:

- The EPC capital cost is divided into the following categories:
    - Engineering
    - GT
    - GSU
    - Environmental Equipment (for options with SCR in the base cost). SCR/CO system option costs are shown separately for LM6000 PF + and 7E.03 options.
    - Balance of Plant ("BOP")
        - Mechanical equipment, electrical equipment, instrumentation and controls, chemical storage, fire protection equipment, and other miscellaneous items are 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.
        - SCGT plants assume that demineralized water trailers are used to treat raw water if dual fuel option is not selected. Permanent onsite water treatment systems are included as part of the dual fuel option breakout cost.
        - Demineralized water tank and related pumps are included for onsite storage.
        - Fuel oil tank assumes 72 hours of storage.
    - Construction
        - Accounts for labor adjustments for each service area.
        - Includes major equipment erection, civil/structural construction, mechanical construction, and electrical construction.
    - Indirect Costs and Fees
    - EPC Contingency
- Base unit estimates assume natural gas operation with evaporative coolers. Optional add costs are shown separately.
- It is assumed that natural gas is available at approximately 900 psig. Fuel compression is excluded.
- Dual fuel capability is included as an option for the LM6000 PF+ and 7E.03 LLI options. Initial fuel oil fill is included in associated Owner's Costs.
- The estimate assumes the turbines are installed outdoors with OEM standard enclosures.
- Cost estimates include a building with administrative/control spaces and a warehouse.

3.5 Simple Cycle O&M

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

Major maintenance costs for aeroderivative engines, representative of the LM6000, are estimated on a dollar per GT hourly operation ("$/GTG-hr") basis and are not affected by number of starts. Variable O&M and major maintenance costs are based on natural gas operation. Fixed costs for all simple cycle units include an allowance for seven full time employees for a plant containing one turbine.

Major Maintenance costs for the frame engines are estimated on a dollar per GT 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. It is assumed that there is no penalty for 10-minute starts, but some OEMs may have penalties depending on specific project conditions including calculation adjustments to the hours in between major maintenance events that increase the equivalent run hours by a multiplicative factor based on the number of these 10-minute starts. The major maintenance $/MWh cost shown in the summary is calculated using the $/hr major maintenance cost (it is intended as another way to show the same cost, so it is also not intended to be added to $/start or $/hr). If a start-based maintenance scheme is desired, it should be noted that the applicable $/MWh will need to be calculated based on the start-based annual cost expectations.

4.0 Reciprocating Engine Technology

This Assessment includes three 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 differences than GTs. With site conditions below 3,000 ft 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 GTs, 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, GE (Jenbacher), Rolls Royce, etc. offer reciprocating engines. They are a popular option to pair with 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 GTs.

One unique characteristic of reciprocating engine technologies is the fundamental difference in design between dual fuel engines and natural gas only engines. Natural gas only engines utilize spark ignition to ignite the natural gas at the top end of the compression stroke, while dual fuel engines do not utilize spark ignition and rely on compression alone to ignite the fuel. Compression ignition engines require fuel oil to begin combustion. Therefore, dual fuel engines are designed to consume a small amount of fuel oil even when operating on natural gas. During fuel oil operation, however, natural gas is not required for operation.

Utility scale applications most commonly rely on medium speed engines in the 9-10 MW and 18-20 MW classes. All 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.

This Assessment includes single fuel (20V34SG and 18V50SG) options with nominal plant sizes of 36 MW and 54 MW, respectively, and a dual fuel capable (31DF) option with a nominal plant size of 44 MW. 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 winter 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 NOx and CO emissions. Operation on natural gas fuel with an SCR yields reduction of NOx emissions to 5 ppm at 15 percent excess O_2, while a CO catalyst results in anticipated CO emissions of 15 ppm. It is assumed that emissions control equipment is not required for CO_2 and 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 Tables. 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 40% load for SG engines. Currently, only Wärtsilä and MAN (licensed by Fairbanks in the United States) offer dual fuel engines in this class. The general assumptions in Section 2.0 apply to the evaluation of reciprocating engine options, and additional assumptions are listed in the scope matrix.

The Summary Tables includes startup times for engine options. Start times of 5-10 minutes require that the engine jacket temperatures be kept warm for standby operation (this is addressed in the O&M costs). Outage and availability statistics, collected using the NERC GADS, are also shown in the Summary Tables. The GADS data delivered was changed from weighted rates which correct for derating or dependable plant capacity impacts by weighting each term in the calculation by the Net Maximum Capacity, to unweighted time-based calculation methods. The outage statistics included in the analysis are now SOF, FOF, and AF which are additive to 100% of the potential uptime for the generating facility. 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.

Emissions estimates are shown for full load at ISO conditions on natural gas fuel. It is assumed that SCR and CO catalyst technologies are installed and operating.

4.4 Reciprocating Engine Cost Estimates

The cost estimate results are included in the Summary Tables. The EPC costs include 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.
- It is assumed that natural gas is available at approximately 125 psig. Fuel compression is not required.
- The reciprocating engine plant includes an indoor engine hall with associated administrative/ control/warehouse facilities.
- Each RICE option is tied to its own three-winding GSU.
- Fuel oil storage tank assumes 72 hours of storage.

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.

Fixed O&M costs include seven (7) full-time equivalent ("FTE") personnel. 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.

Major maintenance costs are shown per engine, regardless of configuration. It is assumed that a long-term service agreement (“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 LTSA 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 Technology

This Assessment includes three CCGT options, including a 1x1 configuration and two 2x1 configurations.

5.1 Combined Cycle Emissions Controls

The basic principle of the CCGT plant is to utilize natural gas to produce power in a GT which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the GT 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 GT manufacturers has resulted in the separation of GT technology into various classes. For the purposes of this Assessment, 1898 & Co. is evaluating greenfield configurations with Siemens SGT-800 and GE 7F.05 technologies and a potential brownfield expansion for the existing GE 7E.03 technology at Heskett Station to best assess the potential of bookends of turbine technology for combined cycle purposes.

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 winter conditions.

Combined cycle plants are designed for capacity factors consistent with intermediate or base load operation, and therefore it is expected that NOx and CO emissions will need to be controlled. An SCR will be required to reduce NOx emissions by approximately 90%, 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 O_2, which correlates to approximately 0.004 lb/MMBtu.

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 NOx 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 GTs. 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 0.002 lb/MMBtu.

5.3 Combined Cycle Performance

For this Assessment, the F class is based on the GE 7F.05 turbine, and the E class is based on the GE 7E.03 turbine.

Estimated performance results are shown in the Summary Tables, based on data outputs from EBSILON® Professional thermal models. The general assumptions in Section 2.0 apply to the evaluation of CCGT options, and additional assumptions are listed in the scope matrix.

- Evaporative cooling is included in base plant.
- Incremental performance ratings with duct firing are shown for all configurations at winter and summer conditions. These values can be added directly to the corresponding base load performances.
- Base performance is based on heat rejection through wet cooling towers.
- Duct fired options include capability for duct firing capability to 1,400 °F. 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 CCGT plants assume SCR and CO catalyst technologies are installed.

The Summary Tables include combined cycle start times to stack emissions compliance and base load according to cold, warm, and hot 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 GTs. GT fast start options are not reflected in combined cycle startup information.

Outage and availability statistics, collected using the NERC GADS, are also shown in the Summary Tables. Combined cycle GADS data are based on the 2013-2022 operating statistics for applicable North American units that are no more than 10 years old. The GADS data delivered was changed from weighted rates which correct for derating or dependable plant capacity impacts by weighting each term in the calculation by the Net Maximum Capacity, to unweighted time-based calculation methods. The outage statistics included in the analysis are now SO, FOF, and AF which are additive to 100% of the potential uptime for the generating facility.

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 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 1898 & Co. project experience. Cost estimates assume an EPC project plus typical Owner's costs. This methodology assumes that the combined cycle plant would be constructed up front in a single project at the same site, and therefore the estimates are not valid for adding a unit to an existing plant at a later date. For the 2x1 7E.03 expansion at the existing Heskett Station, 1898 & Co. assumes that MDU would utilize the existing simple cycle 7E.03 turbines and would construct the remainder of the combined cycle facility in a single project at the same site. In line with the assumptions matrix, the following items are highlighted:

- The EPC capital cost is divided into the following categories:
  - Engineering
  - GTs
  - HRSGs

        - Includes duct firing capability
        - Includes SCR/CO catalyst
    - Steam Turbine
    - GSU Transformers
    - BOP Equipment and Materials
        - Mechanical equipment, electrical equipment, instrumentation and controls, chemical storage, fire protection equipment, and other miscellaneous items required.
        - Includes supplemental fuel gas metering equipment for verification of billing/consumption information provided by gas supplier.
        - Fuel gas compression is excluded.
        - 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
    - EPC Contingency
- Base unit estimates assume natural gas operation with no inlet conditioning and no dual fuel capability.
- The estimate assumes that GTs are installed outdoors in OEM standard enclosures.
- The estimate assumes that HRSGs are installed indoors.
- The estimate assumes that steam turbines are installed indoors.
- An administrative/control building and a warehouse are included.
- Generic well water is assumed for all sites. No intake structures or supply piping outside the plant boundary are included.
- Cost estimates exclude escalation, interest during construction, financing fees, off-site infrastructure, and transmission.
- The owner's cost for a switchyard assumes a breaker and ½ configuration for 230kV interconnection.

5.5 Combined Cycle Plant O&M

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

- O&M estimates are based on plant performance at winter conditions.
- Incremental O&M costs for optional items are meant to be added directly to the base fixed or variable O&M costs, as applicable.
- Combined cycle plants assume the following FTE personnel quantities.
    - 1x1: 22 FTE
    - 2x1: 25 FTE
- SCR systems are included in the O&M evaluations for all combined cycle plants. SCR systems assume 19 percent aqueous ammonia and six-year catalyst life.
- 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.
- Incremental O&M for alternative heat rejection options account for the reduced water and chemical consumption at summer conditions.
- Chemical costs were updated based on recent 1898 & Co. experience.

6.0 Wind Generation Technology

This Assessment includes options for 50 MW and 100 MW wind generation.

6.1 Wind Energy Technology 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.

Almost all percent of turbines over 100 kW used for utility bulk energy generation in operation are horizontal-axis, instead of vertical-axis turbines generally restricted to distributed urban installations. 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. 1898 & Co. notes that average site wind speeds of at least 7.0 meters per second ("m/s") are generally considered to have suitable wind resources for wind generation development.

Appendix A includes sample NREL wind resource map for the North Dakota service area.

6.2 Wind Energy Emission Controls

No emission controls are necessary for a wind energy installation.

6.3 Wind Performance

This Assessment includes up to 100 MW onshore wind generating facilities. 1898 & Co. relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected for their proximity to relatively high wind speeds in accordance with NREL wind maps, but they are otherwise arbitrary. They were not selected with respect to actual, expected, or preferred locations for current or future wind development. Instead, they were intended to represent the average expected wind speeds available if the project were to be built within each service area.

The General Electric GE2.82-127 wind turbine model was assumed for this analysis, with a nameplate capacity of 2.82 MW at a hub height of 89 meters ("m"). For maximum tip heights above 500 feet, a permitting process through the Federal Aviation Administration ("FAA") would be required (as is typical for utility scale wind energy installations) since the tip height reaches altitudes available for general aircraft. A generic power curve at standard atmospheric conditions (i.e., sea level air density, normal turbulence intensity) was utilized for the GE2.82-127. Note that this turbine is intended only to be representative of a typical wind turbine utilized for utility scale projects. Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition. Actual turbine selection requires further site-specific analysis.

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 89 m hub height for the GE2.82-127 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 21 percent, which is a common assumption for screening level estimates in the northern part of the United States 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 for the MDU service areas 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 are based on 100 MW plant with 2.82 MW turbines (36 total turbines) and a 50 MW plant with 2.82 MW turbines (18 total turbines).

- Equipment and construction costs are broken down into subcategories per MDU's request. These breakouts represent the general scale of 100 MW and 50 MW wind project but are not intended to indicate the expected scope for a specific site.
- The BOP scope includes a GSU transformer for interconnection at 115 kV.
- Land costs are excluded from the BOP and Owner's cost. For the 2024 Study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate.
- Cost estimates also exclude escalation, interest during construction, financing fees, off-site infrastructure, and transmission.

6.5 Wind Energy O&M Estimates

O&M costs in the Summary Tables are derived from in-house information based on 1898 & Co. 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 (general and administrative ("G&A"), insurance, environmental costs, etc.)
- Property taxes
- Land lease payments

An allowance for capital replacement costs is not 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.

If a capital replacement allowance is desired for planning purposes, the table below shows indicative budget expectations as a percentage of the total operating cost. As with operating expenses, however, these costs can vary with the type, size, or age of the facility, and project-specific considerations may justify deviations in the budgeted amounts.

Table 6-1: Summary of Indicative Capital Expenditures Budget by Year

Operational Years	Capital Expenditure Budget
0 - 2	None (warranty)
3 - 5	3% - 5%
6 - 10	5% - 10%
11 - 20	10% - 15%
21 - 30	15% - 20%
31 - 40	20% - 25%

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, worth approximately $18/MWh following the credit's extension in December 2020 through December 31, 2022. As a result of the IRA, the PTC has been extended to 2032 with 100% credit at a 2022 value of approximately $27.50/MWh and no anticipated step-downs in credit percentages.

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 and storage 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. Previous PTC legislation required wind projects to start construction in 2016 to qualify for 100% of the PTC; this percentage decreased 20% each year from 2017 through 2019. In 2020, the PTC was raised back to 60% and was set to expire by the end of the year. However, the Taxpayer Certainty and Disaster Relief Act of 2020 extended the deadline for eligible systems to qualify for PTC in 2022. Once the IRA was announced in 2022, many developers were no longer in a rush to complete projects by the end of 2022, causing a temporary slow-down in wind projects.

7.0 Solar Photovoltaic Technology

This Assessment includes two single axis tracking PV options at 5 MWac and 50 MWac. Both contain add-on cost options for co-located 1 MW / 4 MWh or 10 MW / 40 MWh lithium-ion energy storage systems respectively.

7.1 PV Technology 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. A "depletion" layer forms at the junction of these oppositely charged materials. 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

1898 & Co. ran simulations using PVsyst software. The resultant capacity factors for single axis tracking systems are shown in the Summary Tables. An Inverter Loading Ratio (“ILR”) of 1.35 was assumed for all simulations.

Single axis tracking systems have better capacity factors when compared to fixed tilt systems, but costs are higher for similar ILR ratios. 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 is likely that more panels would be required to achieve the same output. Further analysis would be required to select which mounting system is best suited for a given site. Additional assumptions are listed in the scope matrix.

7.4 PV Cost Estimates

Cost estimates were developed using in-house information based on 1898 & Co. project experience. Cost estimates assume an EPC project plus typical Owner’s costs.

PV cost estimates for the single axis tracking system with 840 kW central inverters are included in the Summary Table. The project scope assumes a medium voltage interconnection and the Owner’s costs include an allowance for interconnection downstream of the 34.5kV circuit breaker. The 2024 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.

PV installed costs have steadily declined for years. The main drivers of general cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. US tariffs on PV panels and steel imports also impact PV prices. Recently, however, trade and supply chain headwinds have caused considerable delays in upcoming solar installations. Federal policy also affects PV costs and in recent years has spurred growth in renewable technologies. The Inflation Reduction Act ("IRA") extends the current solar investment tax credit of 30% and production tax credit of 27.5 $/MWh until 2032 at the earliest. A new incentive included is "direct pay" ITC: it gives direct cash payments to developers in lieu of investors claiming tax credits, allowing projects to quickly monetize the ITC.

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 1898 & Co. project experience and vendor information. The 2024 Assessment includes allowances for land lease and property tax costs.

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

- O&M costs assume that the system is remotely operated and that all O&M activities are performed through a third-party contract. Therefore, all O&M costs are modeled as fixed costs, shown in terms of millions of dollars ("$MM") per year.
- Land lease and property tax allowances are based on input from MDU.
- Equipment O&M costs account for inverter maintenance and other routine equipment inspections.
- BOP costs account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs. Panel cleaning and snow removal are not cost-effective and not recommended.
- The capital replacement allowance is a sinking fund for inverter replacements, assuming they will be replaced once during the project life. It is a 15-year levelized cost based on the current inverter capital cost.

7.6 Co-located Solar PV and Battery Systems

The add-on costs for the 10 MW / 40 MWh and 1 MW / 4 MWh batteries are shown in each respective solar PV column within the Summary Tables. The add-on costs assume each battery is co-located with the solar PV system.

Coupling renewables with storage is one common use case for lithium-ion batteries. In regions with high solar PV penetration, coupling solar PV with storage allows for energy shifting to alleviate the high ramping and sufficient production needs for generation at sunset. During periods of low demand, the battery can be charged using the renewable energy resource and then discharged during periods of high demand. For storage projects, pairing with solar PV as a co-located hybrid project was historically driven by the solar ITC. Prior to the IRA, ITC benefits were only achievable for storage projects if they were coupled and charged with solar. This is no longer the case, as the IRA allowed for standalone energy storage projects to qualify for ITC benefits.

There are two methods for connecting solar PV and battery technologies in a co-located environment: AC-coupled or direct current ("DC")-coupled. For this Assessment, 1898 & Co. assumes an AC-coupled system. Alternating current ("AC")-coupled technologies are connected after each respective inverter via a medium voltage ("MV") collection bus. DC-coupled technologies are connected before the system-wide inverter via DC cabling. AC-coupled solar PV and battery systems are more common amongst utility-scale applications due to the fact the systems are easier to retrofit to existing solar PV, allow for flexibility in inverter selection, are more resilient amidst outage scenarios, and offer versatile charging options for the battery. There are some notable advantages to DC-coupled systems though, as DC-coupled systems are more efficient in charging the battery, tend to be more affordable, and allow for solar PV systems to be oversized beyond inverter limitations if needed.

8.0 Lithium-ion Battery Storage Technology

This Assessment includes a 50 MW / 200 MWh standalone storage option using lithium-ion technology.

8.1 Lithium-ion Battery Storage Technology Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Lithium-ion chemistries have been the leading technology in the electrochemical energy storage market due to the maturity of the technology as well as its competitive cost per unit of energy. There are other emerging technologies in the electrochemical energy storage market that have recently gained traction in the energy storage market but have yet to be substantially proven at utility-scale. Most of this section will focus on lithium-ion energy storage technologies due to the technology selection by MDU.

A lithium-ion battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container. Cells can be connected in series to increase overall facility storage and output. During charging, a reduction-oxidation reaction ("redox") occurs and liberates lithium ions from the cathode to the anode via a high-conductivity electrolyte. During discharging, the reverse redox reaction occurs, which forces electrons to migrate from the anode to the cathode through an external circuit, thereby generating electric current. Lithium-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Consequently, lithium-ion has gained traction in several markets including the utility and automotive industries.

Batteries are designated by the electrochemistry utilized within the cell; the most common lithium-ion chemistries utilized for utility-scale applications include lithium-iron phosphate ("LFP") and nickel manganese cobalt ("NMC"). NMC is prominent in the automotive industry due to the chemistry's high energy density, and is also competitive in the stationary storage industry. LFP has recently been seen a majority share in stationary storage because it is less expensive than NMC, has higher thermal stability, and contains no cobalt. One of the most notable drawbacks to NMC batteries is its use of cobalt.

At its core, a battery energy storage system ("BESS") begins with the battery cell. There are three distinct types of cells used in the stationary storage market: the cylindrical cell (preferred by Panasonic), a pouch-type battery (preferred by LG Chem), and a prismatic cell (preferred by CATL, Samsung SDI, BYD, EVE, and other battery OEMs). These battery cells are then incorporated into a battery module which consists of series and parallel combinations of battery cells. The modules are then placed into racks which contain a manufacturer-specific number of modules based on the application. At the top of each rack, there is typically a battery management system ("BMS"), which acts as a small control system for each individual rack. Cables from the racks connect to a DC panel, which is connected to the power conversion system ("PCS") to convert the current to AC. The PCS may be connected to a series of transformers and protection devices before transmitting power to the grid.

The controls system is an integral part for operating the battery and monitoring its health. Each battery rack contains a BMS, which is used to protect the batteries and provide cell balancing functions when needed.

The BMS includes an electronic switch that can be used to disconnect the battery from the charger or load under critical conditions.

Advanced system functions may also be desired including a variety of market participation algorithms that are designed to autonomously optimize the battery's value in the market. Some of these functions include price forecasting for charge and discharge, automatically bidding into the market, and automatically scheduling charge discharge cycles.

8.2 Lithium-ion Battery Emissions Controls

No emission controls are currently required for battery storage facilities.

8.3 Lithium-ion Battery Storage Performance

This assessment includes the performances of a 50 MW / 200 MWh system based on lithium-ion batteries. Lithium-ion systems can respond in seconds and exhibit excellent ramp rates and round-trip efficiencies. The systems in this Assessment are assumed to perform 365 cycles (or equivalent cycles) per year. The project life is assumed to be 20 years, which is common in the industry. Energy capacity degradation is a known characteristic of lithium-ion BESS. To maintain useable capacity throughout the life of the project, additional capacity may be "overbuilt" during the initial installation or added to the project throughout the life. This is known as "augmentation." There are various strategies for augmentation that are driven by project specific technical and economic concerns.

8.4 Lithium-ion Battery Storage Regulatory Trends

There are several FERC Orders that provide clarity on the role of storage in wholesale markets and encourage its growth in the US. FERC Order 841, upheld in July 2020, requires regional transmission organizations ("RTO") and ISOs to develop clear rules regulating the participation of energy storage systems in wholesale energy, capacity, and ancillary services markets, which includes batteries as small as 100 kW connected behind-the-meter. FERC Order 842 addresses requirements for some generating facilities to provide frequency response, including accommodations for storage technologies. FERC Order 2222 mandates reforms by grid operators to enable participation of distributed energy resources ("DER"), which can include storage resources, in electricity markets.

The most recent major catalyst for spurring energy storage growth is the IRA, which was signed into law on August 16, 2022. The IRA directs nearly $250.6 billion in federal funding to the energy industry to stimulate the domestic market for clean energy generation and storage. The legislation aims to accelerate clean energy deployment, generate domestic manufacturing jobs, and reduce greenhouse gas emissions by offering investment tax credits (ITC), production tax credits (PTC), grants, and loan programs. The IRA unlocked new federal ITC benefits for standalone energy storage projects. Prior to the IRA, energy storage projects were only eligible for the ITC if connected to solar energy generation. Now, standalone storage projects are eligible for ITC benefits as well as bonus credits should the project qualify under IRA eligibility requirements. Those interested in pursuing ITC benefits for standalone energy storage projects should consult tax professionals to determine the correct ITC basis from which ITCs are generated.

8.5 Lithium-ion Battery Storage Cost Estimate

The estimated costs of the lithium-ion battery systems are included in the Summary Tables and are based on 1898 & Co. experience and vendor correspondence. Costs are indicative of the general market trend toward modular battery designs, which include battery racks inside a purpose-built enclosure with integrated controls. Key cost components include the modular, purpose-built enclosures, inverters, medium voltage transformers, project collector substation with main power transformer, and related installation and indirect costs. The capital costs account for energy capacity overbuild to account for approximately 3 years of capacity degradation. Costs associated with augmentation are covered in the O&M costs. It is assumed that the scope includes a transformer to connect at 115 kV.

The costs provided in this Assessment are overnight costs indicative of the current market. The current market has undergone massive cost swings that have been driven by supply chain issues, commodity price fluctuation, and manufacturing limitations. With the rapid increase in lithium demand, the commodity price for lithium carbonate has varied drastically. Stationary storage product prices increased approximately 25% - 40% during 2020-2022 and plateaued until approximately Q2 2023. This brought installed project costs during that time frame to levels that were at or higher than pre-2020 levels. As of Q4 2023, observed battery pricing for stationary storage projects is now falling again, in alignment with raw material pricing and a healthier functioning supply chain. However, there is no observable consensus among industry analysts on future pricing of battery modules; some expect increases while others expect decreases.

8.6 Lithium-ion Battery Storage O&M Cost Estimate

O&M estimates for lithium-ion battery system are shown in the Summary Tables, based on 1898 & Co. experience and recent market trends. The battery storage system is assumed to be operated remotely with no permanent onsite personnel.

The technical life of a battery project is expected to be 20 years. O&M costs have been levelized for the assumed 20-year project life and are intended to include routine maintenance and augmentation for BESS, routine maintenance for the PCS and BOP, and an inverter replacement fund. Auxiliary load energy is excluded, as it is assumed that the AC-AC RTE accounts for HVAC and auxiliary loads.

9.0 Emerging Technologies

To meet carbon reduction targets, dispatchable carbon free or low carbon generation technologies will likely be required. This section is intended to cover emerging technologies that should be monitored and potentially evaluated in the future as the technologies develop further.

9.1 Hydrogen Technology

High hydrogen fuel blends or 100% hydrogen combustion is an attractive low carbon / carbon free fuel due to the potential of long duration dispatchable generation and the potential for retrofitting existing units. Low carbon sources of hydrogen include steam methane reforming (with carbon capture utilization and sequestration) and water electrolysis. Methane reforming requires superheated steam to form hydrogen from a natural gas stream. This process also results in carbon monoxide and carbon dioxide that requires sequestration to limit the carbon emissions from the process. Water electrolysis generates hydrogen through the decomposition of water into its formative atoms using an electrical current. Electrolysis has been touted as a potential source of green hydrogen in the future thanks to potential utilization of curtailed energy from renewable sources. However, this mode of operation has seen limited deployment due to the high cost to produce hydrogen and the limited pipeline infrastructure to transport hydrogen. Due to the low density of the hydrogen atom, storage and transportation cost can be significant.

In the following sections some discussion is provided about hydrogen combustion specific performance and cost concerns for GT and RICE applications.

9.1.1 Gas Turbine

To combust high hydrogen fuels, current commercially available GT models typically require either steam injection or water injection methods to control NOx emissions and flashback. Additionally, high hydrogen capable combustors are not typically available on the “state-of-the-art” GT models. Therefore, there is typically a significant heat rate impact for using a high hydrogen combustor. Commercially available GT models with dry low NOx (“DLN”) combustors are typically only capable of combusting approximately 30-percent hydrogen by volume at this time. The prominent GT OEMs are all working on developing DLN combustors capable of combusting 100% hydrogen with similar NOx emission limits and minimal heat rate impact compared to natural gas. The OEMs are targeting these combustors to be commercially available in the next 5-10 years. It is anticipated that existing GTs will be able to be modified to burn 100% hydrogen in the future. This would include modifications to fuel piping, combustors, GT controls, gas and flame detection, and the turbine enclosure. Additionally, costs for simple cycle applications are impacted by potential requirement of on-site hydrogen production, compression, and storage of the hydrogen fuel.

9.1.2 Reciprocating Internal Combustion Engines

Existing RICE units have recently been tested at a commercial facility with up to 25% hydrogen by volume. Similar to the GT OEMs, RICE OEMs are working towards 100% hydrogen capable engines. This is anticipated to be tested in 2025 and commercially available in the next 5 years. It is unclear at this point whether existing engines will be able to be modified to burn 100% hydrogen in the future.

9.1.3 Hydrogen Fuel Cell Technology

Hydrogen fuel cell technology has a plethora of applications including vehicles, power plants, and backup generators. Hydrogen fuel cells generate electricity through an electrochemical reaction rather than combustion. In a fuel cell, hydrogen is passed through an anode and oxygen through a cathode – both on either side of a porous electrolyte membrane. A catalyst separates the hydrogen atoms into protons and electrons, and while the protons travel through the membrane to the cathode, the electrons are forced through a circuit, generating an electric current and excess heat. This process is similar to a battery with a key difference being that there is no need for recharging; the cell will continue to produce electricity as long as a fuel source (the hydrogen) is provided. The byproducts of the reaction are simply heat and water, with no carbon emissions. Hydrogen fuel cells can also achieve a higher efficiency than natural gas power plants (~60%) and produce minimal noise comparably.

As of 2022, there are 205 operating fuel cell power generators across the United States for a total of approximately 350 MW. The largest of which is a 14.9 MW fuel cell facility, the Bridgeport Fuel Cell, LLC located in Connecticut. Most of the fuel cells are less than 1 MW in size. Additionally, most fuel cell power plants currently use pipeline natural gas instead of hydrogen due to the lack of infrastructure for hydrogen transportation. Fuel cell technology is currently more expensive than GT or RICE technologies and the increased efficiency is not sufficient to provide competitive levelized cost of energy.

9.2 Small Modular Reactor Technology

Nuclear power has provided a reliable base load generation in many countries for decades. The nuclear industry is continuing to innovate with the small modular reactor ("SMR"). The SMR is intended to provide a carbon-free solution that is lower cost, safer, and more flexible than traditional nuclear generation. The SMR technologies utilize passive safety systems and are designed to be more flexible than larger reactors. Additionally, the hope is that by moving fabrication and construction from the field to the factory and creating a repeatable design, that costs can be reduced as well. SMRs have a smaller footprint requirement and can be easier to site. Finally, refueling can be staggered between multiple reactors in order maintain a portion of generation at all times.

Currently, SMRs are considered developmental. Several OEMs have been awarded DOE grants to advance research into SMRs, including NuScale, X-energy, and TerraPower. These manufacturers have completed conceptual design of these modular units to target lower output and costs and are in various stages of permitting applications with the Nuclear Regulator Committee ("NRC"). However, there are currently no units in commercial operation. Therefore, the information provided in this assessment for the SMR option is based on 1898 & Co. vendor correspondence and publicly available studies.

SMRs provide emissions-free operation, however, spent fuel management should be carefully considered by establishing and monitoring infrastructure to contain and dispose of spent fuel. These nuclear plants will have on-site storage facilities until the US develops a permanent repository for spent nuclear fuel and high-level nuclear waste.

9.3 Non-Lithium Energy Storage

Lithium-ion batteries are still the dominant technology in the energy storage market due to the technology's cost competitiveness, maturity, and cycling ability. Despite this, research, development, and product commercialization spending on alternative battery technologies specifically targeted at stationary energy storage has been increasing dramatically in the last decade. This is predominantly motivated by industry analysts forecasting significant increases in demand for storage capacity and for longer storage duration as renewable generation capacity increases. Several of these emerging technologies are competing with lithium-ion and are working on improving their product in four main ways: safety, capacity degradation, life-cycle cost, and environmental impact.

9.3.1 Air Energy Storage

Air energy storage provides a long-duration energy storage solution by storing energy in various high-pressure states of air. There are two main technologies that fall under air energy storage: compressed air energy storage and liquid air energy storage.

Compressed Air Energy Storage

Compressed air energy storage ("CAES") is another mature form of energy storage that has been in operation globally for over 30 years. CAES systems utilize off-peak electricity to power a compressor train that compresses ambient air. The compressed ambient air is cooled and then injected into underground storage formations. During peak demand, the compressed air is brought to the surface, heated, and expanded through turbine to run a generator. CAES systems require suitable underground storage at the development site, which is typically a salt cavern or a mined hard-rock cavern.

There are two main types of CAES systems: diabatic and adiabatic. Diabatic CAES ("D-CAES") utilizes natural gas to reheat the compressed air during expansion. An example of an operational D-CAES system is a 110 MW facility located in McIntosh, Alabama. This facility was the first operational case of D-CAES in the US and is one of two globally operating D-CAES facilities. These are considered hybrid systems combining the attributes of a traditional fossil generating plant and a pure energy storage system. The McIntosh site for example still requires about one-third the natural gas per kilowatt-hour ("kWh") produced when compared to a conventional gas turbine plant.

Alternatively adiabatic CAES ("A-CAES") reuses heat stored from compression to reheat the compressed air during expansion. Therefore, A-CAES loses less energy to waste heat and has a higher round trip efficiency than D-CAES. Hydrostor, a Toronto-based company founded in 2010, has proven A-CAES feasibility at a pilot scale in Canada utilizing thermal storage units to capture the CAES process heat. Hydrostor is currently working to execute a few of its first utility scale plants, each to utilize purpose-built caverns for compressed air storage.

Liquid Air Energy Storage

Liquid air energy storage ("LAES") stores energy in the form of liquid air (or liquid nitrogen) at cryogenic temperatures. Ambient air is cleaned, compressed, cooled, and liquified in the charging stage of LAES. Once liquified, the air is stored until electricity demand rises. To discharge the system, the liquid air is evaporated, heated, and expanded through a turbine to produce electricity. The waste heat from compressing the air is stored as a hot thermal stream for future discharge processes. The waste cold from evaporating the air is stored as a cold thermal stream for future charging processes. The LAES process resembles CAES but stores air at a much higher energy density and therefore does not have nearly as many geographical constraints as CAES. Highview Power, a UK-based energy storage system designer and developer, launched the world's first grid-scale LAES 5 MW/15 MWh pilot plant in 2018. Following the success of their pilot plant, Highview Power announced the development of the CRYOBattery in 2019, which is a modular cryogenic LAES system that is intended to be scalable up to multiple gigawatts. Highview Power states that the CRYOBattery can be located "just about anywhere" and provides essential services such as "time shifting, synchronous voltage support, frequency regulation and reserves, synchronous inertia, and black start capabilities". Highview Power has announced CRYOBattery projects in Europe, South America, and North America.

9.3.2 Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage (“PHES”) is another mature form of long duration energy storage that accounts for a vast majority of the world’s energy storage capacity. PHES stores energy in the gravitational potential energy of water that is kept in two reservoirs of varying elevation and cycles through a pump-turbine generator-motor system. During peak demand, water flows from the higher reservoir to the lower reservoir and passes through a turbine that produces electricity. To “charge” the PHES system, water from the lower reservoir is pumped back up to the higher reservoir typically using surplus off-peak electrical power. PHES systems can either be open-loop or closed-loop systems. Open-loop systems are continuously connected to a natural waterbody, typically a lake or river. Closed-loop systems operate independently of natural water sources. Given that PHES requires significant land and infrastructure for larger capacity systems, PHES is not optimal for all regions of the U.S. One notable technology that has recently gained attention is sub-surface PHES. This technology assumes that one or both water reservoirs are located below ground, typically in abandoned mines or caverns. This technology has gained a lot of interest in geographic areas not traditionally suitable for PHES.

9.3.3 Thermal Energy Storage Technology

Thermal Energy Storage (“TES”) has existed in commercial operations for years in a variety of applications, such as residential and commercial water heating, space heating, and space cooling. In recent years, TES has proved to be a viable technology option for utility-scale energy storage. There are three types of TES that are currently being explored from a utility-scale energy storage standpoint: sensible TES, latent TES, and thermochemical TES.

Sensible TES

Sensible TES utilizes a storage medium to store and release sensible heat through heating and cooling processes. Storage mediums can range from molten salt, concrete blocks, rocks, or sand-like particles. The energy capacity of a sensible TES system is defined by the density, specific heat, and volume of the storage medium as well as the temperature change expected of the system.

Malta’s “Long Duration Storage Technology” is the current industry leader for TES utility-scale commercial development. Malta’s technology utilizes sensible TES with molten salt as the storage medium creating a “pumped heat energy storage” system. The system operates using a recuperated air-loop Brayton-cycle. During off-peak periods of surplus energy, the system charges by sending electricity to a heat pump, which converts the electricity to thermal energy by creating a temperature difference. The heat stream is stored in molten salt and the cold stream is stored in anti-freeze liquid. When the system needs to discharge, a heat engine converts the temperature difference back to electrical energy which is then sent to the grid. Malta-provided information indicates their system may be scaled up to 100 MW in capacity and can provide between 8-200 hours of long duration storage.

Latent TES

Latent TES is similar to sensible TES from a process flow perspective but not from a storage medium perspective. Latent TES utilizes the latent heat of phase change to store energy in phase change materials (“PCM”). To change a solid to a liquid, the latent heat of fusion is the energy capacity considered. To change a liquid to a gas, the latent heat of evaporation is the energy capacity considered. Various mediums can provide different energy capacities depending on the material and the original phase of the medium.

Thermochemical TES

Thermochemical TES utilizes chemical reactions typically involving breaking and reforming chemical bonds to release and store heat. Common storage mediums for thermochemical TES include carbonates, hydroxides, metal hydrides, oxides, ammonia, and sulfur-based cycles.

9.3.4 High Temperature Battery Technology

Battery cells that require high temperatures to keep a metal in its molten state for operation are referred to as “high temperature batteries”. In their charged state, high temperature batteries have the pure form of a metal anode and the pure form of another element as its cathode. The battery chemistry leverages the natural electrochemical potential difference of the two elements. The operation of these technologies is typically considered reversible alloying. The two leading chemistries of high temperature batteries are Sodium-Sulfur (most notably supplied by BASF) and Calcium-Antimony (most notably supplied by Ambri). High temperature batteries have the most similar performance attributes to Lithium-ion systems and are currently the most competitive non-lithium technology on a cost basis.

9.3.5 Flow Battery Technology

Flow batteries have recently emerged as an attractive research and development investment for companies looking for a lower cost-per-kWh, flexible-duration, and stationary energy storage product. There are a variety of types of flow batteries: a fully aqueous redox vs. hybrid, inorganic vs. organic, vanadium vs. zinc-bromine vs. iron chemistries, etc. For all combinations of flow battery types, the electrode does not contain any active elements that participate in electrochemical reactions. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in theoretically high cycle life for flow batteries. In many cases, however, stack components are prone to mechanical deterioration that will cause some performance degradation over time. This performance degradation will result in lower round-trip efficiencies (“RTEs”) and therefore slight reductions in discharge capacity over time. Per 1898 & Co. experience, flow battery suppliers that have recently gained significant market share include ESS, Invinity, Redflow, VRB, and CMBlu.

9.3.6 Other Notable Emerging Storage Technologies

Recent technological developments in the energy storage industry have allowed for new electrochemical technologies to be brought to early-commercial maturity. A few notable technologies are described below. Monitoring the progression of these technologies will be important in the selection of long duration technology appropriate for MDU's needs.

Metal-Hydrogen Batteries

Metal-hydrogen batteries were invented in the 1970s originally for the purpose of aerospace energy storage. The battery combines the reactions of a Nickel (“Ni”)-Cadmium battery and a fuel cell. The cathode consists of a nickel hydroxide composition while the anode is made up of a platinum hydrogen composition. During charge, hydrogen is produced and pressurized while the active portion of the cathode oxidizes its Ni(II) to Ni(III). During discharge the process reverses and hydrogen is oxidized back to water at the anode surface and Ni(III) becomes Ni(II). Metal-H2 batteries are known for their high efficiencies, flexible power/current operating ranges, and low lifetime capacity degradations. Aside from low volumetric energy density, these batteries are considered some of the highest performance on the market making them popular for less price sensitive aerospace applications. NASA has been known to use this type of battery in a myriad of their technologies and this battery is still commonly used on satellites.

Enervenue, a Fremont, CA based company started in 2020, is targeting a Metal-H2 battery for stationary storage applications and attempting to deliver the industry leading performance characteristics of metal-H2 systems while solving the cost challenges typically associated with this technology. Enervenue’s metal-hydrogen batteries consist of containers filled with metal-H2 battery vessels. Enervenue is claiming to be meeting cost targets by innovating a low-cost H2-splitting anode used in place of platinum and leveraging low-cost higher volume pressure vessel manufacturing methods. Enervenue currently has a manufacturing plant in Kentucky that is under construction. They have a large advertised backlog but have yet to demonstrate their product with a completed and operational utility-scale project.

Iron-Air Batteries

Iron-air batteries were first explored by NASA in the 1960s but have recently regained interest in the eyes of the storage world after recent development and commercialization investment into the technology motivated by a perception of utility-scale LDES potential. Iron-air batteries use a process known as "reversible rusting" in which a pure iron anode is oxidized via O_2 to form iron (III) in a reversible reaction that releases 3 electrons. The rust is reduced back to pure iron (0) during a battery charge.

Form Energy is an iron-air battery vendor that is currently headquartered in the Boston area with applications engineering taking place in San Francisco. Form's 100-hour duration iron-air battery has won many long-duration energy storage projects across the U.S., as they claim over 3 GWh of commercial contracts in place. The Form 2.5 MW/250 MWh Power Block consists of 64 enclosures and equates to approximately an acre of development area.

Aqueous Zinc Batteries

Aqueous-zinc batteries were first explored in the 1980s, but research activity has recently surged due to technological developments and the need for a safer and cheaper and easier to source raw materials on alternatives to lithium-ion batteries. Aqueous-zinc batteries take on a similar chemistry to a zinc-bromine flow battery, but all the necessary electrolyte is contained within a battery cell instead of being stored in tanks and pumped into and out of the battery stack.

EOS is a vendor of U.S.-designed and manufactured aqueous-zinc batteries. EOS has had 250+ 500 kWh containers shipped since its technology first came to market. EOS can accommodate for between 3- and 12-hour discharge durations. The technology is based on the Z3 battery module that can be scaled and adapted for various system size needs.

9.4 Biofuels

9.4.1 Biomass

The term "biomass" refers to any regenerative organic material used as a fuel for energy production. Biomass fuel typically consists of forestry materials, wood residues, agricultural residues, and crops. Biomass power generation facilities are typically located near the source of the fuel to reduce transportation costs in fuel delivery. The most common process to create energy from biomass is high-temperature deconstruction which utilizes extreme heat and pressure to break down the organic biomass material into liquid or gaseous intermediates. Biomass generation can be paired with carbon capture utilization and sequestration ("CCUS") systems to further reduce CO_2 emissions. There are two predominant solid-fuel boiler technologies commonly used with biomass generation: Stoker and bubbling fluidized bed ("BFB") boilers.

In a stoker boiler, mechanical grates are used to introduce biomass materials into the boiler. Fuel is directed to the grate through multiple fuel delivery chutes and is distributed throughout the grate with the use of a pneumatic distributor. Stokers can burn many types of fuel individually or in combination. For biomass combustion, an overfeed stoker system is used. Underfired and overfire air is supplied to the boiler for combustion air. The bed can be burned in low oxygen environments with underfired air, but overfire air is utilized to complete combustion higher in the furnace. Since reserve fuel is maintained in the boiler, units can quickly respond to increased demand. Stoker boilers can fire a wide range of biomass fuels including wood waste, agricultural waste, and municipal solid wastes. Hot gases from fuel combustion are then directed through heat transfer surfaces for recovery of thermal energy. Thermal energy captured within the boiler generates superheated steam which is used to drive a steam turbine and generator to produce electric power.

In a BFB boiler, combustion occurs on a sand bed at the base of the boiler. The bed becomes fluidized upon the introduction of air flow from the bottom of the boiler. Solid fuels are introduced on the bed for combustion by way of air-swept spouts, and ash particles fall to the bottom for periodic removal. A gas-oil burner above and below the circulating fluidized bed allows the furnace to maintain stable temperatures with variations of fuel while allowing for almost complete carbon burnout. Typically, this system and others alike operate with a ~90% thermal efficiency and leave a remaining < 0.5% carbon content, and any remaining carbon particles are trapped via filters within the system before flue gasses are released back into the atmosphere.

9.4.2 Renewable Natural Gas

Renewable natural gas ("RNG") is a phrase used to describe anaerobically generated "biogas" that is produced from organic matter and then refined for utilization in place of fossil natural gases ("FNG"). RNG is derived from a wide range of sources that include but are not limited to waste landfills, digesters at wastewater treatment plants, organic waste management operations, livestock farms, and food production facilities. Options for RNG delivery and use are pipeline injection or local use (at or nearby the site where the RNG is produced). The technology behind RNG involves multiple treatments and purification processes to meet fuel specifications that allow for the replacement of fossil fuels.

There are three main steps to convert biogas into viable RNG. The first treatment involves the removal of moisture and particulates. The second treatment consists of removing additional moisture, contaminant removal and compression. The third treatment consists of removing CO_2, O_2, nitrogen ("N_2"), and volatile organic compounds ("VOCs"). During primary treatment, the gas passes through a knockout pot, filter, and then a blower to remove particles and moisture. A knockout pot is a vessel within a flare header (a large piping system used to relieve gases to the flare) that removes liquids and particles from gas streams at large levels. During secondary treatment, an aftercooler removes additional moisture from the gas and removes contaminants such as sulfur and siloxanes, and further compression can occur if necessary. Aftercoolers are effective in cooling compressed air or gases and use cold air to absorb heat from the system. The level at which contaminants are removed is relative to quantity and quality of biogas obtained. Primary and secondary treatments produce medium-Btu gas, which means that the heat value (the amount of heat released during combustion) is lower than that of FNG. However, the medium-Btu gas can be used in boilers, electricity generation such as in engines and turbines, and other direct thermal applications. The last step, advanced treatment, routes CO_2, O_2, N_2, some CH_4, hydrogen sulfide ("H_2S"), and other VOCs to destruction via a flare or thermal oxidizer. With any RNG site, the amount and frequency at which gases are refined is project and site specific and depends on the technology used to refine the gas and the specification for the RNG. For example, for pipeline injection projects, CH_4 content (which has higher energy contents relative to other fuel variations) of the RNG produced after refining is about 96-98%, but at the start of treatment, the biogas has a CH_4 content of between 45-65%.

A 2022 revised report curated by the U.S. Environmental Protection Agency states that 100 RNG systems exist across 34 states, all of which vary from landfill gas ("LFG") systems, livestock operations that utilize digesters, wastewater treatments plants that employ anerobic digestion to produce biogas, commercial entities, and organic waste management operations. Benefits of RNG include diversifying fuel supply, improving local air quality, and reducing greenhouse gas emissions. While there is great potential for growth of RNG systems in the U.S., there are still technical and economic barriers to producing RNG.

There are currently incentive programs and policies for pipeline injection, which is the most common delivery method of RNG, in states like California, Washington, and Missouri. For instance, California Senate Bill 1383 directed the California Air Resources Board to implement guidelines to reduce CH_4 emissions into the atmosphere by 40% by 2030. The California biomethane interconnection incentive program has been extended to provide up to $3 and $5 million for non-dairy and dairy clusters respectively that operate by December 31, 2026. However, further policy changes such as interconnection incentives along with pliable biogas quality guidelines for pipeline injection would help developers offset any capital costs and allow them to better design the appropriate treatment systems to meet specifications. Currently, there are strict specifications and requirements of gas systems across the country which may limit or prohibit RNG systems entirely. Examples of these requirements include the level of elevated heating and inlet biogas quality. If specifications and requirements were standardized nationally, then developers would be more encouraged to invest, which would promote prolonged purchase agreements and potential for RNG to grow.

9.4.3 Carbon Capture & Sequestration

CCUS essentially captures CO_2 from post-combustion flue gas emitted into the atmosphere and deposits CO_2 in underground geologic formations. Emission sources such as coal and natural gas-fired power plants are prime candidates for CCUS. Commercial technology for capturing CO_2 is limited to advanced amine systems. Geological storage options currently being investigated for secure storage include but are not limited to:

- Depleted oil and gas reservoirs (with or without enhanced oil recovery ("EOR"))
- Deep unused saline water-saturated reservoir rocks
- Deep coal seams unable to be mined
- Shallow coal seams unable to be mined (CO_2 storage with coal bed methane recovery)
- Other options include deep basalts, oil shales, and cavities.

The CCUS process consists of three main steps: capture, transportation, and sequestration. CO_2 capture separates CO_2 from other gases contained in post-combustion flue gas. Following capture, the CO_2 is dehydrated and compressed into a supercritical fluid for transportation and injection. Due to the potential for well corrosion and subsurface gas migration, the super critical fluid is more suitable for CO_2 geologic storage. In addition, many of the sites where the CO_2 emissions occur do not have an adjacent geological storage unit, resulting in the need to transport the compressed gas to a suitable injection site. The supercritical state is also more suitable for CO_2 transport via pipeline. Upon arrival at the storage facility, CO_2 is injected into the targeted subsurface formation via one or more wells. The minimum injection depth, based on the hydrostatic head needed to maintain the supercritical state, is approximately 2,600 feet.

When considering CCUS as a method to mitigate CO_2 emissions, tax credit eligibility is conditional on multiple components of the actual CCUS process. If eligible, the entity claiming the tax credits must either capture and dispose of the CO_2 itself or contract another entity to do so. The capture equipment owner can permit the entity disposing of the CO_2 to claim the tax credits. As new technologies emerge and potential environmental liabilities continue to pose issues, tax credit eligibility is subject to change yearly.

There are currently only two operating power plants with CCUS capabilities in North America. Petra Nova, located near Houston, Texas, was a retrofitted coal-fired power plant that captured CO_2 from a slipstream for use in EOR. It began operation in 2017, but has been temporarily suspended in response to low oil prices. The CCUS facility is a 240 MW system and is designed to capture about 90% of the CO_2 emissions from the flue gas slipstream of the unit. The total cost of Petra Nova's CCUS system was reported to be approximately

$1 billion, and the project is not supported by 45Q tax credits. The Boundary Dam Carbon Capture Project in Saskatchewan, Canada also consists of a retrofitted coal-fired power plant that uses captured CO_2 for EOR. CCUS operation began on Unit #3 in 2014. This unit produces 110 MW. The total cost of the Boundary Dam retrofit was reported to be approximately $345 million.

The Department of Energy has announced nine project selections for CCUS facilities in the United States, most of which have comprehensive commercial-scale site characterization and all of which are still undergoing development. In the meantime, the Department of Energy's Carbon Storage Program aims to further develop CCUS technologies to guarantee 99% storage performance and advance widescale commercial deployment between 2025-2035. An emerging approach to geologic carbon storage is carbon mineralization. When exposed to igneous or metamorphic rocks, CO_2 reacts with the mineral in these rocks to form solid carbonate precipitates. The CO_2 can either be injected into deep underground rock formations or exposed to broken pieces of rock at the ground surface (e.g., mining spoils). The benefit of carbon mineralization is that the creation of a solid mineral precipitate prevents leakage of CO_2 to drinking water aquifers or the atmosphere.

10.0 Conclusions

This Generation Technology Assessment provides information to support MDU'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. 1898 & Co. recommends that MDU use this information to update production cost models for comparison of generation alternatives and their applicability to future resource plans. MDU should pursue additional engineering studies to define project scope, budget, and timeline for technologies of interest.

Of all technologies evaluated, the simple cycle E class plant without an SCR exhibits the lowest capital cost per kW generated. Frame turbines are a mature technology, and the developments of the advanced class turbines in capacity, turndown capability, and efficiency have made them a considerable option in long-term planning of generation. Additionally, these improvements in performance and efficiency have come while the market for these engines is highly competitive, resulting in costs that remain steady or have decreased over the last couple of years. If an SCR is required for the simple cycle application, then the simple cycle E class cost would increase but still remain competitive for lowest cost per kW with either of the aeroderivative turbines. Siemens, Mitsubishi, and GE all have J class turbines, and the technologies are rapidly advancing as OEMs vie for the highest output and best efficiencies. In future Assessments, it is recommended to track the progress of advanced class turbines as they pursue these improvements and consider including the latest models as an option.

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 $/kilowatt ("kW") scale.

Reciprocating engine plants offer the lowest heat rates and fastest start times when compared to simple cycle GT 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.

CCGT plants offer better heat rates than all combustion plants evaluated, and the advanced class GTs perform the best in combined cycle. Multiple combined cycle plants with G/H class turbines are operating in the U.S., and several J class plants are in development.

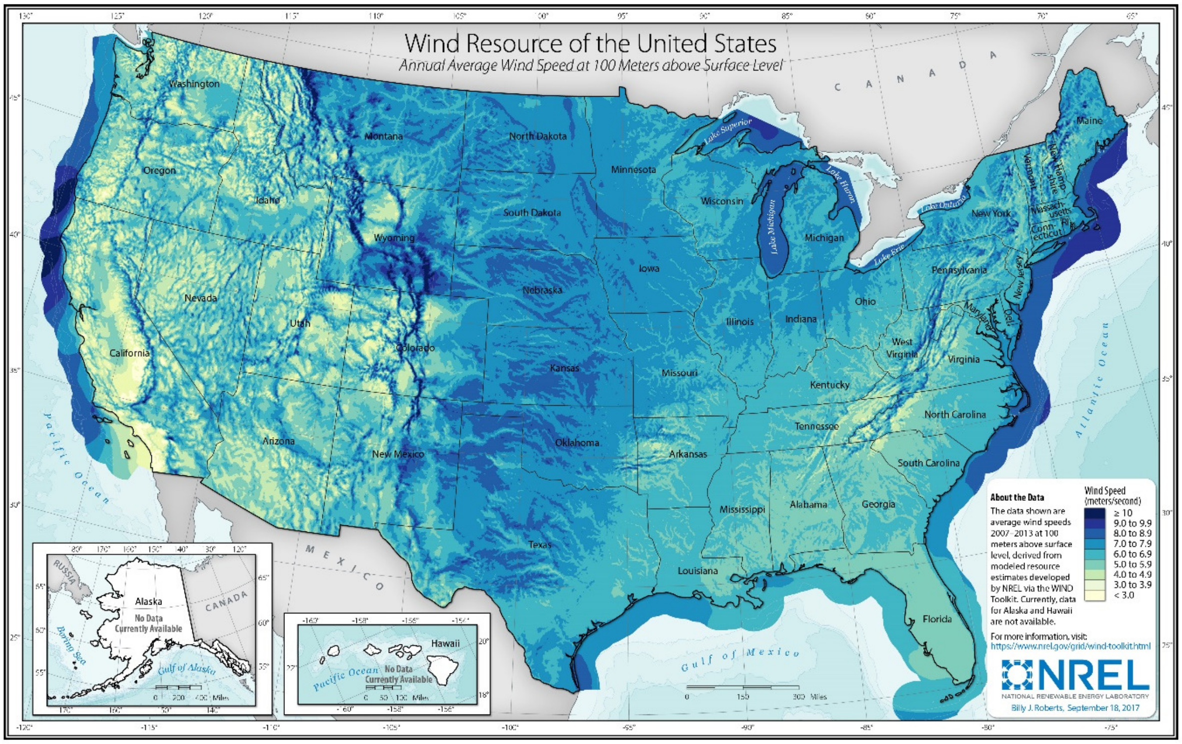
Renewable options include PV and wind systems. Wind and PV are proven technologies for daytime peaking power and a viable option to pursue renewable goals.

Utility-scale battery storage systems are being installed in varied applications from frequency response to arbitrage, and recent cost reduction trends are expected to continue once supply chain issues settle. Lithium-ion technology is achieving the greatest market penetration, aided in large part by its dominance in the automotive industry, but other technologies like flow batteries should be monitored as well.

Several developmental technologies are currently being deployed in controlled settings, with hydrogen fuel-burning capabilities highlighting the list, along with fuel cell technology, SMRs, non-Lithium-ion energy storage, and CCUS. Though each provides a unique method of power production or storage with minimal or no carbon footprint, wide-scale application is limited by technology maturity and the lack of infrastructure to support the transportation of hydrogen fuel. These technologies are expected to become more cost-effective over the coming years, but 1898 & Co. recognizes that progress in the form of minimizing financial risk and increasing generation and/or storage reliability must be made before the pursuit of such technologies is feasible.

11.0 Appendices

APPENDIX A – RENEWABLE ENERGY MAPS



APPENDIX B – SUMMARY TABLE

MONTANA-DAKOTA UTILITIES CO. 2024 GENERIC UNIT ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
NORTH DAKOTA
FEBRUARY 2024 - FINAL DRAFT

PROJECT TYPE	**1x Aeroderivative SCGT - Natural Gas**	**1x Aeroderivative SCGT - Natural Gas**	**1x Frame SCGT - Natural Gas**	**Reciprocating Engine (9 MW) X 4 - Natural Gas**	**Reciprocating Engine (18 MW) X 3 - Natural Gas**	**Reciprocating Engine (11 MW) X 4 - Natural Gas**
BASE PLANT DESCRIPTION						
Number of Gas Turbines/Engines/Units	1	1	1	4	3	4
Representative Class Gas Turbine	GE LM6000 PF+	LMS 100 PB+	7E.03 LLI	Wartsila 20V34SG	Wartsila 18V50SG	Wartsila 31DF
Capacity Factor, %	Peaking (15%)	Peaking (15%)	Peaking (15%)	Peaking (15%)	Peaking (15%)	Peaking (15%)
Startup Time to Base Load, min (Notes 1, 2)	5	8	23	5	5	3
Startup Time to MECL, min (Note 3)	4	7	20	4	4	2
Cold Startup Time to SCR Compliance, min (Note 3)	N/A	45	25	45	45	45
Maximum Ramp Rate, MW/min (Online)	50	50	40	18	27	22
Book Life, Years	35	35	35	35	35	35
Scheduled Outage Factor (SOF), % (Note 4)	6%	6%	6%	4%	4%	4%
Forced Outage Factors (FOF), % (Note 4)	3%	3%	3%	4%	4%	4%
Availability Factor (AF), % (Notes 4)	92%	92%	90%	93%	93%	93%
Assumed Land Use, Acres	20	25	25	20	15	20
Fuel Design	Natural Gas Dual Fuel Option	Natural Gas	Natural Gas Dual Fuel Option	Natural Gas	Natural Gas	Dual Fuel (Natural Gas and Low Sulfur Fuel Oil)
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NO_x Control	Dry Low NOx Nominal 25ppm NOx	SCR	Dry Low NOx Nominal 5ppm NOx	SCR	SCR	SCR
CO Control	Good Combustion Practice	Oxidation Catalyst	Good Combustion Practice	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Execution Schedule Duration (Months)* *Does not account for long lead times.*	20	24	24	24	24	24
Permitting Schedule Duration (Months)* *Does not account for long permitting durations.*	18	18	18	18	18	18
ESTIMATED PERFORMANCE (ALL BASED ON NATURAL GAS OPERATION) (Note 6)						
Base Load Performance @ 6.8° F (Winter Design)						
Gross Plant Output, kW	54,500	112,700	97,300	37,500	56,500	45,500
Net Plant Output, kW	53,100	109,900	94,800	36,500	55,000	44,400
Net Plant Heat Rate, Btu/kWh (HHV)	9,450	8,770	11,330	8,470	8,330	8,280
Heat Input, MMBtu/h (HHV)	500	960	1,070	310	460	370
Min Load Operational Status @ 6.8° F (Winter Design)						
Gross Plant Output, kW	27,400	56,300	48,600	3,800	7,500	4,600
Net Plant Output, kW	26,700	54,900	47,400	3,700	7,300	4,400
Net Plant Heat Rate, Btu/kWh (HHV)	12,090	10,740	14,670	9,550	9,410	9,380
Heat Input, MMBtu/h (HHV)	320	590	700	30	70	40
Base Load Performance @ 84.5° F (Summer Design)						
Gross Plant Output, kW	46,200	102,400	79,900	37,500	56,500	45,500
Net Plant Output, kW	45,000	99,900	77,900	36,500	55,000	44,400
Net Plant Heat Rate, Btu/kWh (HHV)	9,730	8,970	11,800	8,470	8,330	8,370
Heat Input, MMBtu/h (HHV)	440	900	920	310	460	370
Min Load Operational Status @ 84.5° F (Summer Design)						
Gross Plant Output, kW	22,700	51,200	40,000	3,800	7,500	4,600
Net Plant Output, kW	22,200	49,900	39,000	3,700	7,300	4,400
Net Plant Heat Rate, Btu/kWh (HHV)	13,750	11,140	15,570	9,620	9,480	9,460
Heat Input, MMBtu/h (HHV)	300	560	610	40	70	40
ESTIMATED CAPITAL AND O&M COSTS (Note 7, Note 8)						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$82**	**$169**	**$89**	**$78**	**$123**	**$86**
EPC Cost Per Summer kW, 2024 $/kW	**$1,832**	**$1,688**	**$1,146**	**$2,131**	**$2,228**	**$1,944**
Owner's Costs, 2024 MM$	**$64**	**$80**	**$73**	**$61**	**$66**	**$63**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Engineer	$0.8	$1.0	$1.0	$1.0	$1.0	$1.0
Owner's Project Management	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2
Owner's Legal Costs	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Owner's Start-up Engineering and Commissioning	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Land	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Construction Power and Water	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6
Permitting and Licensing Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Switchyard	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.6	$0.8	$0.8	$0.9	$0.9	$1.4
Site Security	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
Operating Spare Parts	$1.8	$2.0	$1.5	$0.4	$0.4	$0.4
Permanent Plant Equipment and Furnishings	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Builders Risk Insurance (0.45% of Construction Costs)	$0.4	$0.8	$0.4	$0.3	$0.6	$0.4
Owner's Contingency (5% for Screening Purposes)	$4.9	$9.3	$5.3	$4.7	$6.9	$5.1
Transmission Network Upgrades ($150/kW)	$8.0	$16.5	$14.2	$5.5	$8.3	$6.7
Transmission Interconnection Costs	$25.5	$25.5	$25.5	$25.5	$25.5	$25.5
Natural Gas Interconnection Costs	$8.5	$10.0	$10.0	$8.5	$8.5	$8.5
Water Interconnection Costs	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
MISO Queue Fees	$0.3	$0.3	$0.3	$0.2	$0.3	$0.2
Total Project Costs, 2024 MM$ (Unloaded)	**$146**	**$248**	**$162**	**$138**	**$188**	**$149**

Total Cost Per Summer kW, 2024 $/kW (Unloaded)	**$3,252**	**$2,485**	**$2,077**	**$3,789**	**$3,425**	**$3,356**
Loaded Costs						
Interest During Construction, 2024 $MM	$9.2	$15.4	$11.7	$10.1	$13.6	$10.8
Total Project Costs, 2024 MM$ (Loaded)	**$156**	**$264**	**$174**	**$148**	**$202**	**$160**
Total Cost Per Summer kW, 2024 $/kW (Loaded)	**$3,457**	**$2,639**	**$2,227**	**$4,065**	**$3,672**	**$3,599**
FIXED O&M COSTS (Note 10)						
Fixed O&M Cost - LABOR, 2024 $MM/Yr	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1
Fixed O&M Cost - OTHER, 2024 $MM/Yr	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9
Property Tax, 2024 $/kW-mo	$0.99	$0.83	$0.73	$1.39	$1.22	$1.23
Property Insurance, 2024 $/kW-mo	$0.34	$0.28	$0.25	$0.47	$0.42	$0.42
LEVELIZED CAPITAL MAINTENANCE COSTS (Note 11)						
Major Maintenance Cost, 2024 $/GT-hr or $/engine-hr	$200	$416	$350	$37.22	$72.11	$52.12
Major Maintenance Cost, 2024 $/GT-start	N/A	N/A	$8,400.0	N/A	N/A	N/A
Major Maintenance Cost, 2024 $/MWh	$3.70	$3.78	$4.28	$4.07	$3.83	$4.71
Catalyst Replacement Cost, 2024 $/MWh	N/A	$0.36	N/A	$0.26	$0.16	$0.22
NON-FUEL VARIABLE O&M COSTS (EXCLUDES LEVELIZED CAP. MAINT. COST) (Note 11)						
Total Variable O&M Cost, 2024 $/MWh - ISO	$0.90	$1.33	$0.90	$5.11	$5.29	$5.76
Water Related O&M, $/MWh	$0.00	$0.20	$0.00	$0.00	$0.00	$0.00
SCR Reagent, $/MWh	N/A	$0.23	N/A	$0.88	$0.90	$1.45
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$4.23	$4.38	$4.31
SCR ADD-ON COSTS						
# Capital Costs, 2024 MM$	$13.4	Included	$34.7	Included	Included	Included
# Owner's Costs, 2024 MM$	$1.30	Included	$2.40	Included	Included	Included
Loaded Costs (Interest During Construction), 2024 $MM	$0.9	Included	$2.6	Included	Included	Included
SCR O&M COSTS						
Catalyst Replacement Cost, 2024 $/MWh	$0.55	Included	$0.55	Included	Included	Included
# Incremental Fixed O&M Cost, 2024 $MM/yr	$0.00	Included	$0.00	Included	Included	Included
# Incremental Variable O&M Cost, 2024 $/MWh	$0.14	Included	$0.04	Included	Included	Included
DUAL FUEL ADD-ON COSTs (Note 20, Note 21)						
# Capital Costs, 2024 MM$	$23.9	N/A	$33.2	N/A	N/A	$3.9
# Owner's Costs, 2024 MM$	$1.85	N/A	$2.35	N/A	N/A	$0.75
Loaded Costs (Interest During Construction), 2024 $MM	$1.6	N/A	$2.5	N/A	N/A	$0.3
ESTIMATED BASE LOAD OPERATING EMISSIONS (ISO) (Note 5)						
Turbine/Engine Only						
Gross Carbon Intensity (lb/MWh)	1,130	N/A	1,350	N/A	N/A	N/A
NO_X [lb/MMBtu, HHV]	0.090	N/A	0.020	N/A	N/A	N/A
NO_X [ppmvd @ 15% O_2]	25	N/A	5.0	N/A	N/A	N/A
NO_X [lb/hr]	40.0	N/A	19.0	N/A	N/A	N/A
CO [lb/MMBtu, HHV]	0.050	N/A	0.050	N/A	N/A	N/A
CO [ppmvd @ 15% O_2]	25	N/A	25	N/A	N/A	N/A
CO [lb/hr]	24.0	N/A	55.0	N/A	N/A	N/A
CO_2 [lb/MMBtu, HHV]	120	N/A	120	N/A	N/A	N/A
CO_2 [lb/hr]	53,200	N/A	121,000	N/A	N/A	N/A
PM/PM_{10} [lb/MMBtu, HHV]	0.007	N/A	0.004	N/A	N/A	N/A
PM/PM_{10} [lb/hr]	3.00	N/A	4.20	N/A	N/A	N/A
Turbine /Engine with SCR and CO Catalyst						
Gross Carbon Intensity (lb/MWh)	1,130	1,050	1,350	1,020	1000	1000
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.010	0.020	0.020	0.020
NO_X [ppmvd @ 15% O_2]	2.5	2.5	2.0	5.0	5.0	5.0
NO_X [lb/hr]	4.40	8.60	8.30	1.20	2.50	1.50
CO [lb/MMBtu, HHV]	0.000	0.010	0.010	0.030	0.030	0.030
CO [ppmvd @ 15% O_2]	2.0	4.0	2.0	15.0	15.0	15.0
CO [lb/hr]	2.20	8.40	5.00	2.50	5.00	3.06
CO_2 [lb/MMBtu, HHV]	120	120	120	120	120	120
CO_2 [lb/hr]	60,000	115,200	128,400	37,200	55,200	44,400
PM/PM_{10} [lb/MMBtu, HHV]	0.010	0.008	0.008	0.020	0.020	0.020
PM/PM_{10} [lb/hr]	4.40	6.70	7.40	1.70	3.30	2.10

Notes

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.

Note 2: Fast start capability for peaking combustion turbines has largely been included within base OEM packages as a response to market demand for quick reacting firm power. Market trends suggest that O&M impacts from fast starts affect the overall equivalent hours of operation (or similar operating time measures across OEMs) and might result in accelerated maintenance schedules. The GE 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. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.

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 2013 or later. Reporting period is 2013-2022.

Note 5: Emissions estimates are shown for steady state operation at annual average conditions as provided by MDU for natural gas, unless otherwise stated. Estimates account for the impacts of SCR and CO catalysts, as applicable. Emissions estimates should not be used for permitting.

Note 6: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at 1695 ft above sea level and ambient conditions. Evaporative cooler is assumed to be operating during full load operation weather conditions above 59 °F.

Note 7: Capital and fixed O&M costs are presented in 2024 USD $MM and presented as overnight costs (exclude forward-looking escalation). Estimated costs exclude decommisioning costs and salvage values.

Note 8: SCR O&M costs are assumed to be at ISO conditions.

Note 9: All gas turbine FOM costs assume 7 full time personnel for first unit. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.

Note 10: Major maintenance $/hr holds for aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27.

Note 11: VOM assumes the use of temporary trailers for demineralized water treatment, where applicable.

Note 12: 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 13: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage (land costs excluded).

Note 14: Natural gas interconnection includes an allowance for 5 mile pipeline.

Note 15: Water interconnection allowance includes on-site wells and pipe for raw water supply.
Note 16: MISO Queue Fees includes M1 and M2 milestone payments. M1 milestone payment includes the application fee and funding for applicable transmission studies. M2 milestone payment is calculated as $8,000 per MW of interconnection studied as part of the application.
Note 17: Reciprocating engine major maintenance cost assumes a minor overhaul at 18,000 operating hours and a major overahul at 36,000 operating hours.
Note 18: Land allowance assumes $5,000/acre.
Note 19: Property tax and property insurance rate provided by MDU.
Note 20: Dual fuel cost breakout for the Wartsila 31DF option includes cost to support operation with fuel oil only. Base cost for the Wartsila 31DF includes pricing for minimal dual fuel equipment needed to support fuel oil injection for natural gas operation.
Note 21: Dual fuel cost breakout for the LM6000 and 7E.03 turbines includes permanent water treatment system.

MONTANA-DAKOTA UTILITIES CO. 2024 GENERIC UNIT ASSESSMENT SUMMARY TABLE
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
NORTH DAKOTA
FEBRUARY 2024 - FINAL DRAFT

PROJECT TYPE	2x1 SGT-800 CCGT - Fired	1x1 F Class CCGT - Fired	2x1 E Class CCGT - Fired, Hesket Expansion
BASE PLANT DESCRIPTION			
Number of Gas Turbines	2	1	2
Number of Steam Turbines	1	1	1
Representative Class Gas Turbine	SGT-800	GE 7F.05	GE 7E.03
Steam Conditions (Main Steam / Reheat)	850 °F / 850 °F	1,050 °F / 1,050 °F	1,000 °F
Main Steam Pressure	1,500 psia	2,400 psia	1,500 psia
Steam Cycle Type	Subcritical	Subcritical	Subcritical
Capacity Factor (%)	70%	70%	70%
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 1)	180	180	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 1)	120	120	120
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 1)	80	80	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (Note 2)	60	60	60
Maximum Ramp Rate, MW/min (Online)	15	32	26
Book Life (Years)	35	35	35
Scheduled Outage Factor (SOF), % (Note 3)	11%	11%	11%
Forced Outage Factor (FOF), % (Note 3)	2%	2%	2%
Availability Factor (AF), % (Note 3)	87%	87%	87%
Assumed Land Use (Acres)	35	45	40
Fuel Design	Natural Gas	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers
NO_x Control	DLN/SCR	DLN/SCR	Dry Low NOx Nominal 5ppm Nox Option for SCR w/ Duct Firing
CO Control	Oxidation Catalyst	Oxidation Catalyst	Option for Oxidation
Particulate Control	Good Combustion	Good Combustion	Good Combustion
Technology Rating	Mature	Mature	Mature
EPC Execution Schedule Duration (Months)* **Does not account for long lead times.*	36	36	36
Permitting Schedule Duration (Months)* **Does not account for long permitting durations.*	18	18	18
ESTIMATED PERFORMANCE (Note 4)			
Base Load Performance @ 6.8 °F (Winter)			
Gross Plant Output, kW	184,400	345,300	289,100
Net Plant Output, kW	177,400	334,900	279,100
Net Plant Heat Rate, Btu/kWh (HHV)	6,790	6,690	7,710
Heat Input, MMBtu/h (HHV)	1200	2,240	2,150
Incremental Duct Fired Performance @ 6.8 °F (Winter)			
Incremental Gross Duct Fired Output, kW	50,100	92,100	88,400
Incremental Duct Fired Output, kW	47,700	90,500	86,300
Incremental Heat Rate, Btu/kWh (HHV)	9,980	8,140	10,210
Incremental Heat Input, MMBtu/h (HHV)	480	740	880
Minimum Load (Single Turbine at MECL) @ 6.8 °F (Winter)			
Gross Plant Output, kW	48,100	192,100	115,700
Net Plant Output, kW	42,700	182,600	108,800
Net Plant Heat Rate, Btu/kWh (HHV)	8,740	7,520	8,300
Heat Input, MMBtu/h (HHV)	370	1,370	900
Base Load Performance @ 84.5 °F (Summer)			
Gross Plant Output, kW	159,900	336,400	250,200
Net Plant Output, kW	152,400	323,900	239,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,900	6,660	7,700
Heat Input, MMBtu/h (HHV)	1050	2,160	1,840
Incremental Duct Fired Performance @ 84.5 °F (Summer)			
Incremental Gross Duct Fired Output, kW	47,700	86,600	91,300
Incremental Duct Fired Output, kW	46,200	85,700	90,400
Incremental Heat Rate, Btu/kWh (HHV)	9,590	8,030	9,990
Incremental Heat Input, MMBtu/h (HHV)	440	690	900
Minimum Load (Single Turbine at MECL) @ 84.5 °F (Summer)			
Gross Plant Output, kW	40,000	184,000	94,200
Net Plant Output, kW	34,000	174,400	86,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,300	7,550	8,460
Heat Input, MMBtu/h (HHV)	320	1,320	730

ESTIMATED CAPITAL AND O&M COSTS (Note 5)			
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$335**	**$486**	**$318**
EPC Cost Per UNFIRED kW, 2024 $/kW	**$2,199**	**$1,500**	**$1,328**
Owner's Costs, 2024 MM$	**$141**	**$165**	**$64**
Owner's Project Development	$3.5	$3.5	$3.5
Owner's Operational Personnel Prior to COD	$1.9	$1.7	$1.8
Owner's Engineer	$2.6	$2.3	$2.6
Owner's Project Management	$6.8	$5.9	$6.8
Owner's Legal Costs	$1.0	$1.0	$0.8
Owner's Start-up Engineering and Commissioning	$0.3	$0.3	$0.3
Land	$0.2	$0.2	$0.0
Temporary Utilities	$1.7	$1.6	$0.1
Permitting and Licensing Fees	$0.5	$0.5	$0.5
Switchyard	$14.5	$10.5	$3.3
Political Concessions & Area Development Fees	$0.5	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$1.9	$1.9	$1.9
Initial Fuel Inventory	$6.5	$3.3	$0.0
Site Security	$0.8	$0.8	$0.4
Operating Spare Parts	$7.2	$6.0	$1.0
Permanent Plant Equipment and Furnishings	$1.3	$1.3	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.4	$2.2	$1.4
Owner's Contingency (5% for Screening Purposes)	$18.7	$26.2	$15.6
Transmission Network Upgrades ($150/kW)	$22.9	$48.6	$21.7
Transmission Interconnection Costs	$25.5	$25.5	$0.6
Natural Gas Interconnection Costs	$11.5	$11.5	$0.5
Water Interconnection Costs	$9.2	$9.2	$0.0
MISO Queue Fees	$0.3	$0.4	$0.4
Total Project Costs, UNFIRED, 2024 MM$ (Unloaded)	**$476**	**$651**	**$382**
Total Cost Per UNFIRED kW, 2024 $/kW (Unloaded)	**$3,122**	**$2,009**	**$1,598**
Loaded Costs			
Interest During Construction, 2024 $MM	$39.5	$53.8	$31.8
Total Project Costs UNFIRED, 2024 MM$ (Loaded)	**$515**	**$705**	**$414**
Total Cost Per UNFIRED kW, 2024 $/kW (Loaded)	**$3,381**	**$2,176**	**$1,731**
DUCT FIRING ADD-ON COST			
Capital Costs, 2024 $MM	$12.8	$11.3	$12.9
Owner's Costs, 2024 $MM	$0.8	$0.7	$0.8
Loaded Costs, Interest During Construction, 2024 MM$	$1.1	$1.0	$1.1
SCR ADD-ON COST			
Capital Costs, 2024 $MM	Included	Included	$6.6
Owner's Costs, 2024 $MM	Included	Included	$0.4
Loaded Costs, Interest During Construction, 2024 MM$	Included	Included	$0.6
Total Project Cost, FIRED, 2024 $MM (Unloaded)	**$489**	**$663**	**$396**
Total Cost Per FIRED Summer kW, 2024 $/kW (Unloaded)	**$2,464**	**$1,618**	**$1,201**
Total Project Cost, FIRED, 2024 $MM (Loaded)	**$529**	**$717**	**$428**
Total Cost Per FIRED Summer kW, 2024 $/kW (Loaded)	**$2,664**	**$1,750**	**$1,299**
FIXED O&M COSTS (Note 6)			
Fixed O&M Cost - LABOR, 2024 $MM/Yr	$3.8	$3.3	$3.8
Fixed O&M Cost - OTHER, 2024 $MM/Yr	$2.5	$2.4	$2.5
Property Tax, 2024 $/kW-mo	$0.99	$0.71	$0.38
Property Insurance, 2024 $/kW-mo	$0.34	$0.24	$0.13
LEVELIZED CAPITAL MAINTENANCE COSTS (Note 7)			
Major Maintenance Cost, 2024 $/GT-hr	$200	$450	$350
Major Maintenance Cost, 2024 $/MWh	$2.10	$1.30	$2.51
Catalyst Replacement Cost, 2024 $/MWh	$0.30	$0.20	Included in SCR Option
NON-FUEL VARIABLE O&M COSTS (EXCLUDES LEVELIZED CAP. MAINT. COST) (Note 8)			
Total Variable O&M Cost, 2024 $/MWh	$3.50	$2.80	$3.00
Water Related O&M ($/MWh)	$1.30	$0.70	$1.20
SCR Reagent, $/MWh	$0.30	$0.40	Included in SCR Option
Other Consumables and Variable O&M ($/MWh)	$1.90	$1.70	$1.80
Incremental Duct Fired Variable O&M, 2024 $/MWh (excl. GT major maint.)	$1.70	$1.20	$1.60
Water Related O&M ($/MWh)	$1.00	$0.50	$0.90
SCR Reagent, $/MWh	$0.20	$0.20	$0.20
Other Consumables and Variable O&M ($/MWh)	$0.50	$0.50	$0.50

Incremental SCR O&M Costs			
Catalyst Replacement Cost, 2024 $/MWh	Included in Base	Included in Base	$0.47
SCR Reagent, $/MWh	Included in Base	Included in Base	$0.20
ESTIMATED BASE LOAD OPERATING EMISSIONS, (ISO) (Note 9)			
Unfired			
Gross Carbon Intensity (lb/MWh)	810	840	430
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]	4.0	17.0	19.0
CO [lb/MMBtu, HHV]	0.004	0.004	0.050
CO [ppmvd @ 15% O_2]	2.0	2.0	10.0
CO [lb/hr]	2.30	11.0	55.0
CO_2 [lb/MMBtu, HHV]	120	120	120
CO_2 [lb/hr]	144,000	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)	900	840	1,000
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.040
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]	0.004	0.004	0.060
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 [lb/hr]	201,600	357,600	363,600
PM/PM_{10} [lb/MMBtu, HHV]	0.008	0.008	0.007
PM/PM_{10} [lb/hr]	3.00	13.5	11.1

Notes

Note 1: 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. Cold start is >72 hours after shutdown. Hot start is <8 hours after shutdown.
Note 2: Startup time to stack emissions compliance 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 2013 or later. Reporting period is 2013-2022.
Note 4: New and clean performance assumed. All performance ratings are based on NATURAL GAS operation and are inclusive of incremental performance for duct firing option. Min load ratings are based on OEM performance information at specified ambient conditions.
Note 5: Capital and fixed O&M costs are presented in 2024 USD $MM. Capital costs include duct firing to 1,400 °F for all fired options. Estimated costs exclude decommisioning costs and salvage values.
Note 6: Base O&M costs are based on performance at annual average conditions. Fixed O&M assumes 22 FTE for 1x1 and 25 FTE for 2x1 configurations.
Note 7: Major maintenance $/hr holds for frame gas turbines where hours per start is >27.
Note 8: Variable O&M costs assume onsite demin treatment system.
Note 9: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts.
Note 10: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage (land costs excluded).
Note 11: Natural gas interconnection includes an allowance for 5 mile pipeline.
Note 12: Water interconnection allowance includes on-site wells and pipe for raw water supply.
Note 13: MISO Queue Fees includes M1 and M2 milestone payments. M1 milestone payment includes the application fee and funding for applicable transmission studies. M2 milestone payment is calculated as $8,000 per MW of interconnection studied as part of the application.
Note 14: Reciprocating engine major maintenance cost assumes a minor overhaul at 18,000 operating hours and a major overahul at 36,000 operating hours.
Note 15: Land allowance assumes $5,000/acre.
Note 16: Property tax and property insurance rate provided by MDU.

MONTANA-DAKOTA UTILITIES CO. 2024 GENERIC UNIT ASSESSMENT SUMMARY TABLE
RENEWABLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
NORTH DAKOTA
FEBRUARY 2024 - FINAL DRAFT

PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
BASE PLANT DESCRIPTION				
Nominal Output, MW	50	100	50 MW PV Opt: 10 MW / 40 MWh Storage	5 MW PV Opt: 1 MW / 4 MWh Storage
Representative Technology	GE 2.82-127	GE 2.82-127	PV: Single Axis Tracking Storage: Lithium-Ion Batteries	PV: Single Axis Tracking Storage: Lithium-Ion Batteries
Number of Turbines	18 x 2.82 MW	36 x 2.82 MW	N/A	N/A
Capacity Factor (%) (Notes 1, 2)	47.5%	47.5%	24%	24%
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	1.35	1.35
PV Degradation (%/yr) (Note 3)	N/A	N/A	0.5%/yr	0.5%/yr
Equivalent Availability Factor (%) (Note 4)	95%	95%	99%	97%
ESTIMATED PERFORMANCE				
Base Load Performance				
Net Plant Output, kW	50,000	100,000	50,000	5,000
ESTIMATED CAPITAL AND O&M COSTS (Note 5)				
Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$108**	**$182**	**$93**	**$9**
Project Cost Per kW, 2024 $/kW	**$2,150**	**$1,820**	**$1,864**	**$1,860**
Owner's Costs, 2024 MM$	**$25**	**$34**	**$21**	**$3**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Excluded	Excluded	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Legal Costs	Included	Included	$0.3	$0.3
Startup / Testing / Warranties	Excluded	Excluded	Allowance Included	Allowance Included
Land (Note 6)	Included - Development Phase	Included - Development Phase	Excluded - Assumes Lease	Excluded - Assumes Lease
Temporary Utilities	Included	Included	$0.3	$0.1
Site Security	Included	Included	$0.1	$0.1
Operating Spare Parts	Included	Included	$0.1	$0.1
Permanent Plant Equipment and Furnishings	Included	Included	$0.3	$0.3
Political Concessions & Area Development Fees	$0.0	$0.0	$0.0	$0.0
Permitting and Licensing Fees	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Switchyard / Interconnection (Notes 7, 8)	Allowance Included	Allowance Included	$5.6	$0.3
Builder's Risk Insurance (Note 9)	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency (Note 10)	$10.8	$18.2	Allowance Included	Allowance Included
Transmission Network Upgrades ($150/kW)	$7.5	$15.0	$7.5	$0.8
MISO Queue Fees	$0.2	$0.3	$0.2	$0.2
Total Project Costs, 2024 MM$	**$133**	**$216**	**$114**	**$12**
Total Cost Per kW, 2024 $/kW	**$2,660**	**$2,156**	**$2,280**	**$2,467**
Loaded Costs				
Interest During Construction, 2024 $MM	$3.2	$4.9	$5.9	$1.0
Total Project Costs, 2024 MM$ (Loaded)	**$136**	**$221**	**$120**	**$13**
Total Cost Per kW, 2024 $/kW (Loaded)	**$2,723**	**$2,205**	**$2,398**	**$2,671**
FIXED O&M COST				
Fixed O&M Cost, 2024 $/kW-mo	$3.70	$3.70	$1.50	$1.90
Property Tax, 2024 $/kW-mo (Note 11)	$0.90	$0.70	$0.80	$0.80
Property Insurance, 2024 $/kW-mo (Note 12)	$0.30	$0.30	$0.60	$0.60
NON-FUEL VARIABLE & MAINTENANCE COST				
Major Maintenance Cost, 2024 $/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Variable O&M Cost, 2024 $/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Co-Located Energy Storage			**10 MW / 40 MWh**	**1 MW / 4 MWh**
Add-On Costs				
Capital Costs, 2024 MM$	N/A	N/A	$18.0	$2.7
Owner's Costs, 2024 MM$ (Note 13)	N/A	N/A	$1.4	$0.5
Incremental O&M Cost, 2024 MM$/Yr	N/A	N/A	$3.33	$4.75
Loaded Costs (Interest During Construction), 2024 $MM	N/A	N/A	$0.94	$0.16

Notes:

Note 1: Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on GE 2.82-127 turbines with 89 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: Estimated Costs exclude decommisioning costs and salvage values.
Note 6: Wind projects assume that there are temporary land leases during development period (which is included in the Owner's Costs) of fifty acres per MW based on MISO land requirements. However, the leases executed for post-development Project operation are categorized in Fixed O&M, not capital costs, and are based on empirical data represented by an overall $/kW-yr cost.

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. PV assumes seven acres per MW for fixed tilt and eight acres per MW for tracking options.
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: Builder's risk insurance assumes 0.45% of project cost.
Note 10: Owner's contigency assumes 10% for screening purposes.
Note 11: Property tax rate of 0.44% provided by MDU.
Note 12: Property Insurance rate of 0.33% provided by MDU.
Note 13: Separate substation / switchyard cost not included in owner's cost for co-located energy storage.

MONTANA-DAKOTA UTILITIES CO. 2024 GENERIC UNIT ASSESSMENT SUMMARY TABLE ENERGY STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION NORTH DAKOTA FEBRUARY 2024 - FINAL DRAFT	
PROJECT TYPE	**Battery Storage**
BASE PLANT DESCRIPTION	
Nominal Output, MW	50 MW / 200 MWh
Representative Technology	Lithium-Ion Batteries
Use Case Assumption	365 cycles per year
Book Life (Years)	20
Assumed Land Use (Acres)	5
Total System Cycles	7,300
Interconnection Voltage Assumption	115 kV
Storage System AC Capacity at POI (MWh)	200
Storage System Capacity Installed at POI (MWh) (Note 1)	240
Storage System Degradation Assumption (%/yr)	2%
Storage System AC Roundtrip Efficiency (%)	85%
Technology Rating	Mature
Permitting & Construction Schedule (Years from FNTP)	2.5
ESTIMATED PERFORMANCE	
Base Load Performance @ (Annual Average)	
Net Plant Output, kW	50,000
ESTIMATED CAPITAL AND O&M COSTS	
Project Capital Costs, 2024 MM$ (w/o Owner's Costs) (Note 2)	**$81**
Project Cost Per kWh, 2024 $/kWh (Note 3)	**$338**
Owner's Costs, 2024 MM$	**$22**
Owner's Project Development	Allowance Included
Owner's Engineer	Allowance Included
Owner's Project Management	Allowance Included
Owner's Startup Personnel	Allowance Included
Land (Note 4)	Excluded - Assumes Lease
Permitting and Licensing Fees	Allowance Included
Switchyard / Substation (Note 5)	Allowance Included
Builder's Risk Insurance (Note 6)	Allowance Included
Owner's Contingency (Note 7)	Allowance Included
Transmission Network Upgrades ($150/kW)	$7.5
MISO Queue Fees	$0.2
Total Project Costs, 2024 MM$ (Unloaded)	**$103**
Total Cost Per kWh, 2024 $/kWh (Unloaded)	**$517**
Loaded Costs	
Interest During Construction, 2024 $MM	$7.4
Total Project Costs, 2024 MM$ (Loaded)	**$111**
Total Cost Per kWh, 2024 $/kWh (Loaded)	**$554**
Fixed O&M Cost	
Fixed O&M Cost, 2024 $/kW-mo (Note 8)	$2.51
Property Tax, 2024 $/kW-mo (Note 9)	$0.70
Property Insurance, 2024 $/kW-mo (Note 10)	$0.53

Non-Fuel Variable & Maintenance Cost	
Major Maintenance Cost, 2024 $/MWh	Included in FOM
Variable O&M Cost, 2024 $/MWh	Included in FOM

Notes

Note 1: Installed MWh capacity is in terms of AC capacity and accounts for 3 years of overbuild.

Note 2: Estimated project capital costs assume full-wrap engineering, procurement, and construction (EPC). Estimated project capital costs exclude decommissioning costs and salvage values.

Note 3: Project cost per kWh is based on installed AC kWh.

Note 4: BESS 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. BESS projects assume one-tenth acres per MW.

Note 5: Switchyard/substation estimate assumes three-position ring bus.

Note 6: Builder's risk insurance assumes 0.45% of project cost.

Note 7: Owner's contingency assumes 5%.

Note 8: Estimated fixed O&M costs include allowances for scheduled O&M, augmentation, and warranties. Fixed O&M cost assumes the site is remotely controlled.

Note 9: Property tax rate of 0.44% provided by MDU.

Note 10: Property Insurance rate of 0.33% provided by MDU.

APPENDIX C – SCOPE ASSUMPTIONS MATRIX

MONTANA-DAKOTA UTILITIES TECHNOLOGY ASSESSMENT ASSUMPTIONS

	Simple Cycle - Aero	Simple Cycle - Frame	Reciprocating Engines	Combined Cycle	Wind	PV / PV + Storage	Storage
Project Description							
Plant Size(s):	1 x LM6000 PF+ 1 x LMS100 PB+	1 x 7E.03 LLI	4 x 20V34SG (9 MW) 3 x 18V50SG (18 MW) 4 x 31DF (11 MW)	2x1 SGT-800 1x1 F-Class 2x1 E-Class (Heskett Expansion)	GE 2.82-127 (50 MW) GE 2.82-127 (100 MW)	50 MW PV Single-Axis Tracking (10 MW / 40 MWh Li-ion Battery) 5 MW PV Single-Axis Tracking (1 MW / 4 MWh Li-ion Battery)	50 MW / 200 MWh Li-ion Battery
Fuel:	Primary Fuel Type: Natural Gas; Dual Fuel Option for LM6000; Performance shown for Gas Only in Summary Table	Primary Fuel Type: Natural Gas; Dual Fuel Option; Performance shown for Gas Only in Summary Table	Primary Fuel Type: Natural Gas for 20V34SG and 18V50SG; Dual Fuel for 31DF Performance shown for Gas Only in Summary Table	Primary Fuel Type: Natural Gas; Performance shown for Gas Only in Summary Table	N/A	N/A	N/A
Project Location:	North Dakota						
Contract Philosophy:	Engineer, Procure, Construct (EPC) Methodology						
Project COD:	Costs shown in 2023 USD (i.e. no escalation)						
Labor Type:	Union Labor						
Site Description:	General Site Layout			General Site Layout; 2x1 E-Class assumes existing Heskett Station layout	General Site Layout		
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.						
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and coal plant stacks.						
Site Elevation:	1,695 ft						
Site Summer Ambient Conditions:	84.5 ℉ / 40% RH						
Site Winter Ambient Conditions:	6.8 ℉ / 70% RH						
Water Supply:	Fresh Water supply from wells or surface water; pipeline/intake excluded from cost.						
Waste Water Disposal:	Discharge offsite, piping beyond site boundary excluded.				N/A		
Performance Basis							
Inlet Cooling	Evaporative Cooler Included		N/A	Evaporative Cooler Included	N/A		
Heat Rejection Design:	Fin Fan Heat Exchanger			Cooling Tower, Wet-Cooled			
Availability Metrics	NERC GADS data for SOF, FOF, and AF, as applicable.				NERC GADS data for EAF, as applicable		
Fuel and Reagent Storage & Disposal							
Design Fuel:	Natural Gas				N/A		
Design Fuel Supply:	Assumed pipeline quality of natural gas at sufficent operating pressures.						
Back-up Fuel:	Ultra-low Sulfur Diesel for LM6000	Ultra-low Sulfur Diesel	Ultra-low Sulfur Diesel for 31DF				
Start-up Fuel:	Natural Gas / Oil	Natural Gas / Oil	Natural Gas / Oil				
Fuel Oil Delivery and Unloading:	Truck. Unloading station included.						
Fuel Oil Storage:	Onsite storage, 3 day storage						
Ammonia:	Aqueous Ammonia delivered by truck.						
Enclosures:							
Gas Turbine or Engine:	Outdoor		Indoor	Outdoor	N/A		
Steam Turbine	N/A			Indoor			
HRSG				Indoor			
Buildings:	Warehouse, Maintenance Hall, and Administration Building included for General Layout sites. Heskett expansion option assumes existing facilities are utilized as applicable. Minimal miscellaneous equipment enclosures included for electrical equipment, CEMS enclosure, etc.				Maintenance Hall Allowance Included	Excluded	
Emissions and Emissions Controls*							
NOx Control:	LM6000: DLN Included, SCR Option LMS 100: DLN & SCR Included	DLN Included, SCR Option	DLN & SCR Included		N/A		
CO Control:	CO catalyst paired with SCR options, as applicable.						
SO_2 Control:	Low Sulfur Fuel						
SO_3 Control:	N/A						
PM10 Control (filterable & condensable particulate):							
Mercury Control:							
VOC Control:	Good combustion practice.						
Transmission/Interconnection:							
Switchyard:	Included with position for generators & 2 outgoing lines.						
Transmission Interconnection:	Cost for 15 mile of transmission line at interconnection voltage, excludes land costs.						
Interconnection Voltage:	115 kV						
Gas Interconnection:	Included, 5 mi. of interconnection, easement allowance and metering.				N/A		
Water Interconnection:	Interconnection includes onsite wells and associated piping.						
MISO Queue Fees:	Included						
Network Upgrades:	Included as provided by MDU ($150/kW).						
Miscellaneous Equipment:							
Fire protection:	New Fire Pump and Emergency Diesel Backup for dedicated onsite storage				N/A		
Emergency Generator:	New Diesel Generator included for greenfield sites, not included for Heskett Expansion options.						
Auxiliary Boiler:	N/A						
Black Start:							
Bypass Dampers							
Miscellaneous Contract Costs:							
Startup Spare Parts:	Allowance Included				Excluded		Allowance Included
Construction Indirects:	Construction Mgmt, Engineering, Performance testing and start-up, initial fills and consumables, startup, surveys, and site security included.						
Performance Bonds:	Included. Allowance is 1% of project cost.						
Indirect / Owner's Indirect Costs:							
Project Development	Allowance Included						
Owner's Operations Personnel Prior to COD	Allowance Included					Excluded	
Owner's Project Management	Allowance Included						
Owner's Engineering	Allowance Included (Assuming full OE support).						
Owner's Legal Costs	Allowance Included					Excluded	Allowance Included
Commisioning Costs	Allowance Included					Excluded	Allowance Included
Operator Training	Allowance Included					Excluded	

<table>
<tr><td>Permitting & License Fees</td><td colspan="4">Allowance Included</td></tr>
<tr><td>Land</td><td>Allowance Included</td><td colspan="3">Excluded, Assumes Lease</td></tr>
<tr><td>Labor Camp</td><td colspan="4">Assumed to not be required. Assumes generic site has local towns/ housing.</td></tr>
<tr><td>Construction Power</td><td>Allowance Included</td><td colspan="2">Excluded</td><td>Allowance Included</td></tr>
<tr><td>Fuel Consumed during Commissioning</td><td>Allowance Included</td><td colspan="3">Excluded</td></tr>
<tr><td>Power generated & sold during commissioning</td><td>Allowance Included</td><td colspan="3">Excluded</td></tr>
<tr><td>Initial Fuel Inventory</td><td>Allowance Included (as applicable)</td><td colspan="3">Excluded</td></tr>
<tr><td>Builder's Risk Insurance</td><td colspan="4">Allowance Included</td></tr>
<tr><td>Operating Spare Parts</td><td colspan="2">Allowance Included for critical equipment only & minor parts. No spare GSU included</td><td>Excluded</td><td>Allowance Included</td></tr>
<tr><td>Workshop Tools & Test Equipment</td><td>Allowance Included</td><td colspan="3">Excluded</td></tr>
<tr><td>Warehouse Shelves</td><td>Allowance Included</td><td colspan="3">Excluded</td></tr>
<tr><td>Mobile Equipment, Vehicles</td><td>Allowance Included</td><td colspan="3">Excluded</td></tr>
<tr><td>Permanent Plant Equipment and Furnishings</td><td colspan="2">Allowance Included</td><td colspan="2">Excluded</td></tr>
<tr><td>Owner's Contingency</td><td colspan="4">Included to reflect anticipated spent contingency for screening purposes. Additional contingency is recommended for budgetary estimate.</td></tr>
<tr><td>Property Insurance</td><td colspan="4" rowspan="2">Included, rate provided by MDU.</td></tr>
<tr><td>Property Tax</td></tr>
<tr><td>Financing Fees</td><td colspan="4">Excluded</td></tr>
<tr><td>Interest During Construction</td><td colspan="4">Included, provided by MDU.</td></tr>
<tr><td>Sales Tax:</td><td colspan="4">Excluded from EPC and Owners Costs.</td></tr>
</table>

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Attachment F

TRANSMISSION SERVICE CHARGE IMPACTS

TRANSMISSION SERVICE CHARGE IMPACTS

Montana-Dakota's electric service customers in the Interconnected System will continue to see transmission service charges resulting from (1) the termination of the Transmission Services Agreement (TSA) with Western Area Power Administration (WAPA) on December 31, 2015; (2) WAPA and Basin Electric Power Cooperative (BEPC) joining Southwest Power Pool (SPP) as a transmission owning member on October 1, 2015; (3) revenue credits provided to BEPC for facilities used by Montana-Dakota's customers; (4) the Midcontinent Independent System Operator, Inc. (MISO) allocation of cost sharing for baseline reliability and market efficiency projects under Regional Economic Criteria Benefit (RECB) I and II criteria; and (5) the allocation of MISO Multi-Value Projects (MVP) which includes Long-Range Transmission Plan (LRTP) projects.

Transmission Services Agreement with Western Area Power Administration

Montana-Dakota and WAPA had a long history of sharing transmission facilities and providing service across each other's systems using a reciprocal wheeling arrangement. This arrangement expired on December 31, 2015. On October 1, 2015, WAPA and BEPC joined Southwest Power Pool (SPP) as a transmission owning member and, as such, transmission service across their facilities are now covered under the SPP Tariff. As part of a Federal Energy Regulatory Commission (FERC) settlement that Montana-Dakota entered into with SPP, WAPA, and BEPC regarding WAPA and BEPC's integration into the SPP footprint, Montana-Dakota agreed to take Network Integrated Transmission Service (NITS) under the SPP Tariff for service that was historically provided under the WAPA TSA, which basically covers Montana-Dakota's customer load west of Beulah, ND and west of Glenham, SD. Montana-Dakota has only a single 115kV transmission path west of Beulah to provide a connection back to the rest of Montana-Dakota's interconnected service territory and MISO. In return for taking NITS service under the SPP Tariff, Montana-Dakota is eligible for Facility Credits under Section 30.9 of the SPP Tariff for transmission facilities that WAPA and BEPC require service from Montana-Dakota which were previously provided under the WAPA TSA and BEPC Interconnection and Common Use Agreement (ICCUA). The impacts of the SPP NITS service is reduced by the Section 30.9 Facility Credit arrangement whereby Montana-Dakota is able to net a significant portion of its SPP transmission bill. BEPC is required to take MISO NITS service in areas that Montana-Dakota does not rely on SPP transmission facilities to serve its customer load providing additional offsets to the SPP NITS payments. Montana-Dakota received approval from FERC in 2021 for a Settlement

Agreement in docket ER20-108 and an Amendment to a Partial Settlement Agreement in ER21-169 which provides for addition future Section 30.9 Credits to Montana-Dakota.

Montana-Dakota continues to see greater value in remaining a MISO transmission owning member as compared to exiting MISO and joining SPP as a full member. The greater MISO membership value is largely related to a difference in resource adequacy requirements between MISO and SPP. SPP requires each load serving entity to carry capacity resources for their full forecasted customer load plus a planning reserve margin while MISO includes a diversity factor reduction as not all MISO customer load experiences their peak at the same time. Montana-Dakota receives a significant benefit from being the western most transmission owning member in MISO As such, Montana-Dakota's customers currently only need to supply 82.6% of their full capacity requirements in the summer and 92% in the winter which provides 111 MWs of capacity savings in the summer and 59.2 MWs in the winter. If Montana-Dakota were to join SPP, Montana-Dakota would have to add approximately 151 MW of additional capacity resources to its generation portfolio as SPP has a lower planning reserve margin than MISO. Using the MISO Cost of New Entry (CONE)[1] value of $341.21 per MW-day for 2024/2025, the resource adequacy diversity value that Montana-Dakota receives in MISO is equal to $13.8 million versus having to carry one hundred percent non-coincident peak requirements. The monetary value of MISO's resource adequacy requirements versus SPP's resource adequacy requirements is $18.9 million per year if Montana-Dakota would exit MISO and join SPP as a transmission owning member and move all its load and generation into SPP's energy market.

To verify that the current netting arrangement is in the best interest of serving its customer obligations, Montana-Dakota annually calculates the cost differential of the two options: 1) continuing to take both SPP and MISO NITS service, versus, 2) withdrawing from MISO membership and switching to SPP.

Based on Montana-Dakota's 2024 load forecast, the estimated cost of taking MISO transmission service is $9.4 million per year. Using the company's Plexos modeling software and removing the MISO market energy purchase option, the increased cost for Montana-Dakota to self-schedule its own generation without access to the MISO energy market is $9.3 million. This value is used as a rough estimate of MISO market benefits that the Company receives versus the self-scheduling of only resources owned by the Company. Additional MISO membership benefits include reliability oversight through Reliability Coordinator services, resource adequacy diversification ($13.8

[1] 2024/2025 Planning Resource Auction (PRA) Results. Page 26. 2024 PRA Results Posting 20240425632665.pdf (misoenergy.org)

million benefit as calculated above), tariff management, coordinated transmission planning studies, and generator interconnection queue management.

In 2024, the total net cost of taking both MISO and SPP transmission services is estimated at $14.2 million or $4.8 million above MISO only tariff costs. This estimate includes the SPP Section 30.9 Facility Credits provided under the SPP Tariff as well as the payments from Basin Electric for Transmission Service taken from MISO and the Basin Electric Facility Sharing Agreement. For Montana-Dakota to have its load and generation in MISO's resource adequacy requirements versus SPP, provides a net savings of $18.9 million using the current MISO CONE value for capacity resources calculated above. If Montana-Dakota would exit MISO and join SPP as a transmission owning member, it would continue to make annual transmission investment payments of $7.4 million (2024 amount) to MISO for Schedule 26 and 26a projects that it has on-going cost responsibility to make under the MISO Tariff.

MISO Allocation of Cost Sharing under RECB I Criteria

The MISO RECB I cost allocations allow for the cost sharing of approved network transmission facilities with the benefiting transmission owners or with the entire MISO footprint. Contained in MISO's FERC Order 1000 compliance filing was the removal of the requirement to cost share future MISO RECB I projects, also referred to as baseline reliability projects, from the MISO Tariff beginning with MTEP 2014. Previously approved MISO RECB I projects will continue to be cost shared as before. Schedule 26 allocations are directly assigned revenue requirements for approved projects to an individual Transmission Owner or all MISO load through a system-wide postage-stamp rate. The CapX2020 Alexandria to Fargo 345 kV transmission line was approved in 2008 as a baseline reliability project eligible for cost sharing under the MISO Tariff and was placed into service in 2015. As defined in RECB I, eighty percent (80%) of the revenue requirements for these projects are allocated under a line outage distribution factor (LODF) calculation to determine beneficiaries, and the remaining twenty percent (20%) are allocated to all MISO load through a postage-stamp rate. Montana-Dakota's allocated investment share of the Alexandria to Fargo 345 kV line is $6.6 million. Annual revenue requirements for all RECB I projects allocated to Montana-Dakota's transmission pricing zone in MISO are forecasted to equal $2.5 million dollars in 2024, which includes the cost of the Mandan 230 kV Junction Substation. Montana-Dakota also receives RECB I (MISO Schedule 26) revenues from Otter Tail Power for the reliability benefits they are assigned for the Mandan 230kV Junction Substation.[2] The MISO

[2] MISO Indicative Annual charges for approved Baseline Reliability Projects (Schedule 26). Schedule 26 Indicative Annual Charges106363.xlsx (live.com)

NITS transmission service that BEPC takes for its customer load in Montana-Dakota's transmission pricing zone is allocated a load ratio portion of the Montana-Dakota RECB I cost responsibilities. Montana-Dakota also receives Schedule 26 revenues as part of its ownership of the Twin Brooks 345 kV substation in South Dakota which is located on the Ellendale 345kV substation to Big Stone South substation transmission line. The Twin Brooks Substation was the cost allocation responsibility of the interconnecting generator and because the voltage of the network upgrade is 345 kV, ten percent of the project cost is allocated to the MISO system wide postage allocation for which Montana-Dakota receives Schedule 26 revenues.

MISO Allocation of Cost Sharing under RECB II Criteria

The MISO RECB II cost allocation allows for the cost sharing of approved market efficiency projects (MEPs) with the benefiting transmission owners or with the entire MISO footprint.

To qualify as an MEP, network transmission upgrades must be shown to have regional economic benefits as demonstrated through multi-future and multi-year planning. MEP's currently involve transmission facilities operating at voltages of 345kV and higher. Project costs must be at least $5 million or more with at least 50% of the project cost associated with 345kV or above facilities. MEPs must have a benefit-cost ratio of 1.25 or higher with annual benefits calculated using 100% adjusted production cost savings for multiple future scenarios with the present value of benefits and costs calculated over the first 20 years after the in-service date, but not to exceed 25 years from the project's approval year.

Revenue requirements for MEP's are allocated 80% to all load within the MISO Local Resource Zone that receives benefits with the remaining 20% allocated to the MISO footprint wide postage stamp.

On February 25, 2019, MISO filed FERC Docket No. ER19-1124-000 to modify cost allocation for MEP's using existing and newly adopted metrics that allow for added precision in allocating costs and facilitate 100% allocation of MEP costs to benefitting Transmission Pricing Zones (eliminating the 20% allocation to all of MISO on a postage stamp basis). The filing also provides an expanded framework for the designation of MEPs at lower voltages, including lowering the voltage threshold from 345 kV to 230 kV and the creation of a new local economic project category between 230kV and 100kV.

Figure 1 – Map of MISO Local Resource Zones

MISO continues to engage stakeholders through the RECB Task Force to review the MEP metrics and potential additional benefit calculations for things like (1) reduced planning reserve margin, (2) reduction in transmission losses, (3) avoided costs by deferring or eliminating future baseline reliability transmission investments, and (4) avoidance of market-to-market settlement payments. Montana-Dakota believes the current cost allocation for MEPs is sufficient and no changes are needed. If changes to voltage threshold or additional benefit criteria are implemented, then MISO should also look to allocate the costs for MEPs to local transmission pricing zones which benefit directly from the MEPs.

Allocation of MISO Multi-Value Projects

On December 17, 2010, the FERC approved a joint application filing by MISO and various MISO Transmission Owners to create a new cost allocation methodology for qualifying multi-value high-voltage transmission facilities called Multi-Value Projects (MVPs). MVPs are one or more network transmission upgrades that, when considered as part of a portfolio, provide widespread regional benefits, respond to documented public policy requirements, and/or provide multiple benefits such as reliability and economic value. Network transmission projects classified as MVPs will be cost-shared on a one hundred percent (100%) basis to all MISO load and system exports to PJM.

MVP Eligibility Criteria

To be eligible as an MVP, the project must meet at least one of the following:

- A project that enables the transmission system to deliver energy in support of documented energy policy mandates or laws that have been adopted through state or federal legislation or regulatory requirement and deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
- A project that provides multiple types of economic value across multiple pricing zones with a total project benefit-to-cost ratio of 1.0 or higher.
- A project that addresses at least one transmission issue associated with a projected reliability violation and at least one economic-based transmission issue, and that provides economic value across multiple pricing zones and generates financially quantifiable benefits in excess of the total project cost.

2011 MVP Portfolio

MTEP 2011 approved $5.6 billion for 17 Multi-Value Projects that were selected as part of a regional portfolio to improve reliability of the transmission system, meet public policy targets, and distribute economic benefits across the entire MISO footprint.[3] The MTEP 2011 Report identified potential benefits of at least 1.8 to 3.0 times their cost for all MISO Local Resource Zones. The MTEP 2014 MVP Triennial Review Report calculates potential benefits from the 2011 MVP Portfolio of at least 2.6 to 3.9 times their cost for all MISO Local Resource Zones. The MTEP17 results provide benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.2 to 3.4; an increase from the 1.8 to 3.0 range calculated in MTEP11.[4]

One of the 2011 MVP Portfolio projects is a 345 kV transmission line from Big Stone, SD to Ellendale, ND. Montana-Dakota completed this project in partnership with Otter Tail Power Company in February 2019 with a construction cost of $247 million.

[3] MISO Transmission Expansion Plan 2011.
https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf
[3] MTEP17 MVP Triennial Review.
https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

The 2024 forecasted MISO Schedule 26-A (MVP Cost Adder) charge is $1.54 per MWh.[5] Assuming a 2024 Total Energy Requirements of 3,251,040 MWh, this would result in a total charge of $5,006.602 to Montana-Dakota's interconnected customers.

Montana-Dakota's cost allocation share of all MVP investments is less than one percent.

Long-Range Transmission Planning

A key part of MISO's Reliability Imperative is the need for additional high voltage electric transmission across the MISO footprint as plant retirements and increasing renewables continue to transform the grid. MISO is responding to this need with the Long-Range Transmission Planning (LRTP) effort. LRTP provides as a road map for investment decisions as the grid evolves.

LRTP is designed to assess the region's future transmission needs holistically, in concert with utility and state plans on where to site and build new generation resources.

The model building process used for LRTP is representative of the MTEP process but has a different data set and time frame of study. Load and renewable availability are dependent on time of day that is accounted for in the reliability base model set. The dispatch method for LRTP captures the ability to realize the target renewable energy levels with the various MISO Futures.

MISO is looking for the development in the LRTP to move forward in various stages or tranches. Tranches 1 and 2 will focus on the northern portion of the MISO footprint. Tranche 3 will look at the MISO South region. And Tranche 4 is expected to look at projects between MISO North and MISO South.

In July of 2022, MISO's Board of Directors approved $10.3 billion for 18 new transmission projects as part of LRTP Tranche 1 which included a 345kV transmission line between Jamestown and Ellendale, ND that Montana-Dakota will construct and operate in partnership with Otter Tail Power Company.

[5] MISO Indicative Annual charges for approved Multi-Value Projects (Schedule 26-A). Schedule 26A Indicative Annual Charges106365.xlsx (live.com)

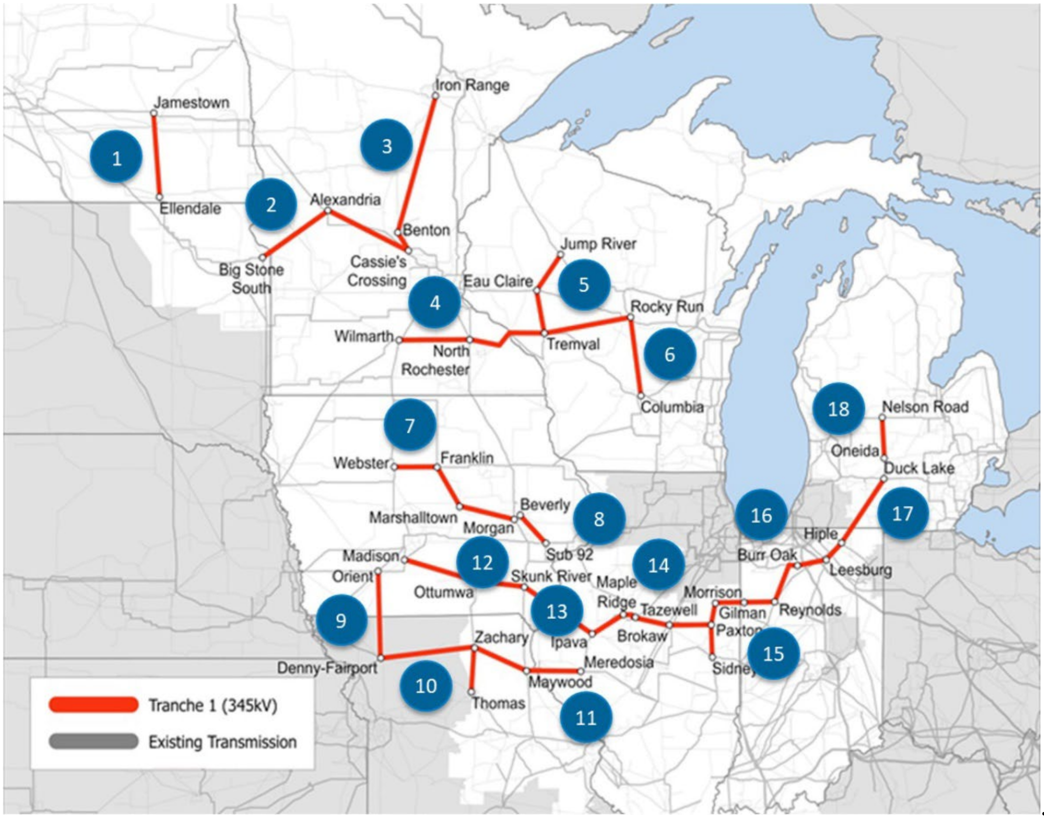


Figure 2 - MISO LRTP Tranche 1 project portfolio[6]

Cost allocation for the LRTP Tranche 1 portfolio will utilize the existing MVP cost allocation methodology but on a sub-region basis assigning costs to only MISO North customers.

MISO is working on the Tranche 2.1 set of LRTP project which is expected to be approved and constructed in two phases. The first phase of LRTP Tranche 2.1 is expected to have a cost of $23 - $27 billion. MISO is expecting Board of Director approval of the LRTP Tranche 2 set of projects in Q4 of 2024.

[6] From MISO Website. Long Range Transmission Planning (misoenergy.org)

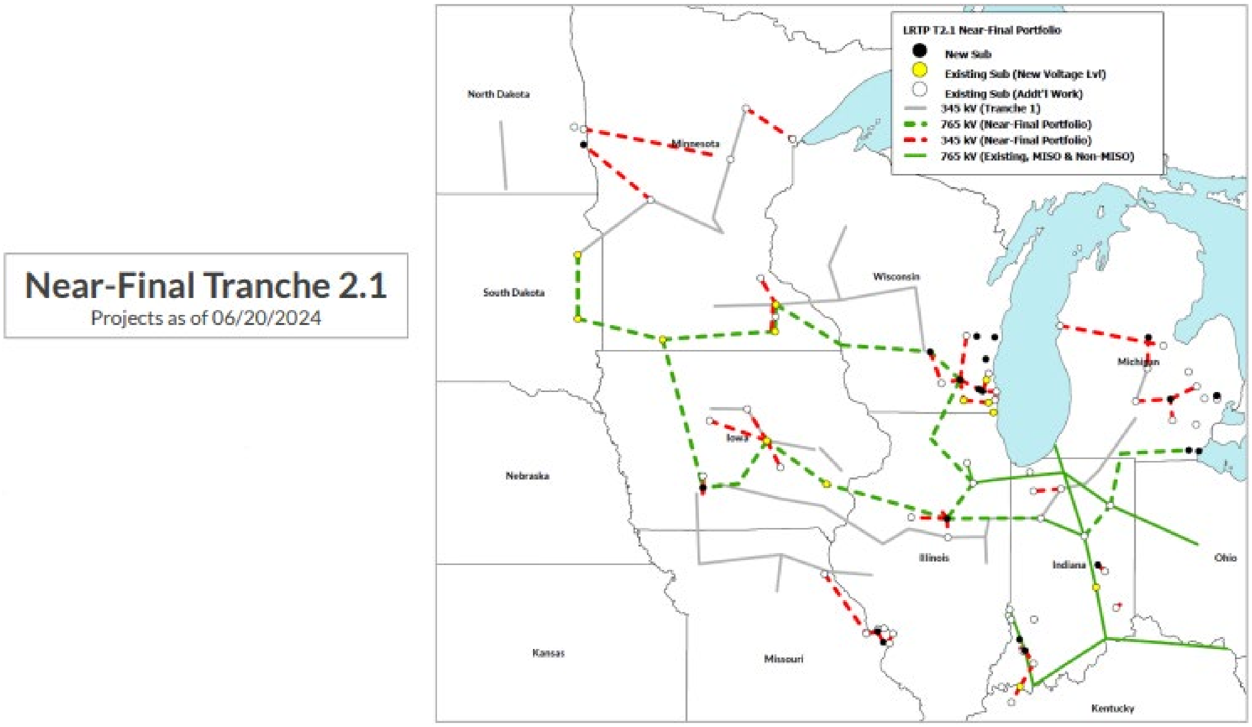


Figure 3 - Anticipated tranche 2 project portfolio (6/20/2024)[7]

No timeframe is set for additional Tranche 2 project portfolios or Tranche 3 or 4 study work.

[7] From MISO Website. 20240621 LRTP Workshop Item 02 Reliability & Economic Deep Dive (misoenergy.org) Page 5.

Attachment G

MISO Overview

MISO OVERVIEW

Established in 2001 as part of a broader restructuring of the electric power industry, Midcontinent Independent System Operator (MISO) operates as a not-for-profit, member-based organization responsible for overseeing the reliable operation and efficient management of the high-voltage electric grid across 15 U.S. states and the Canadian province of Manitoba. At its core, MISO ensures the reliable functioning of the transmission grid, overseeing its operations, maintenance, and expansion to meet the region's evolving energy needs. One of its primary responsibilities involves the coordination of electric transmission, enabling seamless interconnection among utilities, power generators, and consumers. MISO also administers robust energy markets, facilitating the buying and selling of electricity while striving to maintain a fare and competitive marketplace. Additionally, the organization plays a crucial role in integrating renewable energy resources and promoting grid resilience and cybersecurity measures. Through collaborative efforts with stakeholders, MISO continues to navigate the complexities of the modern energy landscape to uphold reliability, affordability, and sustainability in power supply.

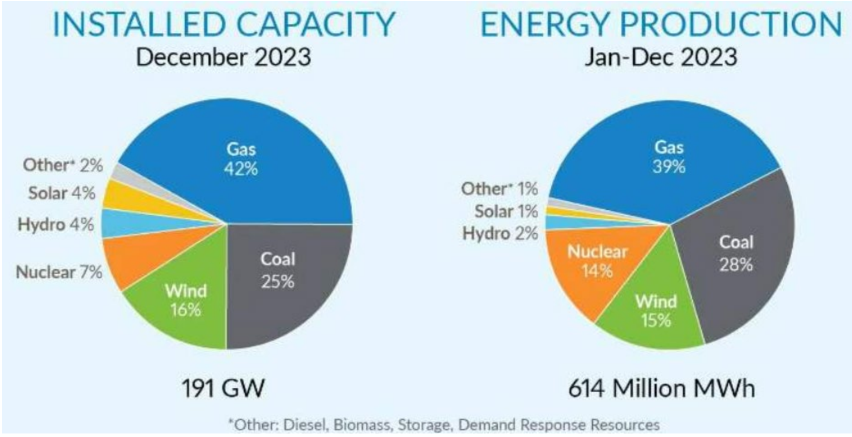
MISO's Reliability Footprint

MISO Scope of Operations[1]

- Managing the flow of high-voltage electricity across 15 U.S. states and the Canadian province of Manitoba

[1] January 2024 MISO Fact Sheet https://cdn.misoenergy.org/2024%20January%20Fact%20Sheet631433.pdf

- Facilitating one of the world's largest energy markets with more than $40 billion in annual transactions
- Planning the grid of the future



Area Served	15 U.S. States and Manitoba, Canada
Population Served	45 Million
Transmission Line	75,000 Miles
Generating Units	2,956
Record Demand	127.1 GW 7/20/2011
Wind Peak	25.6 GW 1/12/2024
Solar Peak	3.3 GW 8/31/2023
Members	54 Transmission Owners
	143 Non-transmission Owners
Market Participants	+500
Carbon Reduction	Approximately 32% since 2014

Non-Discriminatory Open Access Transmission Service to Facilitate Competition between Generation Resources

The primary goal of MISO's open access transmission service is to promote competition and efficiency in the energy market by ensuring that all transmission customers, whether utilities, independent power producers, or other entities, have fair access to the transmission system.

MISO is required to offer transmission services without preference to any market participant. This ensures that no entity is unfairly prioritized over another, allowing for a competitive market where all players can plan and operate on a level playing field.

MISO operates under a tariff that is approved by the Federal Energy Regulatory Commission (FERC). This tariff outlines the rates, terms, and conditions under which MISO offers transmission services. It includes provisions for both point-to-point and network transmission services.

- **Point-to-Point Transmission Service** provides reserved, dedicated capacity for transmitting electricity between specific points on the network.
- **Network Transmission Service** offers more comprehensive access and is typically used by utilities to serve their retail customers. It allows for the integration of a customer's resources to meet its entire load demand.

MISO's processes for requesting and managing transmission service are designed to be open and transparent. This includes public stakeholder meetings and documentation that are accessible to all interested parties, promoting transparency and enabling active participation in the planning and decision-making processes.

MISO adheres to FERC regulations and works closely with regulatory bodies to ensure compliance with all legal and regulatory requirements. This oversight helps maintain the integrity and reliability of the transmission service.

Platform for Wholesale Energy & Capacity Markets to Incentivize Efficient, Cost-Effective Dispatch and New Generation

MISO's wholesale energy and capacity markets play a critical role in managing the electricity supply for millions of consumers, facilitating competition, and promoting efficient market operations across multiple states.

Day-Ahead (DA) Market: In the DA Market, participants submit bids (offers to sell) and offers (requests to buy) for electricity one day before the actual delivery. This market allows participants to lock in prices for the next day and manage risks related to price fluctuations. Prices are determined on the submitted bids and offers, matched with the anticipated demand and cheapest generation options available.

Real-Time (RT) Market: The RT is a spot market where participants submit bids to buy and sell energy and operating reserves at least 30 minutes prior to the operating hour. It operates continuously throughout the day and adjusts for differences between the day-ahead forecasts and actual conditions. This market responds to real-time fluctuations in demand and supply, such as unexpected changes in weather or generator availability. This market helps balance supply and demand and enables real-time adjustments based on current system conditions.

Financial Transmission Rights (FTR) Market: The primary function of MISO's FTR market is the allocation of Auction Revenue Rights (ARRs) and the auction of Financial Transmission Rights (FTRs).

ARRs are financial instruments that entitle holders to a share of the revenue (credit or charge) generated in the Annual FTR Auction. ARRs are acquired in the Annual ARR Allocation process and allocated to Market Participants (MPs) based on firm historical usage of the transmission network and to MPs to fund Network Upgrades. ARRs entitle holders to a share of the FTR Auction revenue, which may then be used to offset the cost of transmission congestion.

FTRs are point-to-point financial instruments settled based on congestion in the Day-Ahead Market. They do not represent the right for the physical delivery of energy. If the FTR path is in the direction of congestion, the MP receives a payment. If the FTR path is in the opposite direction of congestion, the MP incurs a charge. FTRs are acquired in the Annual or Monthly FTR Auctions or in the secondary market. MPs eligible to participate in FTR Auctions include ARR holders converting ARRs into FTRs or any creditworthy MP. MISO conducts the Annual FTR Auction immediately following the Annul ARR Allocation. Multi-Period Monthly FTR Auctions (MPMA) take place over the course of the Planning Year.

Planning Resource Auction (PRA) Market: MISO's Planning Resource Auction is a significant component of its market mechanisms aimed at ensuring the reliability and adequacy of resources within its footprint. The PRA allows market participants, including generators, demand response providers, and other capacity resources, to offer their available capacity into the market through competitive auctions. Key elements of the PRA are Seasonal Peak Demand Forecast, Local Clearing Requirements, and Transmission Limitations. These auctions determine the price and quantity of capacity procured. The PRA facilitates long-term resource planning by incentivizing investment in and availability of capacity resources necessary to maintain grid reliability during peak demand periods and unexpected contingencies.

Performs System Operations to Ensure Least-Cost Dispatch that Accounts for Reliability Needs

MISO oversees the real-time management of electricity, transmission, generation, and distribution to meet demand while maintaining grid stability and reliability. MISO continuously monitors the transmission grid's performance, assessing factors such as voltage levels, line capacities, and generation outputs. Through advanced control systems and grid management tools, operators make real-time adjustments to ensure the grid operates within safe operating limits and meets demand requirements.

MISO dispatches generating units and other grid assets to match electricity supply with demand in real-time. Utilizing economic dispatch principles, MISO optimizes the use of available generation resources while considering factors such as fuel costs, environmental regulations, and system reliability requirements.

MISO collaborates with neighboring transmission system operators and balancing authorities to ensure seamless coordination and reliability across interconnected grids. Through coordinated planning, communication, and emergency response protocols, MISO enhances grid resilience and mitigates risks associated with system disturbances or emergencies.

MISO actively integrates renewable energy resources, such as wind and solar, into its grid operations. Advanced forecasting techniques and grid modeling enables operators to anticipate and manage the variability and intermittency of renewable generation, ensuring reliable grid operation while maximizing the use of clean energy resources.

In the event of system disturbances, outages, or emergencies, MISO System Operations coordinates emergency response efforts and restoration activities. Rapid assessment, prioritization, and coordination of resources help minimize disruptions and resort service to affected areas efficiently.

Transmission & Resource Planning Studies

MISO conducts comprehensive assessments of future transmission system needs and resource adequacy requirements, considering factors such as load growth, generation retirements, renewable energy integration goals, and reliability standards. These assessments serve as the foundation for identifying transmission projects and resource adequacy initiatives necessary to ensure grid reliability and meet forecasted electricity demand. In its planning approach, MISO follows its Tariff, NERC reliability standards, and standards adopted by Regional Reliability Organizations.

MISO Transmission Expansion Plan (MTEP)[2]

The annual MISO Transmission Expansion Plan (MTEP) provides value for customers by ensuring a cost-effective, reliable system that supports policy requirements. Projects that mostly address

[2] MISO Website https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=

local reliability and/or NERC requirements are submitted by transmission owners and vetted through an 18-month process with more than 75 stakeholder meetings.

The annual plan, including Appendix A which lists projects deemed ready for build, is reviewed by the Planning Advisory Committee which recommends approval by MISO's System Planning Committee of the Board of Directors, and the full Board provides final approval each December.

MTEP Appendix A projects typically fall into one of the following categories:

- **Baseline Reliability Projects (BRP)**, which are required to meet standards for both North American Electric Reliability Corporation (NERC) and local reliability.
- **Generator Interconnection Projects (GIP)** are needed to reliably connect new generation to the transmission grid.
- **Market Efficiency Projects (MEP)** address congestion within the MISO region or as an interregional project along the seam.
- **Market Participant Funded Projects (MPFP)** provide network upgrades fully funded by a Market Participant but owned and operated by an incumbent transmission owner.
- **Multi-Value Projects (MVP)** top-down projects developed by MISO through Long Range Transmission Planning with stakeholder input to address regional public policy, economic and/or reliability benefits.
- **Other Projects** address local reliability issues and/or provide local economic benefits but don't meet the threshold to qualify as Market Efficiency Projects.
- **Targeted Market Efficiency Projects (TMEP)** are low-cost interregional projects with short lead times to relieve known market-to-market congestion.
- **Transmission Deliverability Service Projects (TDSP)** are network upgrades required to facilitate long term point-to-point transmission service request.

Figure 1 summarizes the MISO MTEP approved investments from 2003-2023. Highlights in MTEP cycles include:

- MTEP11 reflects the approval of the Multi-Value Project portfolio, which accounts for the significantly higher investment totals compared to other MTEPs.

- MTEP14 reflects the inclusion of the new MISO South region projects.
- MTEP21 reflects the MTEP21 Addendum approval of the Long Range Transmission Plan (LRTP) Tranche 1 portfolio, which accounts for $10.3 billion of the total.

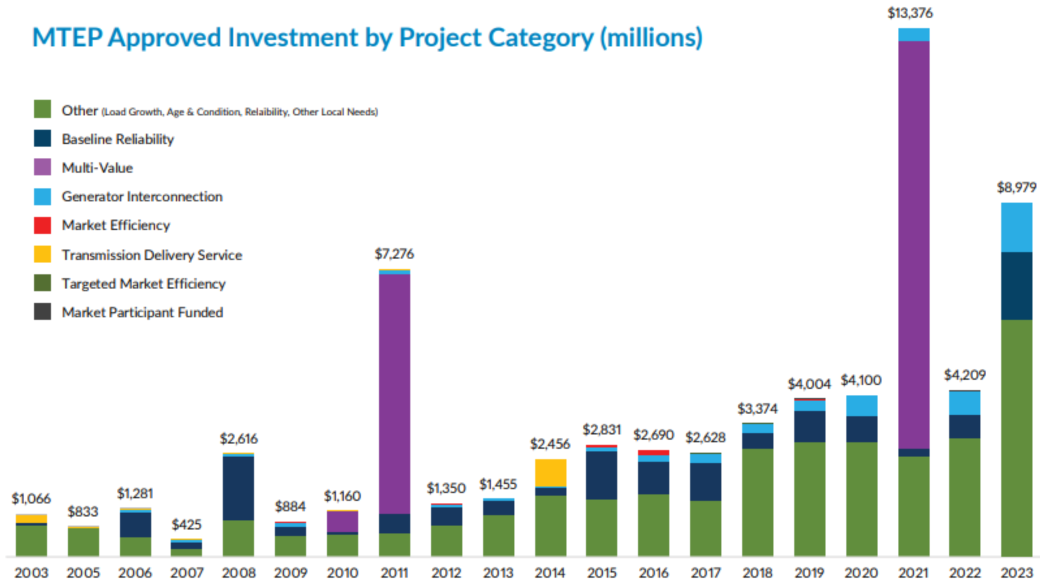


Figure 1 – MTEP Approved Investment by Project Category (millions)

Long Range Transmission Planning (LRTP)[3]

While MTEP addresses local, near-term needs through projects that typically go in service within 3-5 years of approval, longer-term, regional needs of the system are managed through MISO's Long Range Transmission Planning.

The LRTP initiative is MISO's response to the current and future resource evolution that has and continues to affect the bulk electric system. The scale and pace of these changes require prompt attention to develop the most efficient, cost-effective investments that will ensure grid reliability in the future. LRTP sets out to proactively identify key regional backbone transmission projects to support the resource change. This requires MISO to balance regional issues which should be addressed now as part of the LRTP study versus those more localized issues which should be addressed in the future through the interconnection process or in future MTEP cycles as specific load and generation locations are determined. Ultimately, the objective of the LRTP study is to

[3] MISO Website. MTEP23 Report. https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf

identify a least-regrets transmission build-out evaluated against multiple scenarios to manage uncertainty that achieves member goals, maintains reliability, and minimizes costs.

- LRTP Tranche 1: On July 25, 2022, MISO approved Tranche 1 of its LRTP study, which included 18 transmission projects with a total estimated cost of $10.3 billion (2022$).
- LRTP Tranche 2.1: The solutions in the near-final Tranche 2.1 draft portfolio represent key anticipated lines to resolve issues identified in Future 2A. Alternatives assessment and business case analysis will inform the development of the final portfolio. The anticipated portfolio is expected to cost between $23 and $27 billion. Work on Tranche 2.1 is progressing with an anticipated approval by MISO's Board of Directors in Q4 2024.

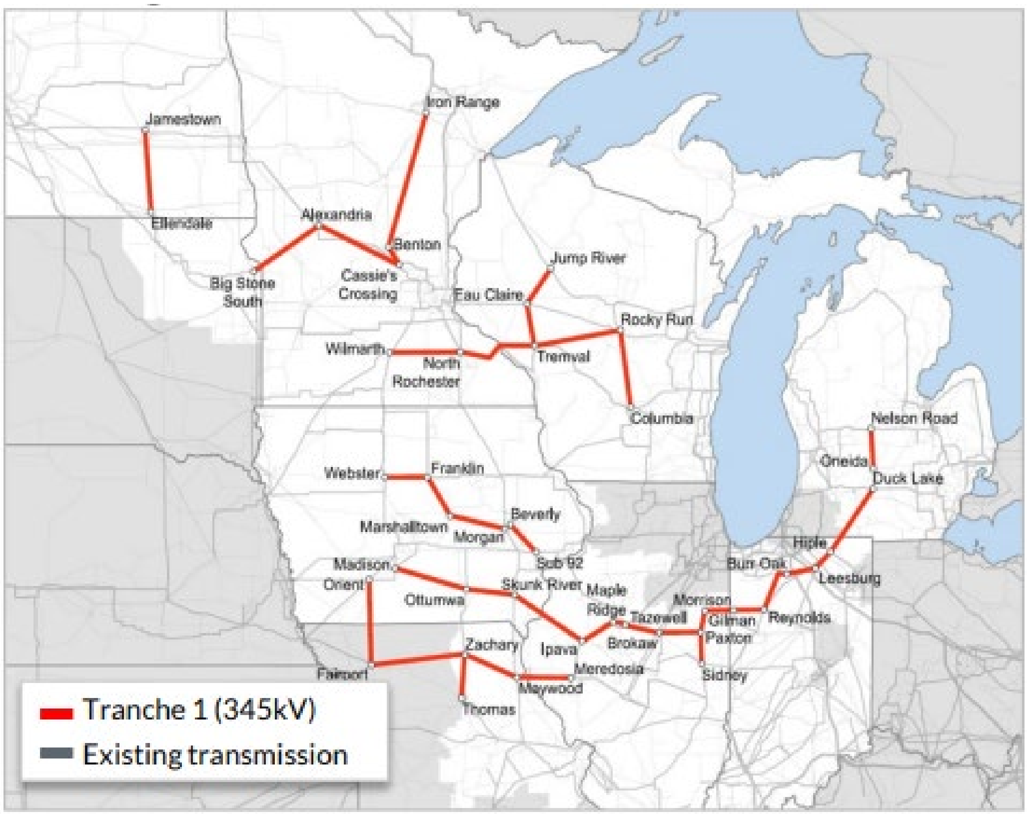


Figure 2 – LRTP Tranche 1 Portfolio

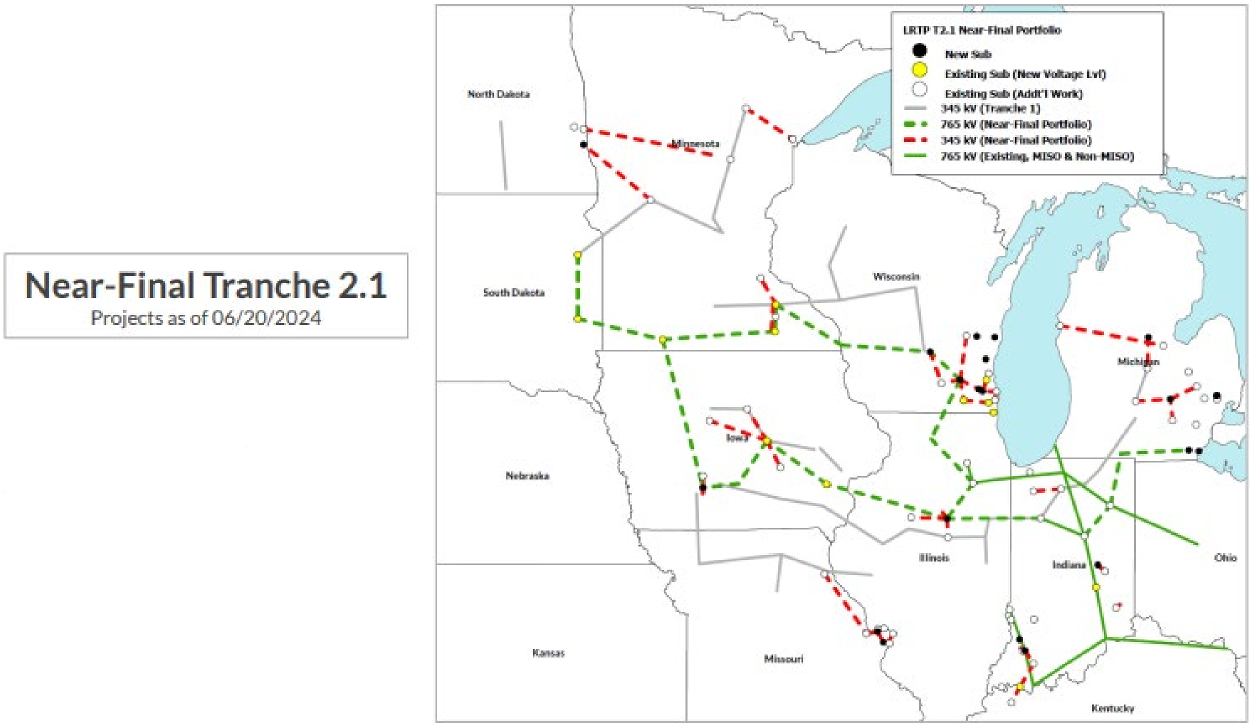


Figure 3 – LRTP Tranche 2 Anticipated Portfolio as of 06/20/2024

MISO Futures[4]

MISO's future scenarios, known as Futures, form the basis for LRTP by outlining a spectrum of potential economic, policy, and technological developments over a 20-year period. These Futures help MISO manage uncertainty by encompassing various factors such as load growth, electrification, carbon policies, generator retirements, renewable energy levels, natural gas prices, and generation capital costs.

MISO conducts resource expansion analysis to determine the optimal resource mix that minimizes overall system costs while meeting reliability and policy requirements. The resulting resource expansion plans, paired with corresponding Futures, help identify transmission issues and solutions.

In preparation for Tranche 2 and to align with recent plans, legislation, policies, and other factors, MISO updated its three Futures in 2023, illustrated in Figure 2. While the defining characteristics of each Future remained consistent, updates were made to data and information informing the potential resource mix. This included incorporating state and member plans, capital costs, operating and fuel costs, as well as defined resource additions and retirements. MISO also modeled

[4] MISO Website. Series 1A Futures Report. https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

the impacts of clean energy tax credits from the federal Inflation Reduction Act, expecting these incentives to accelerate the transition to a decarbonized grid.

Future 2A, the focus of Tranche 2, projects an accelerated pace of fleet change due to stronger renewable mandates, carbon reduction goals, and other policies. It forecasts a 60% reduction in carbon emissions by 2042 and anticipates that wind and solar energy will provide 30% of the region's energy a decade earlier than previously projected in Series 1 Futures that were used for Tranche 1.

Originally developed for MTEP, MISO's Futures are now used in multiple planning projects, including MTEP, LRTP, and the Regional Resource Assessment (RRA). The scenarios provide a consistent set of outlooks across transmission, markets, and operations.

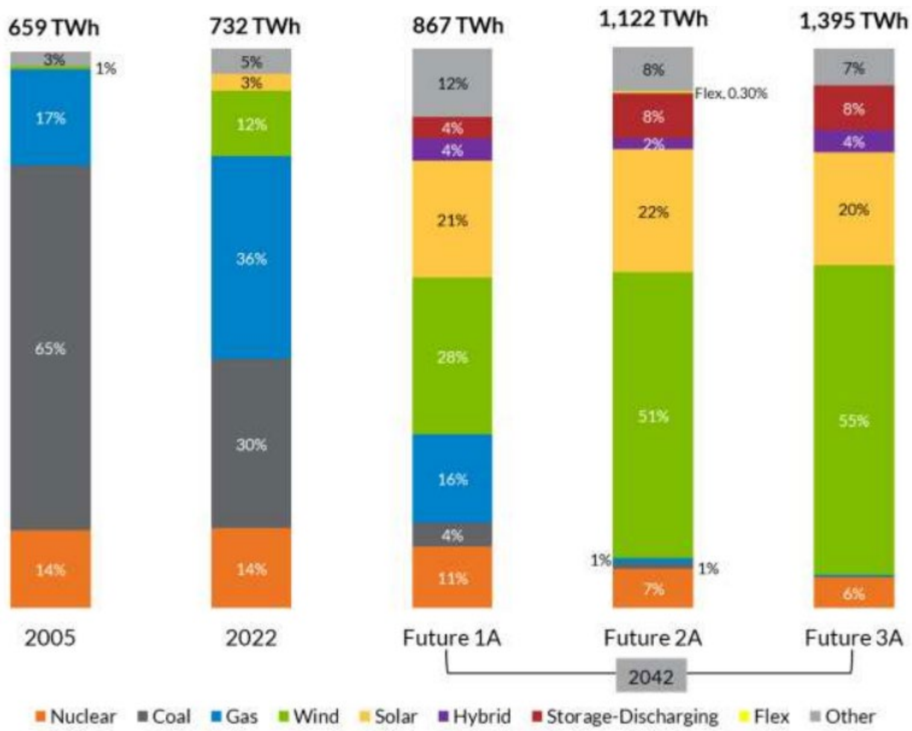


Figure 4 – Overview of MISO's Generation Fleet Mix Transition in Futures Series 1A

Future 1A Assumptions – Future 1 reflected substantial achievement of state and utility announcements, with a 40% decarbonization assumption. Future 1A continues to incorporate 100% of updated utility integrated resource plan (IRP) announcements and state legislation. Updated non-IRP utility goals and non-legislated state goals are applied at 85% of their respective levels to hedge the uncertainty of meeting them. Accordingly, Future 1A incorporates 71% decarbonization for the MISO system. Future 1A assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate of 0.22%.

Future 2A Assumptions – Future 2 incorporated 100% of utility IRPs and announced state and utility goals within their respective timelines, and a 60% decarbonization assumption. To align with 100% achievement of updated member utility goals, F2A therefore incorporates 76% decarbonization for the MISO system. Future 2A introduces an increase in electrification, driving an approximate 0.8% annual energy growth rate.

Future 3A Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction since the updated member utility goals in aggregate did not exceed this level of MISO-wide decarbonization. Future 3A requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.08% annual energy growth rate.

MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study

The JTIQ study stems from observations made by MISO and SPP cluster studies, indicating that transmission systems at their seams are operating at or near capacity. While adding generation resources and transmission infrastructure along the MISO-SPP seam can benefit both markets, the current mechanisms outlined in the Tariff and Joint Operating Agreement (JOA) don't offer a cost-sharing approach conducive to constructing the large-scale transmission necessary to interconnect the anticipated levels of new generation near the seam. Additionally, differences in processes, criteria, and schedules between the two RTOs contribute to delays in studies and raise questions about the study results.

The JTIQ Study is designed to address these barriers effectively. Its primary objective is to provide cost and timing certainty for generation interconnection customers. Under the JTIQ framework, affected system costs will be determined at the outset of the MISO or SPP queue studies, eliminating the need for separate Affected System Studies (AFS) between MISO and SPP. This streamlined approach aims to reduce study delays and uncertainties. Moreover, the JTIQ concept seeks to identify more optimized network upgrades compared to the current practice of conducting individual AFS clusters, ultimately enhancing the efficiency and effectiveness of the interconnection process between MISO and SPP.

The collaboration between MISO and SPP has led to the identification of a strategic portfolio of five transmission projects under the JTIQ study. These projects, collectively estimated to cost

$1.06 billion at the planning level, aim to overcome significant transmission limitations hindering the interconnection of new generating resources along the MISO-SPP seam.

Besides enhancing reliability, economic analysis conducted by the RTOs indicate substantial benefits for customers. Over a 10-year period, customers within the MISO footprint can expect an Adjusted Production Cost (APC) benefit totaling $55.7 million, while those in the SPP region may realize $132.9 million in APC benefits.

One of the key outcomes of implementing the recommended JTIQ portfolio, with an anticipated approval by the MISO Board of Directors in 2024, is the facilitation of approximately 28.7 GW of improved interregional generation enablement. This increased capacity will be instrumental in supporting new generator interconnection projects situated near the MISO-SPP seam, thereby fostering further development and expansion of energy infrastructure in the region.

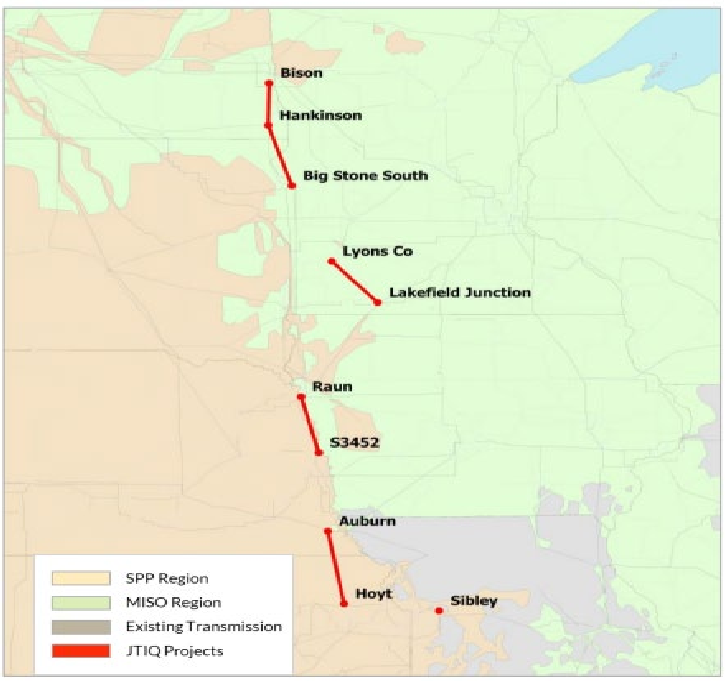


Figure 5 – JTIQ Portfolio

MISO Generation Interconnection Studies

As per its Tariff, MISO manages the generation interconnection process, which involves evaluating requests from developers seeking to connect their generation projects to the grid. This process includes studying the potential impacts of the proposed projects on grid operations and identifying any necessary upgrades or modifications to accommodate the new generation capacity.

Interconnection requests are studied in clusters under MISO's Definitive Planning Process (DPP) that defines the step-by-step process developers must follow to interconnect their generation projects to the MISO grid. This includes submitting applications, conducting feasibility and impact studies, negotiating interconnection agreements, and completing engineering and construction activities.

The DPP also outlines the principles and methodologies for allocating the costs of interconnection-related upgrades or modifications among developers and other stakeholders. This ensures that costs are allocated fairly and equitably based on the specific impacts of each project to the grid.

Member decarbonization goals are driving significant growth in MISO's Generation Interconnection Queue, resulting in a backlog of projects and challenges for interconnection customers. MISO has made several improvements to the queue process that reflect "first-ready, first-served" principles. FERC recently approved a generator replacement process under MISO's Tariff whereby an existing generator can be retired, and its interconnection rights can be transferred to new generator projects following a 180-day system impact study. The replacement generator does not have to go through the GI Queue process. The new generator must commence operation within 3 years of the retirement of the existing generator. Montana-Dakota Utilities Co. utilized this new generator process for the retirement of Heskett 1 & 2 and the construction of Heskett 4 which provided certainty in the interconnection timing and costs.

Additional reforms are needed to achieve reasonable queue speed and volume. Effective January 22, 2024, FERC accepted MISO's generation interconnection process (GIP) reforms which includes an increase in milestone payments, an automatic withdrawal penalty, and expanded site control requirements. These reforms in conjunction with FERC's Order 2023 aim to deter speculative projects from entering the queue. The approved GIP reforms apply to the 2023 Queue cycle.

FERC rejected MISO's cap filing which would limit the MW-value on each cluster with a narrow list of allowed exemptions. FERC had concerns over a section of the cap's formula, proposed exemptions to the cap, and MISO's lack of attention on resource adequacy when designing the cap. MISO will revise the cap filing and resubmit.

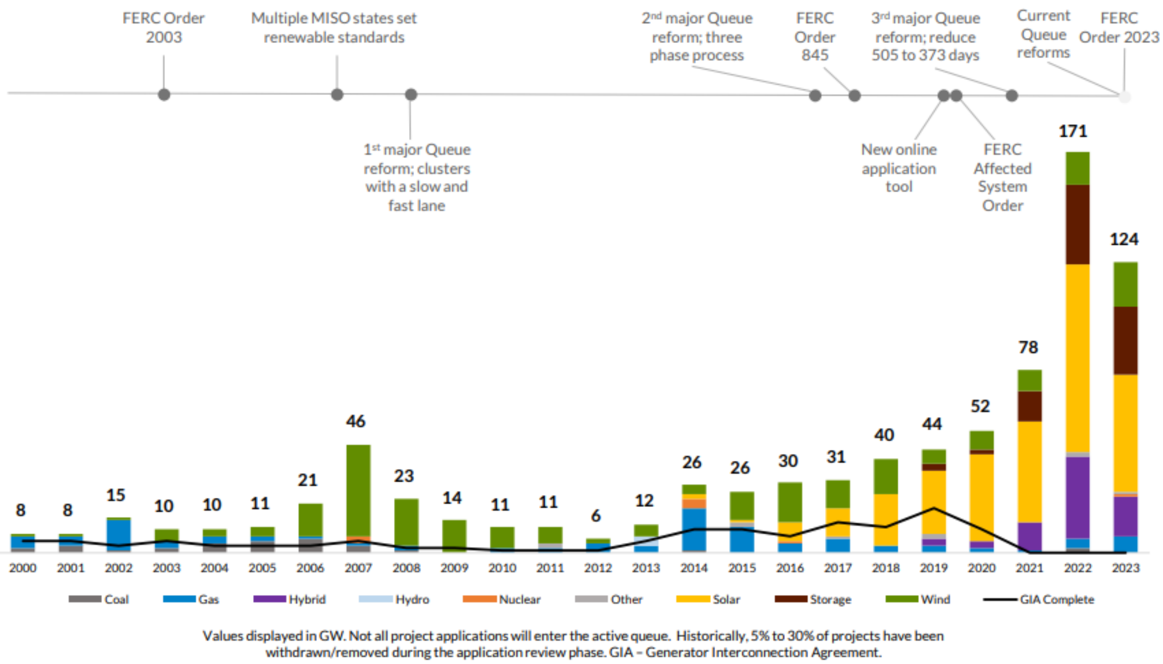


Figure 6 – Historical Queue Reforms

Value Proposition[5]

Participation in MISO has proven highly advantageous for its members and their 45 million customers, delivering increased reliability, more efficient energy dispatch, and resource sharing across the region, leading to reduced reserve requirements. As renewable investments surge and traditional thermal generation retires, alongside the escalating frequency and severity of weather events, the benefits of MISO membership are projected to expand further. MISO's Value Proposition, initiated in 2007, quantifies the annual value provided to the region. Over time, the value of MISO participation has grown significantly, reaching $4.9 billion in 2023, with a cumulative benefit exceeding $45 billion, while maintaining a low membership cost compared to total benefits with a 15:1 benefit-to-cost ratio in 2023. Initially focused on enhancing generator availability and optimizing existing resources, MISO's value drivers have shifted, with renewable optimization and resources sharing across its broad geographic footprint now representing the primary sources of value, expected to further amplify as members pursue renewable and decarbonization objectives.

[5] MISO Website. MISO's 2023 Value Proposition Report. https://cdn.misoenergy.org/2023%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report%20Final632082.pdf?v=20240306103856

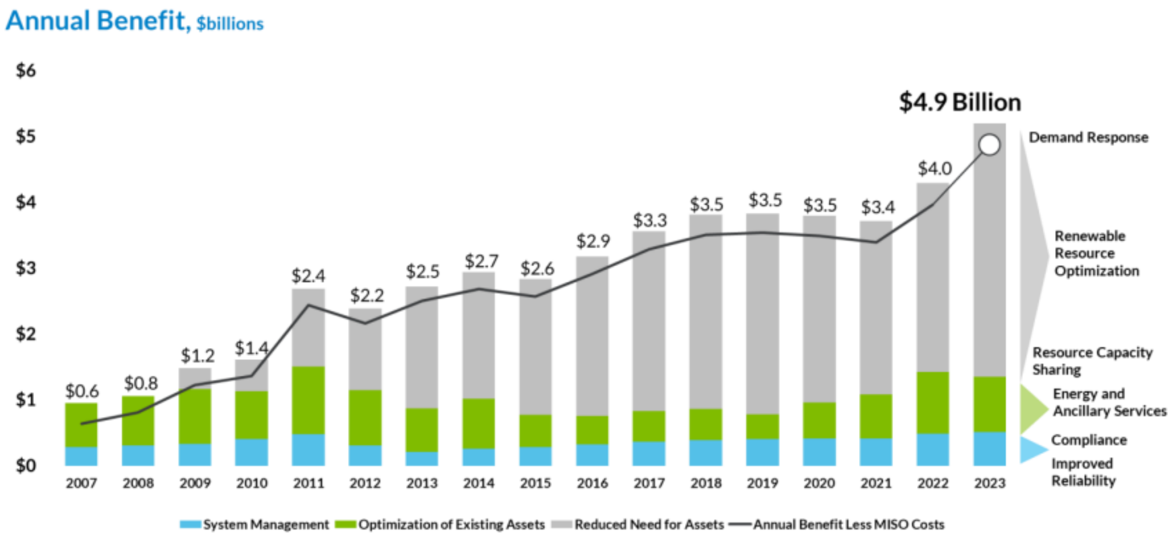


Figure 7 – MISO Annual Benefit

Improved Reliability

Anticipating a future marked by increased intermittent renewables, more severe weather events, and a surge in electrification and emerging technologies, MISO envisions leveraging transmission capacity and expansive geographic coverage to effectively navigate the uncertainties in resource supply.

Compliance

MISO's compliance benefit represents efficiencies gained through the consolidation and coordination of compliance efforts. These efficiencies include reductions in the number of full-time employees (FTEs) involved with standards development, FERC and NERC compliance, tariff compliance, system planning compliance, and operations compliance.

Energy and Ancillary Services

Ancillary services, including frequency regulation and voltage control, play a crucial role in maintaining the balance between energy supply and demand. By optimizing the provisions for both energy and ancillary services, MISO enables power plants to operate at their peak efficiency levels. This approach also facilitates the integration of increasing amounts of renewable energy.

Renewable Resource Optimization

MISO's regional planning allows for a more economic placement of wind and solar resources. This category of value captures the benefits of reduced renewable capacity needed across the footprint to achieve member goals.

Resource Capacity Sharing (formerly known as Footprint Diversity)

MISO's large geographic footprint allows members to lower planning reserve margins (PRM), ultimately reducing the amount of required installed capacity. Much of the value MISO creates comes from the value of sharing capacity across MISO's large geographic footprint by setting requirements for a system peak instead of each balancing authority keeping reserves for their own region. Savings are generated because MISO members do not need as much capacity for the same level of reliability.

Demand Response

MISO believes that the value of demand response will continue to grow as enabling technology improves, consumer preferences limit the acceptance of greenhouse gas emitting energy production, and economic and policy support for demand response continues to grow.

Cost Structure

MISO expects that member costs will increase over time, especially in the near term as MISO works to adapt to the changing resource mix. However, the ratio of benefits-to-cost is expected to continue rising over time as states and members benefit from MISO's market and planning efficiencies. Year-over-year, the 2023 ratio of benefits to cost for MISO membership increased from 12:1 to 15:1.

Qualitative Benefits

MISO operations provide services to the region that are hard to quantify but are highly valuable. These benefits include Price and Information Transparency, Planning Coordination, and Interregional Coordination.

Attachment H

Montana-Dakota's 2024 IRP Work Plan

MDU's 2024 IRP PAG Work Plan

August 22, 2023

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

Integrated Resource Plan (IRP) Public Advisory Group (PAG)

- Purpose
  - Provide input to IRP process from a non-utility perspective
  - Recommend any changes to planning process, resource acquisition process, and energy efficiency programs
- Members
  - Montana
    - Kevin Thompson – Action for Eastern Montana
    - Kyla Maki – Department of Environmental Quality
    - Stephen Schreibeis – Glendive Public Schools
    - Member from MT Public Service Commission

Integrated Resource Plan (IRP)
Public Advisory Group (PAG)

- North Dakota
  - Darin Scherr – Bismarck Public Schools
  - Dr. Patrick O’Neill – University of North Dakota
  - Rich Garman – ND Department of Commerce
  - Rich Wardner – Former ND State Senator
  - Martin Fritz – KLJ
  - Adam Renfandt – ND Public Service Commission
- South Dakota
  - Patrick Steffensen – SD Public Utilities Commission

2021 IRP Action Plan

- Complete Construction of Heskett 4 (new gas turbine resource)
- Retire Heskett 1 and 2 (coal plants north of Mandan, ND)
- Issue new Request for Proposals (RFP) for next IRP
- Evaluate solar and batteries (including small local resources)
- Monitor availability of short-term capacity and energy
- Monitor outcome of EPA Regional Haze for Coyote Station (coal plant near Beulah, ND)
- Monitor changes at MISO regarding Resource Adequacy (generation capacity obligations) and regional transmission development

2021 IRP Action

- Demand Side Management (DSM)
  - Continue existing programs
  - New potential study and evaluate new energy efficiency and demand response programs
- Regional Transmission Organization (RTO)
  - Evaluate transmission and membership arrangements with MISO and SPP

IRP Rule Changes

- Timing of filing
  - By statute every 3 years in MT and ND
  - South Dakota is filed for informational purposes.
- Requirement changes
  - Additional modeling requirements
  - Public input meetings in MT during the IRP process
  - Draft report to MT commission prior to filing for comments
  - Review previous load forecast

Environmental Considerations

- Regional Haze Review for Coyote Station
- Proposed EPA Greenhouse Gas Rule (111d) for existing thermal resources

Load Forecast

- 20-year econometric demand and energy forecast
- Review previous IRP load forecast for accuracy
- New large data center loads
  - 180 MW data center load located near Ellendale, ND
  - Load served outside of IRP process

MISO Changes

- Resource Adequacy
  - Sloped demand curve
  - Accreditation changes
  - Capacity market
- MISO Generator Interconnection Queue
  - Current status
- Transmission
  - MISO Long Range Transmission Plan (LRTP)
  - MISO Joint Transmission Interconnection Queue (JTIQ) projects
  - Ambient Adjusted Ratings (AAR)

Demand Response Resources

- Existing Programs
  - Commercial and Interruptibles
- Customer potential study results
- Disruptive load
  - Distributed Energy Resources (DER)
  - Electric Vehicles (EVs) and charging stations

Supply Side Resources

- Existing Resources
- Available generation study for generic resource alternatives
- Modeled Retirements
  - Wind resources at 25 years
  - No additional retirements planned at this time
- No RFP for this IRP

Modeling

- Base Case
- Sensitivities
  - Load growth, natural gas, market, higher renewable, capacity accreditation, Coyote retirement, seasonal capacity requirement, carbon tax
  - New - extreme weather event and natural gas shortfall

Timeline

- November
  - First IRP meeting
  - 2021 Action plan, environmental, Heskett 4, MISO
- February
  - Second IRP meeting
  - Load forecast, modeling results, resource alternatives, potential study
- May
  - Third IRP meeting
  - Environmental, DSM, Supply Side, Action Plan
- July 1
  - ND IRP filed. Informational filing in SD.
- September 15
  - MT IRP filed

Work Plan Approval

- Questions
- Motion to approve
  - Rich Warder – motion to approve
  - Dr. O'Neill – seconded
    - No one disapproved (Kyla Maki, Stephen Schreibeis, Darin Scherr, Rich Garman, Martin Fritz, Mike Dalton on call)
    - Pat Steffensen and Adam Renfandt not on call

Attachment I

Responses to Montana Public Service Commission Comments Regarding Montana-Dakota's 2021 IRP

Service Date: September 26, 2022

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF Montana-Dakota Utilities Co.'s 2021 Biennial Electric Integrated Resource Plan	)))	REGULATORY DIVISION DOCKET NO. 2021.09.117

MONTANA PUBLIC SERVICE COMMISSION COMMENTS IN RESPONSE TO MONTANA-DAKOTA UTILITIES CO.'S 2021 INTEGRATED RESOURCE PLAN

PROCEDURAL HISTORY

1. On September 15, 2021, Montana-Dakota Utilities Co. ("MDU") filed its biennial electric Integrated Resource Plan ("2021 IRP") with the Montana Public Service Commission ("Commission").

2. On October 14, 2021, the Commission issued a *Notice of Montana-Dakota Utilities 2021 Integrated Resource Plan and Opportunity for Public Comment.*

3. On November 18, 2021, the Commission issued a *Notice of Public Meeting and Opportunity to Comment*. The Commission held the first of two public meetings on January 25, 2022.

4. On January 21, 2022, Denbury Onshore LLC filed written comments.

5. On January 25, 2022, the Montana Department of Environmental Quality filed written comments.

6. The Commission held a second public meeting on April 18, 2022.

BACKGROUND

7. MDU must file a plan every three years to demonstrate how it will meet the requirements of its customers in the most cost-effective manner consistent with its obligation to serve. Mont. Code Ann. § 69-3-1204. The Commission must review the plan, publish a copy of the plan, allow for a minimum of 60 days for public comment, and hold two public meetings. Mont. Code Ann. § 69-3-1204(5). The Commission may identify deficiencies in the plan,

including concerns regarding compliance with Commission planning rules. Mont. Code Ann. 69-3-1204(6). A resource plan must contain:

- an evaluation of the full range of cost-effective means for the utility to meet the service requirements of its Montana customers, including conservation and demand-side management programs in accordance with Mont. Code Ann. § 69-3-1209;
- an annual electric demand and energy forecast developed in accordance with Commission rules;
- an assessment of planning reserve margins and contingency plans for the acquisition of additional resources;
- an assessment of the need for additional resources and the utility's plan for acquiring resources;
- the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process in accordance with Mont. Code Ann. § 69-3-1207; and
- descriptions of at least two alternate scenarios that can be used to represent the costs and benefits from increasing amounts of renewable energy resources and demand-side management programs, based on rules developed by the Commission.

Mont. Code Ann. § 69-3-1204(2).

8. Pursuant to the Commission's rules, an IRP should outline a strategy for meeting customer needs for adequate, reliable, and efficient energy services at the lowest long-term total societal cost. Mont. Admin. R. 38.5.2001. The Commission's rules encourage utilities to actively pursue all cost-effective demand-side resources. *Id*. An IRP should analyze uncertainty and risk associated with forecasting customer needs and estimating the costs of alternatives for meeting the needs. Mont. Admin. R. 38.5.2004.

9. The Commission's rules encourage utilities to thoroughly document resource decisions so that they can be reasonably understood by the Commission and interested parties. Mont. Admin. R. 38.5.2001.

10. Competitive solicitations are important to the least cost planning process, as they can provide important cost information regarding available resources. The Commission's rules encourage utilities to thoroughly test the market for cost-effective alternatives before acquiring any new resources. Mont. Admin. R. 38.5.2010.

11. An IRP must be accompanied by an action plan that illustrates how the plan will be implemented over the near-term under various load and resource scenarios. Mont. Admin. R.

38.5.2012. An IRP that conforms to the Commission's planning rules does not bind the Commission in its review of utility resource plans in conjunction with a rate case or in setting rates. *Id*.

SUMMARY OF 2021 IRP

12. MDU provides electric service through an integrated system to customers in Montana, North Dakota, and South Dakota. MDU serves approximately 128,000 customers across its integrated system and approximately 25,000 residential, industrial, and municipal customers in Montana.

13. The 2021 IRP forecasts MDU's load over a 20-year period (2021-2040). MDU uses an econometric model to forecast load growth and energy sales over the planning period for residential, commercial, industrial, and municipal customer classes in each state. There are several large industrial customers for which MDU forecasts loads individually.[1] MDU's energy load requirement across its integrated system was approximately 3.4 GWh in 2021, including a transmission and distribution line loss rate of 8.041%.[2] MDU forecasts its total annual energy requirement for the integrated system to increase at an average rate of 1.49% per year through 2026 and at an average rate of 0.84% per year through 2040, net of expected savings from demand-side management ("DSM") programs.[3]

14. MDU develops a peak demand forecast for the summer and winter season on its total integrated system – the peak demand forecast is not disaggregated on a state-by-state basis. MDU uses weighted average temperatures for Bismarck, North Dakota, Miles City, Montana, and Williston, North Dakota as part of its econometric analysis to capture weather diversity across its system.[4] In 2021 MDU's summer season peak was about 586 MW, and the winter season peak was about 575 MW.[5] MDU projects its summer and winter season peaks will increase by about 0.97% and 0.91% per year, respectively, on average over the planning horizon.[6]

[1] 2021 IRP, Vol. I, p. 13.
[2] 2021 IRP, Vol. I, p. 15.
[3] 2021 IRP, Vol. III, p. 1.
[4] 2021 IRP, Vol. I, p. 13.
[5] 2021 IRP, Vol. I, p. 15.
[6] *Id.*

15. MDU collects a universal system benefit ("USB") charge from customers in Montana. The USB charge funds financial assistance programs for MDU's low-income customers and demand-side management ("DSM") programs to promote energy efficiency ("EE") on the system. The DSM programs offered by MDU were developed through an EE potential study conducted in 2012 and a program planning study conducted in 2015.[7] MDU offers a lighting rebate program for residential and commercial customers, as well as a partnership program for certain energy conservation projects installed by commercial customers. Montana is the only state in which MDU receives cost recovery for implementing DSM, and therefore, it is the only state in which MDU offers DSM programs.[8] MDU estimates DSM programs offset approximately .05% of MDU's energy load in Montana in 2021. MDU estimates it could acquire enough DSM on its system to offset approximately 0.3% of its load in Montana by 2040, provided it continues to receive cost recovery to implement its DSM portfolio.[9]

16. MDU acquires demand response through two mechanisms. Rate 38/39 is a tariffed, interruptible rate available to commercial and industrial customers with loads of 500 kW or more. Rate 38/39 customers pay a reduced demand charge in exchange for their agreement to shed up to 100% of their load during demand response events, up to 100 hours per year.[10] The demand response resources ("DRR") program is a third-party administered program that was initially offered to customers with loads of at least 50 kW. Participants in the DRR program agree to shed non-critical load during a demand response event up to four hours in duration. Event durations cannot exceed a total of 50 hours per year. In 2020 MDU expanded the DRR program to loads of at least 25 kW and increased the target enrollment from 25 MW to 50 MW.[11] The 2021 IRP assumes MDU will increase enrollment in the DRR program to 40 MW by 2023.

17. MDU is a member of the Midcontinent Independent System Operator ("MISO"). MISO assigns Zonal Resource Credits ("ZRCs") to all resources in the MISO footprint as a measure of the capacity value each resource can contribute to the overall MISO system. MISO requires MDU to satisfy a planning reserve margin requirement ("PRMR") equal to the sum of

[7] 2021 IRP, Vol. III, p. 1.
[8] *Id.*
[9] 2021 IRP, Vol. III, p. 3.
[10] 2021 IRP, Vol. III, p. 9.
[11] *Id.*

MDU's load coincident with MISO's summer peak, plus a 2.1% adder for MISO losses, and a 9.4% planning reserve margin.[12] MDU's projected load coincident with the MISO system summer peak is about 81.1% of the peak load on MDU's integrated system.

18. The following table summarizes MDU's portfolio of owned supply-side resources during the 2020-2021 planning year, as well as the ZRCs MISO assigned to each resource.[13]

Table 1.

2021 Generation Portfolio			
Resource	**Fuel Type**	**Capacity (MW)**	**MISO ZRC**
Coyote	Coal	106.8	94.1
Big Stone	Coal	108.6	106.5
Heskett I	Coal	23.6	0
Heskett II	Coal	69.5	0
Glendive I	Natural Gas	32.9	30.3
Glendive II	Natural Gas	40.9	38.6
Miles City	Natural Gas	21.6	21.0
Heskett III	Natural Gas	81.3	70.9
Lewis and Clark II	Natural Gas	18.4	18.2
Diesel II	Diesel	2	1.8
Diesel III	Diesel	2	1.8
Diamond Willow	Wind	30	5.1
Cedar Hills	Wind	19.5	3.7
Thunder Spirit	Wind	155.5	22.2
Glen Ullin Station 6	Waste Heat	7.5	3.4
Total		**720.1**	**417.6**

19. The least-cost portfolio identified in MDU's 2019 IRP called for the retirement of the Heskett I & II coal units in 2022 and the addition of an 88-MW natural gas combustion turbine at the Heskett Station in 2023 ("Heskett IV"). MDU has committed to those retirements and resource additions identified in the 2019 IRP, and therefore the changes are integrated into all supply portfolios modeled in the 2021 IRP.

20. MISO assigns MDU 14.9 ZRCs for its interruptible rate 38/39 and 27.8 ZRCs for the DRR program for the 2021-2022 planning year. The 2021 IRP assumes MDU will acquire an additional 5 MW from interruptible rate 38/39 and the DRR program will expand to 40 MW by

[12] 2021 IRP, Vol. I, p. 35.
[13] 2021 IRP, Vol. IV, Attachment C, p. 6-7.

2023.[14] The expansion of the DRR program was selected through a competitive solicitation for energy and capacity resources issued in 2020.

21. The 2021 IRP reports MDU has entered into a five-year power purchase agreement ("PPA") to purchase energy and capacity from Minnkota Power Cooperative ("Minnkota") starting in the 2021-2022 planning year through the 2025-2026 planning year. The PPA provides 75 and 90 MW of capacity for the first two years, respectively, and 30 MW of capacity for the last three years of the agreement.[15]

22. With MDU's current resource portfolio, inclusive of its projected expansion of demand response programs, the Minnkota PPA, and the Heskett IV in 2023, the 2021 IRP forecasts that MDU has enough ZRCs to meet the MISO PRMR through 2026.[16] Beginning in 2027, the 2021 IRP forecasts MDU will be capacity deficient for the remainder of the planning horizon. MDU uses the Electric Generation Expansion Analysis System ("EGEAS") software in the 2021 IRP to identify the most cost-effective mix of supply-side resource additions that meet forecasted energy and capacity requirements through 2040. EGEAS selects an optimal mix of resources based on a deterministic set of load and market conditions that are input into the model. MDU hired an independent consultant to develop cost and production characteristics for the resource alternatives available to EGEAS. The cost characteristics of each resource alternative is summarized in Table 2.[17]

Table 2.

[14] 2021 IRP, Vol. I, p. 23.
[15] 2021 IRP, Vol. IV, Attachment C, p. 8.
[16] 2021 IRP, Vol. I, p. 36.
[17] 2021 IRP, Vol. IV, p. 12.

SELF-BUILD SUPPLY-SIDE RESOURCE ALTERNATIVES								
EGEAS Model Input (2021 $)	Plant Size (MW)	ZRC	Capital Cost ($/kW)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)	Fuel Gas Reservation Fee ($/kW-yr)	Heat Rate (BTU/kWh)	Carbon Intensity (ton/GWh)
GE 7EA	78.3	74.6	$1,590	$1.40	$1.50	$2.61	11770	730
GE 7EA Heskett Expansion	78.3	74.6	$878	$0.93	$0.90	$2.61	11770	730
GE LMS100PB	90.7	86.3	$1,760	$1.20	$1.70	$1.82	9050	525
GE LM600PH	45.3	42.8	$2,320	$2.50	$1.60	$2.08	9510	555
GE 7EA (2x1) Heskett Exp.	329.8	311.6	$1,070	$1.40	$4.10	$3.23	9990	515
GE 7FA.05 (1x1)	329.2	311.0	$1,520	$1.10	$3.00	$3.22	6530	430
SIEMENS SGT-800 (2x1)	174	164.4	$2,180	$2.90	$4.00	$2.79	7180	460
WARTSILA 20V34SG	36.5	34.5	$2,710	$2.60	$4.40	$1.58	8470	495
WARTSILA 18V50SG	55	52.0	$2,180	$1.80	$4.60	$1.56	8310	485
BIOMASS	25	22.7	$7,980	$21.00	$5.60	-	12300	1300
PV SOLAR + Storage	50+10	35.0	$1,390	$1.10	$0.00	-	-	-
PV SOLAR + Storage	5+1	3.5	$2,500	$1.20	$0.00	-	-	-
CFBC w/o CO2 Capture	168	152.3	$5,880	$21.00	$14.06	-	10000	1000
CFBC w/ CO2 Capture	122	110.6	$10,400	$29.00	$22.29	-	13800	150
ND Wind	20	3.4	$1,630	$4.20	$0.00	-	-	-
ND Wind	50	8.5	$1,580	$4.20	$0.00	-	-	-

23. In addition to the resources in Table 2, MDU defined three solar resources in EGEAS. The costs for two of the solar resources were based on bids MDU received in response to the 2020 competitive solicitation.[18] The cost for the third solar resource was based on a solar qualifying facility ("QF") PPA submitted to MDU prior to the 2021 competitive solicitation. The QF has since withdrawn the PPA.[19]

24. The cost of fuel for the natural gas fired resources modeled in the 2021 IRP is based on a five-year forward market price strip at Henry Hub, with prices escalated at three percent annually beginning in year six.[20]

25. MDU relies on MISO energy market purchases when prices are lower than MDU's generating cost, or when energy is required due to planned maintenance or forced outages.[21] The EGEAS model includes a 300 MW block of energy during both on-peak and off-peak periods as an available resource alternative to meet load. MDU's base case planning scenario forecasts MISO energy market prices using the three-year historical average to set prices in the first year of the forecast, with a three percent escalation rate annually thereafter.

26. For the base case scenario, EGEAS selects the 20 MW solar QF project in 2024, a mix of purchased capacity and solar generation beginning in year 2030, and a storage facility in

[18] 2021 IRP, Vol. I, p. 32.
[19] *In the Matter of the Application of Montana-Dakota Utilities Co. for Approval of a Solar Energy Purchase Agreement,* Dkt. 2020.11.110.
[20] 2021 IRP, Vol. IV, Attachment C, p. 6.
[21] 2021 IRP, Vol. IV, Attachment C, p. 8.

2037.[22] The net present value ("NPV") of the least-cost plan under the base case scenario is $2.32 billion.

27. The 2021 IRP modeled several sensitivity case scenarios in EGEAS.[23] The sensitivity case results produce an optimal mix of resources under alternative assumptions about the future. MDU considers the sensitivity case results to develop an action plan that is robust under a variety of future conditions. The following provides a brief description of each sensitivity case MDU modeled in the 2021 IRP.

- *Carbon Tax:* MDU did not model a carbon tax in the base case. MDU modeled a carbon tax of $30 and $50 per ton for sensitivity analyses. The carbon tax applied to all carbon emissions from MDU's existing thermal units, energy purchases from the MISO market, and new generating units added to the resource plan beginning in 2023. The $30 and $50 carbon tax increased the NPV over the base case by 54.4% and 80.7%, respectively.
- *High and Low Natural Gas Price:* MDU increased the natural gas price of its base case by $2/MMBtu and $5/MMBtu, as well as decreased the base case price by $1/MMBtu, to test for sensitivity related to high and low natural gas prices. The high natural gas price increased the NPV of the base case by 0.8% and 1.3%, respectively. The low natural gas price decreased the NPV of the base case by 3.9%.
- *High and Low Load Growth*: The 2021 IRP projects energy loads across the integrated system to increase by 0.84% annually, on average, over the planning horizon. The low load growth sensitivity case increases energy loads by about 0.5%, and the high load growth case increases loads by about 4.4%. The low load growth scenario decreased the NPV of the base case portfolio by 3.9% and the high load growth scenario increased the NPV of the base case by 10.9%.
- *High and Low Market Price*: The high market price scenarios increases the forecasted on-peak and off-peak MISO energy market prices by 25% and 50%. These scenarios increase the NPV of the base case by 8.4% and 13.5%, respectively. The low market price scenario decreases the forecasted MISO

[22] 2021 IRP, Vol. IV, Attachment C, p. 14.
[23] 2021 IRP, Vol. I, p. 39-41.

market prices by 25%. The low market price scenario decreases the NPV of the base case by 3.9%.

- *MISO Energy Market Availability*: This sensitivity case reduced the amount of MISO market energy available to MDU from 300 MW per hour to 100 MW per hour over a five- and ten-year period. These sensitivity cases reduced the NPV of the base case by 7.7% and 7.1%, respectively.
- *MISO Peak Coincident Factor*: This sensitivity case increases the amount of ZRCs MDU is required to carry as a member of MISO from 81.1% of MDU's peak load to 90% of its peak load. The results indicate an increase of 6.6% in NPV over the base case.
- *Gas and MISO Market Price Combinations*: These sensitivities examine a combination of both natural gas prices and MISO energy market prices increasing or decreasing. MDU modeled two scenarios for a high gas price and high market price: +$2/MMBtu gas and +25% MISO market, and +$5/MMBtu gas and +50% market. The high gas and market prices increase the NPV of the base case by 9.6% and 17.4%, respectively. The low gas and low market price scenario reduce gas prices by $1/MMBtu and reduces market prices by 25%. This scenario decreases the NPV of the base case by 11.2%.
- *Coyote Retirement*: MDU modeled a least-cost plan under a scenario in which the Coyote Station will retire by the end of 2027, due to unknown technology requirements related to the Regional Haze project. This sensitivity increases the NPV of the base case by 8.1%.

28. The supply side resources that EGEAS selected under each sensitivity case is contained in Volume IV, Attachment C of the 2021 IRP.

29. MDU reports it has seen a reduction in carbon dioxide emissions from its resource fleet. MDU has set a goal to reduce its 2005 carbon dioxide emission intensity rate by 30% no later than 2030. As of 2021 MDU had reduced its 2005 emission rate by 28%.[24]

30. MDU continues to monitor the Regional Haze rule ("RH rule"), which the Environmental Protection Agency ("EPA") promulgated in 1999 to address visibility impairment

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[24] 2021 IRP, Vol. I, p. 2.

in Class I areas of the United States.[25] MDU reports in the 2021 IRP that it is awaiting the round two results of the RH rule state implementation plan from the North Dakota Department of Environmental Quality ("ND DEQ").[26] The ND DEQ could require environmental upgrades to be installed at Coyote Station.

31. The Coyote Station is co-owned by four utilities, and actions taken for economic reasons by one owner may have an impact on the economics related to the plant for other owners. MDU states in the 2021 IRP that if Coyote Station is required to shut down, MDU will be in a capacity deficit position. MDU will continue to monitor this situation and will include additional modeling in the 2023 IRP to analyze the costs that will be required to comply with North Dakota's state implementation plan for the RH rule.

32. MDU has a history of sharing transmission facilities with the Western Area Power Administration ("WAPA") and Basin Electric Power Cooperative ("BEPC") through a reciprocal wheeling arrangement.[27] In 2015, WAPA and BEPC exited MISO and joined the Southwest Power Pool ("SPP"). In order to continue their wheeling arrangement, MDU, WAPA, and BEPC entered into a FERC settlement agreement that allowed MDU to take Network Integrated Transmission Service ("NITS") under the SPP tariff and receive Section 30.9 facility credits from SPP to offset a portion of its SPP transmission bill. MDU sees greater value in continuing to remain in MISO compared to exiting MISO and joining SPP as a full member due to the difference in resource adequacy requirements between MISO and SPP. MDU would need to add about 75 MW of capacity resources to its portfolio if it were to exit MISO and join SPP, based on current resource adequacy requirements between the two organizations.

33. Based on the analyses conducted in the 2021 IRP, MDU states it will complete the following as part of its two-year action plan:[28]

- Continue to evaluate the accuracy of its demand and energy forecasts and make improvements where needed.
- Continue to implement existing, and evaluate new, cost-effective energy efficiency and demand response programs to meet the company's future requirements.
- Retire Heskett I and Heskett II in 2022.

[25] 2021 IRP, Vol. I, p. 4.
[26] 2021 IRP, Vol. I, p. 5.
[27] 2021 IRP, Vol. IV, Attachment G, p. 1-2.
[28] 2021 IRP, Vol. I, p. 50.

- Continue with the design and development for a new 88-MW simple cycle combustion turbine at Heskett Station to be online in 2023.
- Issue a request for proposals for supply-side resources.
- Continue to study the need to install local generation projects, including community solar, throughout its service area to support load growth, mitigate transmission constraints, and provide customer requested programs.
- Monitor the availability and price of energy and short-term capacity in the MISO market or through bi-lateral arrangements and purchase additional capacity as needed to meet customer demand when economical to do so or necessary to fill short-term needs.
- Monitor the development of, and impacts to, Coyote Station associated with changing economics in the MISO market and the next round of Regional Haze reductions and other changes to environmental rules for all generation sources and influence the outcomes where possible.
- Continue to monitor new regional transmission organization ("RTO") resource adequacy requirements associated with changing fleet fuel mix, including seasonal variation and reserve margins. Included in the multi-season resource adequacy requirements may be the need to evaluate the conversion of Heskett III and IV to dual fuel combustion.
- Continue to evaluate solar and battery storage technologies and their potential for implementation within Montana-Dakota's system.
- Monitor the impacts and benefits of its RTO transmission arrangements with MISO and SPP to ensure a safe, reliable, and economic transmission system.
- Maintain its IRP advisory group to provide input to, and review, MDU's future resource plans.

COMMENTS FILED ON 2021 IRP

34. The Montana Department of Environmental Quality ("DEQ") is an active member of MDU's Planning Advisory Group ("PAG"). The PAG provided guidance to MDU on the construction of the 2021 IRP. DEQ is required by statute to review MDU's integrated resource plans and file comments with the Commission on MDU's "need for new resources, the alternatives evaluated to meet the need, the environmental implications of the resource choices, and other related issues that it considers important." Mont. Code Ann. § 69-3-1205.

35. DEQ comments that MDU should evaluate the feasibility of residential demand response programs, particularly an air conditioning cycling or hot water heat load control program.[29] DEQ states residential demand response programs provide financial benefits to

[29] *In the Matter of Montana-Dakota Utilities 2021 Integrated Resource Plan,* Dkt. 2021.09.117, Comments of the Montana Department of Environmental Quality (Jan. 21, 2022).

customers, as well as flexible capacity that provides benefits to the system as whole, and should be thoroughly evaluated.

36. DEQ states MDU should model scenarios that reflect more extreme circumstances to better capture uncertainty and risk associated with resource planning. One such scenario DEQ mentions is a high electrification scenario that models a high future rate of customer adoption of electric vehicles and efficient space and water heating. DEQ states MDU should also model scenarios in which short-term MISO market purchases are not available, to capture risk associated with extreme weather events that could impact the physical delivery of energy.

37. DEQ suggests MDU's next integrated resource plan should more thoroughly analyze emerging technologies such as thermal and renewable resources paired with battery storage, or hydrogen fueled generation, to meet multi-season MISO resource adequacy requirements.

38. DEQ states the 2021 IRP appropriately modeled an early retirement of the Coyote Station in 2028, and MDU should consider modeling a retirement date earlier than 2028 in its next integrated resource plan.

39. Denbury Onshore LLC ("Denbury"), MDU's largest electric customer, warns that MDU and the Commission should be mindful of the risks associated with MDU's plan to transition to an increased reliance on natural gas.[30] Denbury states that depending on natural gas as fuel for MDU's generators will increase MDU's exposure to risk related to the physical deliverability or availability of natural gas on the pipeline system.

40. Denbury states that natural gas prices are subject to volatility, and the 2021 IRP does not adequately account for potential price spikes in natural gas prices. The 2021 IRP assumes gas prices have stabilized due to the development of shale gas formations, but gas prices rose by 38% over the course of 2021 and 2022 winter gas prices are expected to be 30% higher than 2021 winter prices. Denbury states MDU must consider potential volatility in natural gas prices when it models thermal resources in its next integrated resource plan.

41. Denbury comments that MDU should consider new and alternative forms of distributed generation in its next plan, particularly using waste gas to fuel distributed generation. Denbury points out one example in which a company is capturing waste gas from hydraulic

[30] *In the Matter of Montana-Dakota Utilities 2021 Integrated Resource Plan,* Dkt. 2021.09.117, Comments of Denbury Onshore, LLC (Jan. 21, 2022).

fracturing operations in the Bakken shale formation in eastern Montana that would otherwise be burned off and delivering the gas to onsite cryptocurrency mining operations. Denbury states it is interested in pursuing such opportunities with MDU.

42. Denbury also encourages MDU to continue to thoroughly evaluate interruptible capacity demand response programs as part of its resource planning efforts.

43. Generally, comments provided at the public meeting in Sidney reflect community concerns over MDU's decision to retire its coal generation and the resulting resource adequacy. Commenters questioned the resources selected in the IRP and inquired about other alternatives such as hydro. Other comments at the public meeting reiterate the importance of accurate demand and energy forecasts in the planning process.

COMMISSION COMMENTS

44. The 2021 IRP represents a serious effort by MDU to put forth a comprehensive plan setting forth a path for providing service to customers across three separate states and regulatory jurisdictions. The Commission appreciates MDU's work in constructing the 2021 IRP. The Commission also recognizes MDU's effort to engage with the public, the Commission, and other interested parties throughout the process by participating in public listening sessions and informational meetings.

45. The 2021 IRP generally complies with the Commission's planning guidelines in Admin. R. Mont. 38.5.2001, *et seq.*

46. The use of competitive solicitations to acquire new resources is encouraged by Commission planning guidelines. Mont. Admin. R. 38.5.2010. The Commission's planning guidelines encourage utilities to thoroughly document resource decisions so they can be reasonably understood by the Commission. Mont. Admin. R. 38.5.2001. The 2021 IRP does not indicate MDU selected the Minnkota PPA through a competitive solicitation process. MDU should therefore explain in the IRP the process it used to evaluate the cost-effectiveness of the resource or PPA that was acquired and explain why it chose not to use a competitive solicitation.

47. Natural gas market prices have increased sharply since MDU filed the 2021 IRP. In fact, over the past 6 months, market prices have at times exceeded the high natural gas market price sensitivity scenario that MDU modeled in the 2021 IRP. In its next IRP, MDU should

consider any changing natural gas market fundamentals that may warrant changes in the way MDU develops its base case and sensitivity scenarios.

48. The 2021 IRP lacks any significant discussion as to how MDU will meet customer loads if an extreme weather event causes a large outage on the system that also removes MDU's ability to import energy from the MISO market. The consequences of such an event could result in loss of life, and the IRP should discuss how MDU would be able to react in the most critical of situations.

49. In response to MDU's 2019 IRP, the Commission stated MDU should conduct a new energy efficiency assessment and incorporate the results into future resource plan as soon as possible. The Commission is pleased that MDU's two-year action plan in the 2021 IRP states it will evaluate and implement new cost-effective energy efficiency and demand response programs; however, the Commission again reminds that MDU should conduct a new DSM assessment and incorporate the results into its next resource plan. The 2012 and 2015 energy efficiency potential studies MDU has used to inform the DSM portfolio in the last several planning cycles are significantly outdated.

50. The Commission agrees with DEQ that MDU should explore potential costs and benefits related to residential demand response programs. Residential demand response programs may provide cost-effective flexible capacity that can offset extreme energy ramps. But the impacts of, and public sentiment toward, such a program should be studied and resolved before implementation decisions are made. MDU should evaluate the pros and cons of residential demand response programs on its system, such as electric space and water heating programs.

51. A stand-alone battery energy storage system ("BESS") appears to be absent from the supply-side resources MDU considered in the 2021 IRP. BESSs are becoming increasingly prevalent in utility supply portfolios and may play a significant role in the regional energy landscape in the future. In its next IRP MDU should consider the costs and benefits of adding a stand-alone BESS to its supply portfolio.

52. On August 31, 2022, the Federal Energy Regulatory Commission ("FERC") announced it had accepted revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff to establish a seasonal resource adequacy construct.[31] The FERC decision will eliminate the summer-only resource adequacy requirement that has existed

[31] *Order Accepting Proposed Tariff Revisions Subject to Condition,* 180 FERC ¶ 61, 141 (2022).

under MISO, which has historically provided a significant benefit to MDU and its customers. In its next plan, MDU should analyze the costs and benefits of remaining in MISO under the seasonal resource adequacy construct, compared to exiting MISO and joining the SPP. The analysis should include a discussion of the likely customer impacts, as well as the logistical and practical challenges that may need to be addressed if MDU were to join SPP.

53. MDU is one of four joint owners of the Coyote Station plant. Otter Tail Power Company ("OTPC"), one of the four joint owners, has announced it intends to sell its share of Coyote Station by 2028. MDU's next IRP should discuss if OTPC's decision to sell or environmental upgrades related to compliance with the RH rule will have an impact on the continued operation of Coyote Station.

ORDER

DONE AND DATED this 9th day of September, 2022, by a vote of 3 to 0 with Vice President Johnson and Commissioner O'Donnell excused.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

/s/ James Brown
JAMES BROWN, President

Excused
BRAD JOHNSON, Vice President

Excused
TONY O'DONNELL, Commissioner

/s/ Randall Pinocci
RANDALL PINOCCI, Commissioner

/s/ Jennifer Fielder

JENNIFER FIELDER, Commissioner

ATTEST:

/s/ Patricia Trooien

Patricia Trooien, Commission Secretary

CERTIFICATE OF SERVICE

I certify that on the 26th day of September, 2022, a true and accurate copy of the foregoing document was served by email to the following:

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Notification of Montana Dakota Utilities Filings

By: /s/ *Tarin Slayton*
Tarin Slayton
Montana Public Service Commission

Attachment J

Responses to Montana Department of Environmental Quality Comments Regarding Montana-Dakota's 2021 IRP

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF Montana-Dakota Utilities' 2021 Integrated Resource Plan	REGULATORY DIVISION Docket No. 2021.09.117

COMMENTS OF THE
MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY

I. Introduction

The Montana Department of Environmental Quality ("DEQ") appreciates the opportunity to comment on Montana-Dakota Utilities' 2021 Integrated Resource Plan ("2021 IRP"). DEQ is an executive agency established under 2-15-3501, Montana Code Annotated ("MCA") and is home to the Montana Energy Office. DEQ performs multiple energy related functions on behalf of the state including regulation of certain energy development projects pursuant to the Montana Major Facilities Siting Act, analyzing emerging energy issues and providing recommendations for appropriate state action, financing energy efficiency and renewable energy projects, and supporting energy emergency planning and response. DEQ analyzes energy policy and regularly participates in state, regional, and national forums regarding energy issues including supply planning, and regional market coordination, all of which are relevant to the 2021 IRP.

DEQ is required to comment on integrated least-cost plans submitted to the Public Service Commission ("Commission"). Montana statute requires DEQ to "review a plan and comment on the need for new resources, the alternatives evaluated to meet the need, the environmental implications of the resource choices, and other related issues that it considers important."[1] DEQ is also an active member of the Montana-Dakota Utilities' ("MDU") Public Advisory Group. DEQ is committed to participating in energy planning processes that will help guide future energy resource decisions. Consistent with the mission and responsibilities of DEQ, the following general comments are provided in response to the Commission Notice for Opportunity to Comment on the 2021 IRP.

II. DEQ supports MDU's plan to expand their commercial demand response program and encourages MDU to evaluate residential demand response offerings.

Demand response (DR) programs are an effective tool for utilities to secure flexible capacity resources. By providing an incentive to participating customers who agree to curtail their electrical load when called upon by the utility, these voluntary programs are a mechanism for utilities to manage load in peak demand hours. MDU's commercial and industrial DR programs reduce the utility's peak demand, thereby providing fuel cost savings, enhancing grid stability, reducing emissions from generating assets, and deferring the need for new transmission and generation capacity. DEQ commends MDU's goal to expand its current commercial demand response program to 60 megawatts ("MW") by 2023. Enrolling customers with a load of 25 kilowatts ("kW") or higher will capture unrealized demand savings across MDU's service territory.

Voluntary residential DR programs, including air conditioning cycling and hot water heater load control programs could also help provide additional capacity savings during peak demand periods. Notably, a residential air conditioning cycling program was submitted in response to MDU's 2020 request for proposals. While the residential DR program was not

[1] 69-3-1205, MCA

selected by MDU, the increasing importance of deploying a diverse array of flexible capacity resources underscores the need for continued review of these options. DEQ encourages MDU to thoroughly analyze the direct costs and benefits of residential DR programs to customers and the broader costs and benefits as a flexible resource to address system-level needs.

III. MDU should conduct a new electric energy efficiency potential study prior to its 2023 IRP planning process.

MDU conducted its last Energy Efficiency Potential Study in 2012 followed by a program planning study in 2013. To ensure that MDU accurately accounts for cost-effective energy efficiency resources available within its service territory, it is important that MDU conduct another Energy Efficiency Potential Study prior to developing its 2023 IRP. The new study should reflect updated market conditions, avoided costs, and customer demographics, all of which factor into the determination of the available cost-effective efficiency savings potential. DEQ recommends that the next study evaluate energy efficiency savings potential separately for each customer class in Montana, North Dakota, and South Dakota. Factors that affect energy efficiency savings potential, such as end-use characteristics, incentives, and regulatory mechanisms, can vary significantly from one state to another. DEQ also recommends that MDU provide an opportunity for its Public Advisory Group members to review and provide feedback on the inputs and assumptions of the study during the 2023 IRP planning process.

IV. MDU should model diverse scenarios and alternatives that reflect greater uncertainty and risks associated with energy and capacity planning.

Securing a reliable and affordable electricity supply portfolio is increasingly challenged by the risk and uncertainty presented by extreme weather events amplified by changes to climate, rapid technology developments, a shifting regulatory landscape, and evolving market dynamics. These uncertainties demand a fresh evaluation of energy planning assumptions. While DEQ understands that it is impossible to model every scenario MDU might face in an uncertain future, we recommend that MDU analyze additional diverse scenarios that reflect climate, technological, and market uncertainty and that evaluate potential impacts to fuel prices, energy supply, peak demand, and energy load growth.

One additional scenario that MDU should include in its load forecast is a high electrification scenario. Customer adoption of electric vehicles, and efficient electric space and water heating is increasing as the purchase price and operational costs of these electric end uses declines. This trend is leading to increasing electricity demand and shifting load shapes for utilities across the country. The load forecasts included in MDU's 2021 IRP considers two historical periods to develop a high and low-load growth forecast. MDU should model a scenario or scenarios that include projected growth of electric vehicle adoption and other electric end uses in the residential, commercial, and industrial sectors over the IRP action period.

Another source of uncertainty that MDU should reflect in its scenario and resource option analysis is the impact of extreme weather on availability of short-term market purchases and resource adequacy requirements. For example, Winter Storm Uri in February 2021 impacted electricity generation and delivery for customers across 14 states, including Montana. While the storm had a negligible impact on electricity supply for MDU's customers, it impacted several states in the Midcontinent Independent System Operator ("MISO") market footprint, of which MDU is a member. MDU currently relies on bilateral arrangements in the MISO market to meet short-term capacity needs and plans to purchase additional capacity as needed to meet customer demands. In the 2021 IRP, MDU models low and high market price scenarios but does not evaluate scenarios in which market purchases would be significantly limited or unavailable due to extreme weather events. MDU should evaluate supply and demand-side resource options that could meet customer needs under extreme winter and summer scenarios when purchasing short-term capacity from MISO is not an option.

MDU should also analyze emerging energy supply options for meeting MISO multi-season resource adequacy requirements. MDU’s 2-Year Action Plan in the 2021 IRP includes an option to evaluate the conversion of Heskett Station Units 3 and 4 to dual fuel (natural gas generation with diesel fuel back-up). MDU should consider modeling additional resource options to meet multi-seasonal resource adequacy and capacity requirements including thermal and renewable resources paired with longer duration battery storage, and emerging energy supply options such as hydrogen fueled generation, small modular nuclear reactors, and advanced geothermal resources.

The changing economics and ownership dynamics of the Coyote Generating Station are an increasing source of risk and uncertainty for MDU and its customers. The Coyote Station is a 425 MW lignite coal-fired power plant located in Beulah, North Dakota. MDU owns a 25 percent share (107 MW) in the plant, which represents 20 percent of MDU’s supply portfolio. In September 2021, Otter Tail Power, which has the largest (35 percent) ownership interest of the four facility owners, announced plans to sell its ownership share by 2028. MDU appropriately modeled a scenario in the 2021 IRP in which the Coyote station retires in 2028 and the utility plans to conduct detailed analysis of regional haze control costs for Coyote in the 2023 IRP. As part of that planned analysis, DEQ encourages MDU to also evaluate the full range of alternatives to implementing regional haze controls, which could include an earlier retirement with replacement generation, market purchases, and additional investment in demand-side resources such as energy efficiency and demand response. This broad analysis is necessary to identify the least-cost resource options for MDU customers, and to fully evaluate and prepare for the impacts on MDU customers of Coyote's potential retirement.

This concludes DEQ's comments.

Respectfully submitted on this 21st day of January, 2022.

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