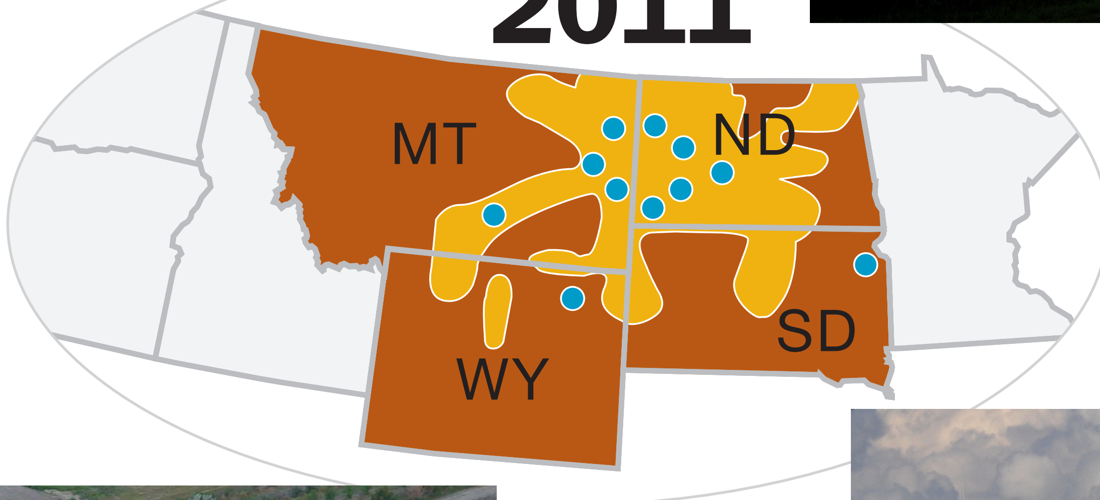
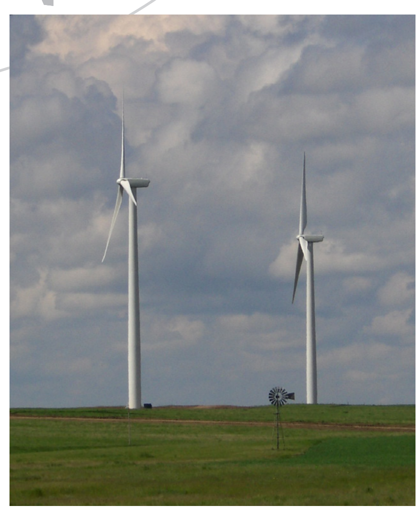
Integrated Resource Plan

2011





Submitted to the
North Dakota Public Service Commission
May 12, 2011

Volume IV: Attachments C-H

Montana-Dakota Utilities Co.

2011 Integrated Resource Plan

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Volume IV

Attachments C – H

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Attachment C

SUPPLY-SIDE AND INTEGRATION ANALYSIS DOCUMENTATION

Supply Side and Integration Analysis

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Supply-Side and Integration Analysis

OVERVIEW

The supply-side analysis was conducted to identify the feasible supply-side resources to be added to Montana-Dakota's generating system to determine the most cost-effective plan. 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 considered 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 as 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. Resource plans in previous IRPs were required to meet the reserve capacity obligation (RCO) of fifteen percent required by the Mid-Continent Area Power Pool (MAPP) Generation Reserve Sharing Pool (GRSP); however the MAPP GRSP was eliminated on December 31, 2009. Montana-Dakota is a member of the Midwest ISO, which at this time requires a planning reserve margin (PRM) of 3.81 percent on an unforced capacity (UCAP) basis for every month of the year. The PRM is adjusted annually through the Midwest ISO's Loss of Load Expectation (LOLE) study. To meet the PRM, sufficient planning resources are needed to cover the projected monthly peak demand with a 1.16 percent adder for Midwest ISO losses, plus 3.81 percent PRM, the product of which is referred to as the planning reserve margin requirement (PRMR).

Montana-Dakota's resource plan as stated in the 2009 IRP was to extend one of the Northern States Power Company (NSP) contracts that would have expired in 2010 to cover Montana-Dakota's capacity for the 2011 timeframe, purchase capacity from Wisconsin Electric Power

Company (WE Energies) for the 2012-2015 timeframe, add 30 MW of incremental wind resources and the Glen Ullin Station 6 waste heat unit, participate in the Big Stone II addition expected on line in 2015, and continue the implementation of identified DSM programs. The 2009 IRP also indicated Montana-Dakota would need additional capacity in 2015 and subsequent years with the plan calling for the addition of two 75 MW combustion turbines.

The Big Stone II plant was subsequently canceled in November 2009. On June 1, 2010, Montana-Dakota issued a request for proposal (RFP) for capacity and energy supply for the time period from 2015 and beyond (2010 RFP). A copy of the 2010 RFP is included in Attachment E. As described in Section 2.3, the results of the 2010 RFP process were used formulate market resource alternatives modeled in the resource expansion analysis.

Load and Capability

To further understand Montana-Dakota's capacity needs a comparison of its planning resource credits (PRC) in the Midwest ISO and the planning reserve margin requirement (PRMR) is shown in Figures 1-1, 1-2, and 1-3 for the base, low-growth, and high-growth forecast scenarios, which are described in detail in the load forecast provided in Chapter 2 and Attachment A. The PRC is established by the Midwest ISO annually through a Generator Verification Test Capability (GVTC) process. The GVTC is run annually by all thermal planning resources (steam units and combustion turbines) greater than 10 MW. All planning resources are corrected to Midwest ISO's summer peak to develop an Installed Capacity (ICAP) value to be used for every month. Capacity resources are determined by applying the equivalent forced outage rate ($XEFOR_d$) to the ICAP value to establish an unforced capacity value (UCAP) for each resource:

$$UCAP = ICAP - (1\text{-}XEFOR_d).$$

UCAP values are then directly converted to a PRC value to be used to meet the PRMR. The PRC value shown in the forecast scenarios includes Montana-Dakota's existing and committed resources at this time.

Figure 1-1 shows that, under the current system forecast and with the current capacity purchase contracts, Montana-Dakota will be capacity deficit by 8.6 PRC in 2013. This capacity deficit will increase to 149.5 PRC in 2015 and grow to 234.7 PRC in 2024. As shown in Figure 1-2, under the low-growth forecast, a capacity deficit of 58.8 PRC will occur in 2015. With the high-growth forecast, as shown in Figure 1-3, a capacity deficit of 11.5 PRC will occur in 2012 and grow to 186.9 PRC in 2015.

Figure 1-1
Planning Resource Credit and Planning Reserve Margin Requirement
Base Forecast

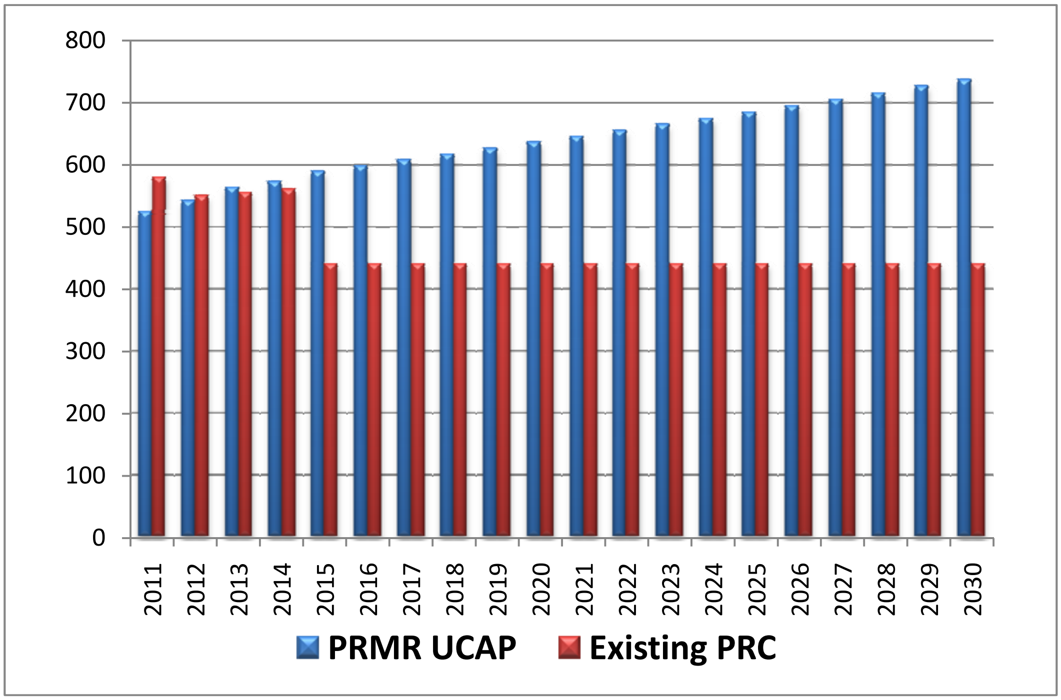


Figure 1-2
Planning Resource Credit and Planning Reserve Margin Requirement
Low Growth Forecast

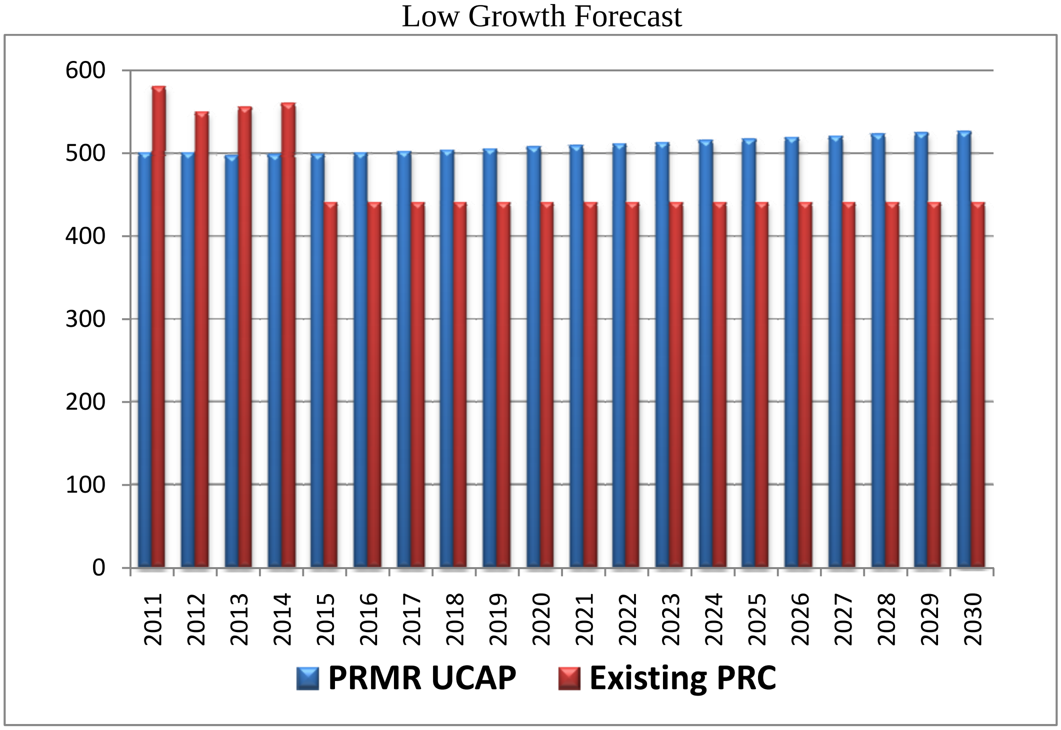
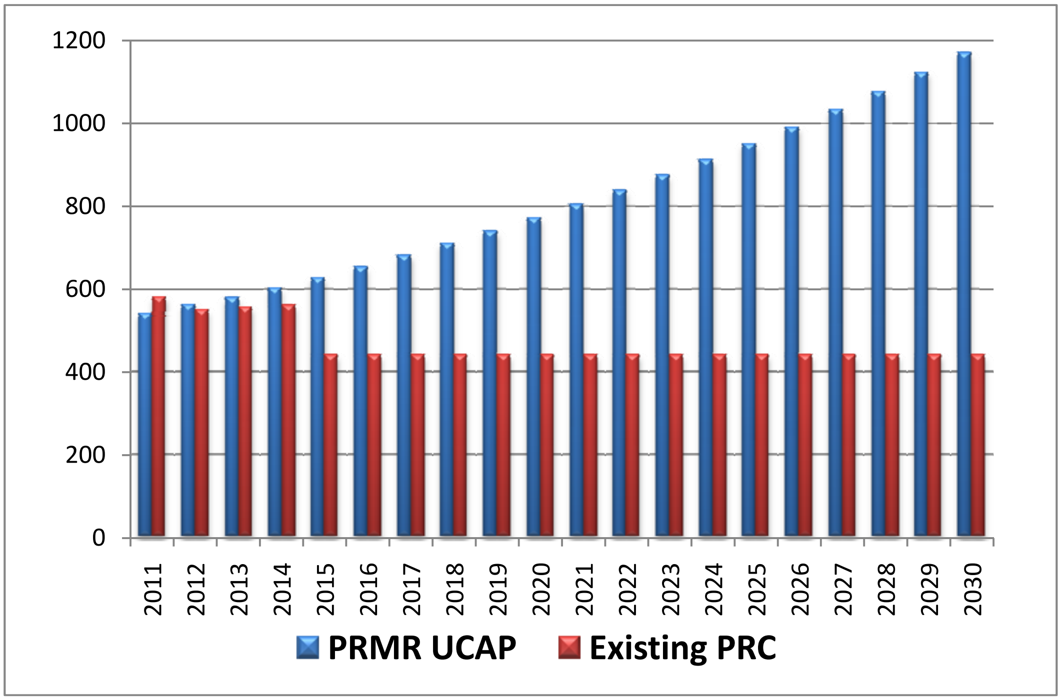


Figure 1-3
Planning Resource Credit and Planning Reserve Margin Requirement
High Growth Forecast



1. Analysis Method

The Electric Generation Expansion Analysis System (EGEAS) version 9.02, 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 2010 with the study period starting in 2011. Costs indicated in this report are in 2010 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2011-2030) in which new resources are allowed to 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. Planning Resources

Montana-Dakota's existing generation portfolio includes coal, natural gas, diesel, waste heat and wind, along with three capacity purchase contracts – the extension of the Northern States Power contract for 2011, the Basin Electric Power Cooperative (Basin Electric) contract for 2011, and the WE Energies contract for the 2012-2015 timeframe. Additional blocks of short-term purchased capacity at the WE Energies contract price through 2014 are also modeled as part of Montana-Dakota's current generation portfolio for resource expansion planning purposes. The resource expansion analysis considered other potential available alternative planning resources to build out the generation portfolio to meet forecasted energy and capacity requirements. All resources were modeled with applicable planning resource credit (PRC) amounts, fixed and variable O&M costs, and fuel costs that are shown in Tables 2-1 through 2-7 below.

For resource capacity accreditation, the Midwest ISO considers wind generation resources differently than thermal resources. The PRC for wind generation resources is only available if the wind resources has been designated as a network resource in the Midwest ISO or if the wind resource has a transmission service request. The PRC value for wind resources is based on an effective load carrying capability (ELCC) study performed annually by the Midwest ISO. This study examined the Midwest ISO's top eight annual summer peaks for the last five years to determine how much wind is actually generated during summer peak conditions and compares the amount of wind generated to the Midwest ISO's peak load. This study is done on a Midwest ISO system-wide basis and on all single commercial pricing nodes (CPNode). On a system-wide basis for the 2011-2012 planning year, the ELCC study concluded that 12.9 percent of nameplate wind capacity could be converted into a PRC value if the wind resource is a network resource or has a transmission service request (TSR). Based upon Montana-Dakota's wind farms' CPNodes, Diamond Willow was determined to contribute up to 21.4 percent of its nameplate capacity to

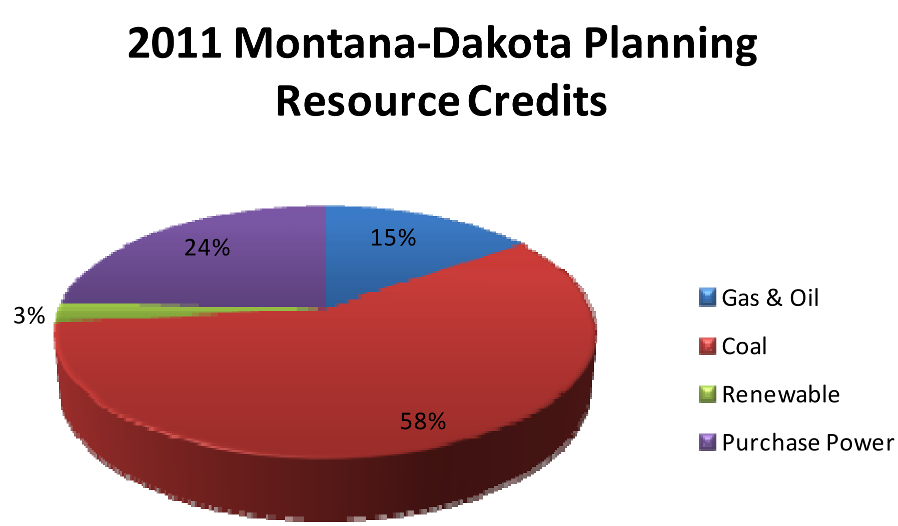
PRCs, and Cedar Hills was allowed up to 30.2 percent of its nameplate capacity to PRCs. Ultimately, Diamond Willow, a designated network resource, was accredited with 6.42 PRCs as Montana-Dakota holds a TSR for Diamond Willow. Cedar Hills, also a designated network resource, was accredited with 3.90 PRCs.

2.1. Current Resources

The existing generation portfolio is broken down into four groups: coal, natural gas/oil, renewable, and purchase power. Figure 2-1 shows Montana-Dakota's 2011 current generation mix by planning resource credits. Fifty-eight percent of Montana-Dakota's PRCs comes from coal generation, 15 percent from gas-fired generation, 24 percent from purchased capacity, and three percent from renewable resources.

Figure 2-1

Montana-Dakota's Current Generation Mix by Planning Resource Credits



2.1.1. Coal

Montana-Dakota currently owns five coal-fired units two of which are jointly owned with other regional utilities. Coal currently accounts for 58 percent of the planning resource credits on Montana-Dakota's system. Table 2-1 shows the capacity in MW established by the Midwest ISO Generator Verification Test Capability (GVTC) process, equivalent forced outage rate ($XEFOR_d$), number of planning 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	GVTC (MW)	$XEFOR_d$	Planning Resource Credit [1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	104.9	8.321	96.2	22.18	2.56	1.26
Big Stone[3]	108.6	4.929	103.3	21.81	1.42	2.03
Heskett 1	29.5	5.501	20.8	52.37	6.16	1.41
Heskett 2	73.1	11.397	64.8	51.56	7.68	1.63
Lewis & Clark	52.3	0.318	52.1	47.55	2.62	1.37

1. Based on Midwest ISO 2011-12 Planning Year ICAP and $EFOR_d$
2. Montana-Dakota's 22.7 percent ownership share
3. Montana-Dakota's 25 percent ownership share

2.1.2. Natural Gas and Diesel

Simple-cycle combustion turbines capable of firing natural gas or fuel oil, along with an internal combustion engine capable of firing diesel, are operated as peaking units and make up about 15 percent of Montana-Dakota's existing planning resource credits. With a total capacity of 9.6 MW, the Williston combustion turbines, built in 1953, are the oldest in Montana-Dakota's fleet and are modeled to be retired from service in 2011. The capacity in MW established by the Midwest ISO Generator Verification Test Capability (GVTC) process, equivalent forced outage rate ($XEFOR_d$), number of planning 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 Generator

Unit	GVTC	$XEFOR_d$	Planning Resource Credit[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Glendive 1	34.0	13.24	29.5	3.29	2.35	5.05
Glendive 2	40.1	8.662	36.6	5.63	2.35	5.05
Miles City	21.6	7.268	20.0	10.48	2.35	5.05
Glendive Diesel	2.04	7.893	1.8	2.74	5.00	16.15

1. Based on Midwest ISO 2011-12 Planning Year ICAP and $EFOR_d$

2.1.3. Renewable

In addition to coal, diesel, and natural gas, Montana-Dakota owns three renewable resources, as shown in Table 2-3. The renewable resources make up about three percent of Montana-Dakota's existing planning resource credits.

Table 2-3
Montana-Dakota's Renewable Generation

Unit	Planning Resource Credits[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[1]	6.42	14.73	-28.26	-
Cedar Hills[1]	3.90	12.56	-30.31	-
Glen Ullin Station 6[2]	4.50	45.88	6.70	-

1. PRC is based on Midwest ISO ELCC study. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2. Based on Midwest ISO 2011-12 Planning Year ICAP and $EFOR_d$

2.1.4. Purchased Power

In addition to generation resources that Montana-Dakota owns, the Company has entered into three purchased power contracts, shown in Table 2-4, to meet the planning reserve margin requirements within the Midwest ISO.

Table 2-4
Montana-Dakota's Purchase Power

Unit	Planning Resource Credit[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
NSP contract[1]	105	17.70	84.30	-
Basin Electric contract	35	4.80	-	-

1. Expires after 2011 summer season

2.2 Future Capacity Resources

As described in the Company's 2009 Integrated Resource Plan, Montana-Dakota has entered into an agreement with Wisconsin Electric Power Company (WE Energies) to purchase peaking capacity during the 2012-2015 timeframe. The contract term begins June 1, 2012 and expires on May 31, 2015. The capacity will be purchased on an annual basis as follows:

- June 2012 through May 2013 – 110 MW
- June 2013 through May 2014 – 115 MW

- June 2014 through May 2015 – 120 MW

The costs of the WE Energies contract are displayed in Table 2-5.

Table 2-5
Montana-Dakota's Future Capacity Resources

Unit	In-Service Date	Planning Resource Credits	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)
WE Energies Contract	2012	110-120	34.80	111.50

2.3 The 2010 Request for Proposal

On June 1, 2010, Montana-Dakota issued a Request for Proposal (2010 RFP) to solicit proposals from capacity, energy, and demand response resources that Montana-Dakota could use as part of its long-term resource evaluation, which would include the cost-effective analysis of the Big Stone AQCS project. The 2010 RFP sought all available resources from 25 to 225 MW in size, beginning in 2015 for five year contract with extension options. Eight qualified responses were received as part of the 2010 RFP. These responses are summarized in Table 2-6.

Table 2-6
2010 RFP Responses Received

1. Existing ND wind project (six options)
2. Simple cycle and combined cycle combustion turbine proposal (three options) (MN and WI)
3. Demand response proposal
4. Wind proposal (two options) (ND and SD)
5. Wind and wind/nuclear proposal (ND and IA)
6. Proposed ND wind project
7. Simple cycle combustion turbine proposal (IL)
8. Utility wholesale sales tariff rate proposal (WI)

The economic analysis of the 2010 RFP responses, as compared to the Big Stone AQCS project and available company resources, selected the demand response proposal, the Illinois combustion turbines, and one North Dakota wind project as part of Montana-Dakota's least-cost plan. The Big Stone AQCS was also selected in all cases as a least-cost resource. While the proposals for the Illinois combustion turbine and a North Dakota wind project were selected as least-cost resources, they ultimately were eliminated from further considerations over concerns with project locations and transmission availability and cost. Montana-Dakota is currently negotiating a contract with the third-party demand response provider for the 25 MW demand response program option described in Section 2.4.7.

As the result of the 2010 RFP process, the following options were added to list of considered supply-side resource alternatives:

- “Energy-only wind” option described in Section 2.4.6, and
- “New purchased capacity” options described in Section 2.4.9.

The “energy-only wind” option was included in the EGEAS model as an alternative to future Midwest ISO energy prices and market purchases as well as an indicator as to when the model may select wind-only energy into Montana-Dakota’s generation portfolio. Montana-Dakota currently has over 2,900 MW of wind generation interconnection requests on its system, and the “energy-only wind” option provides an indication of how a contract purchase of energy from one of these projects would integrate into Montana-Dakota’s resource mix.

The “new purchased capacity” options represent market-priced capacity that was available to Montana-Dakota as part of the 2010 RFP process. These options included five- and ten-year terms for simple cycle combustion turbine capacity and a twenty-year term for a combination of combined cycle and single cycle combustion turbine capacities. The “new purchased capacity” options were the only capacity resources in the 2010 RFP available to Montana-Dakota within its capacity zone identified by the Midwest ISO as part of the new Midwest ISO Resource Adequacy construct.

2.4 Considered Supply-Side Resource Alternatives

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

- Combustion turbine,
- Combined cycle,
- Coal,
- Wind (self-built),
- Purchased capacity,

- Wind (purchased energy),
- Demand response program,
- Big Stone Air Quality Control System (AQCS), and
- New purchased capacity.

Information regarding the resource alternatives available to Montana-Dakota is summarized in Table 2-7. Unless a specific data source is mentioned, the capital cost, fixed O&M cost, variable O&M cost, fuel cost, and other characteristics estimated for these resource alternatives were developed based on manufacturer's budgetary pricing, consulting engineers, Montana-Dakota's experience and expertise, and other available sources.

2.4.1. Combustion Turbine

Simple-cycle combustion turbines (SCCT) are primarily built to serve peaking capacity needs and are usually used to supply a limited amount of energy because SCCTs are fueled by natural gas or fuel oil, which results in higher fuel cost than coal. The SCCT units are, however, lower in capital costs compared to other generating types and can be installed within a relatively short lead time (two to three years). Two options for the combustion turbines were analyzed in the resource expansion analysis: one at 33.4 PRC (43 MW) and the other at 82.3 PRC (88 MW). In particular, the costs associated with the 88 MW combustion turbines were developed through the Combustion Turbine Site Study conducted by Montana-Dakota's Power Production Department in February 2011. The study is included as Attachment G of the 2011 IRP report. The associated costs for the modeled combustion turbines are shown in Table 2-7.

2.4.2. Combined Cycle

A conventional combined cycle combustion turbine (CCCT) burns natural gas or fuel oil in a SCCT. The hot exhaust gases from the SCCT pass through a heat recovery steam generator that produces steam for a steam turbine. Because CCCTs use natural gas or fuel oil as fuel, the units are higher-cost energy producers and their capital costs are between those of a SCCT and a coal-fired baseload unit. The advantage of a CCCT is that it is more efficient to operate than a SCCT, but its hours of operation could be limited because of its high energy costs compared to other available resources. The costs associated with a combined cycle unit are shown in Table 2-7.

2.4.3. Coal

The resource expansion analysis was allowed to consider baseload coal-fired generation. This type of generation is characterized as having a high capital cost with low operating and fuel costs, while providing a stable capacity and energy source. With low operating and fuel costs, baseload units produce large amounts of energy at a relatively low cost. However, as significant new federal regulations that aim to reduce air emissions, including greenhouse gases, at coal-fired electric generating facilities are being proposed, coal-fired baseload generation is unlikely to be available as a new resource option in the foreseeable future.

The coal generation alternative was modeled in blocks of 27.7 PRC (30 MW) instead of a whole, larger unit. The costs associated with a future coal-fired unit are shown in Table 2-7.

2.4.4. Wind (Self-Built)

A wind energy resource is characterized as having high installation costs, but very low energy costs associated with its 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 units and combustion turbines, wind energy resources are allowed limited planning resource credits (PRC) by the Midwest ISO. Therefore, the installation of additional wind generation on Montana-Dakota's system requires adding other capacity resources to meet the Midwest ISO planning reserve margin requirements.

This option represents Montana-Dakota's self-built wind generation. A $22/MWh (after tax) Production Tax Credit (PTC), which was modeled as a negative variable O&M cost, was assumed to be in effect for new wind generation installed before the end of 2012. Once the wind generation was selected (as part of the least-cost plan), the tax credit would continue for ten years from its year of installation. Table 3-5 shows two different options: the option with wind resources installed before the end of 2012 that includes the PTC, and the other wind resource option that does not include the tax credit. The costs associated with both these wind options are shown in Table 2-5.

2.4.5. Purchased Capacity

Another resource alternative is purchased capacity, which was modeled on an annual basis and not limited to the summer season, as Montana will need additional capacity for the winter months. The purchased capacity alternative was assumed to be available for the 2011-2014 timeframe and used to bridge the capacity deficits Montana-Dakota is forecasting in that timeframe. The purchased capacity option was modeled in blocks of 10 PRC (10 MW) to allow EGEAS to determine the needed capacity amounts. The costs associated with the purchased capacity, shown in Table 2-7, were taken from the current WE Energies purchased capacity agreement.

2.4.6. Wind (Purchased Energy)

To reliably and economically serve its customers, Montana-Dakota will not only need additional capacity, but also additional energy supply resources in the future with no new baseload resources built in the planning horizon. This wind energy option, based upon the results of Montana-Dakota's 2010 RFP, was modeled as a power purchase agreement. The wind energy option was modeled in blocks of 25 MW on an energy-only basis with no eligible PRC value. There were two timeframes included in the model: 2015-2020 and 2020-2025 which could be selected independently of each other.

2.4.7. Demand Response Program

As a result of Montana-Dakota's 2010 RFP, an option for a 25 MW demand response program was identified through a proposal from a third-party provider. This demand-side management (DSM) program consists of dispatchable capacity available from commercial and industrial customers who enter into an arrangement with the third-party provider and agree to curtail their load when requested in exchange for a payment based on load curtailed. The DSM program was modeled as a load reduction resource beginning in 2015.

2.4.8. Big Stone Air Quality Control System (AQCS)

An additional alternative was included in the analysis in order to model the cost effectiveness of the required AQCS project at the existing Big Stone plant of which Montana-Dakota is a 22.7 percent owner. To comply with the anticipated regional haze rules, the Big Stone plant will likely be required to install the Air Quality Control Systems (AQCS) using Best Available Retrofit Technology (BART), which was made available as a resource alternative in the model in 2015. The details of the Big Stone AQCS project are described in Attachment H. In this IRP, the AQCS project was studied to compare the required retrofit against other alternatives to determine if it would be more cost effective to retire the Big Stone plant or install the AQCS required to allow continued operation of the plant. The analysis assumed the retirement of the Big Stone plant (with 103.3 PRCs) in 2015 with a new resource option available to the EGEAS model in 2015 that includes the AQCS retrofit project and associated future operating costs for the Big Stone plant. The new resource option was assumed to be accredited with a lower PRC value (101.4 PRCs), as the AQCS would slightly reduce the capacity output of the Big Stone plant.

2.4.9. New Purchased Capacity

The "new purchased capacity" options represent market-priced capacity that was available to Montana-Dakota as part of the 2010 RFP process. Two of these options were to purchase capacity from a 155 MW simple cycle combustion turbine at five- and ten-year terms. The third option was to purchase a total capacity of 345 MW, which would comprise 290 MW from a combined cycle combustion turbine unit and 55 MW from a simple cycle combustion turbine, at a twenty-year term. The costs associated with the "new purchased capacity" options are shown in Table 2-7.

Table 2-7

Considered Resource Alternatives Available to Montana-Dakota

Unit	Size (MW)	Planning Resource Credits	Available Date	Capital Cost ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel Cost ($/MBTU)
Simple Cycle CT (SCCT)	43	33.4	2015	850	$15.82	$2.00	$5.05
Simple Cycle CT (SCCT)	88	82.3	2015	857	$12.08	$2.00	$5.05
Combined Cycle CT (CCCT)	140	132.5	2015	1150	$15.36	$6.00	$5.05
Coal	blocks of 30	27.7	2017	3900	$48.00	$2.50	$1.50
Wind (Self-Built)	blocks of 30	6.4	2013	2400	$23.28	$2.00	-
Wind (Self-Built)2012[1]	blocks of 30	6.4	2011	2400	$23.28	-$27.23	-
Purchased Capacity[2]	blocks of 10	10	2011	-	$34.80	$111.50	-
Wind (Purchased Energy)	blocks of 25	-	2015\	-	$12.00	$49.50	-
Wind (Purchased Energy)	blocks of 25	-	2020\	-	$12.00	$51.00	-
Demand Response Program	blocks of 12.5	12.5	2015	-	$50.04	$300.00	-
Big Stone AQCS project[3]	105.9	101.4	2015	1049	$32.20	$3.19	$2.66
New Purchased Capacity 5 yr[4]	155	155	2015	-	$75.00	$107.41	-
New Purchased Capacity 10 yr[4]	155	155	2015	-	$76.80	$107.41	-
New Purchased Capacity 20 yr[4]	345	345	2015	-	$120.00	$65.79	-

1 – Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value and set to end at the end of 2012.

2 – Prices based on the result of 2008 RFP.

3 – All costs in 2015 dollars

4 – Prices based on the result of 2010 RFP and costs in 2015 dollars

2.4. Retirements

Montana-Dakota is modeling the retirement of the 1953-vintage 9.6 MW Williston combustion turbines in 2011. The Williston combustion turbines have been accredited with PRCs in the Midwest ISO and also provide an emergency source of energy if required. At this time, the cost of maintaining this resource is beginning to exceed the benefit provided by the units.

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

As indicated in Chapter 2 of the current Integrated Resource Plan, the DSM programs planned in the 2009 IRP have been or are expected to be implemented, and the reduction in energy and peak demand is reflected in Montana-Dakota's load forecast, which is modeled in EGEAS. Therefore, those programs have been integrated with the supply-side options in all performed resource expansion analysis.

Included in the load forecast in Chapter 2 were additional and existing interruptible loads associated with the existing programs along with future conservation and demand response programs that had been planned in the 2009 IRP. However, as a result of the demand-side analysis described in Chapter 3, additional new DSM programs were found feasible on a state-by-state basis, and the resulting DSM plan differs from that included in the load forecast. This difference required the demand and energy modeled in EGEAS to be adjusted upward for 2011-2013. The incremental impacts of these new DSM programs are bundled in a "New DSM Package," which was included as a new supply-side option in a separate resource expansion analysis. The amounts of energy and demand reduction and costs associated with the "New DSM Package" are shown in Table 2-8.

Table 2-8
"New DSM Package"

	2014 MW reduction	**2014 MWh reduction[1]**	**$/kW-yr**	**$/kWh**
New DSM Package	8.7	568.98	$50.00	$0.038

1 – Escalated 0.25 percent per year

3. Summaries of Results

Eleven planning scenarios, which include the base case, the base case with "New DSM Package," and nine sensitivity runs, were considered. The least-cost resource plan and associated net present value (NPV) of the total revenue requirement for each scenario are shown in Table 3-1.

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

Year	Base	Base w/ New DSM Package	Low Gas ($1 down)	High Gas ($3 up)	$30 Carbon Tax	$50 Carbon Tax	$30 Carbon, High Gas, additional Envirnmental	High Capital Cost for Combustion Turbines	High Cost for Big Stone AQCS	Low Growth	High Growth
2011											
2012											2-Purchase
2013	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase		3-Purchase
2014	2-Purchase	1-Purchase, New DSM	2-Purchase	2-Purchase	2-Purchase	2-Purchase	2-Purchase	2-Purchase	2-Purchase		5-Purchase
2015	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT88, 2-DSM, BGS AQCS	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT43, 2-DSM, CT88, BGS AQCS, 1-Wind	2-DSM, 2-CT88, BGS AQCS, 5-Wind	2-DSM, 2-CT88, 5-Wind, BGS AQCS, 2-Wind built	2-CT43, 2-DSM, CT88, BGS AQCS, 5-Wind	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT43, 2-DSM, BGS AQCS	2-CT88, 2-DSM, BGS AQCS, 2-Wind
2016											CT43
2017											CT43
2018	CT43		CT43	CT43			CT43	CT43	CT43		CT43
2019											CT43
2020	4-Wind	4-Wind	2-Wind	5-Wind	5-Wind, CT43	5-Wind	5-Wind	4-Wind	4-Wind		5-Wind, CT43
2021		CT43				CT43					CT43
2022	CT43		CT43	CT43			1-Base Load	CT43	CT43		CT43
2023					CT43						CT43
2024		CT43					1-Base Load				CT43
2025	CT43		CT43	1-Base Load		CT43		1-Base Load	CT43		CT43
2026											CT43
2027		CT43			CT43		1-Wind Built				CC
2028	CT43		CT43	CT43		CT43	CT43	CT43	1-Base Load		CT43
2029											CT43, Base Load
2030					2-Wind built						CT43
NPV[1]	$3,723.72	$3,615.71	$3,624.26	$3,759.12	$5,014.11	$5,875.53	$5,317.21	$3,809.08	$3,856.56	$2,529.11	$5,990.34

1 - NPV in millions of dollars
*CT43 - 33.4 PRC (43 MW) Combustion Turbine
*CT88 - 82.3 PRC (88 MW) Combustion Turbine
*CC - 132.5 PRC (140 MW) Combined Cycle
*Base Load - 27.7 PRC (30 MW) Coal-fired Generation
*DSM - 12.5 PRC (12.5 MW) Demand Side Management
*BGS AQCS - Big Stone Air Quality Control System
*Wind - 25 MW Wind (Purchased Energy)
*Purchase - 10 PRC (10 MW) Capacity Purchases
*Wind built - 30 MW Wind (Self-built)
*New DSM - New DSM Package

3.1. Base Case Results

Appendix A to this Attachment shows the input data to the EGEAS model for the base case, while Appendix B shows the EGEAS output report for the same case. Appendix C to this Attachment shows the EGEAS output report for the base case with "New DSM Package," which for reasons explained below is referred to as the least-cost resource plan.

The base case least-cost plan consists of the following resource additions for the 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014;
- Install three combustion turbines (two 43 MW units and one 88 MW unit) in 2015;
- Contract for the 25 MW commercial demand response program to be fully implemented by 2015; and
- Install the Big Stone AQCS project in 2015.

For later years, additional combustion turbines were selected in 2022, 2025, and 2028 to meet PRMR, and a wind energy (100 MW) option was selected in 2020 to meet forecasted growth in energy requirements. The NPV of the base case least-cost plan over the 50-year study period equates to $3,724 million in 2010 dollars, as shown in Attachment C Table 3-1.

When the "New DSM Package" was added as an additional resource option in the base case, it was selected to be implemented in 2014 when full customer participation was expected. The DSM package lowers the NPV over the 50 year study period by about 2.9 percent from the base case. The corresponding least-cost plan consists of the following resource additions for the 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014;
- Install two 88 MW combustion turbines in 2015;
- Contract for the 25 MW commercial demand response program to be fully implemented by 2015; and
- Install the Big Stone AQCS project in 2015.

For the later years, three additional 43 MW combustion turbines were selected in 2021, 2024, and 2027. Also, 100 MW of energy-only wind generation was selected in 2020 to meet future energy requirements.

3.2. Sensitivity Analysis

The nine sensitivity scenarios consist of various assumptions regarding carbon taxes, low and high natural gas prices, low and high load growth, high environmental cost, higher capital costs for combustion turbines, and higher costs for the Big Stone AQCS project.

3.2.1. Carbon Tax

With the potential of a future carbon penalty applied to fossil fuel units and Midwest ISO energy purchases, an assumed carbon tax was applied to every ton of CO_2 emitted from Montana-Dakota's existing coal-fired units and natural gas-fired SCCTs, energy purchases from the Midwest ISO market, and new generating units added to the resource plan starting in 2015. While no carbon tax was modeled in the base case consistent with N.D.C.C. §49-02-23, Montana-Dakota modeled a carbon tax of $30 and $50 per ton for sensitivity analysis. For both the $30 and $50 per ton scenarios, the resource plans selected remained similar to the base case with the only difference being the selection of wind energy-only resources in 2015 (125 MW) and 2020 (125 MW), and 60 MW of self-built wind. At $30 per ton the NPV increased by 34.7 percent above the base case, and at $50 per ton the NPV increased by 57.8 percent over the base case. Montana-Dakota recognizes the amount and applicability of any carbon allowance price or tax have not been established, but this analysis was conducted to provide information regarding possible impacts to customers and to identify potential changes in the Company's future generation resource mix as part of the least-cost plan in the event a carbon tax was implemented.

3.2.2. 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. For the base case, natural gas was priced for delivery at $5.05/MBTU, as of August 31, 2011, for the base year 2010 and escalated by an average of 3.5 percent. Considering the historical fluctuations of natural gas prices, there is a need to consider what impact both higher and lower gas prices would have on the least-cost plan. Therefore, high and low gas price scenarios were also developed, whereby the gas price used in the base case was increased by $3/MBTU and decreased by $1/MBTU from the base case, respectively. The high gas price case was escalated by 2.35 percent annually after 2020, and the low gas price was escalated by 4.35 percent annually after 2020. The results of the high natural gas price case were similar to the base case with the exceptions of the addition of more wind energy and a coal-fired baseload resource in the later years to offset the higher gas prices. The NPV of the revenue requirement in this scenario increased 1.0 percent over the base case. The results of low natural gas price scenario were also similar to the base case with the exception of 50 MW less of wind energy in 2020. This case decreased the NPV of the revenue requirement by 2.7 percent from the base case.

3.2.3. High Environmental Cost

This sensitivity scenario considered the potential for additional future environmental costs such as those of mercury and solid waste regulations for Montana-Dakota's coal-fired units. The sensitivity scenario simulated a $30/ton carbon tax for all coal-fired and natural gas-fired generating units along with energy purchased from the Midwest ISO market, $1.25/MWh adder for mercury control on coal-fired units, and $3.00/MWh for solid waste regulation for coal-fired units. While these environmental costs were not included in the base case model, the sensitivity analysis was conducted to provide information on possible impacts to customers and identify potential changes in the Company's future generation resource mix as part of the least-cost plan in the event regulations are adopted resulting in these additional costs. Along with the environmental costs, the natural gas price was increased by $3/MBTU starting in 2011. The basis for the higher gas price was that, with the additional regulations on coal, more energy would be generated by gas-fired resources, driving natural gas prices up. The selected least-cost plan was different from the base case with the addition of more wind energy, 60 MW of coal-fired baseload, and 30 MW of self-built wind in the later years to offset the additional environmental costs. The results of this scenario indicate an increase of 42.8 percent in the NPV of the revenue requirement over the base case.

3.2.4. Low Growth

This scenario was used to evaluate the load growth potential at less than the base case with an average growth rate of 0.5 percent per year during the 20-year forecast. The basis for this assumption came from Montana-Dakota's historical growth rate during 1985-1993, as described in the load forecast provided in Chapter 2 and Attachment A. The results of this scenario indicate that there is less future capacity and energy needed, resulting in the following resource additions: no purchased capacity was required before 2015; and in 2015 two 43 MW SCCTs, the 25 MW of demand response program, and the Big Stone AQSC were selected.

3.2.5. High Growth

A high-growth scenario simulated an average load growth increase by 4.4 percent per year over the 20-year forecast. The basis for this assumption came from Montana-Dakota's historical growth rate during 1977-1985, as described in the load forecast provided in Chapter 2 and Attachment A. The results of this scenario indicate the need for the following resources over the base case: a total of nine SCCTs (one 88 MW SCCT and eight 43 MW SCCTs) over the study period, a 140 MW CCCT in 2027, 30 MW of coal-fired baseload in 2029, and an additional 10 MW of purchased capacity in 2012.

3.2.6. High Combustion Turbine Costs

Historically the costs of materials associated with the construction of generation have generally increased at a rate higher than general inflation both in the United States and the rest of the world. The base case costs for all generation options reflect the present price forecasts, but for purposes of risk analysis, Montana-Dakota considered the impact of higher installed and O&M costs for new generation (i.e., combustion turbines) on the resource plan. This sensitivity scenario included a 20 percent increase in capital and O&M costs for future combustion turbines to determine the sensitivity of the base case to increases in combustion turbine costs. The least-cost resource plan stays the same with the exception of the addition of 30 MW of coal-fired baseload generation in 2025. The results of this sensitivity case indicate an increase of 2.3 percent in the NPV of the revenue requirement over the base case.

3.2.7. High Big Stone AQCS Cost

As described in Attachment H, a cost based on preliminary studies for the Big Stone AQSC project has been determined and used in the base case analysis. A sensitivity scenario was also developed to address potential fluctuations in project costs. In this sensitivity scenario, the project cost was incrementally increased and, for each project cost point, the resource expansion analysis was performed to determine if other alternatives were selected over the Big Stone AQCS project. With the modeled cost of the Big Stone AQCS project nearly doubled from the original estimated cost, the project was still selected as part of Montana-Dakota's least-cost resource plan and the analysis was stopped. At this project cost point, the resources chosen as part of the scenario stayed similar to the base case with exception of the addition of 30 MW of coal-fired baseload generation in 2029. The high Big Stone AQCS cost caused the NPV of the revenue requirement to increase by 3.6 percent over the base case.

4. Conclusions

Based on the current results of the supply-side and integration analysis, the resource plan resulting from the base case with the "New DSM Package" added as a resource option is the modeled least-cost result. In this plan, the following resources are selected as the least-cost options in meeting the forecasted capacity and energy requirements until 2020 when 100 MW of energy-only wind generation was selected to meet future energy requirements:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014;
- Install two 88 MW combustion turbines in 2015;
- Contract for the 25 MW commercial demand response program to be fully implemented by 2015;
- Install the Big Stone AQCS project in 2015; and
- Implement or continue the DSM programs described in Table 3-3 in the Demand-Side Analysis (Chapter 3) by 2014 that will provide additional capacity reductions of 24.5 MW. These capacity reductions comprise those reflected in the load forecast and those associated with the

modeled "New DSM Package."

Figure 4-1 and 4-2 show a comparison of the resource mix that Montana-Dakota has available to serve its customers' needs in 2011, as compared to the least-cost resource plan in 2015. A Planning Resource Credit (PRC) represents one megawatt of accredited generating capacity under the Midwest ISO resource adequacy rules.

Figure 4-1

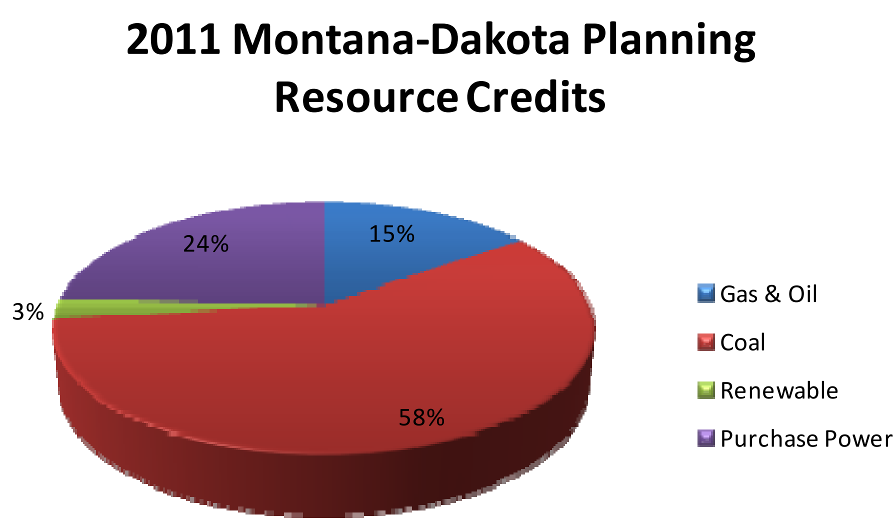
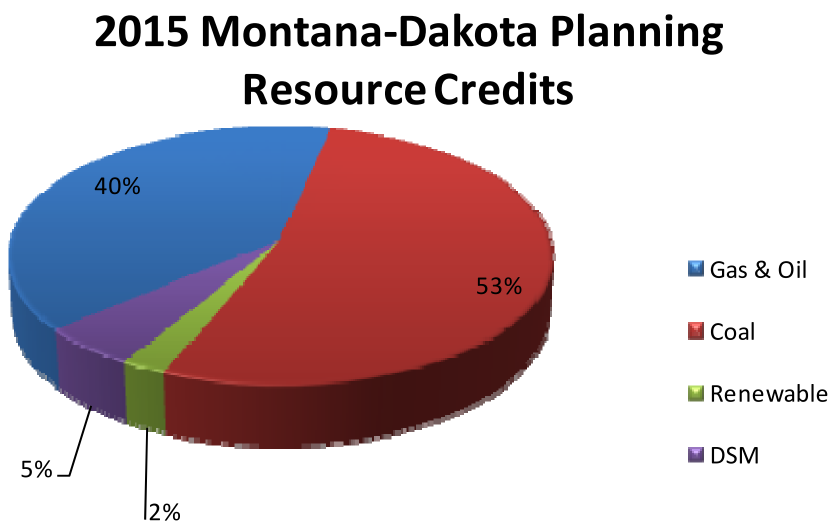


Figure 4-2



As shown in Figures 4-1 and 4-2, in 2011 approximately 15 percent of Montana-Dakota's resource capacity comes from natural gas- and oil-fired combustion turbines while in 2015, based on the least-cost resource plan, approximately 40 percent of the Company's resource capacity would be made up by natural gas and oil-fired combustion turbines. The resource additions were selected mainly to replace the current purchased capacity agreements. In contrast, in the 2015 least-cost resource plan approximately 80 percent of Montana-Dakota's energy requirements would be served from the 53 percent coal-fired capacity and two percent renewable capacity sources. This creates a concern over the imbalance of Montana-Dakota's future generation mix as modeled in the least-cost resource plan, which leaves Montana-Dakota customers vulnerable to future gas and market pricing for 20 percent of their energy needs. The 2009 Integrated Resource Plan identified the Big Stone Unit II project as a least-cost resource, which would have supplied both capacity and energy to meet future customer needs. A clearer national energy policy or development of new technologies may allow the construction of baseload generation for Montana-Dakota in the future.

The sensitivity scenarios showing the most variations are those including carbon tax and high load growth. With a $30 per ton carbon tax, the resource plan remains similar to the base case with the exceptions of more wind energy and self-built wind, but the NPV increased by 34.7 percent. The same can be seen with $50 per ton carbon tax – the NPV increases, but the resource plan remains the same except for more wind energy and self-built wind. Based on Montana-Dakota's current generation portfolio and considering possible future carbon taxes and combustion turbine alternatives, the base case expansion plan with the "New DSM Package" added as a resource option is selected as the least-cost resource outcome.

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 resources to meet the requirements identified for the 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014 through the MISO capacity auction or bilateral agreements;
- Contract for the 25 MW demand response program offered by a third party that is expected to provide 5 MW of dispatchable commercial or industrial demand response the summer of 2012, a total of 15 MW the summer of 2013, and the full 25 MW the summer of 2014;
- Implement the DSM programs identified in Chapter 3 Table 3-3 that are expected to provide an additional peak demand reduction of 24.5 MW and annual energy savings of 7.3 MWh by 2015;
- Install the AQCS equipment required to continue operating the Big Stone Plant beyond 2015; and
- Construct one 88 MW simple-cycle combustion turbine (SCCT) to be operational by 2015.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers' requirements over the five-year planning horizon, as explained below. Montana-Dakota also plans to issue a new request for proposal for capacity and energy resources in 2012 to start the process for the next planning cycle. Each of the resource additions are described in detail in Chapters 3 and 4 and Attachments B, C, and H.

Montana-Dakota has not added a large capacity resource to its generation portfolio since the Glendive Unit II combustion turbine was built in 2002. A power purchase agreement with Basin Electric Power Cooperative for 66 MW of baseload capacity from the Antelope Valley Station Unit II expired in November 2006, which left Montana-Dakota dependent on peaking capacity purchase agreements and market energy prices. Montana-Dakota was unable to acquire additional coal-fired baseload resources when the Big Stone II project was abandoned. Continued reliance on market purchases subjects customers to unknown future prices of capacity and energy. At the expiration of purchased power agreements, there are no remaining assets for continued customer benefit and customers are subjected to the cost impacts of replacement agreements with future market resources.

Montana-Dakota's recommended resource plan satisfies future customer requirements through a balance of a new peaking capacity resource addition, pollution control investments in the Big Stone low-cost energy resource, and expanded demand response and energy efficiency programs. The recommended resource plan does not completely satisfy all customer requirements by 2015. Montana-Dakota is planning to issue a request for proposal of capacity and energy resources in 2012 to acquire additional resources to meet its customers' capacity and energy requirements in 2015 and beyond. In addition, Montana-Dakota will satisfy short-term capacity needs through the Midwest ISO capacity auction or bilateral agreements. Montana-Dakota is also monitoring the development of the mandatory Midwest ISO capacity auction as a potential source of securing future capacity resources.

Details for the Big Stone AQCS project are described in Attachment H to this 2011 IRP. A Combustion Turbine Site Study conducted in February 2011 for the proposed SCCT is included as Attachment F to this 2011 IRP. The study recommends a Mandan, North Dakota site for the new 88 MW simple-cycle combustion turbine.

6. References

Midwest ISO Business Practice Manual-11 Resource Adequacy. (December 1, 2010)

EGEAS User's Guide Version 9.02. New York, New York: Stone & Webster Management Consultants, Inc., June 1999.

Midwest ISO Planning Year 2011 LOLE Study Report. (January 12, 2011)

Appendix A

EGEAS INPUT DATA FOR THE BASE CASE

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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

EDIT PROGRAM

Montana-Dakota Utilities Co.
2011 Integrated Resource Planning Study
Base Case Run
-- Data updated for the 2011 IRP

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3412 HILL VIEW 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

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

INPUT FILES	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
ORTHOGONALIZED LOAD	2011	1	0	4/26/11	13:40:21	2011 IRP	900
HOURLY LOADS							
SYSTEM A	HOURLOAD	1	0				
HOURLY NDT							
TECHNOLOGY 1	wind40cf	1	0				

OUTPUT FILE	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
EGEAS DATABASE	2011	1	0	4/26/11	13:40:23	2011 IRP	900

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** COMMENT **       *               Montana-Dakota Utilities Co.                                                     1
                    *               2011 Integrated Resource Planning Study                                          2
                    *               Base Case Run                                                                    3
                    *                 -- Data updated for the 2011 IRP                                               4
                    *                                                                                                5
                    *               Control record.                                                                  6
                    *                                                                                                7
                    *                M     C   ---REPORTS---                                                         8
                    *                O     O   C M E    F C                                                          9
                    *                D     S   T I R    I N                                                         10
                    *                E     T   L R R    L T     DESCRIPTIVE INFORMATION                             11
                    *                +     -   + - +    - +     ------------------------------                      12

CONTROL RECORD        ECC            1     1   1 1 3    0 1     2011 IRP                                            13

** COMMENT **       *                                                                                               14
                    *               EGEAS DATA BASE     ORTHOGONALIZED LOAD FILE (FROM ORTHOG)                      15
                    *               NAME      V U       NAME      V U                                               16
                    *               --------+--         --------+--                                                 17

FILE IDENTIFICATION   EFF           2011      1 0       2011      1 0                                               18

** COMMENT **       *                                                                                               19
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                    *               BASE  DISC      S    -BENCHMARK- UNS.ENERGY  CUST. INFL. R INF                  21
                    *               YEAR  RATE      W    YEAR  PEAK    $/MWH  TJ DISC. RATE  B  TJ                  22
                    *               ----++++++      +    ++++ ------ ++++++++---++++++-----++---                    23

GENERAL DATA          EGLA          2010  6.73      1    2010 501.80 130.0000 316.73103.0000  1  0                  24

** COMMENT **       *                                                                                               25
                    *               == GENERAL DATA - SYSTEM IDENTIFIERS ==                                         26
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                    *               ----++++----++++----++++----++++----++++                                        28

GENERAL DATA          EGLB          SYSA                                                                            29

** COMMENT **       *                                                                                               30
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                    *               ------------                                                                    33

GENERAL DATA          EGLC       1  SYSA                                                                            34

** COMMENT **       *                                                                                               35
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                    *                U IDENT                                                                    38
                    *                M CODE    NAME                                                             39
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GENERATING COMPANIES EGC    1  1     4 NDAK   NDAK                                                              41
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GENERATING COMPANIES EGC    2  1     1 SYSB   SYSB                                                              45

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GENERATING COMPANIES EGC    5  1     1 SYSE   SYSE                                                              48

GENERATING COMPANIES EGC    6  1     1 SYSF   SYSF                                                              49

GENERATING COMPANIES EGC    7  1     1 SYSG   SYSG                                                              50

GENERATING COMPANIES EGC    8  1     1 SYSH   SYSH                                                              51

GENERATING COMPANIES EGC    9  1     1 SYSI   SYSI                                                              52

GENERATING COMPANIES EGC   10  1     1 SYSJ   SYSJ                                                              53

** COMMENT **       *                                                                                           54
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                    *               --------+++++++++   ---+++                                                  57

SYSTEM DEMAND        ESD       1    500.50002677.8000     1  2                                                  58

** COMMENT **       *                                                                                           59
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                    *               == BASIC PLANT TYPE DATA ==                                                 61
                    *                                                                                           62
                    *                                   LL SA FL  SRVC GEN  OWNER UNIT INST LIFE                63
                    *               NAME              TYPECD TV CLS AREA  CO   PCT. GRP. YEAR OP BK             64
                    * EBPA          ---------------- ++++-+ -+---- ++++ ---- +++++ ---- ++++ -- ++              65
                    *               RATED --CAPACITY MULT.--  EQV. HEAT  ENRGY STOR      CAP.MULT.              66
                    *                CAP.  OPER. EMER. CHRG.  FOR  RATE  LIMIT EFF.       RESERVE               67
                    * EBPB          ------++++++-----++++++-----++++++-----++++++      ------                   68
                    *                INSTALL.  INSTALL. LEVEL. FIXED  VAR. AFUDC  DEBT M CAP                    69

      RECORD COLS                1          2         3         4         5         6         7         8
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** COMMENT **      *                COST 1    COST 2  CARRY.  O+M   O+M   PCT. AFUDC U STR                   70
                   * EBPC         ----------+++++++++----------++++++-----------+++++-----++---              71
                   *               IN FX VR    M    OPR                  B  N  E  S RES HT T RAT             72
                   *               CS OM OM FO N  F CAP EN    CP EN     L  D  N  I CAP RT A CAP              73
                   *               TJ TJ TJ TJ T  L  TJ TJ    SM SM WS K  T  V  T  TJ TJ X  TJ               74
                   * EBPD         ---+++---+++---+++---+++  +++---+++---+++---+++---+++---+++                75
                   *               M S       DISPATCH FL HT-RT  MUST-RUN  SPINNING                           76
                   *               R P       MODIF TJ  2 MUL:2  1ST LAST  1ST LAST                           77
                   * EBPE          - +       -----+++---++++++  ---- ++++ ---- ++++                          78
                   *              CONSTRUCT CONSTRUCT    EXP    %CWIP                                        79
                   *                COST 1    COST 2  TJ PAT    IN RB                                        80
                   * EBPF         ----------++++++++++---+++    ------                                       81
                   *              ..........BASE YEAR...........                                             82
                   *                CWIP     EQ.AFUDC  DEBT.AFUDC                                            83
                   * EBPG         ----------+++++++++----------                                              84
                   *  --- --- --  --------------------------------------------------------------             85
                   *                                                                                         86

BASIC PLANT TYPE     EBPA  1      BIG STONE UP     THRM B G COAL MDU  SDAK 100.0    1      40 30             87
                     EBPB  1       105.90.92511.0000      0.0493 10542                    0.9575             88
                     EBPC  1        1049.000          10.75021.8101.4200               1  1                  89
                     EBPD  1       53 50 51  0 20  6  0  0     0  0  0  3  0  0  0  0  0 20  0              90
                     EBPE  1       M         0.0000  0  0        1980 2080                                   91

** COMMENT **      *                                                                                         92

BASIC PLANT TYPE     EBPA  2      MISO - Off peak  THRM P E PURC MDU  MISO 100.0    1 2010 50 50             93
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                     EBPC  2                                0.000023.500              2  0                   95
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** COMMENT **      *                                                                                         97

BASIC PLANT TYPE     EBPA  3      WIND ENERGY2     NDT  B G PURC MDU  MISO 100.0    1       6  6             98
                     EBPB  3      25.0001.00001.0000      0.0000                          0.0000             99
                     EBPC  3           0.000                12.00051.000               1  1                 100
                     EBPD  3          55 45  0 22     0  0     0  0  0  0  1  0  0  0  0  0  0              101
                     EBPF  3           0.000               0    0.0000                                      102
                     EBPG  3      0.000000000.000000000.00000000                                            103

** COMMENT **      *                                                                                        104

BASIC PLANT TYPE     EBPA  4      C-5              THRM B G PURC MISO MISO 100.0    1       5  5            105
                     EBPB  4       155.01.00001.0000      0.0747 10800                    1.0000            106
                     EBPC  4           0.000                75.000107.41              2  0                  107
                     EBPD  4          47 56  0 16  8  0  0     0  0  0  0  0  0  0  0  0  0  0              108

      RECORD COLS              1          2         3         4         5         6         7        8
                   1 2345 678 90  123456789012345678901234567890123456789012345678901234567890012 34567890
```

```
                       REC. REF SEQ                                                                          ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                     REC. NO.
------------------   - ---- --- ---   --------------------------------------------------------------         --------
       RECORD COLS                1         2         3         4         5         6         7         8
                     1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890

** COMMENT **        *                                                                                          109

BASIC PLANT TYPE       EBPA   5      C-10            THRM B G PURC MISO MISO 100.0    1     10 10               110
                       EBPB   5       155.01.00001.0000      0.0747 10800                1.0000                 111
                       EBPC   5           0.000                76.800107.41            2  0                     112
                       EBPD   5             47 56  0 18  8  0  0     0  0  0  0  0  0  0  0  0  0  0            113

** COMMENT **        *                                                                                          114

BASIC PLANT TYPE       EBPA   6      C-20            THRM B G PURC MISO MISO 100.0    1     20 20               115
                       EBPB   6       345.01.00001.0000      0.0534  7250                1.0000                 116
                       EBPC   6           0.000                120.0065.790            2  0                     117
                       EBPD   6             57 58  0 21  8  0  0     0  0  0  0  0  0  0  0  0  0  0            118

** COMMENT **        *                                                                                          119

BASIC PLANT TYPE       EBPA 110      WILLISTON C.T.  THRM P E GAS  MDU  NDAK 100.0    1 1953 57 30              120
                       EBPB 110      10.6000.90571.0000      0.1750 20700                0.7453                 121
                       EBPC 110                              3.55002.3500              2  0                     122
                       EBPD 110           3  4  0  1  1  0  0     0  0  0 11  0  0  0  0  0  0  0               123

** COMMENT **        *                                                                                          124

BASIC PLANT TYPE       EBPA 120      MILES CITY C.T. THRM P E GAS  MDU  MONT 100.0    1 1972 99 30              125
                       EBPB 120      30.0000.82990.9267      0.0727 13439                0.6667                 126
                       EBPC 120                              10.4802.3500              2  0                     127
                       EBPD 120           3  5  0  2  1  0  0    12  0  0 12  0  0  0  0  0  0  0              128

** COMMENT **        *                                                                                          129

BASIC PLANT TYPE       EBPA 130      GLENDIVE CT #1  THRM P E GAS  MDU  MONT 100.0    1 1979 99 30              130
                       EBPB 130      42.0000.80610.9636      0.1324 11615                0.7024                 131
                       EBPC 130                              3.29002.3500              2  0                     132
                       EBPD 130           3  6  0  3  1  0  0    13  0  0  2  0  0  0  0  0  0  0              133

** COMMENT **        *                                                                                          134

BASIC PLANT TYPE       EBPA 132      GLENDIVE CT #2  THRM P E GAS  MDU  MONT 100.0    1 2003 99 30              135
                       EBPB 132      43.0000.80610.9636      0.0866  8494                0.8512                 136
                       EBPC 132                              5.63002.3500              2  0                     137
                       EBPD 132           3  7  0  4  1  0  0    13  0  0 13  0  0  0  0  0  0  0              138

** COMMENT **        *                                                                                          139

BASIC PLANT TYPE       EBPA 134      GLENDIVE DISEL  THRM P E GAS  MDU  MONT 100.0    1 2005 99 30              140
                       EBPB 134       2.0001.00001.0000      0.0789 11000                0.9500                 141

       RECORD COLS                1         2         3         4         5         6         7         8
                     1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                      REC. REF SEQ                                                                              ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                         DATA FIELDS                                           REC. NO.
------------------  - ---- --- ---  --------------------------------------------------------------              --------
       RECORD COLS                1            2         3         4         5         6         7           8
                    1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890

BASIC PLANT TYPE      EBPC 134                                2.74005.0000             2  0                          142
                      EBPD 134           3  8  0  1  2  0  0     0  0  0  0  0  0  0  0  0  0  0                     143

** COMMENT **       *                                                                                              144

BASIC PLANT TYPE      EBPA 140      HESKETT #1       THRM B E COAL MDU  NDAK 100.0    1 1954 99 30                   145
                      EBPB 140      29.2000.67911.0000      0.0550 15762                 0.7123                      146
                      EBPC 140                                52.3706.1600             2  0                          147
                      EBPD 140           3  9  0  5  3  0  0     0  0  0 14  0  0  0  0  0  0  0                     148

** COMMENT **       *                                                                                              149

BASIC PLANT TYPE      EBPA 150      HESKETT #2       THRM B E COAL MDU  NDAK 100.0    1 1963 99 30                   150
                      EBPB 150      74.6000.93831.0000      0.1140 13502                 0.8686                      151
                      EBPC 150                                51.5607.6800             2  0                          152
                      EBPD 150           3 10  0  6  4  0  0     0  0  0 15  0  0  0  0  0  0  0                     153
                      EBPE 150       M        0.0000  0  0        1980 2080                                          154

** COMMENT **       *                                                                                              155

BASIC PLANT TYPE      EBPA 160      LEWIS & CLARK    THRM B E COAL MDU  NDAK 100.0    1 1958 99 30                   156
                      EBPB 160      52.3000.86040.9398      0.0032 12679                 0.9962                      157
                      EBPC 160                                47.5502.6200             2  0                          158
                      EBPD 160           3 11  0  7  5  0  0    16  0  0 16  0  0  0  0  0  0  0                     159

** COMMENT **       *                                                                                              160

BASIC PLANT TYPE      EBPA 170      BIG STONE        THRM B E COAL MDU  SDAK 100.0    1 1975 40 30                   161
                      EBPB 170       107.80.92511.0000      0.0493 10350                 0.9583                      162
                      EBPC 170                                21.8101.4200             2  0                          163
                      EBPD 170           3 12  0  8  6  0  0     0  0  0 17  0  0  0  0  0  0  0                     164
                      EBPE 170       M        0.0000  0  0        1980 2080                                          165

** COMMENT **       *                                                                                              166

BASIC PLANT TYPE      EBPA 180      COYOTE           THRM B E COAL MDU  NDAK 100.0    1 1981 99 30                   167
                      EBPB 180       106.80.93681.0000      0.0832 11225                 0.9007                      168
                      EBPC 180                                22.1802.5600             2  0                          169
                      EBPD 180           3 13  0  9  7  0  0     0  0  0 18  0  0  0  0  0  0  0                     170
                      EBPE 180       M        0.0000  0  0        1980 2080                                          171

** COMMENT **       *                                                                                              172

BASIC PLANT TYPE      EBPA 220      WAPA PUR-FT PECK HYDR B E HYDR MDU  NDAK 100.0    1 2001 30 30                   173
                      EBPB 220       2.8000.89291.0000      0.0000     14.33             0.0000                      174
                      EBPC 220           0.000                0.000016.840             2  0                          175

       RECORD COLS                1            2         3         4         5         6         7           8
                    1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                      REC. REF SEQ                                                                         ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                       DATA FIELDS                                       REC. NO.
------------------  - ---- --- ---   ------------------------------------------------------------         --------
       RECORD COLS                1          2         3         4         5         6         7         8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890

BASIC PLANT TYPE      EBPD 220             14  0  0      0  0     0  0  0  0  0  0  0  0  0  0  0                 176
                      EBPE 220       M        0.0000  0  0       1980 2080                                        177
                      EBPF 220            0.000              0    0.0000                                          178
                      EBPG 220      0.000000000.000000000.00000000                                                179

** COMMENT **       *                                                                                             180

BASIC PLANT TYPE      EBPA 230      XCEL ENERGY PK 1 THRM P E PURC MDU  MISO 100.0    1 2007  4  4                181
                      EBPB 230      10.0001.00001.0000      0.0000     1                  1.0000                  182
                      EBPC 230           0.000               17.700184.30              2  0                       183
                      EBPD 230          15 16  0 14  8  0  0     0  0  0  0  0  0  0  0  0  0  0                  184
                      EBPF 230           0.000               0    0.0000                                          185
                      EBPG 230      0.000000000.000000000.00000000                                                186

** COMMENT **       *                                                                                             187

BASIC PLANT TYPE      EBPA 240      XCEL ENERGY PK 2 THRM P E PURC MDU  MISO 100.0    1 2007  5  5                188
                      EBPB 240       100.01.00001.0000      0.0000     1                  1.0000                  189
                      EBPC 240           0.000               17.70084.300              2  0                       190
                      EBPD 240          15 16  0 14  8  0  0     0  0  0  0  0  0  0  0  0  0 32                  191
                      EBPF 240           0.000               0    0.0000                                          192
                      EBPG 240      0.000000000.000000000.00000000                                                193

** COMMENT **       *                                                                                             194

BASIC PLANT TYPE      EBPA 250      DIAMOND WILLOW   NDT  B E WIND MDU  MONT 100.0    1 2008 30 20                195
                      EBPB 250      30.0001.00000.3810      0.0000                    0.2140                      196
                      EBPC 250        2400.000         13.75614.730-28.26              1  1                       197
                      EBPD 250       20  3 17  0 10     0  0     0  0  0  0  1  0  0  0  0  0  0                  198
                      EBPF 250        2000.000          20  0     0.0000                                          199
                      EBPG 250      0.000000000.000000000.00000000                                                200

** COMMENT **       *                                                                                             201

BASIC PLANT TYPE      EBPA 260      GLEN ULLIN ORMAT THRM B E PURC MDU  NDAK 100.0    1 2009 30 30                202
                      EBPB 260       5.3000.92450.9245      0.0735     1                  0.9245                  203
                      EBPC 260        2558.000         13.75645.8806.7000              1  1                       204
                      EBPD 260       20 44 18  0 15  8  0  0     0  0  0  0  0  0  0  0  0  0  0                  205
                      EBPE 260       M        0.0000  0  0       1980 2080                                        206
                      EBPF 260        2558.000          20  0     0.0000                                          207
                      EBPG 260      0.000000000.000000000.00000000                                                208

** COMMENT **       *                                                                                             209

BASIC PLANT TYPE      EBPA 270      CEDAR HILLS      NDT  B E WIND MDU  MONT 100.0    1 2010 30 20                210
                      EBPB 270      19.5001.00000.3810      0.0000                    0.2000                      211

       RECORD COLS                1          2         3         4         5         6         7         8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                       REC. REF SEQ                                                                 ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                      DATA FIELDS                                 REC. NO.
------------------   - ---- --- ---   --------------------------------------------------------------  --------
       RECORD COLS                1            2         3         4         5         6         7          8
                     1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890

BASIC PLANT TYPE       EBPC 270        2400.000          13.75612.560-30.31             1  1                   212
                       EBPD 270       20  3 19  0 10     0  0     0  0  0  0  1  0  0  0  0  0  0              213
                       EBPF 270        2000.000           20  0    0.0000                                      214
                       EBPG 270      0.000000000.000000000.00000000                                            215

** COMMENT **        *                                                                                         216

BASIC PLANT TYPE       EBPA 280      WE ENERGIES      THRM P C PURC MDU  MISO 100.0    1 2012  3  3            217
                       EBPB 280       110.01.00001.0000      0.0000     1                  1.0000              218
                       EBPC 280           0.000             34.800113.80                1  1                   219
                       EBPD 280          42 43  0 11  8  0  0     0  0  0  0  0  0  0  0  0  0 41              220
                       EBPF 280           0.000               0    0.0000                                      221
                       EBPG 280      0.000000000.000000000.00000000                                            222

** COMMENT **        *                                                                                         223

BASIC PLANT TYPE       EBPA 310      PURCHASE POWER   THRM P G PURC MDU  MISO 100.0    1        1  1           224
                       EBPB 310      10.0001.00001.0000      0.0000     1                  1.0000              225
                       EBPC 310           0.000             34.800110.00                1  1                   226
                       EBPD 310          21 21  0  0  8  0  0     0  0  0  0  0  0  0  0  0  0  0              227
                       EBPF 310           0.000               0    0.0000                                      228
                       EBPG 310      0.000000000.000000000.00000000                                            229

** COMMENT **        *                                                                                         230

BASIC PLANT TYPE       EBPA 340      CC-140           THRM P G GAS  MDU  NDAK 100.0    1       40 40           231
                       EBPB 340       140.00.85711.0000      0.0537  8500                 0.9464               232
                       EBPC 340         750.000          11.54015.3606.0000             1  1                   233
                       EBPD 340       30 22 23  0 12  1  0  0    13  0  0  1  0  0  0  0  0 20  0              234
                       EBPF 340         750.000           30 37    0.0000                                      235
                       EBPG 340      0.000000000.000000000.00000000                                            236

** COMMENT **        *                                                                                         237

BASIC PLANT TYPE       EBPA 350      COMBUST. TURB.75 THRM P G GAS  MDU  NDAK 100.0    1       40 25           238
                       EBPB 350      88.0000.83710.9276      0.0645 10655                 0.9352               239
                       EBPC 350         857.000          11.54012.0802.0000             1  1                   240
                       EBPD 350       30 22 24  0 12  1  0  0    13  0  0 13  0  0  0  0  0 20  0              241
                       EBPF 350         857.000           30 37    0.0000                                      242
                       EBPG 350      0.000000000.000000000.00000000                                            243

** COMMENT **        *                                                                                         244

BASIC PLANT TYPE       EBPA 360      GENERIC BASELOAD THRM B G COAL MDU  NDAK 100.0    1       40 40           245
                       EBPB 360      30.0000.95001.0000      0.0765  9700                 0.9233               246
                       EBPC 360        3900.000          10.27048.0002.5000             1  1                   247

       RECORD COLS                1            2         3         4         5         6         7          8
                     1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                       REC. REF SEQ                                                                         ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                           DATA FIELDS                                   REC. NO.
------------------   - ---- --- ---  --------------------------------------------------------------       --------
       RECORD COLS                 1          2         3         4         5         6         7          8
                     1 2345 678 90    12345678901234567890123456789012345678901234567890123456789012  34567890

BASIC PLANT TYPE       EBPD 360         30 22 25  0 13  9  0  0     0  0  0  0  0  0  0  0  0 20  0               248
                       EBPE 360         M        0.0000  0  0       1980 2080                                      249
                       EBPF 360          3900.000           30 31    0.0000                                        250
                       EBPG 360       0.000000000.000000000.00000000                                               251

** COMMENT **        *                                                                                             252

BASIC PLANT TYPE       EBPA 370       COMBUST. TURB.43 THRM P G GAS  MDU  NDAK 100.0    1      40 25               253
                       EBPB 370       43.0000.83710.9276      0.2231  8900                   0.7767                254
                       EBPC 370          850.000          11.54015.8202.0000               1  1                    255
                       EBPD 370         30 22 26  0 12  1  0  0    13  0  0 13  0  0  0  0  0 20  0               256
                       EBPF 370          850.000            30 37    0.0000                                        257
                       EBPG 370       0.000000000.000000000.00000000                                               258

** COMMENT **        *                                                                                             259

BASIC PLANT TYPE       EBPA 380       WIND 2012         NDT  B G WIND MDU  NDAK 100.0    1      30 20              260
                       EBPB 380       30.0001.00000.3810      0.0000                         0.2140                261
                       EBPC 380          2400.000         13.75023.280-31.85               1  1                    262
                       EBPD 380         30 22 27  0 10     0  0     0  0  0  0  1  0  0  0  0 20  0               263
                       EBPF 380          2400.000           30 38    0.0000                                        264
                       EBPG 380       0.000000000.000000000.00000000                                               265

** COMMENT **        *                                                                                             266

BASIC PLANT TYPE       EBPA 390       WIND              NDT  B G WIND MDU  NDAK 100.0    1      30 20              267
                       EBPB 390       30.0001.00000.3810      0.0000                         0.2140                268
                       EBPC 390          2400.000         13.75023.2802.0000               1  1                    269
                       EBPD 390         30 22 28  0 10     0  0     0  0  0  0  1  0  0  0  0 20  0               270
                       EBPF 390          2400.000           30 38    0.0000                                        271
                       EBPG 390       0.000000000.000000000.00000000                                               272

** COMMENT **        *                                                                                             273

BASIC PLANT TYPE       EBPA 400       MISO - On peak    THRM P E PURC MDU  MISO 100.0    1 2010 50 50              274
                       EBPB 400       30.0001.00001.0000      0.0000 10500                   0.0000                275
                       EBPC 400                                0.000032.670                2  0                    276
                       EBPD 400                29  0  0  8  0  0    0  0  0  0  0  0  0  0  0  0 52               277

** COMMENT **        *                                                                                             278

BASIC PLANT TYPE       EBPA 420       WIND ENERGY       NDT  B G PURC MDU  MISO 100.0    1       6  6              279
                       EBPB 420       25.0001.00001.0000      0.0000                         0.0000                280
                       EBPC 420            0.000               12.00049.500                1  1                    281
                       EBPD 420              54 45  0 17     0  0     0  0  0  0  1  0  0  0  0  0  0              282
                       EBPF 420            0.000                0    0.0000                                        283

       RECORD COLS                 1          2         3         4         5         6         7          8
                     1 2345 678 90    12345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                          REC. REF SEQ                                                                          ASSIGNED
RECORD DESCRIPTION      C TYPE NO. NO.                          DATA FIELDS                                     REC. NO.
------------------      - ---- --- ---   --------------------------------------------------------------         --------
       RECORD COLS                   1            2         3         4         5         6         7           8
                        1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123  34567890

BASIC PLANT TYPE          EBPG 420      0.000000000.000000000.00000000                                           284

** COMMENT **           *                                                                                        285

BASIC PLANT TYPE          EBPA 440      DSM              DTHR1P G PURC MDU  MISO 100.0    1      30 30           286
                          EBPB 440      12.5001.00001.0000      0.0000     1                  1.0000             287
                          EBPC 440           0.000                50.040300.00               1  1                288
                          EBPD 440          48 49  0 19  8  0  0     0  0  0  0  0  0  0  0  0  0  0             289
                          EBPF 440           0.000                 0    0.0000                                   290
                          EBPG 440      0.000000000.000000000.00000000                                           291

** COMMENT **           *                                                                                        292
                        *               == MAINTENANCE CYCLES ==                                                 293
                        *                Y YBO ----NUMBER OF WEEKS (W) AND STARTING WEEK (S)----                 294
                        *                I RAP  1    2    3    4    5    6    7    8    9   10                   295
                        *                N PST  W S  W S  W S  W S  W S  W S  W S  W S  W S  W S                 296
                        *               ++--+- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++--                 297
                        *                                                                                        298

MAINTENANCE CYCLE         EMC    1  1    1 112 17 1                                                              299
                          EMC    1  2           944                                                              300

** COMMENT **           *                                                                                        301

MAINTENANCE CYCLE         EMC    2  1   101012  120  118  122  119  116  119  116  216  121  819                302
                          EMC    2  2           144  240  142  139  242  143  143  141  139  0                  303

** COMMENT **           *                                                                                        304

MAINTENANCE CYCLE         EMC    3  1   101012  117  116  217  117  617  116  118  117  119  116                305
                          EMC    3  2           142  144  141  137  141  141  241  143  138  141                306

** COMMENT **           *                                                                                        307

MAINTENANCE CYCLE         EMC    4  1   101012  118  117  116  116  118  117  117  118  120  117                308
                          EMC    4  2           143  146  140  138  141  142  142  142  138  142                309

** COMMENT **           *                                                                                        310

MAINTENANCE CYCLE         EMC    5  1   101012  110  111  1 9  116  215  112  214  214  218  110                311
                          EMC    5  2           137  235  136  141  235  536  136  134  236  137                312

** COMMENT **           *                                                                                        313

MAINTENANCE CYCLE         EMC    6  1   101012  213  613  212  211  211  214  212  210  212  213                314
                          EMC    6  2           241  242  238  237  241  242  240  537  239  241                315

       RECORD COLS                   1            2         3         4         5         6         7           8
                        1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123  34567890
```

```
                       REC. REF SEQ                                                                     ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                REC. NO.
------------------   - ---- --- ---   ----------------------------------------------------------      --------
       RECORD COLS                1          2          3          4          5          6          7          8
                     1 2345 678 90   123456789012345678901234567890123456789012345678901234567890l2 34567890

** COMMENT **        *                                                                                    316

MAINTENANCE CYCLE      EMC    7  1   101012  115  217  218  214  216  217  615  217  215  115            317
                       EMC    7  2           634  137  140  139  139  140  137  138  237  136            318

** COMMENT **        *                                                                                    319

MAINTENANCE CYCLE      EMC    8  1   101012  116  215  117  219 12 6  120  120  120  117  116            320
                       EMC    8  2           738  0    0    0    0    0    0    0    0    738            321

** COMMENT **        *                                                                                    322

MAINTENANCE CYCLE      EMC    9  1   101012  123  113  121  121  114  123  121  511  122  123            323
                       EMC    9  2           137  638  143  538  140  141  139  139  144  137            324

** COMMENT **        *                                                                                    325

MAINTENANCE CYCLE      EMC   10  1    1 110  1                                                         326

** COMMENT **        *                                                                                    327

MAINTENANCE CYCLE      EMC   11  1    4 101 22 1  0    0    3022                                       328

** COMMENT **        *                                                                                    329

MAINTENANCE CYCLE      EMC   12  1    1 110  2                                                         330

** COMMENT **        *                                                                                    331

MAINTENANCE CYCLE      EMC   13  1    1 110  3                                                         332

** COMMENT **        *                                                                                    333

MAINTENANCE CYCLE      EMC   14  1    1 112 17 1                                                       334
                       EMC   14  2           944                                                       335

** COMMENT **        *                                                                                    336

MAINTENANCE CYCLE      EMC   15  1   101011  116  117  116  116  116  116  116  115  116  116            337

** COMMENT **        *                                                                                    338

MAINTENANCE CYCLE      EMC   16  1    6 601 22 1  0    0    0    0    2923                              339

** COMMENT **        *                                                                                    340

       RECORD COLS                1          2          3          4          5          6          7          8
                     1 2345 678 90   123456789012345678901234567890123456789012345678901234567890l2 34567890
```

```
                     REC. REF SEQ                                                                       ASSIGNED
RECORD DESCRIPTION C TYPE NO. NO.                        DATA FIELDS                                    REC. NO.
------------------ - ---- --- ---  -------------------------------------------------------------         --------
       RECORD COLS                1          2         3         4         5         6         7         8
                   1 2345 678 90  1234567890123456789012345678901234567890123456789012345678901 2 34567890

MAINTENANCE CYCLE    EMC   17  1   6 601 22 1  0     0     0     0    2923                                  341

** COMMENT **      *                                                                                        342

MAINTENANCE CYCLE    EMC   18  1  101001 22 1  0     0     0     0     0     0     0     0     0            343

** COMMENT **      *                                                                                        344

MAINTENANCE CYCLE    EMC   19  1   1 100  1                                                                 345

** COMMENT **      *                                                                                        346

MAINTENANCE CYCLE    EMC   20  1  101012  116  215  117  219 12 6  120  120  120  117  116                 347
                     EMC   20  2          738  0     0     0     0     0     0     0     0   738            348

** COMMENT **      *                                                                                        349

MAINTENANCE CYCLE    EMC   21  1  101011 22 1  0     0     0     0     0     0     0     0     0            350

** COMMENT **      *                                                                                        351

MAINTENANCE CYCLE    EMC   22  1   6 601 22 1  0     0     0     0    2923                                  352

** COMMENT **      *                                                                                        353
                   *  --- --- --  -------------------------------------------------------------             354
                   *              == FUEL TYPES ==                                                          355
                   *                   MASS    HEAT    AVAILABLE   FUEL     AV CS AV CS                     356
                   *              name UNIT   CONTENT    FUEL      COST     TJ TJ SM SM     NAME            357
                   * EFLA         ---- ++++ ----------+++++++++----------+++---+++---  ++++++++             358
                   *              MIN. FUEL  TJ SM                                                          359
                   * EFLB         ----------+++---                                                          360
                   *  --- --- --  -------------------------------------------------------------             361
                   *                                                                                        362

FUEL TYPE            EFLA   1     GAS  DKT      1.0280 -1.000000  5.050000  0 33  0  0  GAS                 363

** COMMENT **      *                                                                                        364

FUEL TYPE            EFLA   2     OIL2 GAL      0.1400 -1.000000 16.150000  0 34  0  0  OIL2                365

** COMMENT **      *                                                                                        366

FUEL TYPE            EFLA   3     COAL TON     14.1800 -1.000000  1.410000  0 35  0  0  COAL                367

** COMMENT **      *                                                                                        368

       RECORD COLS                1          2         3         4         5         6         7         8
                   1 2345 678 90  1234567890123456789012345678901234567890123456789012345678901 2 34567890
```

```
                       REC. REF SEQ                                                                                   ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                              REC. NO.
------------------   - ---- --- ---   ------------------------------------------------------------                  --------
       RECORD COLS                 1              2         3         4         5         6         7           8
                     1 2345 678 90    123456789012345678901234567890123456789012345678901234567890123456789012  34567890

FUEL TYPE              EFLA   4       COAL TON     14.0100 -1.000000  1.630000  0 36  0  0  COAL                     369

** COMMENT **        *                                                                                               370

FUEL TYPE              EFLA   5       COAL TON     12.7800 -1.000000  1.370000  0 37  0  0  COAL                     371

** COMMENT **        *                                                                                               372

FUEL TYPE              EFLA   6       COAL TON     16.7200 -1.000000  2.030000  0 38  0  0  COAL                     373

** COMMENT **        *                                                                                               374

FUEL TYPE              EFLA   7       COAL TON     13.9400 -1.000000  1.260000  0 39  0  0  COAL                     375

** COMMENT **        *                                                                                               376

FUEL TYPE              EFLA   8       PURC NONE     0.0100 -1.000000  0.000000  0      0  0  PURC                     377

** COMMENT **        *                                                                                               378

FUEL TYPE              EFLA   9       COAL TON     16.7200 -1.000000  1.500000  0 40  0  0  COAL                     379

** COMMENT **        *                                                                                               380
                     *                == PLANNING ALTERNATIVES ==                                                    381
                     *                                            1ST  LAST T  EX PREREQ M M R                       382
                     *                NAME             BP         YEAR YEAR Y RET PA NfR N X Q                       383
                     *                ----------------+++         ++++ ---- + ---+++--+- +-- +                       384
                     *                                                                                               385

PLANNING ALTERNATIVE   EPA    1  1    COMBUST. TURB.75350         2015 2030 0   0  0  00 0-1 0                       386

** COMMENT **        *                                                                                               387

PLANNING ALTERNATIVE   EPA    2  1    CC-140          340         2015 2030 0   0  1 101 0-1 0                       388

** COMMENT **        *                                                                                               389

PLANNING ALTERNATIVE   EPA    3  1    WIND 2012       380         2011 2012 0   0  0  00 0-1 0                       390

** COMMENT **        *                                                                                               391

PLANNING ALTERNATIVE   EPA    4  1    WIND            390         2013 2030 0   0  0  00 0-1 0                       392

** COMMENT **        *                                                                                               393

PLANNING ALTERNATIVE   EPA    5  1    GENERIC BASELOAD360         2017 2030 0   0  0  00 0-1 0                       394

       RECORD COLS                 1              2         3         4         5         6         7           8
                     1 2345 678 90    123456789012345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                       REC. REF SEQ                                                                              ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                         REC. NO.
------------------   - ---- --- ---   ----------------------------------------------------------------           --------
       RECORD COLS               1             2         3         4         5         6         7          8
                     1 2345 678 90   1234567890123456789012345678901234567890123456789012345678901234 34567890

** COMMENT **        *                                                                                              395

PLANNING ALTERNATIVE  EPA    6  1   COMBUST. TURB.43370         2015 2030 0   0  0  00 0-1 0                        396

** COMMENT **        *                                                                                              397

PLANNING ALTERNATIVE  EPA    7  1   PURCHASE POWER  310         2010 2014 1   0  0  00 0-1 0                        398

** COMMENT **        *                                                                                              399

PLANNING ALTERNATIVE  EPA    8  1   WIND ENERGY     420         2015 2015 0   0  0  00 0-1 0                        400

** COMMENT **        *                                                                                              401

PLANNING ALTERNATIVE  EPA    9  1   WIND ENERGY2      3         2020 2020 0   0  0  00 0-1 0                        402

** COMMENT **        *                                                                                              403

PLANNING ALTERNATIVE  EPA   10  1   DSM             440         2015 2015 0   0  0  00 0-1 0                        404

** COMMENT **        *                                                                                              405

PLANNING ALTERNATIVE  EPA   11  1   BIG STONE UP      1         2015 2015 0   0  0  00 0-1 0                        406

** COMMENT **        *                                                                                              407

PLANNING ALTERNATIVE  EPA   12  1   CP-5              4         2015 2015 0   0  0  00 0-1 0                        408

** COMMENT **        *                                                                                              409

PLANNING ALTERNATIVE  EPA   13  1   CP-10             5         2015 2015 0   0  0  00 0-1 0                        410

** COMMENT **        *                                                                                              411

PLANNING ALTERNATIVE  EPA   14  1   CP-20             6         2015 2015 0   0  0  00 0-1 0                        412

** COMMENT **        *                                                                                              413
                     *              == TRAJECTORIES ==                                                              414
                     *              T B                                                                             415
                     *              Y A  N YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE                    416
                     *              - + -- ++++------ ++++------ ++++------ ++++------ ++++------                   417
                     *                                                                                              418

TRAJECTORY            ETJ    1  1    1 1 21 20101.0589 20113.3412 20123.9410 20131.6565 20142.8969                  419
                      ETJ    1  2           20151.5660 20161.5246 20171.5187 20181.5296 20191.4900                  420
                      ETJ    1  3           20201.4845 20211.4949 20221.4887 20231.4981 20241.5067                  421

       RECORD COLS               1             2         3         4         5         6         7          8
                     1 2345 678 90   1234567890123456789012345678901234567890123456789012345678901234 34567890
```

```
                       REC. REF SEQ                                                                   ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                        DATA FIELDS                                  REC. NO.
------------------  - ---- --- ---  ------------------------------------------------------------      --------
       RECORD COLS                1           2         3         4         5         6         7         8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123  34567890

TRAJECTORY            ETJ    1  4           20251.4692 20261.4778 20271.4710 20281.5076 20291.5138       422
                      ETJ    1  5           20301.2000                                                   423

** COMMENT **       *                                                                                    424

TRAJECTORY            ETJ    2  1    1 1 21 20102.5132 20113.8104 20125.2953 20131.9462 20143.2265       425
                      ETJ    2  2           20151.7481 20161.6931 20171.6925 20181.6914 20191.6218       426
                      ETJ    2  3           20201.6251 20211.6220 20221.6243 20231.6206 20241.6248       427
                      ETJ    2  4           20251.6230 20261.6235 20271.6236 20281.6283 20291.6249       428
                      ETJ    2  5           2030.00000                                                   429

** COMMENT **       *                                                                                    430

TRAJECTORY            ETJ    3  1    1 1  1 20103.0000                                                   431

** COMMENT **       *                                                                                    432

TRAJECTORY            ETJ    4  1    1 1  1 20103.0000                                                   433

** COMMENT **       *                                                                                    434

TRAJECTORY            ETJ    5  1    1 1  1 20103.0000                                                   435

** COMMENT **       *                                                                                    436

TRAJECTORY            ETJ    6  1    1 1  1 20103.0000                                                   437

** COMMENT **       *                                                                                    438

TRAJECTORY            ETJ    7  1    1 1  1 20103.0000                                                   439

** COMMENT **       *                                                                                    440

TRAJECTORY            ETJ    8  1    1 1  1 20103.0000                                                   441

** COMMENT **       *                                                                                    442

TRAJECTORY            ETJ    9  1    1 1  1 20103.0000                                                   443

** COMMENT **       *                                                                                    444

TRAJECTORY            ETJ   10  1    1 1  7 20103.0000 20113.0000 20123.0000 201312.532 20142.7457       445
                      ETJ   10  2           20153.0000 20163.0000                                        446

** COMMENT **       *                                                                                    447

       RECORD COLS                1           2         3         4         5         6         7         8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123  34567890
```

```
                        REC. REF SEQ                                                                        ASSIGNED
RECORD DESCRIPTION  C TYPE NO.  NO.                        DATA FIELDS                                      REC. NO.
------------------  - ---- ---  ---  -------------------------------------------------------------          --------
       RECORD COLS                1         2         3         4         5         6         7         8
                    1 2345 678 90  1234567890123456789012345678901234567890123456789012 34567890

TRAJECTORY            ETJ   11  1    1 1  1 20103.0000                                                      448

** COMMENT **       *                                                                                       449

TRAJECTORY            ETJ   12  1    1 1  1 20103.0000                                                      450

** COMMENT **       *                                                                                       451

TRAJECTORY            ETJ   13  1    1 1  1 20103.0000                                                      452

** COMMENT **       *                                                                                       453

TRAJECTORY            ETJ   14  1    1 1  1 20103.0000                                                      454

** COMMENT **       *                                                                                       455

TRAJECTORY            ETJ   15  1    1 1  1 20101.5000                                                      456

** COMMENT **       *                                                                                       457

TRAJECTORY            ETJ   16  1    1 1  1 20103.0000                                                      458

** COMMENT **       *                                                                                       459

TRAJECTORY            ETJ   17  1    1 1 11 2010-0.212 2011-0.248 2012-0.213 2013-0.249 2014-0.214          460
                      ETJ   17  2           2015-0.250 2016-0.251 20177.0863 2018-0.235 2019-109.0          461
                      ETJ   17  3           20203.0000                                                      462

** COMMENT **       *                                                                                       463

TRAJECTORY            ETJ   18  1    1 1  6 20101.4925 20111.4705 20121.4492 20131.5714 20141.5471          464
                      ETJ   18  2           20151.5000                                                      465

** COMMENT **       *                                                                                       466

TRAJECTORY            ETJ   19  1    1 1 11 2010-0.197 2011-0.198 2012-0.231 2013-0.199 2014-0.232          467
                      ETJ   19  2           2015-0.233 2016-0.233 2017-0.268 2018-0.235 2019-109.0          468
                      ETJ   19  3           20203.0000                                                      469

** COMMENT **       *                                                                                       470

TRAJECTORY            ETJ   20  1    1 1  1 20103.0000                                                      471

** COMMENT **       *                                                                                       472

TRAJECTORY            ETJ   21  1    1 1  1 20103.0000                                                      473

       RECORD COLS                1         2         3         4         5         6         7         8
                    1 2345 678 90  1234567890123456789012345678901234567890123456789012 34567890
```

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS	ASSIGNED REC. NO.
RECORD COLS	1	2345	678	1 90	2 3 4 5 6 7 8 123456789012345678901234567890123456789012345678901234567890123456789012 34567890	
** COMMENT **	*					474
TRAJECTORY		ETJ	22	1	1 1 1 20103.0000	475
** COMMENT **	*					476
TRAJECTORY		ETJ	23	1	1 1 1 20103.0000	477
** COMMENT **	*					478
TRAJECTORY		ETJ	24	1	1 1 1 20103.0000	479
** COMMENT **	*					480
TRAJECTORY		ETJ	25	1	1 1 1 20103.0000	481
** COMMENT **	*					482
TRAJECTORY		ETJ	26	1	1 1 1 20103.0000	483
** COMMENT **	*					484
TRAJECTORY		ETJ	27	1	1 1 12 2010-0.188 2011-0.188 2012-0.220 2013-0.189 2014-0.221	485
		ETJ	27	2	2015-0.222 2016-0.222 2017-0.223 2018-0.255 2019-0.256	486
		ETJ	27	3	2020-108.8 20214.0000	487
** COMMENT **	*					488
TRAJECTORY		ETJ	28	1	1 1 1 20103.0000	489
** COMMENT **	*					490
TRAJECTORY		ETJ	29	1	1 1 11 20104.9892 20115.0145 20124.9972 20134.9973 20144.9861	491
		ETJ	29	2	20155.0131 20165.0022 20175.0032 20184.9927 20194.2817	492
		ETJ	29	3	20205.0000	493
** COMMENT **	*					494
TRAJECTORY		ETJ	30	1	1 1 1 20103.0000	495
** COMMENT **	*					496
TRAJECTORY		ETJ	31	1	1 1 1 20103.0000	497
** COMMENT **	*					498
RECORD COLS	1	2345	678	1 90	2 3 4 5 6 7 8 123456789012345678901234567890123456789012345678901234567890123456789012 34567890	

```
                           REC. REF SEQ                                                                        ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                       REC. NO.
------------------   - ---- --- ---   ----------------------------------------------------------------         --------
       RECORD COLS                 1         2         3         4         5         6         7        8
                     1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890

TRAJECTORY             ETJ   32  1    1 1  2 20105.0000 20114.0000                                               499

** COMMENT **        *                                                                                           500

TRAJECTORY             ETJ   33  1    1 1 11 2010-0.792 201114.770 20122.6087 20133.2203 20143.7766              501
                       ETJ   33  2           2015-0.316 20162.5396 20173.0959 20183.1531 20193.7845              502
                       ETJ   33  3           20203.5000                                                          503

** COMMENT **        *                                                                                           504

TRAJECTORY             ETJ   34  1    1 1  6 201032.941 20117.6385 20129.7360 20137.0583 20146.8876              505
                       ETJ   34  2           20157.0000                                                          506

** COMMENT **        *                                                                                           507

TRAJECTORY             ETJ   35  1    1 1  6 20107.8014 20115.2631 20122.5000 20131.8292 20143.5928              508
                       ETJ   35  2           20154.0000                                                          509

** COMMENT **        *                                                                                           510

TRAJECTORY             ETJ   36  1    1 1  6 20105.5214 20114.6511 20123.3333 20131.0752 20144.2553              511
                       ETJ   36  2           20153.7500                                                          512

** COMMENT **        *                                                                                           513

TRAJECTORY             ETJ   37  1    1 1  6 2010.00000 20111.4184 20123.4965 20131.3513 20142.0000              514
                       ETJ   37  2           20152.2500                                                          515

** COMMENT **        *                                                                                           516

TRAJECTORY             ETJ   38  1    1 1  6 2010.00000 20117.3891 20129.6330 20137.1129 20143.9062              517
                       ETJ   38  2           20154.5000                                                          518

** COMMENT **        *                                                                                           519

TRAJECTORY             ETJ   39  1    1 1  6 20104.7619 20117.5757 20122.1126 2013-0.689 20146.2500               520
                       ETJ   39  2           20154.0000                                                          521

** COMMENT **        *                                                                                           522

TRAJECTORY             ETJ   40  1    1 1  1 20104.0000                                                          523

** COMMENT **        *                                                                                           524

TRAJECTORY             ETJ   41  1    1 1  6 2010.00000 2011.00000 20124.5454 20134.3478 2014.00000              525
                       ETJ   41  2           2015.00000                                                          526

       RECORD COLS                 1         2         3         4         5         6         7        8
                     1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                        REC. REF SEQ                                                                              ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                          DATA FIELDS                                          REC. NO.
------------------  - ---- --- ---   ---------------------------------------------------------------------      --------
       RECORD COLS                1          2          3          4          5          6          7          8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890

** COMMENT **       *                                                                                            527

TRAJECTORY            ETJ   42  1    1 1  1 2010.00000                                                           528

** COMMENT **       *                                                                                            529

TRAJECTORY            ETJ   43  1    1 1  4 20122.1353 2013.23230 20142.5493 20153.0000                          530

** COMMENT **       *                                                                                            531

TRAJECTORY            ETJ   44  1    1 1 21 20103.0078 20113.0046 201222.370 2013-13.31 20143.0015               532
                      ETJ   44  2           20152.9892 201620.226 2017-11.75 20182.9938 20193.0070               533
                      ETJ   44  3           202018.293 2021-10.30 20222.9960 20232.9979 202416.599               534
                      ETJ   44  4           2025-9.008 20262.9879 20273.0067 202815.081 2029-7.809               535
                      ETJ   44  5           2030.00000                                                           536

** COMMENT **       *                                                                                            537

TRAJECTORY            ETJ   45  1    1 1  1 2010.00000                                                           538

** COMMENT **       *                                                                                            539

TRAJECTORY            ETJ   46  1    1 1 11 20105.0212 20114.9837 20125.0173 20134.9981 20145.0052               540
                      ETJ   46  2           20155.0000 20165.0158 20174.9879 20184.9812 20195.0192               541
                      ETJ   46  3           20205.0000                                                           542

** COMMENT **       *                                                                                            543

TRAJECTORY            ETJ   47  1    1 1  1 20152.3000                                                           544

** COMMENT **       *                                                                                            545

TRAJECTORY            ETJ   48  1    1 1  1 2010.00000                                                           546

** COMMENT **       *                                                                                            547

TRAJECTORY            ETJ   49  1    1 1  1 2010.00000                                                           548

** COMMENT **       *                                                                                            549

TRAJECTORY            ETJ   50  1    1 1  7 20103.0000 20113.0000 20123.0000 20133.0000 201431.164               550
                      ETJ   50  2           20153.0000 20163.0000                                                551

** COMMENT **       *                                                                                            552

TRAJECTORY            ETJ   51  1    1 1  7 20103.0000 20113.0000 20123.0000 20133.0000 2014118.25               553

       RECORD COLS                1          2          3          4          5          6          7          8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                      REC. REF SEQ                                                                        ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                            DATA FIELDS                                 REC. NO.
------------------  - ---- --- ---  -------------------------------------------------------------           --------
       RECORD COLS                1          2         3         4         5         6         7          8
                    1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890

TRAJECTORY            ETJ   51  2          20153.0000 20163.0000                                               554

** COMMENT **       *                                                                                          555

TRAJECTORY            ETJ   52  1    1 1  6 2010.00000 2011.00000 2012.00000 2013.00000 2014.00000             556
                      ETJ   52  2          2015.00000                                                          557

** COMMENT **       *                                                                                          558

TRAJECTORY            ETJ   53  1    1 1  1 2010.00000                                                         559

** COMMENT **       *                                                                                          560

TRAJECTORY            ETJ   54  1    1 1 12 2010.00000 2011.00000 2012.00000 2013.00000 2014-41.66             561
                      ETJ   54  2          201571.428 2016.00000 2017.00000 2018.00000 2019-58.33              562
                      ETJ   54  3          2020140.00 2021.00000                                               563

** COMMENT **       *                                                                                          564

TRAJECTORY            ETJ   55  1    1 1 16 2010.00000 2011.00000 2012.00000 2013.00000 2014.00000             565
                      ETJ   55  2          2015.00000 2016.00000 2017.00000 2018.00000 2019-41.66              566
                      ETJ   55  3          202071.428 2021.00000 2022.00000 2023.00000 2024-58.33              567
                      ETJ   55  4          2025.00000                                                          568

** COMMENT **       *                                                                                          569

TRAJECTORY            ETJ   56  1    1 1 12 2015.79136 20162.6048 20172.9618 20182.9903 20193.4043             570
                      ETJ   56  2          20203.2183 20213.2294 20223.2285 20233.2320 20243.2393              571
                      ETJ   56  3          20253.2427 2026.00000                                               572

** COMMENT **       *                                                                                          573

TRAJECTORY            ETJ   57  1    1 1  1 20151.5000                                                         574

** COMMENT **       *                                                                                          575

TRAJECTORY            ETJ   58  1    1 1 21 2015.57759 20162.5540 20172.9619 20182.9912 20193.4463             576
                      ETJ   58  2          20203.2375 20213.2530 20223.2514 20233.2588 20243.2624              577
                      ETJ   58  3          20253.2623 20263.2701 20273.2632 20283.2744 20293.2813              578
                      ETJ   58  4          20303.2842 20313.2836 20323.2888 20333.2902 20343.2882              579
                      ETJ   58  5          2035.00000                                                          580

** COMMENT **       *                                                                                          581
                    *               == LOADING BLOCKS ==                                                       582
                    *                 -A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-                               583
                    *               N     1       2       3       4       5                                    584

       RECORD COLS                1          2         3         4         5         6         7          8
                    1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                      REC. REF SEQ                                                                 ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                         DATA FIELDS                             REC. NO.
------------------  - ---- --- ---  --------------------------------------------------------------  --------
       RECORD COLS                1            2         3         4         5         6         7         8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890012  34567890

** COMMENT **       *               - +++++++--------+++++++--------+++++++                               585
                    *                                                                                     586

LOADING BLOCK         ELBA   1      3 0.5357140.3214290.142857                                            587
                      ELBB   1        1.2588240.1608241.917647                                            588
                      ELBC   1        1.0000000.0000000.000000                                            589

** COMMENT **       *                                                                                     590

LOADING BLOCK         ELBA   2      5 0.2380950.1904760.1904760.1904760.190476                            591
                      ELBB   2        1.4318550.7829530.8091260.8681880.999828                            592
                      ELBC   2        1.0000000.0000000.0000000.0000000.000000                            593

** COMMENT **       *                                                                                     594

LOADING BLOCK         ELBA   3      2 0.4091340.590866                                                    595
                      ELBB   3        1.0000001.000000                                                    596
                      ELBC   3        1.0000000.000000                                                    597

** COMMENT **       *                                                                                     598

LOADING BLOCK         ELBA  11      2 0.4000000.600000                                                    599
                      ELBB  11        1.0000001.000000                                                    600
                      ELBC  11        0.8196210.300631                                                    601

** COMMENT **       *                                                                                     602

LOADING BLOCK         ELBA  12      5 0.3333330.1333330.1333330.1333330.266667                            603
                      ELBB  12        1.3478680.7135200.7760250.8386040.900960                            604
                      ELBC  12        0.7765970.0829150.1079250.1268060.224415                            605

** COMMENT **       *                                                                                     606

LOADING BLOCK         ELBA  13      5 0.2325580.1860470.1860470.1860470.209302                            607
                      ELBB  13        1.4318340.7830230.8091590.8682600.999882                            608
                      ELBC  13        1.0000000.0000000.0000000.0000000.000000                            609

** COMMENT **       *                                                                                     610

LOADING BLOCK         ELBA  14      5 0.2054790.2054790.2054790.1712330.212329                            611
                      ELBB  14        1.2067000.9717680.9358580.9539400.926469                            612
                      ELBC  14        0.5927850.0957030.3085340.2479170.255951                            613

** COMMENT **       *                                                                                     614

LOADING BLOCK         ELBA  15      5 0.4557640.1474530.1340480.1340480.128686                            615

       RECORD COLS                1            2         3         4         5         6         7         8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890012  34567890
```

```
                       REC. REF SEQ                                                                         ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                    REC. NO.
------------------   - ---- --- ---   --------------------------------------------------------------        --------
       RECORD COLS                1           2         3         4         5         6         7        8
                     1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890

LOADING BLOCK          ELBB  15        1.0504370.9880020.9637090.9495630.925493                              616
                       ELBC  15        0.7029890.1389030.3102050.2295310.295489                              617

** COMMENT **        *                                                                                       618

LOADING BLOCK          ELBA  16      5 0.3250480.1529640.1529640.1720840.196941                              619
                       ELBB  16        1.1930750.9070120.9070120.9070120.907012                              620
                       ELBC  16        0.7011860.1023260.1006370.2382350.453448                              621

** COMMENT **        *                                                                                       622

LOADING BLOCK          ELBA  17      2 0.3987760.601224                                                      623
                       ELBB  17        1.1925820.872301                                                      624
                       ELBC  17        1.0000000.000000                                                      625

** COMMENT **        *                                                                                       626

LOADING BLOCK          ELBA  18      2 0.3932580.606742                                                      627
                       ELBB  18        1.1353230.912339                                                      628
                       ELBC  18        1.0000000.000000                                                      629

** COMMENT **        *                                                                                       630
                     *               == SEGMENT MULTIPLIERS ==                                               631
                     *                T Y                  MULTIPLIERS, BY SEGMENT                           632
                     *                Y R    1       2       3       4       5       6       7               633
                     *                +--++++++++--------++++++++--------++++++++--------++++++++            634
                     *                                                                                       635

SEGMENT MULTIPLIERS    ESM   12  1    1  1.0000001.0000001.0000001.000000                                    636

** COMMENT **        *                                                                                       637

SEGMENT MULTIPLIERS    ESM   13  1    1  1.0000001.0000001.0000001.000000                                    638

** COMMENT **        *                                                                                       639

SEGMENT MULTIPLIERS    ESM   16  1    1  1.0000001.0000001.0000001.000000                                    640

** COMMENT **        *                                                                                       641
                     *               == ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ==                      642
                     *               YEAR OPT   RATE                                                         643
                     *               ---- +    ------                                                        644

A. F. U. D. C.         EZA    1      2010 1    10.500                                                        645

** COMMENT **        *                                                                                       646

       RECORD COLS                1           2         3         4         5         6         7        8
                     1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                       REC. REF SEQ                                                                         ASSIGNED
RECORD DESCRIPTION   C TYPE NO. NO.                          DATA FIELDS                                    REC. NO.
------------------   - ---- --- ---  ---------------------------------------------------------------       --------
       RECORD COLS                 1           2         3         4         5         6         7         8
                     1 2345 678 90  123456789012345678901234567890123456789012345678901234567890123  34567890

** COMMENT **        *  --- --- --  ---------------------------------------------------------------         647
                     *              == EXPENDITURE PATTERNS - CONSTRUCTION COST AND CAPITAL EXPENS  ES ==   648
                     *                         COST PERCENTAGES FOR YEARS BEFORE ON-LINE                    649
                     *              YR          1    2    3    4    5    6    7    8    9   10              650
                     * EZCA         --         +++++-----+++++-----+++++-----+++++-----+++++-----           651
                     *                         ANNUAL EXPENDITURES FOR YEARS OF OPERATING LIFE              652
                     *              YR F TJ       1         2         3         4         5                 653
                     * EZCB         -- +---    ++++++++++----------++++++++++----------++++++++++           654
                     *  --- --- --  ---------------------------------------------------------------         655
                     *                                                                                      656

CONSTRUCTION EXPEND.   EZCA  31  1   4         13.7035.1034.8016.50                                         657

** COMMENT **        *                                                                                      658

CONSTRUCTION EXPEND.   EZCA  37  1   3         69.0027.004.000                                              659

** COMMENT **        *                                                                                      660

CONSTRUCTION EXPEND.   EZCA  38  1   1         100.0                                                        661

** COMMENT **        *                                                                                      662
                     *              == RETURN ON RATE BASE ==                                               663
                     *                  --CAPITAL STRUC-- -RATES OF RETURN- INCOME  PROP                    664
                     *              YEAR COMM  PREF  DEBT  COMM  PREF  DEBT  TAX    TAX                     665
                     *              ----+++++-----+++++-----+++++-----+++++------                           666

RETURN ON RATE BASE    EZR    1  1  201050.0000.000050.00010.750       4.4038.4001.3220                     667

** COMMENT **        *                                                                                      668
                     *              == TAX DEPRECIATION TABLES ==                                           669
                     *                                DEPRECIATION PERCENTAGES FOR YEARS                    670
                     *              YR          1    2    3    4    5    6    7    8    9   10              671
                     *              --         +++++-----+++++-----+++++-----+++++-----+++++-----           672
                     *                                                                                      673

TAX DEPRECIATION       EZT   20  1  21         3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464           674
                       EZT   20  2             4.4624.4624.4624.4624.4624.4624.4624.4624.4624.462           675
                       EZT   20  3             2.224                                                        676

** COMMENT **        *                                                                                      677
```

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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     **
**                                                  **
**                                                  **
******************************************************
******************************************************
```

HEADER INFORMATION	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
	2011	1	0	4/26/11	13:40:23	2011 IRP	900

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	1	
NUMBER OF YEARS	21	
FIRST CALENDAR YEAR	2011	
LAST CALENDAR YEAR	2031	
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

SOURCE FILE HEADERS	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
ORTHOGONALIZED LOAD	2011	1	0	4/26/11	13:40:21	2011 IRP	900
HOURLY LOADS							
SYSTEM A	HOURLOAD	1	0				
HOURLY NDT							
TECHNOLOGY 1	wind40cf	1	0				

ADDITIONAL HOURLY FILE PARAMETERS

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

GENERAL DATA

BASE YEAR 2010
ALL DATA BASE COSTS
ARE IN 2010 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) 6.73
CUSTOMER DISCOUNT RATE (PERCENT) 6.73
INFLATION RATE (PERCENT) 3.00

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

BENCHMARK YEAR 2010
BENCHMARK PEAK . . . . . 502. 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 2010 -
PEAK LOAD . . . . 500.5 MW
ENERGY . . . . 2677.8 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	2011	INITIAL LOAD	500.0	179.8	2569.0	0.58814103	0.35967218	SUNDAY
		LOAD AFTER CONTRACTS	500.0	179.8	2569.0	0.58814103	0.35967218	

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	0.998310716718052	0.996233015623106	0.979851153690528
0.952375541882615	0.920066039004252	0.885524126955650	0.847326665606080	0.796796979301395
0.742655231529349	0.683181890841302	0.614575913636275	0.534582767569821	0.459160658421450
0.374710751359865	0.300888505132823	0.230265984748439	0.158614981057487	0.114618750720937
0.082964320063211	0.062508929854790	0.044339058105409	0.032797189887250	0.024569323434700
0.018398423595288	0.014398766291965	0.011656144141115	0.008799246067313	0.006170899839415
0.004913864686943	0.003428277688566	0.001828414767237	0.000571379614764	0.000000000000000

CUMULANTS

0.588141025284708D+00	0.102623558626373D-01	0.343529392138470D-03	0.393356592731653D-04
0.157540583158450D-04	0.842629154763908D-06	-0.132174421072634D-05	-0.525980997412995D-06

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	2012	INITIAL LOAD	502.9	188.1	2621.0	0.59658560	0.37395918	MONDAY
		LOAD AFTER CONTRACTS	502.9	188.1	2621.0	0.59658560	0.37395918	

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	0.997728347001245	0.995270585839520
0.980865044554107	0.948628833820478	0.918866130786306	0.887293790293864	0.828882256581552
0.771077829462044	0.717073009094162	0.643383411844126	0.568019337830220	0.481423944775963
0.384796505326268	0.311697733165743	0.254132450089330	0.186287652177842	0.123468394852391
0.088061177087136	0.064989377123970	0.046372033589337	0.033808182124246	0.025241919761685
0.019416861355143	0.014848188095110	0.011764333644588	0.008908912857067	0.006167708901048
0.004911323754539	0.003426504945028	0.001827469304016	0.000685300989008	0.000000000000000

CUMULANTS

0.596585598121676D+00	0.937749044316882D-02	0.379225177714367D-03	0.441128086521814D-04
0.122147824340999D-04	0.476824540721090D-06	-0.101331633755536D-05	-0.449548192638103D-06

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	2013	INITIAL LOAD	534.1	204.5	2811.0	0.60245646	0.38281375	TUESDAY
		LOAD AFTER CONTRACTS	534.1	204.5	2811.0	0.60245646	0.38281375	

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	0.996691780658587
0.990830839491603	0.965362225176012	0.934140732135134	0.905808542706651	0.866634217543273
0.792499390363510	0.738043867444630	0.674559920608613	0.599178894371495	0.500459042021115
0.395103792961949	0.318801586052848	0.260661131985884	0.194639162534596	0.136156033885704
0.093892835448029	0.068649141246066	0.049573589518790	0.036894629987488	0.027299741693529
0.021017374358199	0.015763030768650	0.012678959531306	0.009594888293962	0.006739266777903
0.005025893868267	0.003540970679917	0.001941822630924	0.000685349163858	0.000000000000000

CUMULANTS

0.602456456081729D+00	0.891325814263767D-02	0.396803044300212D-03	0.497437477624642D-04
0.110670640781357D-04	0.139693828044180D-06	-0.973045073907720D-06	-0.430630304009906D-06

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	2014	INITIAL LOAD	539.7	206.8	2834.0	0.60108349	0.38308437	THURSDAY
		LOAD AFTER CONTRACTS	539.7	206.8	2834.0	0.60108349	0.38308437	

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	0.994633030571889
0.978804172006312	0.957433406681175	0.933439339743653	0.901238550914074	0.847356508301782
0.780186536883584	0.736184534221814	0.674101879163528	0.602173158241675	0.504292954302966
0.428185994023304	0.332553573716088	0.256471952410132	0.176943100078198	0.120549621730696
0.089042334232901	0.064498613899474	0.045548578665293	0.033105483240440	0.025456975043511
0.019634976266745	0.014840389038820	0.011758154392296	0.008675919745773	0.006164469293050
0.004908744066689	0.003424705162807	0.001940666258925	0.000684941032564	0.000000000000000

CUMULANTS

0.601083485668423D+00	0.892268464517367D-02	0.315197542693405D-03	0.494055116771146D-04
0.145208438220494D-04	0.706857480276794D-06	-0.967307942973264D-06	-0.431298108010024D-06

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	2015	INITIAL LOAD	547.7	209.0	2877.0	0.60129070	0.38153667	FRIDAY
		LOAD AFTER CONTRACTS	547.7	209.0	2877.0	0.60129070	0.38153667	

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	0.995867343825758
0.978946465592107	0.950202265423329	0.923703055713242	0.886809759435837	0.840656821009800
0.785422329012052	0.737166706122332	0.676006716366589	0.600141128085960	0.510566669845209
0.418162098054433	0.339418926210787	0.268397382880487	0.182410508219868	0.125414363196879
0.092404571790780	0.068875101099927	0.047058941381709	0.035065764573265	0.026499209710090
0.020559731671622	0.015648240216736	0.012335839002975	0.009137658520723	0.006396360964507
0.005025712186399	0.003540842676782	0.002055973167165	0.000685324389057	0.000000000000000

CUMULANTS

0.601290698992614D+00	0.928987664586195D-02	0.306507751956907D-03	0.449576670974458D-04
0.146509387950142D-04	0.500494719952866D-06	-0.108241357588365D-05	-0.417087200842364D-06

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	2016	INITIAL LOAD	555.9	211.5	2921.0	0.60148145	0.38038600	SATURDAY
		LOAD AFTER CONTRACTS	555.9	211.5	2921.0	0.60148145	0.38038600	

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	0.995877227077226
0.979327819640664	0.951629048670413	0.924339458018387	0.893799145932400	0.845163428871162
0.781079573372875	0.737599317006854	0.675201512881507	0.595024634750987	0.508671753976906
0.423853053474659	0.334317722438426	0.267819802254160	0.189439092208788	0.125569096705344
0.091748848639119	0.068897329675454	0.047759674634064	0.035191339204048	0.026964792377128
0.020109336688029	0.015539032895296	0.012339820240383	0.009369122775106	0.006398425309830
0.005027334172010	0.003427727844553	0.001942379111915	0.000685545568913	0.000000000000000

CUMULANTS

0.601481450606705D+00	0.930419552534152D-02	0.315364637977708D-03	0.437437345912119D-04
0.138370762376931D-04	0.482289774612287D-06	-0.104266740261394D-05	-0.412316283205966D-06

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	2017	INITIAL LOAD	564.2	214.8	2965.0	0.60156004	0.38070802	SUNDAY
		LOAD AFTER CONTRACTS	564.2	214.8	2965.0	0.60156004	0.38070802	

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	0.996955880929559
0.990772568764676	0.965612207188767	0.932657561171811	0.905237654924852	0.864279907121758
0.791066876695288	0.731364395107131	0.666111622441362	0.596209283255770	0.493795851927226
0.393472454730208	0.315759323348348	0.259281396127221	0.192804344192383	0.130804784816883
0.093219829179544	0.069572151924440	0.048780474337827	0.036671035743425	0.026846396883817
0.021477117507054	0.015650878183333	0.012337918567884	0.009367678912653	0.006854399204381
0.005026559416547	0.003541439588932	0.001827839787837	0.000685439920441	0.000000000000000

CUMULANTS

0.601560041957512D+00	0.895113840256808D-02	0.408333207545417D-03	0.500686010935307D-04
0.109260892783191D-04	0.129536638977855D-06	-0.983317152347529D-06	-0.439010264674881D-06

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	2018	INITIAL LOAD	572.6	216.9	3009.0	0.60153131	0.37879951	TUESDAY
		LOAD AFTER CONTRACTS	572.6	216.9	3009.0	0.60153131	0.37879951	

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	0.997783831585873	0.995758611596080
0.988986835848654	0.959158183971900	0.929605390078133	0.901741255001555	0.863501752077992
0.794720158619484	0.734413713699811	0.673993052028396	0.590614823256878	0.488714352849594
0.397006988122657	0.318550520607898	0.264069130027057	0.191313059167527	0.130778180744370
0.094799903945702	0.068530051045087	0.050369587518140	0.036663577309123	0.027183586914553
0.021586966079205	0.016332995499082	0.012906492946827	0.009708423898057	0.006510354849286
0.005025537076643	0.003540719303999	0.002055901531356	0.000685300510454	0.000000000000000

CUMULANTS

0.601531309134890D+00	0.905160906158780D-02	0.395597821986032D-03	0.519543797381419D-04
0.115654748821053D-04	0.113041504565965D-07	-0.105185414630831D-05	-0.448655046190919D-06

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	2019	INITIAL LOAD	581.1	220.1	3055.0	0.60179383	0.37875619	WEDNESDAY
		LOAD AFTER CONTRACTS	581.1	220.1	3055.0	0.60179383	0.37875619	

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	0.998141338999250	0.995904753231587
0.989023531095919	0.958625699179747	0.928686849136011	0.900693704692320	0.856081767054006
0.795462333130526	0.734448704016521	0.669550312000127	0.591626538487485	0.498406729694579
0.399445032551613	0.319693135320199	0.260850403122236	0.194923691514033	0.135852443851223
0.095633722038246	0.068897412651211	0.052558556914689	0.037362278502399	0.028107402176118
0.021594711427994	0.016681628933795	0.013368154693521	0.009826164988401	0.006855463945397
0.005027340226625	0.003656247437547	0.002056639183621	0.000685546394543	0.000000000000000

CUMULANTS

0.601793832208108D+00	0.916123891556589D-02	0.394892916731864D-03	0.505957547748115D-04
0.115174989013918D-04	-0.255729315984741D-07	-0.108119010231593D-05	-0.448492409851722D-06

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	2020	INITIAL LOAD	588.9	227.5	3095.0	0.60159810	0.38631866	THURSDAY
		LOAD AFTER CONTRACTS	588.9	227.5	3095.0	0.60159810	0.38631866	

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	0.994792131984558
0.978512839447606	0.957191315517696	0.930975422899042	0.895182487760978	0.840858007756634
0.775472120473043	0.727066515680398	0.669919784199606	0.597323907886952	0.511619955916682
0.429030692129910	0.342562927005084	0.262825502437468	0.187422873482970	0.127192029174384
0.092285517131908	0.068900435534825	0.050534590963457	0.036161321298908	0.027491730072672
0.020875463084229	0.015742152489747	0.012434018995526	0.009125885501304	0.007186634832278
0.005019237025719	0.003650354200524	0.001939250669030	0.000684441412601	0.000000000000000

CUMULANTS

0.601598099863498D+00	0.926625955806028D-02	0.344738757227772D-03	0.453048598774369D-04
0.136347990403257D-04	0.540816017339135D-06	-0.109158123395796D-05	-0.457003608013890D-06

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	2021	INITIAL LOAD	596.9	229.1	3135.0	0.60120602	0.38388315	FRIDAY
		LOAD AFTER CONTRACTS	596.9	229.1	3135.0	0.60120602	0.38388315	

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	0.996059489897348
0.978361531095388	0.953356139856809	0.922460372732388	0.890658184819497	0.836190976563224
0.768546567780332	0.718071444012292	0.652179710043607	0.583464190517340	0.501487546485478
0.423295932197202	0.343162323355113	0.269961974180196	0.203841845986316	0.140919236945163
0.100379261973095	0.075027502976478	0.054357825596354	0.038712821170513	0.029348657937529
0.022268436956491	0.016901172664415	0.013018470836104	0.009478360345585	0.007194418093638
0.005138870066885	0.003654307603119	0.002169745139353	0.000685182675588	0.000000000000000

CUMULANTS

0.601206023209666D+00	0.981035075759756D-02	0.375021100714812D-03	0.343400538887400D-04
0.111465641812217D-04	0.377736933703134D-06	-0.110559341060460D-05	-0.437378360520962D-06

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	2022	INITIAL LOAD	605.0	231.1	3176.0	0.60091424	0.38203107	SUNDAY
		LOAD AFTER CONTRACTS	605.0	231.1	3176.0	0.60091424	0.38203107	

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	0.996066810802858
0.978514926380217	0.951052858759971	0.919634184837795	0.879100744362530	0.836587685292179
0.771637879461264	0.723181946272346	0.654955078079459	0.579414106763717	0.503644569725385
0.424560829709509	0.344219978219393	0.267993309735883	0.199995007265585	0.138510827889080
0.101026049384446	0.072683899783380	0.053827227669769	0.038741889978879	0.029256412491426
0.022285157952454	0.016799580610312	0.013371094771474	0.009828326071341	0.007199820261564
0.005142728758261	0.003657051561431	0.002171374364601	0.000685697167771	0.000000000000000

CUMULANTS

0.600914237396242D+00	0.989518889562782D-02	0.361438949016417D-03	0.340280954775758D-04
0.119337952538469D-04	0.412291056616221D-06	-0.115583269596708D-05	-0.441401635896035D-06

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	2023	INITIAL LOAD	613.2	232.4	3217.0	0.60053217	0.37900719	MONDAY
		LOAD AFTER CONTRACTS	613.2	232.4	3217.0	0.60053217	0.37900719	

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	0.998400181320209	0.996438215692847
0.985212949814614	0.955294509378252	0.921153492996331	0.894985960046507	0.836809661999893
0.769723173117902	0.720341498206111	0.654195317826063	0.577952379055579	0.498741844931393
0.410861886764494	0.323660879921294	0.265831640782815	0.195773689020191	0.139544468355899
0.102515469381853	0.073257988711002	0.054972063291720	0.039771887786942	0.029828915840207
0.022514545672494	0.016685906945098	0.013485869996724	0.009942971946738	0.007200083133846
0.005142916524176	0.003657185083860	0.002057166609673	0.000685722203226	0.000000000000000

CUMULANTS

0.600532174807995D+00	0.967908468073646D-02	0.413822140663884D-03	0.403487480445909D-04
0.102922536989288D-04	0.453462466502880D-07	-0.111953687947774D-05	-0.447606808284530D-06

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	2024	INITIAL LOAD	621.6	236.3	3260.0	0.60033545	0.38007811	TUESDAY
		LOAD AFTER CONTRACTS	621.6	236.3	3260.0	0.60033545	0.38007811	

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	0.995407820157786
0.984848952614743	0.951847725702044	0.918686444154518	0.894758857756859	0.838466031235942
0.775360818883621	0.716499349189532	0.655817314841172	0.576512920493898	0.495123591255751
0.398469139132111	0.326269455665513	0.260924172528023	0.201062409653819	0.140400966741219
0.102587524925643	0.073342083521452	0.056777282726109	0.039641281903341	0.030273601453561
0.022619521086058	0.017707200850197	0.013708800658218	0.010281600493664	0.007768320372992
0.005140800246834	0.003655680175527	0.002170560104221	0.000685440032914	0.000000000000000

CUMULANTS

0.600335445370965D+00	0.975819958974820D-02	0.429232332738764D-03	0.422129947695239D-04
0.988583381221872D-05	-0.187673301949018D-06	-0.117481820520966D-05	-0.455327839816484D-06

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	2025	INITIAL LOAD	630.1	236.6	3303.0	0.60004868	0.37556611	WEDNESDAY
		LOAD AFTER CONTRACTS	630.1	236.6	3303.0	0.60004868	0.37556611	

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	0.998450273499210	0.996087842718302
0.987553897926753	0.957740711455417	0.923705235929593	0.891142001073614	0.832513447281477
0.771782002414412	0.712437169113062	0.646617610958585	0.571999642254030	0.491977235648261
0.403824886647916	0.327014718567702	0.259005715580012	0.201969593746638	0.142418853315401
0.100813345605285	0.073381142719494	0.056350316761232	0.040462499256545	0.030404024865088
0.023203071607568	0.018173834411840	0.013830402288256	0.010172775236817	0.007772457484311
0.005143538041089	0.003657627051442	0.002171716061795	0.000685805072148	0.000000000000000

CUMULANTS

0.600048680880188D+00	0.979682391833315D-02	0.448138063451582D-03	0.398836258626985D-04
0.927015008410759D-05	-0.115837420114009D-06	-0.117520825363989D-05	-0.469501738127880D-06

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	2026	INITIAL LOAD	638.7	244.2	3347.0	0.59985483	0.38230997	FRIDAY
		LOAD AFTER CONTRACTS	638.7	244.2	3347.0	0.59985483	0.38230997	

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	0.995365630436426
0.974243021111228	0.946849407341204	0.910930331565191	0.873157521882327	0.813002340811177
0.759804419959264	0.705883552988768	0.639705988618846	0.572038965646398	0.502880627974844
0.429424870640036	0.351513787432667	0.275202051974422	0.203231403263802	0.142456188797056
0.103500647193371	0.078596517956998	0.059175866717624	0.041240324102438	0.030730324608189
0.023190542362314	0.017478586115440	0.013480216742627	0.010281521244378	0.007654021370815
0.005254999747128	0.003655651998003	0.002170543373816	0.000685434749628	0.000000000000000

CUMULANTS

0.599854833012750D+00	0.104146251081486D-01	0.384049823575249D-03	0.232172101216351D-04
0.108446397620974D-04	0.626244817337908D-06	-0.122869086208042D-05	-0.473642683428309D-06

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	2027	INITIAL LOAD	647.5	246.7	3392.0	0.59965774	0.38100414	SATURDAY
		LOAD AFTER CONTRACTS	647.5	246.7	3392.0	0.59965774	0.38100414	

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	0.994962727674605
0.973092623510611	0.945930981885373	0.912592538935472	0.874287102512953	0.814514968691741
0.756837778474757	0.706052363783122	0.638161451892174	0.569652826944335	0.497526890040839
0.425699854792888	0.348316403249923	0.273811459156969	0.208588617556017	0.146313104393538
0.104430816655487	0.077580442570106	0.058728052254838	0.041246744871589	0.030735109059440
0.023194152933333	0.017709821205255	0.013482315498195	0.010168865079148	0.007655213037112
0.005141560995076	0.003656221152055	0.002170881309034	0.000685541466013	0.000000000000000

CUMULANTS

0.599657742377312D+00	0.104575351866276D-01	0.397302940170815D-03	0.236275616178689D-04
0.101110271246334D-04	0.526370437906505D-06	-0.120058961135761D-05	-0.472073108241709D-06

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	2028	INITIAL LOAD	656.4	250.2	3437.0	0.59937458	0.38119355	SUNDAY
		LOAD AFTER CONTRACTS	656.4	250.2	3437.0	0.59937458	0.38119355	

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	0.995663851361018
0.975464783979622	0.946983825254670	0.911232019192548	0.871580638082360	0.814754588809973
0.754385458457508	0.701219462976644	0.635074545953262	0.568482472089204	0.496558964243856
0.423155589838019	0.345750473836847	0.273719125120838	0.204660498732791	0.146006400492612
0.106103320013426	0.079120148113461	0.059340111085097	0.042304125436390	0.031785261814369
0.023667443149549	0.017721998493625	0.014063263320748	0.010290192673719	0.007660476768214
0.005259431811014	0.003773070647032	0.002172374008899	0.000800348319070	0.000000000000000

CUMULANTS

0.599374577248851D+00	0.105075228110640D-01	0.411988830301748D-03	0.231358598420338D-04
0.955634678965290D-05	0.466210636225616D-06	-0.120026421424432D-05	-0.475326060451767D-06

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	2029	INITIAL LOAD	665.4	253.2	3483.0	0.59918100	0.38055623	MONDAY
		LOAD AFTER CONTRACTS	665.4	253.2	3483.0	0.59918100	0.38055623	

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	0.995834258431635
0.984534148913187	0.952864572239609	0.919334547426118	0.886034685637195	0.822681010550421
0.754457620762448	0.700869763101145	0.635402658159169	0.564499225592785	0.487089631578120
0.402994400791938	0.327811436311900	0.263254635504573	0.202582668728129	0.148194992295762
0.109689431460241	0.078267979739860	0.059757888180945	0.042847434164159	0.032335530315886
0.024337342605244	0.018510091558918	0.014625257528035	0.010511903848276	0.007883927886208
0.005370211748577	0.003656314382011	0.002170936664321	0.000685558946630	0.000000000000000

CUMULANTS

0.599181004475121D+00	0.102102133807036D-01	0.485499463453099D-03	0.340158238839004D-04
0.719137956467188D-05	-0.327364343162611D-06	-0.117968826191718D-05	-0.457326359628575D-06

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	2030	INITIAL LOAD	674.6	255.1	3530.0	0.59898474	0.37816379	WEDNESDAY
		LOAD AFTER CONTRACTS	674.6	255.1	3530.0	0.59898474	0.37816379	

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	0.998539885407590	0.995603906498966
0.982668172559485	0.950330093072782	0.916835829145181	0.883208271352649	0.824477850096521
0.754866452521479	0.705601243400226	0.633475148375839	0.564206664089344	0.483736345710313
0.405094898203533	0.329768279152707	0.261414230302338	0.205633668698691	0.147795627363763
0.108360599180857	0.077155489923080	0.058295259052994	0.041378203484675	0.031890935834875
0.024689756775388	0.018745926440573	0.014630966978009	0.010744616374476	0.008001310066100
0.005372308187240	0.003886350603536	0.002171784160801	0.000685826577097	0.000000000000000

CUMULANTS

0.598984741047330D+00	0.102602584397260D-01	0.471131572913680D-03	0.347660219871720D-04
0.811070412787560D-05	-0.265110984534084D-06	-0.123440781753858D-05	-0.473696716964995D-06

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	2031	INITIAL LOAD	683.6	258.9	3577.0	0.59896890	0.37874954	THURSDAY
		LOAD AFTER CONTRACTS	683.6	258.9	3577.0	0.59896890	0.37874954	

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	0.998917068310781	0.996171680523248
0.976380650935937	0.952885946149042	0.918181201648609	0.871815626358426	0.806181473350303
0.753772386721039	0.698886047882129	0.629706391637252	0.566870305612147	0.492719237618472
0.425483472540807	0.349786063558809	0.267342208761196	0.201021215997513	0.142247094824180
0.104169697254685	0.077412607070717	0.058774121173337	0.041965179903920	0.031102258675386
0.024012773242027	0.018066753201145	0.014064624327474	0.010176841993051	0.007775564668849
0.005602980423142	0.003887782334426	0.002286930784958	0.000800425774737	0.000000000000000

CUMULANTS

0.598968903041618D+00	0.104274676884489D-01	0.430120091383503D-03	0.263967607011125D-04
0.100827677612998D-04	0.568578301305112D-06	-0.126269639521701D-05	-0.529780674268829D-06

BASIC PLANT TYPES - 1

DATA SET REF. NO.	1	2	3	4	5
NAME	BIG STONE UP	MISO - Off peak	WIND ENERGY2	C-5	C-10
TYPE / LOADING / STATUS /AVD	THRM B G	THRM P E	NDT B G	THRM B G	THRM B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	COAL MDU SDAK	PURC MDU MISO	PURC MDU MISO	PURC MISO MISO	PURC MISO MISO
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE		1/ 1/2010			
OPERATING/BOOK LIVES, YEARS	40 30	50 50	6 6	5 5	10 10
RATED CAPACITY, MW	105.900	30.000	25.000	155.000	155.000
- RESERVE	0.9575	0.0000	0.0000	1.0000	1.0000
CAPACITY - OPERATING	0.9251	1.0000	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	0.0493	0.0000	0.0000	0.0747	0.0747
FULL LOAD HEAT RATE, BTU/KWH	10542.	10500.	0.	10800.	10800.
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	1049.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	1049.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	1	2	1	2	2
LEVEL. CARRYING CHARGE, PCT	10.75	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	21.81	0.00	12.00	75.00	76.80
VARIABLE O+M COST, $/MWH	1.42	23.50	51.00	107.41	107.41
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	1	0	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	53 50 51	0 0 46	0 55 45	0 47 56	0 47 56
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	52	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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	1	2	3	4	5
MAINTENANCE REQUIREMENTS	20	0	22	16	18
FUEL 1 / FUEL 2	6 0	8 0	0 0	8 0	8 0
LOADING BLOCKS / NDT NO.	3 0	0 0	0 1	0 0	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 20	0 0 0	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR	M 1980 2080				
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TRAJECTORY FOR DISPATCH MODIF	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 MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0	0.00 0	0.00 0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	6	110	120	130	132
NAME	C-20	WILLISTON C.T.	MILES CITY C.T.	GLENDIVE CT #1	GLENDIVE CT #2
TYPE / LOADING / STATUS /AVD	THRM B G	THRM P E	THRM P E	THRM P E	THRM P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MISO MISO	GAS MDU NDAK	GAS MDU MONT	GAS MDU MONT	GAS MDU MONT
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE		1/ 1/1953	1/ 1/1972	1/ 1/1979	1/ 1/2003
OPERATING/BOOK LIVES, YEARS	20 20	57 30	99 30	99 30	99 30
RATED CAPACITY, MW	345.000	10.600	30.000	42.000	43.000
CAPACITY MULTIPLIERS - RESERVE	1.0000	0.7453	0.6667	0.7024	0.8512
- OPERATING	1.0000	0.9057	0.8299	0.8061	0.8061
- EMERGENCY	1.0000	1.0000	0.9267	0.9636	0.9636
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0534	0.1750	0.0727	0.1324	0.0866
FULL LOAD HEAT RATE, BTU/KWH	7250.	20700.	13439.	11615.	8494.
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	120.00	3.55	10.48	3.29	5.63
VARIABLE O+M COST, $/MWH	65.79	2.35	2.35	2.35	2.35
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 57 58	0 3 4	0 3 5	0 3 6	0 3 7
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	12 0	13 0	13 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.	6	110	120	130	132
MAINTENANCE REQUIREMENTS	21	1	2	3	4
FUEL 1 / FUEL 2	8 0	1 0	1 0	1 0	1 0
LOADING BLOCKS / NDT NO.	0 0	11 0	12 0	2 0	13 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
TRAJECTORY FOR DISPATCH MODIF	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 MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0	0.00 0	0.00 0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	134	140	150	160	170
NAME	GLENDIVE DISEL	HESKETT #1	HESKETT #2	LEWIS & CLARK	BIG STONE
TYPE / LOADING / STATUS /AVD	THRM P E	THRM B E	THRM B E	THRM B E	THRM B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU MONT	COAL MDU NDAK	COAL MDU NDAK	COAL MDU NDAK	COAL MDU SDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2005	1/ 1/1954	1/ 1/1963	1/ 1/1958	1/ 1/1975
OPERATING/BOOK LIVES, YEARS	99 30	99 30	99 30	99 30	40 30
RATED CAPACITY, MW	2.000	29.200	74.600	52.300	107.800
- RESERVE	0.9500	0.7123	0.8686	0.9962	0.9583
CAPACITY - OPERATING	1.0000	0.6791	0.9383	0.8604	0.9251
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	0.9398	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0789	0.0550	0.1140	0.0032	0.0493
FULL LOAD HEAT RATE, BTU/KWH	11000.	15762.	13502.	12679.	10350.
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	2.74	52.37	51.56	47.55	21.81
VARIABLE O+M COST, $/MWH	5.00	6.16	7.68	2.62	1.42
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 8	0 3 9	0 3 10	0 3 11	0 3 12
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	16 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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	134	140	150	160	170
MAINTENANCE REQUIREMENTS	1	5	6	7	8
FUEL 1 / FUEL 2	2 0	3 0	4 0	5 0	6 0
LOADING BLOCKS / NDT NO.	0 0	14 0	15 0	16 0	17 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
TRAJECTORY FOR DISPATCH MODIF	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 MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0	0.00 0	0.00 0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	180	220	230	240	250
NAME	COYOTE	WAPA PUR-FT PECK	XCEL ENERGY PK 1	XCEL ENERGY PK 2	DIAMOND WILLOW
TYPE / LOADING / STATUS /AVD	THRM B E	HYDR B E	THRM P E	THRM P E	NDT B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	COAL MDU NDAK	HYDR MDU NDAK	PURC MDU MISO	PURC MDU MISO	WIND MDU MONT
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/1981	1/ 1/2001	1/ 1/2007	1/ 1/2007	1/ 1/2008
OPERATING/BOOK LIVES, YEARS	99 30	30 30	4 4	5 5	30 20
RATED CAPACITY, MW	106.800	2.800	10.000	100.000	30.000
- RESERVE	0.9007	0.0000	1.0000	1.0000	0.2140
CAPACITY - OPERATING	0.9368	0.8929	1.0000	1.0000	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	0.0832	0.0000	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	11225.	0.	1.	1.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	14.330000	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	2400.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	2400.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	1
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	13.76
FIXED O+M COST, $/KW-YR	22.18	0.00	17.70	17.70	14.73
VARIABLE O+M COST, $/MWH	2.56	16.84	184.30	84.30	-28.26
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	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 13	0 0 14	0 15 16	0 15 16	20 3 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	32	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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	180	220	230	240	250
MAINTENANCE REQUIREMENTS	9	0	14	14	10
FUEL 1 / FUEL 2	7 0	0 0	8 0	8 0	0 0
LOADING BLOCKS / NDT NO.	18 0	0 0	0 0	0 0	0 1
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
TRAJECTORY FOR DISPATCH MODIF	0	0	0	0	0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00	0.00	2000.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	0.00	2000.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	0 0	20 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 MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0	0.00 0	0.00 0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	260	270	280	310	340
NAME	GLEN ULLIN ORMAT	CEDAR HILLS	WE ENERGIES	PURCHASE POWER	CC-140
TYPE / LOADING / STATUS /AVD	THRM B E	NDT B E	THRM P C	THRM P G	THRM P G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MDU NDAK	WIND MDU MONT	PURC MDU MISO	PURC MDU MISO	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/ 1/2009	1/ 1/2010	1/ 1/2012		
OPERATING/BOOK LIVES, YEARS	30 30	30 20	3 3	1 1	40 40
RATED CAPACITY, MW	5.300	19.500	110.000	10.000	140.000
- RESERVE	0.9245	0.2000	1.0000	1.0000	0.9464
CAPACITY - OPERATING	0.9245	1.0000	1.0000	1.0000	0.8571
MULTIPLIERS - EMERGENCY	0.9245	0.3810	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0735	0.0000	0.0000	0.0000	0.0537
FULL LOAD HEAT RATE, BTU/KWH	1.	0.	1.	1.	8500.
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	2558.00	2400.00	0.00	0.00	750.00
INSTALLATION COST 2, $/KW	2558.00	2400.00	0.00	0.00	750.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	13.76	13.76	0.00	0.00	11.54
FIXED O+M COST, $/KW-YR	45.88	12.56	34.80	34.80	15.36
VARIABLE O+M COST, $/MWH	6.70	-30.31	113.80	110.00	6.00
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	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	20 44 18	20 3 19	0 42 43	0 21 21	30 22 23
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	41	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	13 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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	260	270	280	310	340
MAINTENANCE REQUIREMENTS	15	10	11	0	12
FUEL 1 / FUEL 2	8 0	0 0	8 0	8 0	1 0
LOADING BLOCKS / NDT NO.	0 0	0 1	0 0	0 0	1 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 0	0 0 20
MUST RUN / 1ST YR / LAST YR	M 1980 2080				
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TRAJECTORY FOR DISPATCH MODIF	0	0	0	0	0
CONSTRUCTION COST 1, $/KW	2558.00	2000.00	0.00	0.00	750.00
CONSTRUCTION COST 2, $/KW	2558.00	2000.00	0.00	0.00	750.00
TRAJECTORY / EXPEND. PATTERN	20 0	20 0	0 0	0 0	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 MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0	0.00 0	0.00 0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	350	360	370	380	390
NAME	COMBUST. TURB.75	GENERIC BASELOAD	COMBUST. TURB.43	WIND 2012	WIND
TYPE / LOADING / STATUS /AVD	THRM P G	THRM B G	THRM P G	NDT B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	COAL MDU NDAK	GAS MDU NDAK	WIND 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	40 25	40 40	40 25	30 20	30 20
RATED CAPACITY, MW	88.000	30.000	43.000	30.000	30.000
- RESERVE	0.9352	0.9233	0.7767	0.2140	0.2140
CAPACITY - OPERATING	0.8371	0.9500	0.8371	1.0000	1.0000
MULTIPLIERS - EMERGENCY	0.9276	1.0000	0.9276	0.3810	0.3810
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0645	0.0765	0.2231	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	10655.	9700.	8900.	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	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	857.00	3900.00	850.00	2400.00	2400.00
INSTALLATION COST 2, $/KW	857.00	3900.00	850.00	2400.00	2400.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	11.54	10.27	11.54	13.75	13.75
FIXED O+M COST, $/KW-YR	12.08	48.00	15.82	23.28	23.28
VARIABLE O+M COST, $/MWH	2.00	2.50	2.00	-31.85	2.00
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	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 24	30 22 25	30 22 26	30 22 27	30 22 28
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	13 0	0 0	13 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
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC

BASIC PLANT TYPES - 2

DATA SET REF. NO.	350	360	370	380	390
MAINTENANCE REQUIREMENTS	12	13	12	10	10
FUEL 1 / FUEL 2	1 0	9 0	1 0	0 0	0 0
LOADING BLOCKS / NDT NO.	13 0	0 0	13 0	0 1	0 1
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		M 1980 2080			
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TRAJECTORY FOR DISPATCH MODIF	0	0	0	0	0
CONSTRUCTION COST 1, $/KW	857.00	3900.00	850.00	2400.00	2400.00
CONSTRUCTION COST 2, $/KW	857.00	3900.00	850.00	2400.00	2400.00
TRAJECTORY / EXPEND. PATTERN	30 37	30 31	30 37	30 38	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 MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0	0.00 0	0.00 0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	400	420	440
NAME	MISO - On peak	WIND ENERGY	DSM
TYPE / LOADING / STATUS /AVD	THRM P E	NDT B G	DTHR P G
LOAD COMPONENT FOR DSM			
CLASS / AREA / GENERATING CO.	PURC MDU MISO	PURC MDU MISO	PURC MDU MISO
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2010		
OPERATING/BOOK LIVES, YEARS	50 50	6 6	30 30
RATED CAPACITY, MW	30.000	25.000	12.500
- RESERVE	0.0000	0.0000	1.0000
CAPACITY - OPERATING	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	10500.	0.	1.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	1	1
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	0.00	12.00	50.04
VARIABLE O+M COST, $/MWH	32.67	49.50	300.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00
CAPITAL STRUCTURE	0	1	1
YEARLY TRAJECTORIES			
COSTS-CAPITAL/FIX OM/VAR OM	0 0 29	0 54 45	0 48 49
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0
RATED CAPACITY	52	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	400	420	440
MAINTENANCE REQUIREMENTS	0	17	19
FUEL 1 / FUEL 2	8 0	0 0	8 0
LOADING BLOCKS / NDT NO.	0 0	0 1	0 0
EMISSIONS / SITE / TAX DEPR.	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
TRAJECTORY FOR DISPATCH MODIF	0	0	0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
REBOUND BENEFITS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
CUSTOMER BENEFITS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
TRANS/DISTR COSTS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
OTHER COSTS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
PERCENTAGE FOR 2ND FUEL			
MINIMUM / TRAJ / SEG MULT	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
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIP/ TRAJ / SEG MULT	1.00 0 0	1.00 0 0	1.00 0 0
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0

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
1	1	1	1 - BASE YEAR=0	2 - TWO PERIODS	1	17	1	9	44
2	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	20	1	44
					2	1	18	2	40
					3	1	22	1	42
					4	1	19	1	39
					5	1	16	2	42
					6	1	19	1	43
					7	1	16	1	43
					8	2	16	1	41
					9	1	21	1	39
					10	8	19	0	0
3	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	17	1	42
					2	1	16	1	44
					3	2	17	1	41
					4	1	17	1	37
					5	6	17	1	41
					6	1	16	1	41
					7	1	18	2	41
					8	1	17	1	43
					9	1	19	1	38
					10	1	16	1	41
4	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	18	1	43
					2	1	17	1	46
					3	1	16	1	40
					4	1	16	1	38
					5	1	18	1	41
					6	1	17	1	42
					7	1	17	1	42
					8	1	18	1	42
					9	1	20	1	38
					10	1	17	1	42
5	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	10	1	37
					2	1	11	2	35
					3	1	9	1	36
					4	1	16	1	41
					5	2	15	2	35
					6	1	12	5	36
					7	2	14	1	36
					8	2	14	1	34
					9	2	18	2	36
					10	1	10	1	37

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
6	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	2	13	2	41
					2	6	13	2	42
					3	2	12	2	38
					4	2	11	2	37
					5	2	11	2	41
					6	2	14	2	42
					7	2	12	2	40
					8	2	10	5	37
					9	2	12	2	39
					10	2	13	2	41
7	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	15	6	34
					2	2	17	1	37
					3	2	18	1	40
					4	2	14	1	39
					5	2	16	1	39
					6	2	17	1	40
					7	6	15	1	37
					8	2	17	1	38
					9	2	15	2	37
					10	1	15	1	36
8	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	16	7	38
					2	2	15	0	0
					3	1	17	0	0
					4	2	19	0	0
					5	12	6	0	0
					6	1	20	0	0
					7	1	20	0	0
					8	1	20	0	0
					9	1	17	0	0
					10	1	16	7	38
9	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	23	1	37
					2	1	13	6	38
					3	1	21	1	43
					4	1	21	5	38
					5	1	14	1	40
					6	1	23	1	41
					7	1	21	1	39
					8	5	11	1	39
					9	1	22	1	44
					10	1	23	1	37
10	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			

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
11	4	1	0 - INSTALLATION	1 - START WEEKS	1	22	1		
					2	0	0		
					3	0	0		
					4	30	22		
12	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
13	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	3			
14	1	1	1 - BASE YEAR=0	2 - TWO PERIODS	1	17	1	9	44
15	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	1	16		
					2	1	17		
					3	1	16		
					4	1	16		
					5	1	16		
					6	1	16		
					7	1	16		
					8	1	15		
					9	1	16		
					10	1	16		
16	6	6	0 - INSTALLATION	1 - START WEEKS	1	22	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	29	23		
17	6	6	0 - INSTALLATION	1 - START WEEKS	1	22	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	29	23		
18	10	10	0 - INSTALLATION	1 - START WEEKS	1	22	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	0	0		
					7	0	0		
					8	0	0		
					9	0	0		
					10	0	0		
19	1	1	0 - INSTALLATION	0 - NO. WEEKS ONLY	1	1			

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
20	10	10	1 - BASE YEAR=0	2 - TWO PERIODS	1	1	16	7	38
					2	2	15	0	0
					3	1	17	0	0
					4	2	19	0	0
					5	12	6	0	0
					6	1	20	0	0
					7	1	20	0	0
					8	1	20	0	0
					9	1	17	0	0
					10	1	16	7	38
21	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	22	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	0	0		
					7	0	0		
					8	0	0		
					9	0	0		
					10	0	0		
22	6	6	0 - INSTALLATION	1 - START WEEKS	1	22	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	29	23		

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	1.03	-1.00	0.00	5.050000	0	0	33	0	0	0
2	OIL2	GAL	0.14	-1.00	0.00	16.150000	0	0	34	0	0	0
3	COAL	TON	14.18	-1.00	0.00	1.410000	0	0	35	0	0	0
4	COAL	TON	14.01	-1.00	0.00	1.630000	0	0	36	0	0	0
5	COAL	TON	12.78	-1.00	0.00	1.370000	0	0	37	0	0	0
6	COAL	TON	16.72	-1.00	0.00	2.030000	0	0	38	0	0	0
7	COAL	TON	13.94	-1.00	0.00	1.260000	0	0	39	0	0	0
8	PURC	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
9	COAL	TON	16.72	-1.00	0.00	1.500000	0	0	40	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	COMBUST. TURB.75	350	0	2015	2030	0	0	0	0	0	0 - NO	0	-1	0
2	CC-140	340	0	2015	2030	0	0	1	1	0	1 - YES	0	-1	0
3	WIND 2012	380	0	2011	2012	0	0	0	0	0	0 - NO	0	-1	0
4	WIND	390	0	2013	2030	0	0	0	0	0	0 - NO	0	-1	0
5	GENERIC BASELOAD	360	0	2017	2030	0	0	0	0	0	0 - NO	0	-1	0
6	COMBUST. TURB.43	370	0	2015	2030	0	0	0	0	0	0 - NO	0	-1	0
7	PURCHASE POWER	310	0	2010	2014	1	0	0	0	0	0 - NO	0	-1	0
8	WIND ENERGY	420	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
9	WIND ENERGY2	3	0	2020	2020	0	0	0	0	0	0 - NO	0	-1	0
10	DSM	440	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
11	BIG STONE UP	1	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
12	CP-5	4	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
13	CP-10	5	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
14	CP-20	6	0	2015	2015	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	2010	1.06	2011	3.34	2012	3.94	2013	1.66	2014	2.90
		2015	1.57	2016	1.52	2017	1.52	2018	1.53	2019	1.49
		2020	1.48	2021	1.49	2022	1.49	2023	1.50	2024	1.51
		2025	1.47	2026	1.48	2027	1.47	2028	1.51	2029	1.51
		2030	1.20								
2	1 - RATE	2010	2.51	2011	3.81	2012	5.30	2013	1.95	2014	3.23
		2015	1.75	2016	1.69	2017	1.69	2018	1.69	2019	1.62
		2020	1.63	2021	1.62	2022	1.62	2023	1.62	2024	1.62
		2025	1.62	2026	1.62	2027	1.62	2028	1.63	2029	1.62
		2030	0.00								
3	1 - RATE	2010	3.00								
4	1 - RATE	2010	3.00								
5	1 - RATE	2010	3.00								
6	1 - RATE	2010	3.00								
7	1 - RATE	2010	3.00								
8	1 - RATE	2010	3.00								
9	1 - RATE	2010	3.00								
10	1 - RATE	2010	3.00	2011	3.00	2012	3.00	2013	12.53	2014	2.75
		2015	3.00	2016	3.00						
11	1 - RATE	2010	3.00								
12	1 - RATE	2010	3.00								
13	1 - RATE	2010	3.00								
14	1 - RATE	2010	3.00								
15	1 - RATE	2010	1.50								
16	1 - RATE	2010	3.00								
17	1 - RATE	2010	-0.21	2011	-0.25	2012	-0.21	2013	-0.25	2014	-0.21
		2015	-0.25	2016	-0.25	2017	7.09	2018	-0.23	2019	-109.00
		2020	3.00								
18	1 - RATE	2010	1.49	2011	1.47	2012	1.45	2013	1.57	2014	1.55
		2015	1.50								

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
19	1 - RATE	2010	-0.20	2011	-0.20	2012	-0.23	2013	-0.20	2014	-0.23
		2015	-0.23	2016	-0.23	2017	-0.27	2018	-0.23	2019	-109.00
		2020	3.00								
20	1 - RATE	2010	3.00								
21	1 - RATE	2010	3.00								
22	1 - RATE	2010	3.00								
23	1 - RATE	2010	3.00								
24	1 - RATE	2010	3.00								
25	1 - RATE	2010	3.00								
26	1 - RATE	2010	3.00								
27	1 - RATE	2010	-0.19	2011	-0.19	2012	-0.22	2013	-0.19	2014	-0.22
		2015	-0.22	2016	-0.22	2017	-0.22	2018	-0.25	2019	-0.26
		2020	-108.80	2021	4.00						
28	1 - RATE	2010	3.00								
29	1 - RATE	2010	4.99	2011	5.01	2012	5.00	2013	5.00	2014	4.99
		2015	5.01	2016	5.00	2017	5.00	2018	4.99	2019	4.28
		2020	5.00								
30	1 - RATE	2010	3.00								
31	1 - RATE	2010	3.00								
32	1 - RATE	2010	5.00	2011	4.00						
33	1 - RATE	2010	-0.79	2011	14.77	2012	2.61	2013	3.22	2014	3.78
		2015	-0.32	2016	2.54	2017	3.10	2018	3.15	2019	3.78
		2020	3.50								
34	1 - RATE	2010	32.94	2011	7.64	2012	9.74	2013	7.06	2014	6.89
		2015	7.00								
35	1 - RATE	2010	7.80	2011	5.26	2012	2.50	2013	1.83	2014	3.59
		2015	4.00								
36	1 - RATE	2010	5.52	2011	4.65	2012	3.33	2013	1.08	2014	4.26
		2015	3.75								
37	1 - RATE	2010	0.00	2011	1.42	2012	3.50	2013	1.35	2014	2.00
		2015	2.25								

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
38	1 - RATE	2010	0.00	2011	7.39	2012	9.63	2013	7.11	2014	3.91
		2015	4.50								
39	1 - RATE	2010	4.76	2011	7.58	2012	2.11	2013	-0.69	2014	6.25
		2015	4.00								
40	1 - RATE	2010	4.00								
41	1 - RATE	2010	0.00	2011	0.00	2012	4.55	2013	4.35	2014	0.00
		2015	0.00								
42	1 - RATE	2010	0.00								
43	1 - RATE	2012	2.14	2013	0.23	2014	2.55	2015	3.00		
44	1 - RATE	2010	3.01	2011	3.00	2012	22.37	2013	-13.31	2014	3.00
		2015	2.99	2016	20.23	2017	-11.75	2018	2.99	2019	3.01
		2020	18.29	2021	-10.30	2022	3.00	2023	3.00	2024	16.60
		2025	-9.01	2026	2.99	2027	3.01	2028	15.08	2029	-7.81
		2030	0.00								
45	1 - RATE	2010	0.00								
46	1 - RATE	2010	5.02	2011	4.98	2012	5.02	2013	5.00	2014	5.01
		2015	5.00	2016	5.02	2017	4.99	2018	4.98	2019	5.02
		2020	5.00								
47	1 - RATE	2015	2.30								
48	1 - RATE	2010	0.00								
49	1 - RATE	2010	0.00								
50	1 - RATE	2010	3.00	2011	3.00	2012	3.00	2013	3.00	2014	31.16
		2015	3.00	2016	3.00						
51	1 - RATE	2010	3.00	2011	3.00	2012	3.00	2013	3.00	2014	118.25
		2015	3.00	2016	3.00						
52	1 - RATE	2010	0.00	2011	0.00	2012	0.00	2013	0.00	2014	0.00
		2015	0.00								
53	1 - RATE	2010	0.00								
54	1 - RATE	2010	0.00	2011	0.00	2012	0.00	2013	0.00	2014	-41.66
		2015	71.43	2016	0.00	2017	0.00	2018	0.00	2019	-58.33
		2020	140.00	2021	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
55	1 - RATE	2010	0.00	2011	0.00	2012	0.00	2013	0.00	2014	0.00
		2015	0.00	2016	0.00	2017	0.00	2018	0.00	2019	-41.66
		2020	71.43	2021	0.00	2022	0.00	2023	0.00	2024	-58.33
		2025	0.00								
56	1 - RATE	2015	0.79	2016	2.60	2017	2.96	2018	2.99	2019	3.40
		2020	3.22	2021	3.23	2022	3.23	2023	3.23	2024	3.24
		2025	3.24	2026	0.00						
57	1 - RATE	2015	1.50								
58	1 - RATE	2015	0.58	2016	2.55	2017	2.96	2018	2.99	2019	3.45
		2020	3.24	2021	3.25	2022	3.25	2023	3.26	2024	3.26
		2025	3.26	2026	3.27	2027	3.26	2028	3.27	2029	3.28
		2030	3.28	2031	3.28	2032	3.29	2033	3.29	2034	3.29
		2035	0.00								

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
1	3	1	0.535714	1.258824	1.000000
		2	0.321429	0.160824	0.000000
		3	0.142857	1.917647	0.000000
2	5	1	0.238095	1.431855	1.000000
		2	0.190476	0.782953	0.000000
		3	0.190476	0.809126	0.000000
		4	0.190476	0.868188	0.000000
		5	0.190476	0.999828	0.000000
3	2	1	0.409134	1.000000	1.000000
		2	0.590866	1.000000	0.000000
11	2	1	0.400000	1.000000	0.819621
		2	0.600000	1.000000	0.300631
12	5	1	0.333333	1.347868	0.776597
		2	0.133333	0.713520	0.082915
		3	0.133333	0.776025	0.107925
		4	0.133333	0.838604	0.126806
		5	0.266667	0.900960	0.224415
13	5	1	0.232558	1.431834	1.000000
		2	0.186047	0.783023	0.000000
		3	0.186047	0.809159	0.000000
		4	0.186047	0.868260	0.000000
		5	0.209302	0.999882	0.000000
14	5	1	0.205479	1.206700	0.592785
		2	0.205479	0.971768	0.095703
		3	0.205479	0.935858	0.308534
		4	0.171233	0.953940	0.247917
		5	0.212329	0.926469	0.255951
15	5	1	0.455764	1.050437	0.702989
		2	0.147453	0.988002	0.138903
		3	0.134048	0.963709	0.310205
		4	0.134048	0.949563	0.229531
		5	0.128686	0.925493	0.295489
16	5	1	0.325048	1.193075	0.701186
		2	0.152964	0.907012	0.102326
		3	0.152964	0.907012	0.100637
		4	0.172084	0.907012	0.238235
		5	0.196941	0.907012	0.453448
17	2	1	0.398776	1.192582	1.000000
		2	0.601224	0.872301	0.000000

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
18	2	1	0.393258	1.135323	1.000000
		2	0.606742	0.912339	0.000000

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

DATA SET REF. NO.	CALENDAR YEAR	COMPOUNDING OPTION	AFUDC RATE
1	2010	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
2010	50.00	0.00	50.00	10.75	0.00	4.40	38.40	1.32	10.93

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								

SUBPERIOD DEFINITION

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

SUBWEEK	NUMBER OF HOURS
1	60
2	60
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

SEGMENT MULTIPLIER TABLES

DATA SET REF. NO.	TYPE OF MULTIPLIERS	FIRST YEAR	SEG. 1 / 8	SEG. 2 / 9	SEG. 3 /10	SEG. 4 /11	SEG. 5 /12	SEG. 6 /13	SEG. 7
12	1 - CAPACITY		1.000000	1.000000	1.000000	1.000000			
13	1 - CAPACITY		1.000000	1.000000	1.000000	1.000000			
16	1 - CAPACITY		1.000000	1.000000	1.000000	1.000000			

Appendix B

EGEAS OUTPUT REPORT FOR THE 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.
2011 Integrated Resource Planning Study
Base Case Run
-- Data updated for the 2011 IRP

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3412 HILL VIEW 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	2011	1	0		4/26/11	13:40:23	2011 IRP	900
EXPANSION PLAN	2011	1	0	1	4/26/11	13:40:25	2011 IRP	900
SUBPERIOD REPORT	2011	1	0	1	4/26/11	13:40:25	2011 IRP	900
UNIT REPORT	2011	1	0	1	4/26/11	13:40:25	2011 IRP	900

```
                    REC. REF SEQ                                                                  ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                       DATA FIELDS                              REC. NO.
------------------  - ---- --- ---   ------------------------------------------------------------------   --------
       RECORD COLS                1           2         3         4         5         6         7         8
                    1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890

** COMMENT **       *               Montana-Dakota Utilities Co.                                             1
                    *               2011 Integrated Resource Planning Study                                  2
                    *               Base Case Run                                                            3
                    *                 -- Data updated for the 2011 IRP                                       4
                    *                                                                                        5
                    *               CONTROL RECORD                                                           6
                    *                SbUnUcc                                                                 7
                    *                                                                                        8
                    *                          C M E S   F                                                   9
                    *                          T I R E   I                                                  10
                    *                          L R R L   L        DESCRIPTIVE INFORMATION                   11
                    *                          + - + -   +        -------------------------------           12

CONTROL RECORD        RCC                      1 1 3 1   0        2011 IRP                                  13

** COMMENT **       *                                                                                       14
                    *               --INPUT FILES---                                                        15
                    *               NAME     V U RUN                                                        16
                    *               --------+--++++                                                         17

FILE IDENTIFICATION   RFF           2011     1 0   1                                                        18

** COMMENT **       *                                                                                       19
                    *               == PLAN SELECTION ==                                                    20
                    *                  PLANS C O   C E M                                                    21
                    *               DR  1  L P M   S N O               --AREAS TO INCLUDE--                 22
                    *                -+++--- + -   + - +               --++--++--++--++--++                 23

PLAN SELECTION        RRA            1  1  1 0 1   3 2 0                                                    24

** COMMENT **       *                                                                                       25
                    *               == TIME PERIODS ==                                                      26
                    *               --YEARS-- -SG- -SW-                                                     27
                    *                1ST LAST  1 L 1 L                                                      28
                    *               ---- ++++ --++ - +                                                      29

TIME PERIOD           RRB           2011 2030  113 1 3                                                      30

** COMMENT **       *                                                                                       31
                    *               == REPORT SELECTION ==                                                  32
                    *                    -PROD-  MNT -STORAGE--   -FL -EM-    -ECON INT- -COST-             33
                    *                S S S  UOBRRSU DOSPD  -PJ-    SU SSU GCf TSTU  CUT  UCTCA              34
                    *                Y U YAFNRLEEYN EPWRS C 1 L    YN YIN E+m RYIN  OFF  NOOOS              35
                    *                S M SRLTDKLSST TRKDP E 1 L    ST STT NRt NSET  PCT. TNTVT              36
                    *                - + -+-+-+-+-+ +-+-+ -++--    +- +-+ -+- +-+-++++++ -+-+-              37

       RECORD COLS                1           2         3         4         5         6         7         8
                    1 2345 678 90   12345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                     REC. REF SEQ                                                                           ASSIGNED
RECORD DESCRIPTION C TYPE NO. NO.                        DATA FIELDS                                        REC. NO.
------------------ - ---- --- ---   --------------------------------------------------------------------    --------
       RECORD COLS                1            2         3         4         5         6         7         8
                   1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123 34567890

REPORT SELECTION     RRC            1 2 1011101100 00000 0       00 000 001 00000.0000 00100                    38

** COMMENT **      *                                                                                             39
```

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

```
RRA     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

RRB     FIRST YEAR = 2011         FIRST SEGMENT =  1       FIRST SUBWEEK =  1
        LAST  YEAR = 2030         LAST  SEGMENT = 13       LAST  SUBWEEK =  3

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

        EXPANSION PLAN SUMMARY        =  2 - YES, WITH RESERVE CAPACITY

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

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

        COST ANALYSIS REPORTS
           UNIT OUTLAYS               =  0 - NO
           CONSTRUCTION COST          =  0 - NO
           TOTAL COST                 =  1 - YES
           INTEREST COVERAGE          =  0 - NO
           EARNING ASSETS             =  0 - NO
```

PLAN 1

	NEW UNITS ADDED													
YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14
2011	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0	0.	0.	0.
2012	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0	0.	0.	0.
2013	0.	0.	0.	0.	0.	0.	0.	0.	1	0	0	0.	0.	0.
2014	0.	0.	0.	0.	0.	0.	0.	0.	2	0	0	0.	0.	0.
2015	0	0.	1+	0	2	1	2+	0.	0.	0	0	0	0	0
2016	0	0.	0+	0	0	0	0+	0.	0.	0	0	0	0	0
2017	0	0.	0+	0	0	0	0+	0	0.	0	0	0	0	0
2018	0	0.	0+	0	1	0	0+	0	0.	0	0	0	0	0
2019	0	0.	0+	0	0	0	0+	0	0.	0	0	0	0	0
2020	0	4	0+	0	0	0	0+	0	0.	0	0	0	0	0
2021	0	0	0+	0	0	0	0+	0	0.	0	0	0	0	0
2022	0	0	0+	0	1	0	0+	0	0.	0	0	0	0	0
2023	0	0	0+	0	0	0	0+	0	0.	0	0	0	0	0
2024	0	0	0+	0	0	0	0+	0	0.	0	0	0	0	0
2025	0	0	0+	0	1	0	0+	0	0.	0	0	0	0	0
2026	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
2028	0	0	0+	0	1+	0	0+	0	0.	0	0	0	0	0
2029	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

TOTAL COST, M$
--W/O EXT 2004.901
--WITH EXT 3723.720

UNIT TYPES

1	PA 8	WIND ENERGY	25.000 MW	2	PA 9	WIND ENERGY2	25.000 MW	3	PA 11	BIG STONE UP	105.900 MW
4	PA 2	CC-140	140.000 MW	5	PA 6	COMBUST. TURB.43	43.000 MW	6	PA 1	COMBUST. TURB.75	88.000 MW
7	PA 10	DSM	12.500 MW	8	PA 5	GENERIC BASELOAD	30.000 MW	9	PA 7	PURCHASE POWER	10.000 MW
10	PA 4	WIND	30.000 MW	11	PA 3	WIND 2012	30.000 MW	12	PA 12	CP-5	155.000 MW
13	PA 13	CP-10	155.000 MW	14	PA 14	CP-20	345.000 MW				

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2010.
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
2011	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00	0.00 .
2012	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00	0.00 .
2013	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	1.00	0.00
2014	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	2.00	0.00
2015	0.00	0.00 .	1.00 +	0.00	2.00	1.00	2.00 +	0.00 .	0.00 .	0.00
2016	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00 .	0.00 .	0.00
2017	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 .	0.00
2018	0.00	0.00 .	0.00 +	0.00	1.00	0.00	0.00 +	0.00	0.00 .	0.00
2019	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 .	0.00
2020	0.00	4.00	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 .	0.00
2021	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 .	0.00
2022	0.00	0.00	0.00 +	0.00	1.00	0.00	0.00 +	0.00	0.00 .	0.00
2023	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 .	0.00
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	1.00	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	1.00 +	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
TOTAL	0.00	4.00	1.00	0.00	6.00	1.00	2.00	0.00	3.00	0.00

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

UNIT TYPES

1 PA 8	WIND ENERGY	25.000 MW	2 PA 9	WIND ENERGY2	25.000 MW	3 PA 11	BIG STONE UP	105.900 MW
4 PA 2	CC-140	140.000 MW	5 PA 6	COMBUST. TURB.43	43.000 MW	6 PA 1	COMBUST. TURB.75	88.000 MW
7 PA 10	DSM	12.500 MW	8 PA 5	GENERIC BASELOAD	30.000 MW	9 PA 7	PURCHASE POWER	10.000 MW
10 PA 4	WIND	30.000 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14
2011	0.00	0.00 .	0.00 .	0.00 .
2012	0.00	0.00 .	0.00 .	0.00 .
2013	0.00	0.00 .	0.00 .	0.00 .
2014	0.00	0.00 .	0.00 .	0.00 .
2015	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00
TOTAL	0.00	0.00	0.00	0.00

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

11 PA 3 WIND 2012 30.000 MW
12 PA 12 CP-5 155.000 MW
13 PA 13 CP-10 155.000 MW
14 PA 14 CP-20 345.000 MW

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2011	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.000	0.000
2014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	20.000	0.000
2015	0.000	0.000	105.900	0.000	86.000	88.000	25.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	43.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	43.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
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	43.000	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	43.000	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
TOTAL	0.000	100.000	105.900	0.000	258.000	88.000	25.000	0.000	30.000	0.000

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1	PA	8	WIND ENERGY	25.000 MW
2	PA	9	WIND ENERGY2	25.000 MW
3	PA	11	BIG STONE UP	105.900 MW
4	PA	2	CC-140	140.000 MW
5	PA	6	COMBUST. TURB.43	43.000 MW
6	PA	1	COMBUST. TURB.75	88.000 MW
7	PA	10	DSM	12.500 MW
8	PA	5	GENERIC BASELOAD	30.000 MW
9	PA	7	PURCHASE POWER	10.000 MW
10	PA	4	WIND	30.000 MW

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14
2011	0.000	0.000	0.000	0.000
2012	0.000	0.000	0.000	0.000
2013	0.000	0.000	0.000	0.000
2014	0.000	0.000	0.000	0.000
2015	0.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000
2017	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000

UNIT TYPES

11 PA 3 WIND 2012 30.000 MW 12 PA 12 CP-5 155.000 MW 13 PA 13 CP-10 155.000 MW
14 PA 14 CP-20 345.000 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	501.8	2578.25				715.3	550.4	9.69	1.0000		
2011	505.8	2745.10	0.0	10.0	5.0	710.3	545.4	7.83	9.0048	0.000	0.000
2012	522.7	2849.70	110.0	105.0	0.0	715.3	550.4	5.30	8.8863	0.000	0.000
2013	543.3	3000.60	10.0	0.0	5.0	730.3	565.4	4.07	48.7688	0.000	0.000
2014	552.3	3059.00	20.0	10.0	5.0	745.3	580.4	5.09	47.4785	0.000	0.000
2015	568.3	3157.69	304.9	247.8	0.0	802.4	612.6	8.16	18.0945	283.260	0.000
2016	577.2	3212.89	0.0	0.0	0.0	802.4	612.6	6.41	26.6862	0.000	0.000
2017	586.0	3267.29	0.0	0.0	0.0	802.4	612.6	4.74	19.7079	0.000	0.000
2018	594.9	3322.59	43.0	0.0	0.0	845.4	646.0	8.97	29.0437	46.300	0.000
2019	604.0	3378.79	0.0	0.0	0.0	845.4	646.0	7.26	28.5831	0.000	0.000
2020	613.0	3433.59	100.0	0.0	0.0	945.4	646.0	5.61	20.1680	0.000	0.000
2021	622.1	3489.38	0.0	0.0	0.0	945.4	646.0	4.00	16.2785	0.000	0.000
2022	631.4	3545.98	43.0	0.0	0.0	988.4	679.4	7.92	29.9928	52.112	0.000
2023	640.8	3603.58	0.0	0.0	0.0	988.4	679.4	6.27	34.2351	0.000	0.000
2024	650.4	3661.98	0.0	0.0	0.0	988.4	679.4	4.64	24.6056	0.000	0.000
2025	660.2	3721.48	43.0	0.0	0.0	1031.4	712.8	8.28	20.3664	56.944	0.000
2026	669.9	3781.88	0.0	100.0	0.0	931.4	712.8	6.65	19.3086	0.000	0.000
2027	679.8	3843.28	0.0	0.0	0.0	931.4	712.8	5.04	14.3349	0.000	0.000
2028	689.8	3905.68	43.0	0.0	0.0	974.4	746.2	8.48	19.1798	62.224	0.000
2029	700.2	3969.27	0.0	0.0	0.0	974.4	746.2	6.81	18.7981	0.000	0.000
2030	710.8	4033.77	0.0	0.0	0.0	974.4	746.2	5.16	11.1822	0.000	0.000

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	..................COST SUMMARY.................. ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2011	72.721	18.207	90.928	90.928	85.194	85.194
2012	82.430	18.207	100.637	191.565	88.346	173.540
2013	90.733	18.207	108.940	300.505	89.604	263.144
2014	99.157	18.207	117.364	417.869	90.446	353.590
2015	109.117	50.018	159.134	577.003	114.903	468.493
2016	112.184	50.018	162.202	739.205	109.733	578.226
2017	119.809	50.018	169.827	909.032	107.647	685.872
2018	128.988	55.361	184.349	1093.381	109.484	795.356
2019	134.999	55.361	190.359	1283.740	105.924	901.280
2020	151.153	55.361	206.514	1490.254	107.667	1008.947
2021	161.727	55.361	217.088	1707.342	106.044	1114.991
2022	171.124	61.374	232.498	1939.840	106.410	1221.401
2023	176.762	61.374	238.136	2177.977	102.118	1323.519
2024	188.890	61.374	250.264	2428.241	100.551	1424.070
2025	204.151	67.946	272.097	2700.338	102.430	1526.500
2026	214.475	67.946	282.421	2982.759	99.612	1626.112
2027	229.017	67.946	296.963	3279.722	98.137	1724.249
2028	245.820	65.222	311.042	3590.764	96.308	1820.557
2029	256.963	65.222	322.185	3912.949	93.468	1914.024
2030	275.550	58.784	334.334	4247.283	90.876	2004.900
EXT.	1484.668	234.152			1718.820	3723.720

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 2010.

PLAN 1

	ENERGY, GWH							
	GENERATION	DUMP	CHARGING	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	UNMET	TOTAL
2011	2741.64	0.00	0.00	0.00	0.00	0.00	3.45	2745.10
2012	2845.88	0.00	0.00	0.00	0.00	0.00	3.82	2849.70
2013	3000.19	0.00	0.00	0.00	0.00	0.00	0.41	3000.60
2014	3058.50	0.00	0.00	0.00	0.00	0.00	0.49	3059.00
2015	3156.20	0.00	0.00	0.00	0.00	0.00	1.49	3157.69
2016	3211.84	0.00	0.00	0.00	0.00	0.00	1.05	3212.89
2017	3265.81	0.00	0.00	0.00	0.00	0.00	1.48	3267.29
2018	3321.49	0.00	0.00	0.00	0.00	0.00	1.10	3322.59
2019	3377.61	0.00	0.00	0.00	0.00	0.00	1.17	3378.79
2020	3432.05	0.00	0.00	0.00	0.00	0.00	1.53	3433.59
2021	3487.28	0.00	0.00	0.00	0.00	0.00	2.10	3489.38
2022	3544.88	0.00	0.00	0.00	0.00	0.00	1.11	3545.98
2023	3602.58	0.00	0.00	0.00	0.00	0.00	1.00	3603.58
2024	3660.53	0.00	0.00	0.00	0.00	0.00	1.45	3661.98
2025	3719.65	0.00	0.00	0.00	0.00	0.00	1.83	3721.48
2026	3780.06	0.00	0.00	0.00	0.00	0.00	1.82	3781.88
2027	3840.72	0.00	0.00	0.00	0.00	0.00	2.56	3843.28
2028	3903.63	0.00	0.00	0.00	0.00	0.00	2.05	3905.68
2029	3967.12	0.00	0.00	0.00	0.00	0.00	2.15	3969.27
2030	4030.29	0.00	0.00	0.00	0.00	0.00	3.48	4033.77
EXT.	4030.29	0.00	0.00	0.00	0.00	0.00	3.48	4033.77

NOTE - GENERATION INCLUDES CHARGING OF STORAGE UNITS (IF ANY).

PLAN 1

	COST, M$									
	FUEL	VARIABLE O+M	FIXED O+M	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	EMISSION COST	ALLOWANCES CREDIT	UNMET ENERGY	TOTAL
2011	45.002	10.731	16.525	0.000	0.000	0.000	0.000	0.000	0.463	72.721
2012	50.283	12.713	18.906	0.000	0.000	0.000	0.000	0.000	0.527	82.430
2013	55.908	14.805	19.963	0.000	0.000	0.000	0.000	0.000	0.058	90.733
2014	59.607	18.522	20.956	0.000	0.000	0.000	0.000	0.000	0.072	99.157
2015	66.488	21.183	21.221	0.000	0.000	0.000	0.000	0.000	0.225	109.117
2016	68.876	21.325	21.820	0.000	0.000	0.000	0.000	0.000	0.163	112.184
2017	73.735	23.350	22.487	0.000	0.000	0.000	0.000	0.000	0.237	119.809
2018	79.581	25.291	23.934	0.000	0.000	0.000	0.000	0.000	0.182	128.988
2019	83.525	26.659	24.615	0.000	0.000	0.000	0.000	0.000	0.199	134.999
2020	82.670	42.200	26.016	0.000	0.000	0.000	0.000	0.000	0.268	151.153
2021	84.095	49.966	27.288	0.000	0.000	0.000	0.000	0.000	0.379	161.727
2022	90.370	51.597	28.951	0.000	0.000	0.000	0.000	0.000	0.205	171.124
2023	95.385	51.440	29.746	0.000	0.000	0.000	0.000	0.000	0.191	176.762
2024	103.209	54.830	30.565	0.000	0.000	0.000	0.000	0.000	0.285	188.890
2025	120.419	51.543	31.818	0.000	0.000	0.000	0.000	0.000	0.371	204.151
2026	134.705	47.221	32.169	0.000	0.000	0.000	0.000	0.000	0.380	214.475
2027	145.852	49.519	33.096	0.000	0.000	0.000	0.000	0.000	0.550	229.017
2028	157.689	52.467	35.210	0.000	0.000	0.000	0.000	0.000	0.454	245.820
2029	164.928	55.265	36.279	0.000	0.000	0.000	0.000	0.000	0.491	256.963
2030	178.396	59.059	37.278	0.000	0.000	0.000	0.000	0.000	0.816	275.550
EXT.	1055.084	244.470	181.095	0.000	0.000	0.000	0.000	0.000	4.018	1484.668

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1

YEAR	......TOTAL SYSTEM..... ENERGY, GWH	COST, M$	..FUEL CLASS - COAL.. ENERGY, GWH	COST, M$	..FUEL CLASS - PURC.. ENERGY, GWH	COST, M$	..FUEL CLASS - GAS .. ENERGY, GWH	COST, M$
2011	2741.64	72.258	2179.51	61.233	304.47	10.250	73.73	4.739
2012	2845.88	81.903	2242.99	65.992	334.88	13.861	84.07	5.974
2013	3000.19	90.676	2379.67	72.383	347.73	15.732	88.85	6.445
2014	3058.50	99.085	2358.96	74.998	395.91	19.223	119.71	8.707
2015	3156.20	108.892	2268.80	76.927	446.76	16.254	256.71	19.511
2016	3211.84	112.021	2410.46	84.267	423.96	15.834	193.49	15.675
2017	3265.81	119.572	2423.35	88.178	438.23	17.281	220.29	17.823
2018	3321.49	128.807	2394.56	90.748	460.32	18.970	282.67	22.962
2019	3377.61	134.799	2466.77	96.100	455.35	19.577	271.56	22.948
2020	3432.05	150.885	2323.14	93.763	639.70	30.649	285.28	24.773
2021	3487.28	161.349	2237.76	94.338	772.12	38.986	293.47	26.272
2022	3544.88	170.919	2260.15	99.327	781.81	40.158	318.99	29.629
2023	3602.58	176.571	2400.42	107.991	736.13	38.871	282.10	27.852
2024	3660.53	188.605	2366.45	111.438	765.71	41.554	344.44	33.698
2025	3719.65	203.781	2347.57	113.413	638.99	36.259	549.15	52.137
2026	3780.05	214.095	2532.68	126.842	496.54	29.856	566.90	55.366
2027	3840.72	228.467	2541.66	132.738	487.69	31.070	627.44	62.568
2028	3903.63	245.366	2486.12	135.129	504.32	33.570	729.26	74.513
2029	3967.12	256.472	2567.57	143.625	503.84	35.159	711.77	75.469
2030	4030.29	274.733	2484.26	143.542	519.45	38.198	842.65	90.708
EXT.	4030.29	1480.648	2484.26	773.891	337.70	135.851	1024.40	559.652

YEAR	..FUEL CLASS - HYDR.. ENERGY, GWH	COST, M$	..FUEL CLASS - WIND.. ENERGY, GWH	COST, M$
2011	14.33	0.249	169.61	-4.212
2012	14.33	0.256	169.61	-4.180
2013	14.33	0.264	169.61	-4.147
2014	14.33	0.272	169.61	-4.114
2015	14.33	0.280	169.61	-4.080
2016	14.33	0.288	169.61	-4.044
2017	14.33	0.297	169.61	-4.007
2018	14.33	0.306	169.61	-4.179
2019	14.33	0.315	169.61	-4.141
2020	14.33	0.324	169.61	1.376
2021	14.33	0.334	169.61	1.418
2022	14.33	0.344	169.61	1.460
2023	14.33	0.354	169.61	1.504
2024	14.33	0.365	169.61	1.549
2025	14.33	0.376	169.61	1.596
2026	14.33	0.387	169.61	1.643
2027	14.33	0.399	169.61	1.693
2028	14.33	0.411	169.61	1.744
2029	14.33	0.423	169.61	1.796
2030	14.33	0.436	169.61	1.850
EXT.	14.33	2.146	169.61	9.108

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2010.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1 YEAR 2011 * 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	39.22	102.79	0.	-2899.	455.	-2444.	-23.77
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2021.	252.	-1769.	-26.47
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	264.	250.	515.	13.24
COYOTE		MUST	106.800	11226.	1.320	82.56	770.25	11413.	2031.	2440.	15884.	20.62
BIG STONE		MUST	107.800	10378.	2.030	72.87	686.27	14458.	1004.	2422.	17884.	26.06
MISO - Off peak			30.000	10500.	0.000	70.47	184.70	0.	4558.	0.	4558.	24.68
LEWIS & CLARK			52.300	12740.	1.370	65.08	297.35	5190.	802.	2561.	8554.	28.77
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	249.	0.	249.	17.35
HESKETT #2		MUST	74.600	13759.	1.720	56.10	365.62	8653.	2892.	3962.	15506.	42.41
MISO - On peak			30.000	10500.	0.000	27.11	71.04	0.	2437.	0.	2437.	34.30
HESKETT #1			29.200	15883.	1.520	23.53	60.02	1449.	381.	1575.	3405.	56.73
GLENDIVE CT #2			43.000	8704.	5.010	11.19	42.03	1833.	102.	249.	2184.	51.96
GLENDIVE CT #1			42.000	11961.	5.010	5.88	21.57	1293.	52.	142.	1487.	68.94
MILES CITY C.T.			30.000	13862.	5.010	3.84	10.07	699.	24.	324.	1048.	104.02
XCEL ENERGY PK 2			105.000	1.	0.000	1.07	9.83	0.	853.	1886.	2740.	278.74
GLENDIVE DISEL			2.000	11000.	21.470	0.34	0.06	14.	0.	6.	20.	336.37

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2012 * 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	39.22	102.79	0.	-2892.	469.	-2423.	-23.57
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2017.	260.	-1757.	-26.30
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	268.	258.	526.	13.53
BIG STONE		MUST	107.800	10413.	2.180	80.73	760.24	17258.	1145.	2494.	20898.	27.49
LEWIS & CLARK			52.300	12689.	1.389	80.21	366.48	6461.	1019.	2638.	10118.	27.61
MISO - Off peak			30.000	10500.	0.000	77.31	202.62	0.	5250.	0.	5250.	25.91
COYOTE		MUST	106.800	11225.	1.420	74.32	693.45	11054.	1883.	2513.	15450.	22.28
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	256.	0.	256.	17.87
HESKETT #2		MUST	74.600	13716.	1.800	54.34	354.11	8742.	2885.	4081.	15708.	44.36
MISO - On peak			30.000	10500.	0.000	31.24	81.87	0.	2949.	0.	2949.	36.02
HESKETT #1			29.200	15885.	1.600	26.94	68.72	1746.	449.	1622.	3818.	55.56
GLENDIVE CT #2			43.000	8705.	5.750	12.74	47.84	2394.	119.	257.	2771.	57.91
GLENDIVE CT #1			42.000	11955.	5.750	6.75	24.76	1702.	62.	147.	1911.	77.15
MILES CITY C.T.			30.000	13854.	5.750	4.35	11.40	908.	28.	334.	1270.	111.42
WE ENERGIES			110.000	1.	0.000	1.20	11.49	0.	1307.	3828.	5135.	447.00
GLENDIVE DISEL			2.000	11000.	23.110	0.39	0.07	17.	0.	6.	23.	345.34

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2013 * 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	39.22	102.79	0.	-2885.	483.	-2402.	-23.37
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2012.	268.	-1745.	-26.12
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	272.	316.	588.	15.12
BIG STONE		MUST	107.800	10404.	2.390	82.86	780.30	19403.	1211.	2569.	23183.	29.71
COYOTE		MUST	106.800	11225.	1.450	82.58	770.50	12541.	2155.	2588.	17285.	22.43
LEWIS & CLARK			52.300	12688.	1.438	80.29	366.85	6693.	1050.	2717.	10461.	28.52
MISO - Off peak			30.000	10500.	0.000	79.80	209.15	0.	5691.	0.	5691.	27.21
HESKETT #2		MUST	74.600	13707.	1.860	60.09	391.63	9985.	3287.	4203.	17475.	44.62
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	264.	0.	264.	18.40
MISO - On peak			30.000	10500.	0.000	31.71	83.11	0.	3143.	0.	3143.	37.82
HESKETT #1			29.200	15885.	1.640	27.60	70.40	1834.	474.	1671.	3979.	56.52
GLENDIVE CT #2			43.000	8694.	5.900	13.27	49.85	2557.	128.	265.	2950.	59.17
GLENDIVE CT #1			42.000	11934.	5.900	7.14	26.20	1845.	67.	151.	2063.	78.74
MILES CITY C.T.			30.000	13851.	5.900	4.88	12.78	1044.	33.	344.	1421.	111.17
WE ENERGIES			115.000	1.	0.000	1.63	16.39	0.	1905.	4002.	5907.	360.35
PURCHASE POWER	2013		10.000	1.	0.000	0.21	0.18	0.	22.	380.	402.	2225.16
GLENDIVE DISEL			2.000	11000.	25.360	0.11	0.02	5.	0.	6.	11.	596.99

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2014 * 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	39.22	102.79	0.	-2878.	497.	-2381.	-23.16
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2008.	276.	-1733.	-25.93
MISO - Off peak			30.000	10500.	0.000	85.58	224.29	0.	6408.	0.	6408.	28.57
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	277.	274.	550.	14.15
BIG STONE		MUST	107.800	10381.	2.560	82.64	778.24	20682.	1244.	2646.	24572.	31.57
LEWIS & CLARK			52.300	12681.	1.457	80.76	368.98	6819.	1088.	2799.	10707.	29.02
COYOTE		MUST	106.800	11225.	1.440	75.98	708.86	11458.	2042.	2666.	16167.	22.81
HESKETT #2		MUST	74.600	13717.	1.880	59.28	386.33	9963.	3648.	4329.	17940.	46.44
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	272.	0.	272.	18.95
HESKETT #1			29.200	15841.	1.670	45.69	116.54	3083.	808.	1721.	5612.	48.16
MISO - On peak			30.000	10500.	0.000	40.55	106.27	0.	4220.	0.	4220.	39.71
GLENDIVE CT #2			43.000	8687.	6.090	17.56	65.97	3490.	174.	272.	3937.	59.68
GLENDIVE CT #1			42.000	11919.	6.090	9.77	35.85	2602.	95.	156.	2852.	79.57
MILES CITY C.T.			30.000	13811.	6.090	6.82	17.87	1503.	47.	354.	1904.	106.56
WE ENERGIES			120.000	1.	0.000	2.48	25.98	0.	3027.	4176.	7203.	277.24
PURCHASE POWER	2014		10.000	1.	0.000	0.31	0.27	0.	34.	392.	425.	1563.83
PURCHASE POWER	2014		10.000	1.	0.000	0.23	0.20	0.	25.	392.	417.	2053.57
GLENDIVE DISEL			2.000	11000.	27.150	0.14	0.02	7.	0.	6.	13.	561.22

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2015 * 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	39.22	102.79	0.	-2872.	512.	-2360.	-22.96
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2004.	284.	-1720.	-25.74
MISO - Off peak			30.000	10500.	0.000	97.67	255.97	0.	7679.	0.	7679.	30.00
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	281.	282.	563.	14.47
COYOTE		MUST	106.800	11225.	1.530	82.58	770.50	13233.	2287.	2746.	18266.	23.71
LEWIS & CLARK			52.300	12684.	1.487	80.55	368.03	6939.	1118.	2883.	10940.	29.73
HESKETT #2		MUST	74.600	13651.	1.960	64.47	420.14	11241.	4077.	4459.	19777.	47.07
BIG STONE UP	2015	MUST	105.900	10542.	2.660	63.23	584.96	16403.	2040.	3410.	21853.	37.36
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	280.	0.	280.	19.52
MISO - On peak			30.000	10500.	0.000	57.32	150.24	0.	6263.	0.	6263.	41.69
HESKETT #1			29.200	15811.	1.730	49.07	125.18	3424.	894.	1773.	6091.	48.66
GLENDIVE CT #2			43.000	8628.	6.320	29.05	109.12	5950.	297.	281.	6528.	59.82
COMBUST. TURB.43	2015		43.000	9101.	6.320	16.12	60.56	3483.	140.	789.	4412.	72.86
COMBUST. TURB.43	2015		43.000	9132.	6.320	9.82	36.90	2130.	86.	789.	3004.	81.40
COMBUST. TURB.75	2015		88.000	11396.	6.320	5.44	41.79	3010.	97.	1232.	4339.	103.83
GLENDIVE CT #1			42.000	12017.	6.320	1.53	5.62	427.	15.	160.	602.	107.18
MILES CITY C.T.			30.000	13910.	6.320	1.02	2.68	236.	7.	364.	608.	226.55
DSM	2015 D		12.500	1.	0.000	0.89	0.97	0.	290.	626.	916.	946.24
DSM	2015 D		12.500	1.	0.000	0.63	0.69	0.	207.	626.	833.	1205.54
GLENDIVE DISEL			2.000	11000.	29.020	0.21	0.04	12.	0.	6.	18.	499.01

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2016 * 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	39.22	102.79	0.	-2865.	528.	-2337.	-22.74
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1999.	292.	-1707.	-25.54
MISO - Off peak			30.000	10500.	0.000	97.64	255.89	0.	8060.	0.	8060.	31.50
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	285.	290.	575.	14.79
COYOTE		MUST	106.800	11225.	1.591	82.58	770.50	13763.	2355.	2828.	18946.	24.59
BIG STONE UP	2015	MUST	105.900	10542.	2.780	81.17	750.96	22006.	2698.	3512.	28216.	37.57
LEWIS & CLARK			52.300	12684.	1.520	80.52	367.90	7093.	1151.	2969.	11214.	30.48
HESKETT #2		MUST	74.600	13678.	2.033	62.26	405.77	11286.	4055.	4593.	19934.	49.13
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	288.	0.	288.	20.11
MISO - On peak			30.000	10500.	0.000	48.85	128.04	0.	5605.	0.	5605.	43.78
HESKETT #1			29.200	15821.	1.799	45.21	115.33	3283.	848.	1826.	5957.	51.65
GLENDIVE CT #2			43.000	8660.	6.300	22.50	84.50	4610.	237.	289.	5136.	60.78
COMBUST. TURB.43	2015		43.000	9121.	6.300	12.06	45.31	2604.	108.	812.	3524.	77.78
COMBUST. TURB.43	2015		43.000	9148.	6.300	7.49	28.13	1621.	67.	812.	2501.	88.90
COMBUST. TURB.75	2015		88.000	11418.	6.300	3.84	29.54	2125.	71.	1269.	3465.	117.28
GLENDIVE CT #1			42.000	12031.	6.300	1.13	4.14	314.	12.	165.	490.	118.46
MILES CITY C.T.			30.000	13901.	6.300	0.70	1.83	160.	5.	375.	541.	295.74
DSM	2015	D	12.500	1.	0.000	0.61	0.66	0.	199.	626.	824.	1245.32
DSM	2015	D	12.500	1.	0.000	0.44	0.48	0.	144.	626.	769.	1607.40
GLENDIVE DISEL			2.000	11000.	31.051	0.19	0.03	11.	0.	7.	18.	542.69

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2017 * 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	39.22	102.79	0.	-2858.	543.	-2314.	-22.51
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1994.	301.	-1693.	-25.34
MISO - Off peak			30.000	10500.	0.000	98.89	259.18	0.	8574.	0.	8574.	33.08
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	289.	349.	638.	16.41
BIG STONE UP	2015	MUST	105.900	10542.	2.905	82.86	766.55	23474.	2837.	3617.	29928.	39.04
COYOTE		MUST	106.800	11225.	1.655	82.58	770.50	14313.	2426.	2913.	19652.	25.51
LEWIS & CLARK			52.300	12681.	1.554	74.17	338.87	6679.	1092.	3059.	10829.	31.96
HESKETT #2		MUST	74.600	13656.	2.110	64.19	418.36	12053.	4307.	4731.	21090.	50.41
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	297.	0.	297.	20.71
MISO - On peak			30.000	10500.	0.000	52.92	138.68	0.	6375.	0.	6375.	45.97
HESKETT #1			29.200	15818.	1.871	50.60	129.07	3820.	978.	1881.	6679.	51.75
GLENDIVE CT #2			43.000	8652.	6.460	24.85	93.34	5217.	270.	298.	5785.	61.97
COMBUST. TURB.43	2015		43.000	9106.	6.460	13.59	51.06	3003.	126.	837.	3966.	77.67
COMBUST. TURB.43	2015		43.000	9130.	6.460	8.70	32.69	1928.	80.	837.	2845.	87.03
COMBUST. TURB.75	2015		88.000	11377.	6.460	4.64	35.70	2624.	88.	1307.	4019.	112.58
GLENDIVE CT #1			42.000	12018.	6.460	1.40	5.12	398.	15.	170.	583.	113.69
MILES CITY C.T.			30.000	13890.	6.460	0.89	2.33	209.	7.	387.	603.	258.47
DSM	2015	D	12.500	1.	0.000	0.78	0.85	0.	255.	626.	881.	1035.11
DSM	2015	D	12.500	1.	0.000	0.57	0.63	0.	188.	626.	813.	1299.88
GLENDIVE DISEL			2.000	11000.	33.225	0.26	0.05	16.	0.	7.	23.	521.37

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PLAN 1 YEAR 2018 * 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	39.22	102.79	0.	-3060.	560.	-2500.	-24.32
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1989.	310.	-1679.	-25.13
MISO - Off peak			30.000	10500.	0.000	99.21	260.00	0.	9030.	0.	9030.	34.73
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	294.	308.	602.	15.47
BIG STONE UP	2015	MUST	105.900	10542.	3.035	83.57	773.18	24742.	2947.	3726.	31415.	40.63
LEWIS & CLARK			52.300	12680.	1.589	80.82	369.25	7441.	1226.	3150.	11817.	32.00
COYOTE		MUST	106.800	11225.	1.721	75.98	708.86	13695.	2299.	3001.	18994.	26.80
HESKETT #2		MUST	74.600	13626.	2.189	62.70	408.64	12188.	4333.	4872.	21393.	52.35
MISO - On peak			30.000	10500.	0.000	61.15	160.25	0.	7735.	0.	7735.	48.27
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	306.	0.	306.	21.33
HESKETT #1			29.200	15810.	1.946	52.78	134.63	4142.	1051.	1937.	7130.	52.96
GLENDIVE CT #2			43.000	8638.	6.660	30.48	114.49	6586.	341.	307.	7234.	63.19
COMBUST. TURB.43	2015		43.000	9087.	6.660	17.04	64.01	3874.	162.	862.	4898.	76.51
COMBUST. TURB.43	2015		43.000	9115.	6.660	11.44	42.98	2609.	109.	862.	3579.	83.29
COMBUST. TURB.43	2018		43.000	9140.	6.660	7.07	26.56	1617.	67.	862.	2546.	95.85
COMBUST. TURB.75	2015		88.000	11394.	6.660	3.71	28.52	2164.	72.	1347.	3583.	125.63
GLENDIVE CT #1			42.000	12026.	6.660	1.15	4.23	339.	13.	175.	527.	124.44
MILES CITY C.T.			30.000	13895.	6.660	0.71	1.85	171.	6.	398.	575.	310.49
DSM	2015	D	12.500	1.	0.000	0.62	0.68	0.	204.	626.	829.	1220.59
DSM	2015	D	12.500	1.	0.000	0.45	0.49	0.	148.	626.	774.	1566.93
GLENDIVE DISEL			2.000	11000.	35.551	0.20	0.03	13.	0.	7.	21.	598.82

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PLAN 1 YEAR 2019

* 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	39.22	102.79	0.	-3053.	577.	-2476.	-24.09
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1984.	320.	-1665.	-24.92
MISO - Off peak			30.000	10500.	0.000	99.01	259.48	0.	9461.	0.	9461.	36.46
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	298.	317.	615.	15.82
BIG STONE UP	2015	MUST	105.900	10542.	3.172	83.37	771.27	25791.	3028.	3838.	32657.	42.34
COYOTE		MUST	106.800	11225.	1.790	82.58	770.50	15481.	2574.	3091.	21145.	27.44
LEWIS & CLARK			52.300	12680.	1.625	79.15	361.62	7451.	1236.	3245.	11932.	33.00
HESKETT #2		MUST	74.600	13633.	2.271	66.27	431.85	13370.	4716.	5019.	23105.	53.50
MISO - On peak			30.000	10500.	0.000	59.44	155.79	0.	7895.	0.	7895.	50.68
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	315.	0.	315.	21.97
HESKETT #1			29.200	15810.	2.024	51.56	131.52	4208.	1057.	1995.	7261.	55.20
GLENDIVE CT #2			43.000	8636.	6.870	29.22	109.78	6513.	337.	316.	7166.	65.27
COMBUST. TURB.43	2015		43.000	9088.	6.870	16.41	61.66	3849.	161.	888.	4898.	79.44
COMBUST. TURB.43	2015		43.000	9112.	6.870	10.83	40.67	2546.	106.	888.	3539.	87.03
COMBUST. TURB.43	2018		43.000	9138.	6.870	6.85	25.73	1615.	67.	888.	2570.	99.88
COMBUST. TURB.75	2015		88.000	11387.	6.870	3.61	27.77	2172.	72.	1387.	3632.	130.79
GLENDIVE CT #1			42.000	12017.	6.870	1.11	4.08	336.	12.	180.	529.	129.86
MILES CITY C.T.			30.000	13883.	6.870	0.70	1.84	175.	6.	410.	591.	321.71
DSM	2015	D	12.500	1.	0.000	0.62	0.68	0.	204.	626.	830.	1218.03
DSM	2015	D	12.500	1.	0.000	0.46	0.50	0.	150.	626.	776.	1547.44
GLENDIVE DISEL			2.000	11000.	38.039	0.22	0.04	16.	0.	7.	23.	615.19

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2020 * 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	39.22	102.79	0.	275.	594.	869.	8.45
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	179.	329.	508.	7.60
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
MISO - Off peak			30.000	10500.	0.000	96.79	253.67	0.	9713.	0.	9713.	38.29
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	303.	327.	629.	16.18
COYOTE		MUST	106.800	11225.	1.861	82.58	770.47	16100.	2651.	3184.	21934.	28.47
LEWIS & CLARK			52.300	12686.	1.662	81.89	374.16	7886.	1317.	3342.	12546.	33.53
BIG STONE UP	2015	MUST	105.900	10542.	3.315	69.37	641.77	22427.	2595.	3953.	28974.	45.15
HESKETT #2		MUST	74.600	13665.	2.356	63.22	411.99	13264.	4634.	5169.	23068.	55.99
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	324.	0.	324.	22.63
MISO - On peak			30.000	10500.	0.000	54.96	144.04	0.	7613.	0.	7613.	52.85
HESKETT #1			29.200	15818.	2.105	48.90	124.74	4153.	1033.	2055.	7241.	58.05
GLENDIVE CT #2			43.000	8615.	7.130	28.44	106.84	6563.	337.	325.	7226.	67.63
COMBUST. TURB.43	2015		43.000	9062.	7.130	17.34	65.14	4209.	175.	914.	5298.	81.33
COMBUST. TURB.43	2015		43.000	9092.	7.130	11.84	44.48	2884.	120.	914.	3917.	88.06
COMBUST. TURB.43	2018		43.000	9120.	7.130	7.70	28.91	1880.	78.	914.	2872.	99.33
COMBUST. TURB.75	2015		88.000	11333.	7.130	4.24	32.59	2633.	88.	1429.	4150.	127.34
GLENDIVE CT #1			42.000	11986.	7.130	1.38	5.06	432.	16.	186.	634.	125.34
MILES CITY C.T.			30.000	13872.	7.130	0.84	2.21	218.	7.	423.	648.	293.57
DSM	2015	D	12.500	1.	0.000	0.82	0.89	0.	268.	626.	893.	1001.02
DSM	2015	D	12.500	1.	0.000	0.60	0.65	0.	196.	626.	822.	1256.31
GLENDIVE DISEL			2.000	11000.	40.702	0.26	0.05	21.	0.	7.	28.	614.64

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2021 * 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	39.22	102.79	0.	283.	612.	895.	8.70
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	184.	339.	523.	7.83
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
MISO - Off peak			30.000	10500.	0.000	93.53	245.13	0.	9855.	0.	9855.	40.20
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	307.	387.	694.	17.83
COYOTE		MUST	106.800	11228.	1.936	82.36	768.40	16703.	2723.	3279.	22704.	29.55
LEWIS & CLARK			52.300	12691.	1.699	72.50	331.24	7142.	1201.	3442.	11786.	35.58
BIG STONE UP	2015	MUST	105.900	10542.	3.464	67.08	620.55	22661.	2585.	4071.	29317.	47.24
HESKETT #2		MUST	74.600	13683.	2.444	61.54	401.08	13416.	4647.	5324.	23387.	58.31
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	334.	0.	334.	23.31
MISO - On peak			30.000	10500.	0.000	52.20	136.81	0.	7592.	0.	7592.	55.49
HESKETT #1			29.200	15821.	2.189	45.67	116.49	4034.	993.	2117.	7144.	61.33
GLENDIVE CT #2			43.000	8600.	7.380	27.74	104.19	6613.	339.	335.	7287.	69.94
COMBUST. TURB.43	2015		43.000	9046.	7.380	17.50	65.75	4389.	182.	942.	5513.	83.85
COMBUST. TURB.43	2015		43.000	9073.	7.380	12.34	46.35	3104.	128.	942.	4174.	90.04
COMBUST. TURB.43	2018		43.000	9100.	7.380	8.30	31.16	2093.	86.	942.	3121.	100.14
COMBUST. TURB.75	2015		88.000	11278.	7.380	4.81	36.96	3076.	102.	1471.	4650.	125.80
GLENDIVE CT #1			42.000	11961.	7.380	1.66	6.09	538.	20.	191.	749.	122.91
MILES CITY C.T.			30.000	13845.	7.380	1.11	2.90	297.	9.	435.	741.	255.37
DSM	2015	D	12.500	1.	0.000	1.01	1.10	0.	330.	626.	956.	868.27
DSM	2015	D	12.500	1.	0.000	0.75	0.82	0.	247.	626.	873.	1059.19
GLENDIVE DISEL			2.000	11000.	43.551	0.37	0.06	31.	0.	8.	39.	603.78

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2022 * 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	39.22	102.79	0.	292.	630.	922.	8.97
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	189.	349.	539.	8.06
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
MISO - Off peak			30.000	10500.	0.000	94.25	247.01	0.	10427.	0.	10427.	42.21
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	312.	347.	658.	16.93
LEWIS & CLARK			52.300	12691.	1.737	79.12	361.47	7969.	1350.	3546.	12865.	35.59
BIG STONE UP	2015	MUST	105.900	10542.	3.620	77.31	715.18	27292.	3068.	4193.	34554.	48.31
COYOTE		MUST	106.800	11228.	2.013	74.13	691.66	15636.	2525.	3377.	21538.	31.14
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	344.	0.	344.	24.01
HESKETT #2		MUST	74.600	13668.	2.536	57.52	374.86	12994.	4473.	5484.	22952.	61.23
MISO - On peak			30.000	10500.	0.000	55.50	145.45	0.	8475.	0.	8475.	58.27
HESKETT #1			29.200	15817.	2.277	45.85	116.97	4212.	1027.	2180.	7420.	63.43
GLENDIVE CT #2			43.000	8595.	7.638	29.90	112.34	7375.	376.	345.	8096.	72.07
COMBUST. TURB.43	2015		43.000	9042.	7.638	19.00	71.38	4929.	204.	970.	6103.	85.50
COMBUST. TURB.43	2015		43.000	9072.	7.638	13.44	50.47	3497.	144.	970.	4611.	91.36
COMBUST. TURB.43	2018		43.000	9101.	7.638	9.01	33.85	2353.	97.	970.	3419.	101.02
COMBUST. TURB.43	2022		43.000	9129.	7.638	5.77	21.66	1510.	62.	970.	2542.	117.36
COMBUST. TURB.75	2015		88.000	11356.	7.638	3.11	23.93	2076.	68.	1516.	3659.	152.92
GLENDIVE CT #1			42.000	11994.	7.638	1.00	3.67	336.	12.	197.	545.	148.66
MILES CITY C.T.			30.000	13865.	7.638	0.63	1.66	176.	6.	448.	629.	379.45
DSM	2015	D	12.500	1.	0.000	0.58	0.63	0.	190.	626.	815.	1289.28
DSM	2015	D	12.500	1.	0.000	0.42	0.46	0.	139.	626.	765.	1647.86
GLENDIVE DISEL			2.000	11000.	46.600	0.17	0.03	15.	0.	8.	23.	778.96

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2023 * 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	39.22	102.79	0.	300.	649.	949.	9.23
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	195.	360.	555.	8.30
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	316.	357.	674.	17.32
COYOTE		MUST	106.800	11228.	2.094	82.38	768.65	18071.	2890.	3479.	24439.	31.80
BIG STONE UP	2015	MUST	105.900	10542.	3.783	81.64	755.31	30120.	3337.	4319.	37777.	50.02
MISO - Off peak			30.000	10500.	0.000	81.22	212.87	0.	9436.	0.	9436.	44.33
LEWIS & CLARK			52.300	12692.	1.776	78.89	360.43	8126.	1387.	3652.	13164.	36.52
HESKETT #2		MUST	74.600	13650.	2.631	64.40	419.68	15073.	5159.	5649.	25880.	61.67
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	354.	0.	354.	24.73
MISO - On peak			30.000	10500.	0.000	51.14	134.02	0.	8200.	0.	8200.	61.18
HESKETT #1			29.200	15832.	2.368	37.78	96.37	3612.	872.	2246.	6730.	69.83
GLENDIVE CT #2			43.000	8603.	7.905	27.15	101.97	6935.	352.	356.	7642.	74.95
COMBUST. TURB.43	2015		43.000	9052.	7.905	16.69	62.71	4487.	184.	999.	5670.	90.42
COMBUST. TURB.43	2015		43.000	9079.	7.905	11.65	43.78	3142.	129.	999.	4269.	97.52
COMBUST. TURB.43	2018		43.000	9104.	7.905	7.77	29.20	2101.	86.	999.	3186.	109.12
COMBUST. TURB.43	2022		43.000	9128.	7.905	4.97	18.69	1348.	55.	999.	2402.	128.56
COMBUST. TURB.75	2015		88.000	11343.	7.905	2.72	20.89	1873.	61.	1561.	3495.	167.34
GLENDIVE CT #1			42.000	11989.	7.905	0.90	3.30	312.	11.	203.	527.	159.77
MILES CITY C.T.			30.000	13873.	7.905	0.59	1.54	169.	5.	462.	636.	412.12
DSM	2015	D	12.500	1.	0.000	0.52	0.56	0.	169.	626.	795.	1410.02
DSM	2015	D	12.500	1.	0.000	0.38	0.42	0.	125.	626.	750.	1805.85
GLENDIVE DISEL			2.000	11000.	49.862	0.15	0.03	15.	0.	8.	23.	856.58

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	309.	668.	978.	9.51
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	201.	370.	571.	8.55
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
MISO - Off peak			30.000	10500.	0.000	85.65	224.47	0.	10447.	0.	10447.	46.54
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	321.	368.	689.	17.71
BIG STONE UP	2015	MUST	105.900	10542.	3.953	81.41	753.12	31384.	3428.	4449.	39261.	52.13
LEWIS & CLARK			52.300	12688.	1.816	79.68	364.06	8389.	1443.	3762.	13594.	37.34
COYOTE		MUST	106.800	11227.	2.178	75.87	707.91	17307.	2741.	3583.	23631.	33.38
HESKETT #2		MUST	74.600	13624.	2.730	66.81	435.41	16194.	5512.	5818.	27524.	63.21
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	365.	0.	365.	25.47
MISO - On peak			30.000	10500.	0.000	57.85	151.61	0.	9740.	0.	9740.	64.24
HESKETT #1			29.200	15825.	2.462	41.54	105.95	4128.	987.	2313.	7429.	70.11
GLENDIVE CT #2			43.000	8591.	8.182	31.71	119.13	8374.	423.	366.	9163.	76.92
COMBUST. TURB.43	2015		43.000	9037.	8.182	20.14	75.64	5593.	229.	1029.	6851.	90.57
COMBUST. TURB.43	2015		43.000	9065.	8.182	14.42	54.16	4017.	164.	1029.	5210.	96.19
COMBUST. TURB.43	2018		43.000	9092.	8.182	9.84	36.97	2750.	112.	1029.	3891.	105.24
COMBUST. TURB.43	2022		43.000	9116.	8.182	6.43	24.17	1803.	73.	1029.	2905.	120.18
COMBUST. TURB.75	2015		88.000	11312.	8.182	3.61	27.77	2570.	84.	1608.	4262.	153.48
GLENDIVE CT #1			42.000	11980.	8.182	1.22	4.48	439.	16.	209.	664.	148.28
MILES CITY C.T.			30.000	13860.	8.182	0.80	2.09	237.	7.	476.	720.	344.76
DSM	2015	D	12.500	1.	0.000	0.72	0.78	0.	235.	626.	861.	1097.11
DSM	2015	D	12.500	1.	0.000	0.53	0.58	0.	175.	626.	800.	1374.03
GLENDIVE DISEL			2.000	11000.	53.352	0.24	0.04	25.	0.	8.	33.	790.21

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
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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	39.22	102.79	0.	319.	688.	1007.	9.80
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	207.	382.	589.	8.81
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
MISO - Off peak			30.000	10500.	0.000	94.17	246.80	0.	12061.	0.	12061.	48.87
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	326.	429.	755.	19.41
COYOTE		MUST	106.800	11225.	2.265	82.58	770.50	19588.	3073.	3691.	26352.	34.20
LEWIS & CLARK			52.300	12682.	1.857	80.66	368.55	8680.	1504.	3874.	14059.	38.15
MISO - On peak			30.000	10500.	0.000	75.18	197.03	0.	13290.	0.	13290.	67.45
HESKETT #2		MUST	74.600	13577.	2.832	71.57	466.40	17935.	6082.	5993.	30009.	64.34
BIG STONE UP	2015	MUST	105.900	10542.	4.131	66.60	616.14	26832.	2888.	4582.	34302.	55.67
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	376.	0.	376.	26.24
HESKETT #1			29.200	15807.	2.561	49.39	125.98	5099.	1209.	2382.	8691.	68.99
GLENDIVE CT #2			43.000	8562.	8.468	44.42	166.86	12098.	611.	377.	13087.	78.43
COMBUST. TURB.43	2015		43.000	9001.	8.468	30.75	115.51	8804.	360.	1060.	10224.	88.51
COMBUST. TURB.43	2015		43.000	9034.	8.468	22.95	86.19	6594.	269.	1060.	7923.	91.92
COMBUST. TURB.43	2018		43.000	9054.	8.468	17.19	64.56	4950.	201.	1060.	6211.	96.21
COMBUST. TURB.43	2022		43.000	9081.	8.468	11.57	43.47	3343.	135.	1060.	4538.	104.40
COMBUST. TURB.43	2025		43.000	9109.	8.468	8.00	30.06	2318.	94.	1060.	3472.	115.51
COMBUST. TURB.75	2015		88.000	11308.	8.468	4.52	34.71	3324.	108.	1656.	5088.	146.59
GLENDIVE CT #1			42.000	11973.	8.468	1.40	5.12	519.	19.	215.	753.	147.10
MILES CITY C.T.			30.000	13856.	8.468	1.01	2.64	309.	10.	490.	809.	306.88
DSM	2015	D	12.500	1.	0.000	0.91	0.99	0.	297.	626.	923.	931.18
DSM	2015	D	12.500	1.	0.000	0.68	0.75	0.	224.	626.	849.	1137.99
GLENDIVE DISEL			2.000	11000.	57.087	0.22	0.04	24.	0.	9.	33.	859.82

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	328.	709.	1037.	10.09
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	213.	393.	606.	9.07
MISO - Off peak			30.000	10500.	0.000	96.14	251.97	0.	12929.	0.	12929.	51.31
BIG STONE UP	2015	MUST	105.900	10542.	4.317	85.77	793.47	36109.	3831.	4720.	44660.	56.28
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	331.	390.	721.	18.54
COYOTE		MUST	106.800	11225.	2.355	82.58	770.50	20372.	3165.	3801.	27338.	35.48
LEWIS & CLARK			52.300	12680.	1.899	80.82	369.25	8891.	1552.	3991.	14434.	39.09
MISO - On peak			30.000	10500.	0.000	77.83	203.98	0.	14447.	0.	14447.	70.82
HESKETT #2		MUST	74.600	13566.	2.938	72.76	474.21	18904.	6369.	6172.	31446.	66.31
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	387.	0.	387.	27.02
HESKETT #1			29.200	15806.	2.663	49.10	125.24	5272.	1238.	2454.	8964.	71.57
GLENDIVE CT #2			43.000	8565.	8.765	45.95	172.59	12956.	651.	388.	13995.	81.09
COMBUST. TURB.43	2015		43.000	9003.	8.765	31.67	118.98	9388.	382.	1092.	10861.	91.29
COMBUST. TURB.43	2015		43.000	9027.	8.765	24.25	91.11	7208.	292.	1092.	8592.	94.31
COMBUST. TURB.43	2018		43.000	9057.	8.765	17.65	66.29	5262.	213.	1092.	6566.	99.05
COMBUST. TURB.43	2022		43.000	9087.	8.765	12.16	45.67	3638.	147.	1092.	4876.	106.75
COMBUST. TURB.43	2025		43.000	9115.	8.765	7.97	29.93	2391.	96.	1092.	3579.	119.58
COMBUST. TURB.75	2015		88.000	11318.	8.765	4.45	34.20	3392.	110.	1706.	5208.	152.29
GLENDIVE CT #1			42.000	11977.	8.765	1.50	5.51	578.	21.	222.	820.	149.02
MILES CITY C.T.			30.000	13855.	8.765	0.99	2.58	314.	10.	505.	828.	320.59
DSM	2015	D	12.500	1.	0.000	0.89	0.97	0.	291.	626.	916.	944.85
DSM	2015	D	12.500	1.	0.000	0.66	0.72	0.	217.	626.	843.	1163.42
GLENDIVE DISEL			2.000	11000.	61.083	0.27	0.05	32.	0.	9.	41.	865.83

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	338.	730.	1068.	10.39
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	220.	405.	624.	9.35
MISO - Off peak			30.000	10500.	0.000	89.43	234.39	0.	12628.	0.	12628.	53.88
BIG STONE UP	2015	MUST	105.900	10542.	4.511	86.01	795.73	37841.	3957.	4861.	46660.	58.64
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	336.	402.	738.	18.97
COYOTE		MUST	106.800	11225.	2.450	82.58	770.50	21187.	3260.	3915.	28362.	36.81
MISO - On peak			30.000	10500.	0.000	80.95	212.15	0.	15776.	0.	15776.	74.36
HESKETT #2		MUST	74.600	13543.	3.049	75.35	491.09	20276.	6794.	6357.	33428.	68.07
LEWIS & CLARK			52.300	12680.	1.942	74.22	339.10	8348.	1468.	4110.	13927.	41.07
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	399.	0.	399.	27.83
HESKETT #1			29.200	15797.	2.770	56.94	145.24	6355.	1479.	2528.	10361.	71.34
GLENDIVE CT #2			43.000	8554.	9.071	48.76	183.17	14214.	711.	400.	15325.	83.67
COMBUST. TURB.43	2015		43.000	8998.	9.071	34.17	128.34	10476.	424.	1124.	12025.	93.69
COMBUST. TURB.43	2015		43.000	9017.	9.071	26.65	100.13	8190.	331.	1124.	9645.	96.33
COMBUST. TURB.43	2018		43.000	9043.	9.071	19.87	74.63	6123.	247.	1124.	7494.	100.41
COMBUST. TURB.43	2022		43.000	9071.	9.071	14.07	52.84	4348.	175.	1124.	5647.	106.87
COMBUST. TURB.43	2025		43.000	9099.	9.071	9.47	35.59	2937.	118.	1124.	4179.	117.44
COMBUST. TURB.75	2015		88.000	11279.	9.071	5.50	42.25	4323.	140.	1757.	6220.	147.20
GLENDIVE CT #1			42.000	11963.	9.071	1.92	7.03	763.	27.	228.	1019.	144.87
MILES CITY C.T.			30.000	13846.	9.071	1.30	3.40	427.	13.	520.	960.	282.35
DSM	2015	D	12.500	1.	0.000	1.18	1.29	0.	387.	626.	1013.	784.53
DSM	2015	D	12.500	1.	0.000	0.88	0.96	0.	289.	626.	915.	948.49
GLENDIVE DISEL			2.000	11000.	65.358	0.36	0.06	45.	1.	9.	54.	872.57

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	348.	752.	1100.	10.70
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	226.	417.	643.	9.63
MISO - Off peak			30.000	10500.	0.000	91.97	241.03	0.	13636.	0.	13636.	56.57
BIG STONE UP	2015	MUST	105.900	10542.	4.714	86.13	796.87	39601.	4082.	5007.	48690.	61.10
MISO - On peak			30.000	10500.	0.000	84.92	222.55	0.	17377.	0.	17377.	78.08
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	341.	414.	755.	19.41
LEWIS & CLARK			52.300	12680.	1.985	80.82	369.25	9295.	1647.	4234.	15176.	41.10
COYOTE		MUST	106.800	11225.	2.548	75.98	708.86	20272.	3089.	4033.	27394.	38.64
HESKETT #2		MUST	74.600	13539.	3.163	71.11	463.42	19845.	6603.	6548.	32996.	71.20
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	411.	0.	411.	28.67
HESKETT #1			29.200	15793.	2.881	57.91	147.73	6721.	1549.	2603.	10873.	73.60
GLENDIVE CT #2			43.000	8545.	9.389	52.58	197.52	15846.	790.	412.	17049.	86.31
COMBUST. TURB.43	2015		43.000	8980.	9.389	37.93	142.47	12012.	485.	1158.	13655.	95.85
COMBUST. TURB.43	2015		43.000	9002.	9.389	30.80	115.72	9780.	394.	1158.	11332.	97.93
COMBUST. TURB.43	2018		43.000	9026.	9.389	23.42	87.96	7454.	299.	1158.	8911.	101.31
COMBUST. TURB.43	2022		43.000	9051.	9.389	17.44	65.52	5568.	223.	1158.	6949.	106.06
COMBUST. TURB.43	2025		43.000	9078.	9.389	12.03	45.20	3852.	154.	1158.	5164.	114.26
COMBUST. TURB.43	2028		43.000	9106.	9.389	8.17	30.68	2623.	104.	1158.	3885.	126.65
COMBUST. TURB.75	2015		88.000	11287.	9.389	4.61	35.44	3755.	121.	1810.	5686.	160.45
GLENDIVE CT #1			42.000	11974.	9.389	1.62	5.95	669.	24.	235.	928.	155.97
MILES CITY C.T.			30.000	13849.	9.389	1.05	2.76	359.	11.	535.	905.	327.97
DSM	2015	D	12.500	1.	0.000	0.96	1.05	0.	315.	626.	940.	895.73
DSM	2015	D	12.500	1.	0.000	0.72	0.79	0.	236.	626.	862.	1093.87
GLENDIVE DISEL			2.000	11000.	69.934	0.29	0.05	39.	0.	9.	49.	962.82

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	359.	775.	1133.	11.03
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	233.	429.	663.	9.92
MISO - Off peak			30.000	10500.	0.000	91.95	240.98	0.	14314.	0.	14314.	59.40
BIG STONE UP	2015	MUST	105.900	10542.	4.926	85.41	790.18	41035.	4169.	5157.	50362.	63.73
MISO - On peak			30.000	10500.	0.000	84.74	222.08	0.	18208.	0.	18208.	81.99
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	346.	476.	822.	21.14
COYOTE		MUST	106.800	11225.	2.649	82.58	770.50	22916.	3459.	4154.	30528.	39.62
LEWIS & CLARK			52.300	12680.	2.030	79.17	361.71	9310.	1662.	4361.	15333.	42.39
HESKETT #2		MUST	74.600	13530.	3.282	76.74	500.11	22206.	7340.	6745.	36290.	72.57
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	423.	0.	423.	29.53
HESKETT #1			29.200	15792.	2.996	56.87	145.07	6863.	1567.	2681.	11112.	76.59
GLENDIVE CT #2			43.000	8547.	9.717	52.35	196.65	16333.	810.	425.	17568.	89.34
COMBUST. TURB.43	2015		43.000	8984.	9.717	37.29	140.08	12229.	491.	1193.	13913.	99.32
COMBUST. TURB.43	2015		43.000	9006.	9.717	29.52	110.88	9704.	389.	1193.	11286.	101.78
COMBUST. TURB.43	2018		43.000	9029.	9.717	22.60	84.90	7449.	298.	1193.	8940.	105.29
COMBUST. TURB.43	2022		43.000	9052.	9.717	16.58	62.27	5477.	218.	1193.	6888.	110.62
COMBUST. TURB.43	2025		43.000	9076.	9.717	11.63	43.69	3853.	153.	1193.	5199.	119.01
COMBUST. TURB.43	2028		43.000	9102.	9.717	7.92	29.74	2630.	104.	1193.	3927.	132.07
COMBUST. TURB.75	2015		88.000	11276.	9.717	4.53	34.84	3817.	122.	1864.	5804.	166.59
GLENDIVE CT #1			42.000	11965.	9.717	1.60	5.88	683.	24.	242.	950.	161.62
MILES CITY C.T.			30.000	13842.	9.717	1.07	2.79	376.	12.	551.	939.	335.93
DSM	2015	D	12.500	1.	0.000	0.98	1.07	0.	320.	626.	945.	887.22
DSM	2015	D	12.500	1.	0.000	0.74	0.81	0.	244.	626.	869.	1069.85
GLENDIVE DISEL			2.000	11000.	74.829	0.32	0.06	45.	0.	10.	56.	1006.07

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	369.	798.	1167.	11.36
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	240.	442.	682.	10.21
MISO - Off peak			30.000	10500.	0.000	93.95	246.23	0.	15357.	0.	15357.	62.37
MISO - On peak			30.000	10500.	0.000	88.29	231.40	0.	19921.	0.	19921.	86.09
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	351.	439.	790.	20.32
COYOTE		MUST	106.800	11225.	2.755	82.58	770.50	23832.	3563.	4278.	31673.	41.11
LEWIS & CLARK			52.300	12680.	2.076	82.47	376.78	9916.	1783.	4492.	16191.	42.97
HESKETT #2		MUST	74.600	13530.	3.405	76.74	500.11	23039.	7560.	6947.	37546.	75.08
BIG STONE UP	2015	MUST	105.900	10542.	5.148	73.97	684.30	37136.	3719.	5312.	46167.	67.47
HESKETT #1			29.200	15791.	3.116	59.81	152.57	7506.	1697.	2762.	11966.	78.43
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	436.	0.	436.	30.41
GLENDIVE CT #2			43.000	8537.	10.058	55.95	210.19	18047.	892.	437.	19376.	92.18
COMBUST. TURB.43	2015		43.000	8966.	10.058	41.96	157.63	14213.	569.	1229.	16011.	101.58
COMBUST. TURB.43	2015		43.000	8989.	10.058	34.86	130.97	11841.	473.	1229.	13543.	103.40
COMBUST. TURB.43	2018		43.000	9012.	10.058	27.67	103.95	9421.	375.	1229.	11025.	106.07
COMBUST. TURB.43	2022		43.000	9030.	10.058	21.05	79.09	7183.	286.	1229.	8698.	109.97
COMBUST. TURB.43	2025		43.000	9055.	10.058	15.36	57.69	5254.	208.	1229.	6691.	115.98
COMBUST. TURB.43	2028		43.000	9080.	10.058	10.70	40.20	3671.	145.	1229.	5045.	125.50
COMBUST. TURB.75	2015		88.000	11227.	10.058	6.52	50.14	5661.	181.	1920.	7762.	154.82
GLENDIVE CT #1			42.000	11950.	10.058	2.39	8.76	1052.	37.	250.	1339.	152.93
DSM	2015	D	12.500	1.	0.000	1.52	1.66	0.	499.	626.	1125.	675.87
MILES CITY C.T.			30.000	13836.	10.058	1.51	3.96	551.	17.	568.	1135.	286.88
DSM	2015	D	12.500	1.	0.000	1.16	1.26	0.	379.	626.	1005.	794.94
GLENDIVE DISEL			2.000	11000.	80.067	0.46	0.08	71.	1.	10.	82.	1012.50

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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.
2011	505.8	2745.10	545.4	7.83	701.5	29.86	0.003418	651.9	3.45	0.13
2012	522.7	2849.70	550.4	5.30	706.5	30.26	0.003464	656.9	3.82	0.13
2013	543.3	3000.60	565.4	4.07	721.5	5.51	0.000631	671.9	0.41	0.01
2014	552.3	3059.00	580.4	5.09	736.5	5.66	0.000648	686.9	0.49	0.02
2015	568.3	3157.69	612.6	8.16	781.0	14.86	0.001701	715.8	1.49	0.05
2016	577.2	3212.89	612.6	6.41	781.0	10.08	0.001153	715.8	1.05	0.03
2017	586.0	3267.29	612.6	4.74	781.0	13.64	0.001562	715.8	1.48	0.05
2018	594.9	3322.59	646.0	8.97	820.8	9.26	0.001060	751.8	1.10	0.03
2019	604.0	3378.79	646.0	7.26	820.8	9.41	0.001077	751.8	1.17	0.03
2020	613.0	3433.59	646.0	5.61	920.8	13.33	0.001526	851.8	1.53	0.04
2021	622.1	3489.38	646.0	4.00	920.8	16.52	0.001891	851.8	2.10	0.06
2022	631.4	3545.98	679.4	7.92	960.7	8.96	0.001026	887.8	1.11	0.03
2023	640.8	3603.58	679.4	6.27	960.7	7.85	0.000899	887.8	1.00	0.03
2024	650.4	3661.98	679.4	4.64	960.7	10.93	0.001251	887.8	1.45	0.04
2025	660.2	3721.48	712.8	8.28	1000.6	13.20	0.001511	923.8	1.83	0.05
2026	669.9	3781.88	712.8	6.65	900.6	13.93	0.001594	823.8	1.82	0.05
2027	679.8	3843.28	712.8	5.04	900.6	18.76	0.002147	823.8	2.56	0.07
2028	689.8	3905.68	746.2	8.48	940.5	14.02	0.001605	859.8	2.05	0.05
2029	700.2	3969.27	746.2	6.81	940.5	14.30	0.001637	859.8	2.15	0.05
2030	710.8	4033.77	746.2	5.16	940.5	24.05	0.002752	859.8	3.48	0.09
EXT.	710.8	4033.77	746.2	5.16	940.5	24.05	0.002752	859.8	3.48	0.09

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.
2011	505.8	0.0	0.0	505.8	545.4	0.0	0.0	545.4	7.83
2012	522.7	0.0	0.0	522.7	550.4	0.0	0.0	550.4	5.30
2013	543.3	0.0	0.0	543.3	565.4	0.0	0.0	565.4	4.07
2014	552.3	0.0	0.0	552.3	580.4	0.0	0.0	580.4	5.09
2015	568.3	0.0	-25.0	543.3	587.6	0.0	0.0	587.6	8.16
2016	577.2	0.0	-25.0	552.2	587.6	0.0	0.0	587.6	6.41
2017	586.0	0.0	-25.0	561.0	587.6	0.0	0.0	587.6	4.74
2018	594.9	0.0	-25.0	569.9	621.0	0.0	0.0	621.0	8.97
2019	604.0	0.0	-25.0	579.0	621.0	0.0	0.0	621.0	7.26
2020	613.0	0.0	-25.0	588.0	621.0	0.0	0.0	621.0	5.61
2021	622.1	0.0	-25.0	597.1	621.0	0.0	0.0	621.0	4.00
2022	631.4	0.0	-25.0	606.4	654.4	0.0	0.0	654.4	7.92
2023	640.8	0.0	-25.0	615.8	654.4	0.0	0.0	654.4	6.27
2024	650.4	0.0	-25.0	625.4	654.4	0.0	0.0	654.4	4.64
2025	660.2	0.0	-25.0	635.2	687.8	0.0	0.0	687.8	8.28
2026	669.9	0.0	-25.0	644.9	687.8	0.0	0.0	687.8	6.65
2027	679.8	0.0	-25.0	654.8	687.8	0.0	0.0	687.8	5.04
2028	689.8	0.0	-25.0	664.8	721.2	0.0	0.0	721.2	8.48
2029	700.2	0.0	-25.0	675.2	721.2	0.0	0.0	721.2	6.81
2030	710.8	0.0	-25.0	685.8	721.2	0.0	0.0	721.2	5.16
EXT.	710.8	0.0	-25.0	685.8	721.2	0.0	0.0	721.2	5.16

PLAN 1

YEAR	FIXED CHARGES	OPERATING COSTS	TOTAL SYSTEM COST	OTHER ELECTRIC REVENUES	SALES GWH	SYSTEM AVERAGE RATE $/MWH	SYSTEM AVERAGE RATE PERCENT INCREASE 1 YEAR
2011	18207.	72721.	90928.	0.	2745.10	33.124	
2012	18207.	82430.	100637.	0.	2849.70	35.315	6.616
2013	18207.	90733.	108940.	0.	3000.60	36.306	2.807
2014	18207.	99157.	117364.	0.	3059.00	38.367	5.676
2015	50018.	109117.	159134.	0.	3156.03	50.422	31.421
2016	50018.	112184.	162202.	0.	3211.75	50.503	0.159
2017	50018.	119809.	169827.	0.	3265.81	52.001	2.968
2018	55361.	128988.	184349.	0.	3321.42	55.503	6.734
2019	55361.	134999.	190359.	0.	3377.61	56.359	1.542
2020	55361.	151153.	206514.	0.	3432.04	60.172	6.766
2021	55361.	161727.	217088.	0.	3487.46	62.248	3.450
2022	61374.	171124.	232498.	0.	3544.89	65.587	5.364
2023	61374.	176762.	238136.	0.	3602.60	66.101	0.784
2024	61374.	188890.	250264.	0.	3660.61	68.367	3.427
2025	67946.	204151.	272097.	0.	3719.74	73.149	6.996
2026	67946.	214475.	282421.	0.	3780.18	74.711	2.135
2027	67946.	229017.	296963.	0.	3841.02	77.313	3.483
2028	65222.	245820.	311042.	0.	3903.84	79.676	3.056
2029	65222.	256963.	322185.	0.	3967.40	81.208	1.923
2030	58784.	275550.	334334.	0.	4030.84	82.944	2.137
TOTAL	1021513.	3225770.	4247283.				
PRESENT VALUE REVENUE REQUIREMENTS (THOUSANDS OF 2010 DOLLARS)	489454.	1515447.	2004901.				

LEVELIZED SYSTEM AVERAGE RATE = 54.265 $/MWH

PERCENT INCREASE IN SYSTEM AVERAGE RATE

MINIMUM	0.159
MAXIMUM	31.421
COMPOUND AVERAGE	4.950

NOTE - ALL COSTS ARE IN THOUSANDS OF CURRENT YEAR DOLLARS EXCEPT PRESENT VALUE TOTALS.
- ** INDICATES CONSTRAINT WAS NOT SATISFIED.

Appendix C

EGEAS OUTPUT DATA FOR THE BASE CASE WITH “NEW DSM PACKAGE”

```
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.
2011 Integrated Resource Planning Study
Base Case Run with DSM
-- Data updated for the 2011 IRP

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3412 HILL VIEW 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	2011	1	0		4/26/11	10:58:13	2011 IRP	900
EXPANSION PLAN	2011	1	0	1	4/26/11	10:58:15	2011 IRP	900
SUBPERIOD REPORT	2011	1	0	1	4/26/11	10:58:15	2011 IRP	900
UNIT REPORT	2011	1	0	1	4/26/11	10:58:15	2011 IRP	900

```
ELECTRIC POWER RESEARCH INSTITUTE                    2011 IRP                                   4/26/11    11:18:27
--------------------------------------------------------------------------------------------------------------------
EGEAS   REPORT   VERSION 9.02                                     MIRROR IMAGE REPORT                           PAGE   2
********************************************************************************************************************

                      REC. REF SEQ                                                                              ASSIGNED
RECORD DESCRIPTION  C TYPE NO. NO.                            DATA FIELDS                                       REC. NO.
------------------  - ---- --- ---   ---------------------------------------------------------------------      --------
       RECORD COLS               1            2         3         4         5         6         7          8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890

** COMMENT **       *               Montana-Dakota Utilities Co.                                                    1
                    *               2011 Integrated Resource Planning Study                                         2
                    *               Base Case Run with DSM                                                          3
                    *                 -- Data updated for the 2011 IRP                                              4
                    *                                                                                               5
                    *               CONTROL RECORD                                                                  6
                    *                SbUnUcc                                                                        7
                    *                                                                                               8
                    *                          C M E S  F                                                           9
                    *                          T I R E  I                                                          10
                    *                          L R R L  L        DESCRIPTIVE INFORMATION                           11
                    *                          + - + -  +        ------------------------------                    12

CONTROL RECORD        RCC                      1 1 3 1  0        2011 IRP                                          13

** COMMENT **       *                                                                                              14
                    *               --INPUT FILES---                                                               15
                    *               NAME     V U RUN                                                               16
                    *               --------++--++++                                                               17

FILE IDENTIFICATION   RFF           2011     1 0   1                                                               18

** COMMENT **       *                                                                                              19
                    *               == PLAN SELECTION ==                                                           20
                    *                  PLANS C O   C E M                                                         21
                    *               DR  1  L P M   S N O                    --AREAS TO INCLUDE--                   22
                    *                -+++--- + -   + - +                    --++--++--++--++--++                   23

PLAN SELECTION        RRA            1  1  1 0 1   3 2 0                                                           24

** COMMENT **       *                                                                                              25
                    *               == TIME PERIODS ==                                                             26
                    *               --YEARS-- -SG- -SW-                                                            27
                    *                1ST LAST  1 L 1 L                                                             28
                    *               ---- ++++ --++ - +                                                             29

TIME PERIOD           RRB           2011 2030  113 1 3                                                             30

** COMMENT **       *                                                                                              31
                    *               == REPORT SELECTION ==                                                         32
                    *                    -PROD-  MNT -STORAGE--   -FL -EM-    -ECON INT- -COST-                    33
                    *                S S S  UOBRRSU DOSPD  -PJ-    SU SSU GCf TSTU  CUT  UCTCA                     34
                    *                Y U YAFNRLEEYN EPWRS C 1 L    YN YIN E+m RYIN  OFF  NOOOS                     35
                    *                S M SRLTDKLSST TRKDP E 1 L    ST STT NRt NSET  PCT. TNTVT                     36
                    *                - + -+-+-+-+-+ +-+-+ -++--    +- +-+ -+- +-+-++++++ -+-+-                     37

       RECORD COLS               1            2         3         4         5         6         7          8
                    1 2345 678 90   123456789012345678901234567890123456789012345678901234567890123456789012  34567890
```

```
                     REC. REF SEQ                                                                     ASSIGNED
RECORD DESCRIPTION C TYPE NO. NO.                         DATA FIELDS                                 REC. NO.
------------------ - ---- --- ---  ------------------------------------------------------------------- --------
       RECORD COLS                1          2         3         4         5         6         7         8
                   1 2345 678 90  1234567890123456789012345678901234567890123456789012  34567890

REPORT SELECTION     RRC           1 2 1011101100 00000 0        00 000 001 00000.0000 00100                  38

** COMMENT **      *                                                                                        39
```

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

```
RRA     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

RRB     FIRST YEAR = 2011          FIRST SEGMENT =  1     FIRST SUBWEEK =  1
        LAST  YEAR = 2030          LAST  SEGMENT = 13     LAST  SUBWEEK =  3

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

        EXPANSION PLAN SUMMARY         =  2 - YES, WITH RESERVE CAPACITY

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

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

        COST ANALYSIS REPORTS
           UNIT OUTLAYS                =  0 - NO
           CONSTRUCTION COST           =  0 - NO
           TOTAL COST                  =  1 - YES
           INTEREST COVERAGE           =  0 - NO
           EARNING ASSETS              =  0 - NO
```

PLAN 1

NEW UNITS ADDED

YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2011	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0	0.	0.	0.
2012	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0	0.	0.	0.
2013	0.	0.	0.	0.	0.	0.	0.	0.	0.	1	0	0	0.	0.	0.
2014	0.	0.	0.	0.	0.	0.	0.	0.	1+	1	0	0	0.	0.	0.
2015	0	0.	1+	0	0	2+	2+	0.	0+	0.	0	0	0	0	0
2016	0	0.	0+	0	0	0	0+	0.	0+	0.	0	0	0	0	0
2017	0	0.	0+	0	0	0	0+	0	0+	0.	0	0	0	0	0
2018	0	0.	0+	0	0	0	0+	0	0+	0.	0	0	0	0	0
2019	0	0.	0+	0	0	0	0+	0	0+	0.	0	0	0	0	0
2020	0	4	0+	0	0	0	0+	0	0+	0.	0	0	0	0	0
2021	0	0	0+	0	1	0	0+	0	0+	0.	0	0	0	0	0
2022	0	0	0+	0	0	0	0+	0	0+	0.	0	0	0	0	0
2023	0	0	0+	0	0	0	0+	0	0+	0.	0	0	0	0	0
2024	0	0	0+	0	1	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	1	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

TOTAL COST, M$

--W/O EXT 1981.422

--WITH EXT 3615.709

UNIT TYPES

1	PA 8	WIND ENERGY1	25.000 MW	2	PA 9	WIND ENERGY2	25.000 MW	3	PA 11	BIG STONE UP	105.900 MW
4	PA 2	CC-140	140.000 MW	5	PA 6	COMBUST. TURB.43	43.000 MW	6	PA 1	COMBUST. TURB.75	88.000 MW
7	PA 10	DSM	12.500 MW	8	PA 5	GENERIC BASELOAD	30.000 MW	9	PA 12	NEW DSM	8.700 MW
10	PA 7	PURCHASE POWER	10.000 MW	11	PA 4	WIND	30.000 MW	12	PA 3	WIND 2012	30.000 MW
13	PA 13	C-5	155.000 MW	14	PA 14	C-10	155.000 MW	15	PA 15	C-20	345.000 MW

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2010.
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
2011	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00
2012	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00
2013	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	1.00
2014	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	1.00 +	1.00
2015	0.00	0.00 .	1.00 +	0.00	0.00	2.00 +	2.00 +	0.00 .	0.00 +	0.00 .
2016	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00 .	0.00 +	0.00 .
2017	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2018	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2019	0.00	0.00 .	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2020	0.00	4.00	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2021	0.00	0.00	0.00 +	0.00	1.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2022	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2023	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00 +	0.00	0.00 +	0.00 .
2024	0.00	0.00	0.00 +	0.00	1.00	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	1.00	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 .
TOTAL	0.00	4.00	1.00	0.00	3.00	2.00	2.00	0.00	1.00	2.00

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

UNIT TYPES

1	PA 8	WIND ENERGY1	25.000	MW
2	PA 9	WIND ENERGY2	25.000	MW
3	PA 11	BIG STONE UP	105.900	MW
4	PA 2	CC-140	140.000	MW
5	PA 6	COMBUST. TURB.43	43.000	MW
6	PA 1	COMBUST. TURB.75	88.000	MW
7	PA 10	DSM	12.500	MW
8	PA 5	GENERIC BASELOAD	30.000	MW
9	PA 12	NEW DSM	8.700	MW
10	PA 7	PURCHASE POWER	10.000	MW

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14	15
2011	0.00 .	0.00	0.00 .	0.00 .	0.00 .
2012	0.00 .	0.00	0.00 .	0.00 .	0.00 .
2013	0.00	0.00	0.00 .	0.00 .	0.00 .
2014	0.00	0.00	0.00 .	0.00 .	0.00 .
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00
TOTAL	0.00	0.00	0.00	0.00	0.00

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

11 PA 4 WIND	30.000 MW	12 PA 3 WIND 2012	30.000 MW	13 PA 13 C-5	155.000 MW
14 PA 14 C-10	155.000 MW	15 PA 15 C-20	345.000 MW		

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2011	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.000
2014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	8.700	10.000
2015	0.000	0.000	105.900	0.000	0.000	176.000	25.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	43.000	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	43.000	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	43.000	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
TOTAL	0.000	100.000	105.900	0.000	129.000	176.000	25.000	0.000	8.700	20.000

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1	PA	8	WIND ENERGY1	25.000 MW
2	PA	9	WIND ENERGY2	25.000 MW
3	PA	11	BIG STONE UP	105.900 MW
4	PA	2	CC-140	140.000 MW
5	PA	6	COMBUST. TURB.43	43.000 MW
6	PA	1	COMBUST. TURB.75	88.000 MW
7	PA	10	DSM	12.500 MW
8	PA	5	GENERIC BASELOAD	30.000 MW
9	PA	12	NEW DSM	8.700 MW
10	PA	7	PURCHASE POWER	10.000 MW

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14	15
2011	0.000	0.000	0.000	0.000	0.000
2012	0.000	0.000	0.000	0.000	0.000
2013	0.000	0.000	0.000	0.000	0.000
2014	0.000	0.000	0.000	0.000	0.000
2015	0.000	0.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000	0.000
2017	0.000	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000

UNIT TYPES

11 PA 4 WIND	30.000 MW	12 PA 3 WIND 2012	30.000 MW	13 PA 13 C-5	155.000 MW
14 PA 14 C-10	155.000 MW	15 PA 15 C-20	345.000 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	500.5	2571.57				715.3	550.3	9.95	1.0000		
2011	511.7	2747.20	0.0	10.0	5.0	710.3	545.3	6.57	8.6182	0.000	0.000
2012	527.0	2853.50	110.0	105.0	0.0	715.3	550.3	4.43	8.5215	0.000	0.000
2013	542.0	3002.09	10.0	0.0	5.0	730.3	565.3	4.30	49.4626	0.000	0.000
2014	552.3	3058.99	18.7	10.0	5.0	744.0	579.0	4.92	45.4555	0.000	0.000
2015	568.3	3157.69	306.9	237.8	0.0	813.1	636.7	12.80	32.4540	285.945	0.000
2016	577.2	3212.89	0.0	0.0	0.0	813.1	636.7	10.95	48.6656	0.000	0.000
2017	586.0	3267.29	0.0	0.0	0.0	813.1	636.7	9.18	35.0347	0.000	0.000
2018	594.9	3322.59	0.0	0.0	0.0	813.1	636.7	7.45	25.3025	0.000	0.000
2019	604.0	3378.78	0.0	0.0	0.0	813.1	636.7	5.74	24.9841	0.000	0.000
2020	613.0	3433.58	100.0	0.0	0.0	913.1	636.7	4.09	17.9495	0.000	0.000
2021	622.1	3489.38	43.0	0.0	0.0	956.1	670.1	8.16	29.0591	50.594	0.000
2022	631.4	3545.98	0.0	0.0	0.0	956.1	670.1	6.48	26.6913	0.000	0.000
2023	640.8	3603.58	0.0	0.0	0.0	956.1	670.1	4.83	30.4786	0.000	0.000
2024	650.4	3661.98	43.0	0.0	0.0	999.1	703.5	8.61	45.2209	55.285	0.000
2025	660.2	3721.48	0.0	0.0	0.0	999.1	703.5	6.91	18.2493	0.000	0.000
2026	669.9	3781.87	0.0	100.0	0.0	899.1	703.5	5.28	17.2368	0.000	0.000
2027	679.8	3843.27	43.0	0.0	0.0	942.1	736.9	8.84	25.6528	60.412	0.000
2028	689.8	3905.67	0.0	0.0	0.0	942.1	736.9	7.18	17.1780	0.000	0.000
2029	700.2	3969.27	0.0	0.0	0.0	942.1	736.9	5.51	16.8747	0.000	0.000
2030	710.8	4033.77	0.0	0.0	0.0	942.1	736.9	3.86	10.1332	0.000	0.000

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	..........COST SUMMARY.......... ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2011	72.835	18.207	91.042	91.042	85.301	85.301
2012	82.596	18.207	100.803	191.845	88.491	173.793
2013	90.794	18.207	109.001	300.847	89.655	263.448
2014	99.154	18.207	117.361	418.208	90.444	353.891
2015	110.224	50.328	160.552	578.760	115.927	469.818
2016	113.051	50.328	163.378	742.138	110.529	580.346
2017	120.761	50.328	171.088	913.226	108.446	688.793
2018	130.038	50.328	180.366	1093.592	107.118	795.911
2019	135.977	50.328	186.304	1279.896	103.668	899.578
2020	152.282	50.328	202.610	1482.506	105.632	1005.210
2021	162.199	56.166	218.365	1700.871	106.667	1111.878
2022	170.997	56.166	227.163	1928.034	103.968	1215.846
2023	176.077	56.166	232.243	2160.276	99.590	1315.436
2024	187.869	62.546	250.415	2410.692	100.612	1416.048
2025	202.531	62.546	265.077	2675.768	99.787	1515.835
2026	212.119	62.546	274.665	2950.433	96.877	1612.711
2027	225.499	69.517	295.017	3245.450	97.494	1710.205
2028	241.394	59.613	301.007	3546.457	93.201	1803.406
2029	251.513	59.613	311.126	3857.582	90.259	1893.665
2030	269.683	53.175	322.858	4180.440	87.757	1981.422
EXT.	1416.324	217.963			1634.287	3615.709

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 2010.

PLAN 1

	ENERGY, GWH							
	GENERATION	DUMP	CHARGING	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	UNMET	TOTAL
2011	2743.79	0.00	0.00	0.00	0.00	0.00	3.41	2747.20
2012	2849.68	0.00	0.00	0.00	0.00	0.00	3.81	2853.50
2013	3001.69	0.00	0.00	0.00	0.00	0.00	0.40	3002.09
2014	3058.48	0.00	0.00	0.00	0.00	0.00	0.51	3058.99
2015	3156.90	0.00	0.00	0.00	0.00	0.00	0.79	3157.69
2016	3212.33	0.00	0.00	0.00	0.00	0.00	0.56	3212.89
2017	3266.46	0.00	0.00	0.00	0.00	0.00	0.82	3267.29
2018	3321.35	0.00	0.00	0.00	0.00	0.00	1.24	3322.59
2019	3377.49	0.00	0.00	0.00	0.00	0.00	1.30	3378.78
2020	3431.91	0.00	0.00	0.00	0.00	0.00	1.67	3433.58
2021	3488.19	0.00	0.00	0.00	0.00	0.00	1.19	3489.38
2022	3544.77	0.00	0.00	0.00	0.00	0.00	1.21	3545.98
2023	3602.49	0.00	0.00	0.00	0.00	0.00	1.08	3603.58
2024	3661.16	0.00	0.00	0.00	0.00	0.00	0.81	3661.98
2025	3719.49	0.00	0.00	0.00	0.00	0.00	1.98	3721.48
2026	3779.89	0.00	0.00	0.00	0.00	0.00	1.98	3781.87
2027	3841.80	0.00	0.00	0.00	0.00	0.00	1.47	3843.27
2028	3903.46	0.00	0.00	0.00	0.00	0.00	2.22	3905.67
2029	3966.93	0.00	0.00	0.00	0.00	0.00	2.34	3969.27
2030	4030.02	0.00	0.00	0.00	0.00	0.00	3.75	4033.77
EXT.	4030.02	0.00	0.00	0.00	0.00	0.00	3.75	4033.77

NOTE - GENERATION INCLUDES CHARGING OF STORAGE UNITS (IF ANY).

PLAN 1

	COST, M$									
	FUEL	VARIABLE O+M	FIXED O+M	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	EMISSION COST	ALLOWANCES CREDIT	UNMET ENERGY	TOTAL
2011	45.066	10.788	16.525	0.000	0.000	0.000	0.000	0.000	0.456	72.835
2012	50.374	12.790	18.906	0.000	0.000	0.000	0.000	0.000	0.526	82.596
2013	55.942	14.832	19.963	0.000	0.000	0.000	0.000	0.000	0.057	90.794
2014	59.607	18.473	20.999	0.000	0.000	0.000	0.000	0.000	0.075	99.154
2015	67.808	20.986	21.311	0.000	0.000	0.000	0.000	0.000	0.119	110.224
2016	69.849	21.215	21.900	0.000	0.000	0.000	0.000	0.000	0.087	113.051
2017	74.864	23.209	22.556	0.000	0.000	0.000	0.000	0.000	0.132	120.761
2018	81.339	25.365	23.131	0.000	0.000	0.000	0.000	0.000	0.204	130.038
2019	85.252	26.731	23.774	0.000	0.000	0.000	0.000	0.000	0.220	135.977
2020	84.567	42.286	25.137	0.000	0.000	0.000	0.000	0.000	0.292	152.282
2021	85.242	49.432	27.311	0.000	0.000	0.000	0.000	0.000	0.214	162.199
2022	91.887	50.894	27.992	0.000	0.000	0.000	0.000	0.000	0.224	170.997
2023	96.716	50.409	28.746	0.000	0.000	0.000	0.000	0.000	0.207	176.077
2024	104.152	53.007	30.550	0.000	0.000	0.000	0.000	0.000	0.160	187.869
2025	122.618	48.781	30.730	0.000	0.000	0.000	0.000	0.000	0.402	202.531
2026	137.003	43.668	31.035	0.000	0.000	0.000	0.000	0.000	0.413	212.119
2027	146.546	45.598	33.040	0.000	0.000	0.000	0.000	0.000	0.316	225.499
2028	159.127	47.796	33.980	0.000	0.000	0.000	0.000	0.000	0.491	241.394
2029	166.240	49.741	34.999	0.000	0.000	0.000	0.000	0.000	0.532	251.513
2030	180.769	52.087	35.947	0.000	0.000	0.000	0.000	0.000	0.880	269.683
EXT.	982.163	255.922	173.907	0.000	0.000	0.000	0.000	0.000	4.332	1416.324

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1

YEAR	......TOTAL SYSTEM..... ENERGY, GWH	COST, M$	..FUEL CLASS - COAL.. ENERGY, GWH	COST, M$	..FUEL CLASS - PURC.. ENERGY, GWH	COST, M$	..FUEL CLASS - GAS .. ENERGY, GWH	COST, M$
2011	2743.79	72.379	2179.87	61.240	305.21	10.305	74.77	4.798
2012	2849.68	82.070	2244.62	66.032	336.13	13.928	85.00	6.034
2013	3001.69	90.737	2380.35	72.406	348.28	15.752	89.13	6.463
2014	3058.48	99.079	2358.96	74.998	395.88	19.217	119.71	8.707
2015	3156.90	110.106	2268.80	76.927	446.80	16.492	257.37	20.487
2016	3212.33	112.963	2410.46	84.267	424.40	16.160	193.53	16.292
2017	3266.46	120.629	2423.34	88.178	438.69	17.576	220.50	18.586
2018	3321.35	129.834	2394.56	90.748	461.61	19.481	281.25	23.478
2019	3377.49	135.757	2466.77	96.100	456.75	20.087	270.04	23.396
2020	3431.91	151.990	2323.14	93.763	641.26	31.174	283.58	25.352
2021	3488.19	161.985	2237.75	94.338	772.91	38.888	293.59	27.007
2022	3544.77	170.773	2260.15	99.327	783.59	39.895	317.10	29.747
2023	3602.49	175.870	2400.42	107.991	738.03	38.280	280.10	27.741
2024	3661.16	187.709	2366.45	111.438	767.12	40.170	343.66	34.187
2025	3719.49	202.129	2347.57	113.413	641.23	33.938	546.75	52.806
2026	3779.89	211.706	2532.68	126.842	498.91	26.746	564.37	56.087
2027	3841.81	225.183	2520.91	131.631	509.95	27.842	627.01	63.619
2028	3903.46	240.902	2465.07	133.968	528.02	29.565	726.43	75.215
2029	3966.94	250.980	2546.47	142.416	527.73	30.250	708.79	76.095
2030	4030.02	268.803	2468.41	142.596	538.33	31.802	839.35	92.119
EXT.	4030.02	1411.991	2468.41	768.425	538.33	152.706	839.35	479.606

YEAR	..FUEL CLASS - HYDR.. ENERGY, GWH	COST, M$	..FUEL CLASS - WIND.. ENERGY, GWH	COST, M$
2011	14.33	0.249	169.61	-4.212
2012	14.33	0.256	169.61	-4.180
2013	14.33	0.264	169.61	-4.147
2014	14.33	0.272	169.61	-4.114
2015	14.33	0.280	169.61	-4.080
2016	14.33	0.288	169.61	-4.044
2017	14.33	0.297	169.61	-4.007
2018	14.33	0.306	169.61	-4.179
2019	14.33	0.315	169.61	-4.141
2020	14.33	0.324	169.61	1.376
2021	14.33	0.334	169.61	1.418
2022	14.33	0.344	169.61	1.460
2023	14.33	0.354	169.61	1.504
2024	14.33	0.365	169.61	1.549
2025	14.33	0.376	169.61	1.596
2026	14.33	0.387	169.61	1.643
2027	14.33	0.399	169.61	1.693
2028	14.33	0.411	169.61	1.744
2029	14.33	0.423	169.61	1.796
2030	14.33	0.436	169.61	1.850
EXT.	14.33	2.146	169.61	9.108

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2010.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1 YEAR 2011 * 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	39.22	102.79	0.	-2899.	455.	-2444.	-23.77
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2021.	252.	-1769.	-26.47
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	264.	250.	515.	13.24
COYOTE		MUST	106.800	11226.	1.320	82.56	770.32	11414.	2031.	2440.	15885.	20.62
BIG STONE		MUST	107.800	10377.	2.030	72.92	686.73	14467.	1004.	2422.	17893.	26.06
MISO-Off peak			30.000	10500.	0.000	70.48	184.72	0.	4559.	0.	4559.	24.68
LEWIS & CLARK			52.300	12741.	1.370	65.05	297.23	5188.	802.	2561.	8552.	28.77
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	249.	0.	249.	17.35
HESKETT #2		MUST	74.600	13759.	1.720	56.10	365.60	8652.	2892.	3962.	15506.	42.41
MISO-On Peak			30.000	10500.	0.000	27.17	71.21	0.	2442.	0.	2442.	34.30
HESKETT #1			29.200	15883.	1.520	23.52	60.00	1448.	381.	1575.	3404.	56.74
GLENDIVE CT #2			43.000	8700.	5.010	11.29	42.41	1849.	103.	249.	2201.	51.89
GLENDIVE CT #1			42.000	11955.	5.010	5.98	21.96	1315.	53.	142.	1511.	68.80
MILES CITY C.T.			30.000	13857.	5.010	3.94	10.33	717.	25.	324.	1066.	103.18
XCEL ENERGY PK 2			105.000	1.	0.000	1.13	10.39	0.	902.	1886.	2789.	268.38
GLENDIVE DISEL			2.000	11000.	21.470	0.35	0.06	14.	0.	6.	20.	333.64

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2012 * 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	39.22	102.79	0.	-2892.	469.	-2423.	-23.57
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2017.	260.	-1757.	-26.30
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	268.	258.	526.	13.53
BIG STONE		MUST	107.800	10412.	2.180	80.82	761.08	17274.	1147.	2494.	20915.	27.48
LEWIS & CLARK			52.300	12688.	1.389	80.26	366.69	6465.	1019.	2638.	10122.	27.60
MISO-Off peak			30.000	10500.	0.000	77.52	203.16	0.	5264.	0.	5264.	25.91
COYOTE		MUST	106.800	11225.	1.420	74.32	693.45	11054.	1883.	2513.	15450.	22.28
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	256.	0.	256.	17.87
HESKETT #2		MUST	74.600	13715.	1.800	54.40	354.54	8752.	2889.	4081.	15722.	44.34
MISO-On Peak			30.000	10500.	0.000	31.38	82.23	0.	2962.	0.	2962.	36.02
HESKETT #1			29.200	15884.	1.600	26.99	68.86	1750.	450.	1622.	3822.	55.51
GLENDIVE CT #2			43.000	8703.	5.750	12.84	48.25	2414.	120.	257.	2791.	57.86
GLENDIVE CT #1			42.000	11952.	5.750	6.84	25.09	1724.	63.	147.	1933.	77.06
MILES CITY C.T.			30.000	13852.	5.750	4.42	11.59	923.	29.	334.	1286.	110.92
WE ENERGIES			110.000	1.	0.000	1.23	11.85	0.	1348.	3828.	5176.	436.92
GLENDIVE DISEL			2.000	11000.	23.110	0.40	0.07	18.	0.	6.	24.	343.49

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2013 * 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	39.22	102.79	0.	-2885.	483.	-2402.	-23.37
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2012.	268.	-1745.	-26.12
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	272.	316.	588.	15.12
BIG STONE		MUST	107.800	10405.	2.390	82.85	780.22	19402.	1211.	2569.	23181.	29.71
COYOTE		MUST	106.800	11225.	1.450	82.58	770.50	12541.	2155.	2588.	17285.	22.43
LEWIS & CLARK			52.300	12688.	1.438	80.28	366.79	6692.	1050.	2717.	10460.	28.52
MISO-Off peak			30.000	10500.	0.000	79.87	209.31	0.	5695.	0.	5695.	27.21
HESKETT #2		MUST	74.600	13706.	1.860	60.18	392.17	9998.	3291.	4203.	17492.	44.60
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	264.	0.	264.	18.40
MISO-On Peak			30.000	10500.	0.000	31.85	83.47	0.	3157.	0.	3157.	37.82
HESKETT #1			29.200	15885.	1.640	27.70	70.67	1841.	476.	1671.	3988.	56.43
GLENDIVE CT #2			43.000	8695.	5.900	13.32	50.02	2566.	128.	265.	2959.	59.16
GLENDIVE CT #1			42.000	11933.	5.900	7.16	26.27	1850.	67.	151.	2068.	78.72
MILES CITY C.T.			30.000	13853.	5.900	4.89	12.81	1047.	33.	344.	1424.	111.11
WE ENERGIES			115.000	1.	0.000	1.63	16.42	0.	1908.	4002.	5910.	360.02
PURCHASE POWER	2013		10.000	1.	0.000	0.21	0.18	0.	22.	380.	402.	2233.58
GLENDIVE DISEL			2.000	11000.	25.360	0.11	0.02	5.	0.	6.	11.	602.48

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2014 * 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	39.22	102.79	0.	-2878.	497.	-2381.	-23.16
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2008.	276.	-1733.	-25.93
MISO-Off peak			30.000	10500.	0.000	85.58	224.29	0.	6408.	0.	6408.	28.57
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	277.	274.	550.	14.15
BIG STONE		MUST	107.800	10381.	2.560	82.64	778.24	20682.	1244.	2646.	24572.	31.57
LEWIS & CLARK			52.300	12681.	1.457	80.76	368.98	6819.	1088.	2799.	10707.	29.02
COYOTE		MUST	106.800	11225.	1.440	75.98	708.86	11458.	2042.	2666.	16167.	22.81
HESKETT #2		MUST	74.600	13717.	1.880	59.28	386.33	9963.	3648.	4329.	17940.	46.44
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	272.	0.	272.	18.95
HESKETT #1			29.200	15841.	1.670	45.69	116.54	3083.	808.	1721.	5612.	48.16
MISO-On Peak			30.000	10500.	0.000	40.55	106.27	0.	4220.	0.	4220.	39.71
GLENDIVE CT #2			43.000	8687.	6.090	17.56	65.97	3490.	174.	272.	3937.	59.68
GLENDIVE CT #1			42.000	11919.	6.090	9.77	35.85	2602.	95.	156.	2852.	79.57
MILES CITY C.T.			30.000	13811.	6.090	6.82	17.87	1503.	47.	354.	1904.	106.56
WE ENERGIES			120.000	1.	0.000	2.45	25.65	0.	2988.	4176.	7164.	279.31
NEW DSM	2014	DHYDR	8.700	1.	0.000	0.75	0.57	0.	22.	435.	457.	801.16
PURCHASE POWER	2014		10.000	1.	0.000	0.24	0.21	0.	26.	392.	418.	1980.50
GLENDIVE DISEL			2.000	11000.	27.150	0.14	0.02	7.	0.	6.	14.	552.18

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2015 * 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	39.22	102.79	0.	-2872.	512.	-2360.	-22.96
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2004.	284.	-1720.	-25.74
MISO-Off peak			30.000	10500.	0.000	97.67	255.97	0.	7679.	0.	7679.	30.00
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	281.	282.	563.	14.47
COYOTE		MUST	106.800	11225.	1.530	82.58	770.50	13233.	2287.	2746.	18266.	23.71
LEWIS & CLARK			52.300	12684.	1.487	80.55	368.03	6939.	1118.	2883.	10940.	29.73
HESKETT #2		MUST	74.600	13651.	1.960	64.47	420.14	11241.	4077.	4459.	19777.	47.07
BIG STONE UP	2015	MUST	105.900	10542.	2.660	63.23	584.96	16403.	2040.	3410.	21853.	37.36
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	280.	0.	280.	19.52
MISO-On Peak			30.000	10500.	0.000	57.32	150.24	0.	6263.	0.	6263.	41.69
HESKETT #1			29.200	15811.	1.730	49.07	125.18	3424.	894.	1773.	6091.	48.66
GLENDIVE CT #2			43.000	8628.	6.320	29.05	109.12	5950.	297.	281.	6528.	59.82
COMBUST. TURB.75	2015		88.000	11237.	6.320	14.62	112.38	7981.	261.	1232.	9474.	84.30
COMBUST. TURB.75	2015		88.000	11431.	6.320	3.95	30.39	2196.	70.	1232.	3499.	115.11
GLENDIVE CT #1			42.000	12045.	6.320	1.05	3.86	294.	11.	160.	465.	120.30
NEW DSM	2014	DHYDR	8.700	1.	0.000	1.05	0.80	0.	30.	435.	465.	582.16
MILES CITY C.T.			30.000	13958.	6.320	0.60	1.58	140.	4.	364.	509.	321.05
DSM	2015	D	12.500	1.	0.000	0.48	0.52	0.	157.	626.	783.	1492.60
DSM	2015	D	12.500	1.	0.000	0.34	0.38	0.	113.	626.	738.	1963.75
GLENDIVE DISEL			2.000	11000.	29.020	0.12	0.02	7.	0.	6.	13.	622.85

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2016 * 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	39.22	102.79	0.	-2865.	528.	-2337.	-22.74
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1999.	292.	-1707.	-25.54
MISO-Off peak			30.000	10500.	0.000	97.64	255.89	0.	8060.	0.	8060.	31.50
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	285.	290.	575.	14.79
COYOTE		MUST	106.800	11225.	1.591	82.58	770.50	13763.	2355.	2828.	18946.	24.59
BIG STONE UP	2015	MUST	105.900	10542.	2.780	81.17	750.96	22006.	2698.	3512.	28216.	37.57
LEWIS & CLARK			52.300	12684.	1.520	80.52	367.90	7093.	1151.	2969.	11214.	30.48
HESKETT #2		MUST	74.600	13678.	2.033	62.26	405.77	11286.	4055.	4593.	19934.	49.13
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	288.	0.	288.	20.11
MISO-On Peak			30.000	10500.	0.000	48.85	128.04	0.	5605.	0.	5605.	43.78
HESKETT #1			29.200	15821.	1.799	45.21	115.33	3283.	848.	1826.	5957.	51.65
GLENDIVE CT #2			43.000	8660.	6.300	22.50	84.50	4610.	237.	289.	5136.	60.78
COMBUST. TURB.75	2015		88.000	11275.	6.300	10.84	83.36	5922.	199.	1269.	7390.	88.65
COMBUST. TURB.75	2015		88.000	11458.	6.300	2.85	21.93	1583.	52.	1269.	2905.	132.44
NEW DSM	2014	DHYDR	8.700	1.	0.000	1.22	0.93	0.	35.	435.	470.	506.94
GLENDIVE CT #1			42.000	12208.	6.300	0.72	2.65	204.	7.	165.	377.	141.86
MILES CITY C.T.			30.000	13900.	6.300	0.40	1.05	92.	3.	375.	471.	446.22
DSM	2015	D	12.500	1.	0.000	0.35	0.38	0.	115.	626.	740.	1936.51
DSM	2015	D	12.500	1.	0.000	0.25	0.28	0.	83.	626.	708.	2571.75
GLENDIVE DISEL			2.000	11000.	31.051	0.11	0.02	7.	0.	7.	13.	682.70

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2017 * 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	39.22	102.79	0.	-2858.	543.	-2314.	-22.51
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1994.	301.	-1693.	-25.34
MISO-Off peak			30.000	10500.	0.000	98.89	259.18	0.	8574.	0.	8574.	33.08
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	289.	349.	638.	16.41
BIG STONE UP	2015	MUST	105.900	10542.	2.905	82.86	766.55	23474.	2837.	3617.	29928.	39.04
COYOTE		MUST	106.800	11225.	1.655	82.58	770.50	14313.	2426.	2913.	19652.	25.51
LEWIS & CLARK			52.300	12681.	1.554	74.17	338.87	6679.	1092.	3059.	10829.	31.96
HESKETT #2		MUST	74.600	13656.	2.110	64.19	418.36	12053.	4307.	4731.	21090.	50.41
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	297.	0.	297.	20.71
MISO-On Peak			30.000	10500.	0.000	52.92	138.68	0.	6375.	0.	6375.	45.97
HESKETT #1			29.200	15818.	1.871	50.60	129.07	3820.	978.	1881.	6679.	51.75
GLENDIVE CT #2			43.000	8652.	6.460	24.85	93.34	5217.	270.	298.	5785.	61.97
COMBUST. TURB.75	2015		88.000	11228.	6.460	12.42	95.51	6927.	235.	1307.	8470.	88.68
COMBUST. TURB.75	2015		88.000	11427.	6.460	3.49	26.84	1981.	66.	1307.	3355.	124.99
NEW DSM	2014	DHYDR	8.700	1.	0.000	1.39	1.05	0.	40.	435.	475.	450.78
GLENDIVE CT #1			42.000	12109.	6.460	0.93	3.41	267.	10.	170.	447.	130.90
MILES CITY C.T.			30.000	13881.	6.460	0.52	1.36	122.	4.	387.	513.	376.00
DSM	2015	D	12.500	1.	0.000	0.46	0.50	0.	151.	626.	777.	1541.81
DSM	2015	D	12.500	1.	0.000	0.34	0.37	0.	111.	626.	737.	1982.97
GLENDIVE DISEL			2.000	11000.	33.225	0.16	0.03	10.	0.	7.	17.	619.81

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
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PLAN 1 YEAR 2018 * 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	39.22	102.79	0.	-3060.	560.	-2500.	-24.32
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1989.	310.	-1679.	-25.13
MISO-Off peak			30.000	10500.	0.000	99.21	260.00	0.	9030.	0.	9030.	34.73
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	294.	308.	602.	15.47
BIG STONE UP	2015	MUST	105.900	10542.	3.035	83.57	773.18	24742.	2947.	3726.	31415.	40.63
LEWIS & CLARK			52.300	12680.	1.589	80.82	369.25	7441.	1226.	3150.	11817.	32.00
COYOTE		MUST	106.800	11225.	1.721	75.98	708.86	13695.	2299.	3001.	18994.	26.80
HESKETT #2		MUST	74.600	13626.	2.189	62.70	408.64	12188.	4333.	4872.	21393.	52.35
MISO-On Peak			30.000	10500.	0.000	61.15	160.25	0.	7735.	0.	7735.	48.27
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	306.	0.	306.	21.33
HESKETT #1			29.200	15810.	1.946	52.78	134.63	4142.	1051.	1937.	7130.	52.96
GLENDIVE CT #2			43.000	8638.	6.660	30.48	114.49	6586.	341.	307.	7234.	63.19
COMBUST. TURB.75	2015		88.000	11177.	6.660	15.85	121.84	9069.	309.	1347.	10725.	88.02
COMBUST. TURB.75	2015		88.000	11359.	6.660	4.85	37.25	2818.	94.	1347.	4259.	114.34
NEW DSM	2014	DHYDR	8.700	1.	0.000	1.56	1.18	0.	45.	435.	480.	406.00
GLENDIVE CT #1			42.000	12078.	6.660	1.48	5.42	436.	16.	175.	627.	115.73
MILES CITY C.T.			30.000	14024.	6.660	0.85	2.22	207.	7.	398.	612.	275.89
DSM	2015	D	12.500	1.	0.000	0.67	0.74	0.	221.	626.	847.	1148.88
DSM	2015	D	12.500	1.	0.000	0.50	0.54	0.	162.	626.	788.	1457.08
GLENDIVE DISEL			2.000	11000.	35.551	0.21	0.04	15.	0.	7.	22.	582.93

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2019

* 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	39.22	102.79	0.	-3053.	577.	-2476.	-24.09
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-1984.	320.	-1665.	-24.92
MISO-Off peak			30.000	10500.	0.000	99.01	259.48	0.	9461.	0.	9461.	36.46
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	298.	317.	615.	15.82
BIG STONE UP	2015	MUST	105.900	10542.	3.172	83.37	771.27	25791.	3028.	3838.	32657.	42.34
COYOTE		MUST	106.800	11225.	1.790	82.58	770.50	15481.	2574.	3091.	21145.	27.44
LEWIS & CLARK			52.300	12680.	1.625	79.15	361.62	7451.	1236.	3245.	11932.	33.00
HESKETT #2		MUST	74.600	13633.	2.271	66.26	431.85	13370.	4716.	5019.	23105.	53.50
MISO-On Peak			30.000	10500.	0.000	59.44	155.79	0.	7895.	0.	7895.	50.68
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	315.	0.	315.	21.97
HESKETT #1			29.200	15810.	2.024	51.56	131.52	4208.	1057.	1995.	7261.	55.20
GLENDIVE CT #2			43.000	8636.	6.870	29.22	109.78	6513.	337.	316.	7166.	65.27
COMBUST. TURB.75	2015		88.000	11179.	6.870	15.26	117.28	9007.	306.	1387.	10701.	91.24
COMBUST. TURB.75	2015		88.000	11359.	6.870	4.67	35.88	2800.	94.	1387.	4280.	119.31
NEW DSM	2014	DHYDR	8.700	1.	0.000	1.73	1.31	0.	50.	435.	485.	369.49
GLENDIVE CT #1			42.000	12106.	6.870	1.37	5.03	419.	15.	180.	614.	122.06
MILES CITY C.T.			30.000	13946.	6.870	0.77	2.03	194.	6.	410.	611.	301.39
DSM	2015	D	12.500	1.	0.000	0.67	0.73	0.	218.	626.	844.	1160.44
DSM	2015	D	12.500	1.	0.000	0.49	0.54	0.	162.	626.	788.	1457.65
GLENDIVE DISEL			2.000	11000.	38.039	0.23	0.04	17.	0.	7.	25.	599.37

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2020 * 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	39.22	102.79	0.	275.	594.	869.	8.45
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	179.	329.	508.	7.60
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
WIND ENERGY2	2020	NDT	25.000	0.	0.000	23.07	50.39	0.	2570.	175.	2745.	54.47
MISO-Off peak			30.000	10500.	0.000	96.79	253.67	0.	9713.	0.	9713.	38.29
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	303.	327.	629.	16.18
COYOTE		MUST	106.800	11225.	1.861	82.58	770.47	16100.	2651.	3184.	21934.	28.47
LEWIS & CLARK			52.300	12686.	1.662	81.89	374.16	7886.	1317.	3342.	12546.	33.53
BIG STONE UP	2015	MUST	105.900	10542.	3.315	69.37	641.77	22427.	2595.	3953.	28974.	45.15
HESKETT #2		MUST	74.600	13665.	2.356	63.22	411.99	13264.	4634.	5169.	23068.	55.99
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	324.	0.	324.	22.63
MISO-On Peak			30.000	10500.	0.000	54.96	144.04	0.	7613.	0.	7613.	52.85
HESKETT #1			29.200	15818.	2.105	48.90	124.74	4153.	1033.	2055.	7241.	58.05
GLENDIVE CT #2			43.000	8615.	7.130	28.44	106.84	6563.	337.	325.	7226.	67.63
COMBUST. TURB.75	2015		88.000	11115.	7.130	16.45	126.44	10020.	340.	1429.	11789.	93.23
COMBUST. TURB.75	2015		88.000	11309.	7.130	5.38	41.33	3333.	111.	1429.	4873.	117.88
NEW DSM	2014	DHYDR	8.700	1.	0.000	1.89	1.44	0.	55.	435.	490.	340.19
GLENDIVE CT #1			42.000	11988.	7.130	1.73	6.35	543.	20.	186.	748.	117.88
MILES CITY C.T.			30.000	14031.	7.130	0.98	2.56	256.	8.	423.	687.	267.99
DSM	2015	D	12.500	1.	0.000	0.88	0.96	0.	288.	626.	913.	952.35
DSM	2015	D	12.500	1.	0.000	0.65	0.71	0.	212.	626.	837.	1186.79
GLENDIVE DISEL			2.000	11000.	40.702	0.29	0.05	22.	0.	7.	30.	602.26

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2021

* 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	39.22	102.79	0.	283.	612.	895.	8.70
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	184.	339.	523.	7.83
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
MISO-Off peak			30.000	10500.	0.000	93.53	245.13	0.	9855.	0.	9855.	40.20
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	307.	387.	694.	17.83
COYOTE		MUST	106.800	11228.	1.936	82.36	768.40	16703.	2723.	3279.	22704.	29.55
LEWIS & CLARK			52.300	12691.	1.699	72.50	331.24	7142.	1201.	3442.	11786.	35.58
BIG STONE UP	2015	MUST	105.900	10542.	3.464	67.08	620.55	22661.	2585.	4071.	29317.	47.24
HESKETT #2		MUST	74.600	13683.	2.444	61.54	401.08	13416.	4647.	5324.	23387.	58.31
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	334.	0.	334.	23.31
MISO-On Peak			30.000	10500.	0.000	52.20	136.80	0.	7230.	0.	7230.	52.85
HESKETT #1			29.200	15821.	2.189	45.67	116.49	4034.	993.	2117.	7144.	61.33
GLENDIVE CT #2			43.000	8600.	7.380	27.74	104.19	6612.	339.	335.	7287.	69.94
COMBUST. TURB.43	2021		43.000	9046.	7.380	17.50	65.75	4389.	182.	942.	5513.	83.85
COMBUST. TURB.75	2015		88.000	11143.	7.380	11.60	89.19	7334.	247.	1471.	9053.	101.50
COMBUST. TURB.75	2015		88.000	11322.	7.380	3.70	28.41	2374.	79.	1471.	3924.	138.12
NEW DSM	2014	DHYDR	8.700	1.	0.000	2.06	1.57	0.	60.	435.	495.	315.30
GLENDIVE CT #1			42.000	12015.	7.380	1.15	4.21	374.	14.	191.	579.	137.31
MILES CITY C.T.			30.000	13910.	7.380	0.69	1.80	184.	6.	435.	625.	348.18
DSM	2015	D	12.500	1.	0.000	0.61	0.66	0.	199.	626.	824.	1243.87
DSM	2015	D	12.500	1.	0.000	0.45	0.49	0.	147.	626.	773.	1575.84
GLENDIVE DISEL			2.000	11000.	43.551	0.22	0.04	19.	0.	8.	27.	680.70

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

PLAN 1 YEAR 2022 * 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	39.22	102.79	0.	292.	630.	922.	8.97
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	189.	349.	539.	8.06
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
MISO-Off peak			30.000	10500.	0.000	94.25	247.01	0.	10427.	0.	10427.	42.21
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	312.	347.	658.	16.93
LEWIS & CLARK			52.300	12691.	1.737	79.12	361.47	7969.	1350.	3546.	12865.	35.59
BIG STONE UP	2015	MUST	105.900	10542.	3.620	77.31	715.18	27292.	3068.	4193.	34553.	48.31
COYOTE		MUST	106.800	11228.	2.013	74.13	691.66	15636.	2525.	3377.	21538.	31.14
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	344.	0.	344.	24.01
HESKETT #2		MUST	74.600	13668.	2.536	57.52	374.86	12994.	4473.	5484.	22952.	61.23
MISO-On Peak			30.000	10500.	0.000	55.50	145.45	0.	7687.	0.	7687.	52.85
HESKETT #1			29.200	15817.	2.277	45.85	116.97	4212.	1027.	2180.	7419.	63.43
GLENDIVE CT #2			43.000	8595.	7.638	29.90	112.34	7375.	376.	345.	8096.	72.07
COMBUST. TURB.43	2021		43.000	9042.	7.638	19.00	71.38	4929.	204.	970.	6103.	85.50
COMBUST. TURB.75	2015		88.000	11143.	7.638	12.62	97.00	8255.	277.	1516.	10048.	103.58
COMBUST. TURB.75	2015		88.000	11332.	7.638	3.96	30.48	2638.	87.	1516.	4241.	139.13
NEW DSM	2014	DHYDR	8.700	1.	0.000	2.24	1.70	0.	65.	435.	500.	293.89
GLENDIVE CT #1			42.000	12195.	7.638	1.12	4.10	382.	14.	197.	593.	144.56
MILES CITY C.T.			30.000	13861.	7.638	0.68	1.77	188.	6.	448.	642.	361.91
DSM	2015	D	12.500	1.	0.000	0.62	0.68	0.	204.	626.	829.	1219.87
DSM	2015	D	12.500	1.	0.000	0.46	0.50	0.	150.	626.	776.	1549.11
GLENDIVE DISEL			2.000	11000.	46.600	0.19	0.03	17.	0.	8.	25.	757.96

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PLAN 1 YEAR 2023 * 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	39.22	102.79	0.	300.	649.	949.	9.23
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	195.	360.	555.	8.30
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	316.	357.	674.	17.32
COYOTE		MUST	106.800	11228.	2.094	82.38	768.65	18071.	2890.	3479.	24439.	31.80
BIG STONE UP	2015	MUST	105.900	10542.	3.783	81.64	755.31	30120.	3337.	4319.	37777.	50.02
MISO-Off peak			30.000	10500.	0.000	81.22	212.87	0.	9436.	0.	9436.	44.33
LEWIS & CLARK			52.300	12692.	1.776	78.89	360.43	8126.	1387.	3652.	13164.	36.52
HESKETT #2		MUST	74.600	13650.	2.631	64.40	419.67	15073.	5158.	5649.	25880.	61.67
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	354.	0.	354.	24.73
MISO-On Peak			30.000	10500.	0.000	51.14	134.02	0.	7083.	0.	7083.	52.85
HESKETT #1			29.200	15832.	2.368	37.78	96.37	3612.	872.	2246.	6730.	69.83
GLENDIVE CT #2			43.000	8603.	7.905	27.15	101.97	6935.	352.	356.	7642.	74.95
COMBUST. TURB.43	2021		43.000	9052.	7.905	16.69	62.71	4487.	184.	999.	5670.	90.42
COMBUST. TURB.75	2015		88.000	11156.	7.905	10.91	83.88	7398.	246.	1561.	9205.	109.74
COMBUST. TURB.75	2015		88.000	11332.	7.905	3.41	26.22	2349.	77.	1561.	3987.	152.05
NEW DSM	2014	DHYDR	8.700	1.	0.000	2.41	1.83	0.	70.	435.	505.	275.16
GLENDIVE CT #1			42.000	12088.	7.905	0.99	3.64	348.	13.	203.	563.	154.76
MILES CITY C.T.			30.000	13871.	7.905	0.63	1.65	181.	6.	462.	648.	393.56
DSM	2015	D	12.500	1.	0.000	0.55	0.60	0.	181.	626.	807.	1335.64
DSM	2015	D	12.500	1.	0.000	0.41	0.45	0.	134.	626.	759.	1700.47
GLENDIVE DISEL			2.000	11000.	49.862	0.17	0.03	16.	0.	8.	24.	831.80

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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	39.22	102.79	0.	309.	668.	978.	9.51
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	201.	370.	571.	8.55
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
WIND ENERGY2	2020	NDT	25.000	0.	0.000	39.99	87.34	0.	4454.	300.	4754.	54.44
MISO-Off peak			30.000	10500.	0.000	85.65	224.47	0.	10447.	0.	10447.	46.54
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	321.	368.	689.	17.71
BIG STONE UP	2015	MUST	105.900	10542.	3.953	81.41	753.12	31384.	3428.	4449.	39261.	52.13
LEWIS & CLARK			52.300	12688.	1.816	79.68	364.06	8389.	1443.	3762.	13594.	37.34
COYOTE		MUST	106.800	11227.	2.178	75.87	707.91	17307.	2741.	3583.	23631.	33.38
HESKETT #2		MUST	74.600	13624.	2.730	66.81	435.41	16194.	5512.	5818.	27524.	63.21
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	365.	0.	365.	25.47
MISO-On Peak			30.000	10500.	0.000	57.85	151.61	0.	8013.	0.	8013.	52.85
HESKETT #1			29.200	15825.	2.462	41.54	105.95	4128.	987.	2313.	7429.	70.11
GLENDIVE CT #2			43.000	8591.	8.182	31.71	119.13	8374.	423.	366.	9163.	76.92
COMBUST. TURB.43	2021		43.000	9037.	8.182	20.14	75.64	5593.	229.	1029.	6851.	90.57
COMBUST. TURB.43	2024		43.000	9065.	8.182	14.42	54.16	4017.	164.	1029.	5210.	96.19
COMBUST. TURB.75	2015		88.000	11189.	8.182	9.11	70.05	6413.	212.	1608.	8232.	117.53
COMBUST. TURB.75	2015		88.000	11392.	8.182	2.69	20.67	1926.	63.	1608.	3597.	174.03
NEW DSM	2014	DHYDR	8.700	1.	0.000	2.59	1.97	0.	75.	435.	510.	258.88
GLENDIVE CT #1			42.000	11997.	8.182	0.75	2.74	269.	10.	209.	488.	177.99
MILES CITY C.T.			30.000	13875.	8.182	0.48	1.26	143.	4.	476.	623.	495.50
DSM	2015	D	12.500	1.	0.000	0.43	0.47	0.	140.	626.	765.	1640.55
DSM	2015	D	12.500	1.	0.000	0.31	0.34	0.	103.	626.	728.	2125.11
GLENDIVE DISEL			2.000	11000.	53.352	0.14	0.03	15.	0.	8.	23.	923.43

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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	39.22	102.79	0.	319.	688.	1007.	9.80
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	207.	382.	589.	8.81
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
WIND ENERGY2	2020	NDT	25.000	0.	0.000	17.69	38.63	0.	1970.	125.	2095.	54.24
MISO-Off peak			30.000	10500.	0.000	94.17	246.80	0.	12061.	0.	12061.	48.87
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	326.	429.	755.	19.41
COYOTE		MUST	106.800	11225.	2.265	82.58	770.50	19588.	3073.	3691.	26352.	34.20
LEWIS & CLARK			52.300	12682.	1.857	80.66	368.55	8680.	1504.	3874.	14059.	38.15
MISO-On Peak			30.000	10500.	0.000	75.18	197.03	0.	10413.	0.	10413.	52.85
HESKETT #2		MUST	74.600	13577.	2.832	71.57	466.40	17935.	6082.	5993.	30009.	64.34
BIG STONE UP	2015	MUST	105.900	10542.	4.131	66.60	616.14	26832.	2888.	4582.	34302.	55.67
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	376.	0.	376.	26.24
HESKETT #1			29.200	15807.	2.561	49.39	125.98	5099.	1209.	2382.	8691.	68.99
GLENDIVE CT #2			43.000	8562.	8.468	44.42	166.86	12098.	611.	377.	13086.	78.43
COMBUST. TURB.43	2021		43.000	9004.	8.468	30.11	113.10	8624.	352.	1060.	10036.	88.73
COMBUST. TURB.43	2024		43.000	9034.	8.468	22.96	86.25	6598.	269.	1060.	7927.	91.90
COMBUST. TURB.75	2015		88.000	11086.	8.468	16.62	127.74	11992.	398.	1656.	14046.	109.96
COMBUST. TURB.75	2015		88.000	11282.	8.468	5.68	43.70	4175.	136.	1656.	5967.	136.56
NEW DSM	2014	DHYDR	8.700	1.	0.000	2.77	2.11	0.	80.	435.	515.	244.39
GLENDIVE CT #1			42.000	12008.	8.468	1.66	6.10	620.	22.	215.	858.	140.63
MILES CITY C.T.			30.000	13975.	8.468	1.13	2.96	350.	11.	490.	851.	287.51
DSM	2015	D	12.500	1.	0.000	0.99	1.08	0.	323.	626.	948.	881.49
DSM	2015	D	12.500	1.	0.000	0.73	0.80	0.	239.	626.	865.	1083.92
GLENDIVE DISEL			2.000	11000.	57.087	0.24	0.04	26.	0.	9.	35.	843.05

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	328.	709.	1037.	10.09
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	213.	393.	606.	9.07
MISO-Off peak			30.000	10500.	0.000	96.14	251.97	0.	12929.	0.	12929.	51.31
BIG STONE UP	2015	MUST	105.900	10542.	4.317	85.77	793.47	36109.	3831.	4720.	44660.	56.28
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	331.	390.	721.	18.54
COYOTE		MUST	106.800	11225.	2.355	82.58	770.50	20372.	3165.	3801.	27338.	35.48
LEWIS & CLARK			52.300	12680.	1.899	80.82	369.25	8891.	1552.	3991.	14434.	39.09
MISO-On Peak			30.000	10500.	0.000	77.83	203.98	0.	10780.	0.	10780.	52.85
HESKETT #2		MUST	74.600	13566.	2.938	72.76	474.21	18904.	6369.	6172.	31446.	66.31
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	387.	0.	387.	27.02
HESKETT #1			29.200	15806.	2.663	49.10	125.24	5272.	1238.	2454.	8964.	71.57
GLENDIVE CT #2			43.000	8565.	8.765	45.94	172.59	12955.	651.	388.	13995.	81.09
COMBUST. TURB.43	2021		43.000	9003.	8.765	31.67	118.98	9388.	382.	1092.	10861.	91.29
COMBUST. TURB.43	2024		43.000	9027.	8.765	24.25	91.11	7208.	292.	1092.	8592.	94.31
COMBUST. TURB.75	2015		88.000	11101.	8.765	16.82	129.34	12584.	415.	1706.	14705.	113.69
COMBUST. TURB.75	2015		88.000	11295.	8.765	5.62	43.20	4277.	139.	1706.	6121.	141.70
NEW DSM	2014	DHYDR	8.700	1.	0.000	2.96	2.25	0.	85.	435.	520.	231.51
GLENDIVE CT #1			42.000	12103.	8.765	1.73	6.36	675.	24.	222.	921.	144.70
MILES CITY C.T.			30.000	13851.	8.765	1.05	2.75	333.	10.	505.	848.	308.90
DSM	2015	D	12.500	1.	0.000	0.95	1.04	0.	311.	626.	936.	903.52
DSM	2015	D	12.500	1.	0.000	0.71	0.78	0.	233.	626.	859.	1105.24
GLENDIVE DISEL			2.000	11000.	61.083	0.29	0.05	34.	0.	9.	44.	851.26

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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	39.22	102.79	0.	338.	730.	1068.	10.39
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	220.	405.	624.	9.35
MISO-On Peak			30.000	10500.	0.000	97.35	255.13	0.	13484.	0.	13484.	52.85
BIG STONE UP	2015	MUST	105.900	10542.	4.511	86.01	795.73	37841.	3957.	4861.	46660.	58.64
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	336.	402.	738.	18.97
COYOTE		MUST	106.800	11225.	2.450	82.58	770.50	21187.	3260.	3915.	28362.	36.81
MISO-Off peak			30.000	10500.	0.000	80.95	212.15	0.	11430.	0.	11430.	53.88
LEWIS & CLARK			52.300	12680.	1.942	74.22	339.10	8348.	1468.	4110.	13927.	41.07
HESKETT #2		MUST	74.600	13559.	3.049	73.58	479.52	19822.	6634.	6357.	32813.	68.43
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	399.	0.	399.	27.83
HESKETT #1			29.200	15804.	2.770	53.34	136.06	5956.	1385.	2528.	9869.	72.53
GLENDIVE CT #2			43.000	8554.	9.071	48.76	183.17	14214.	711.	400.	15325.	83.67
COMBUST. TURB.43	2021		43.000	8998.	9.071	34.17	128.34	10476.	424.	1124.	12025.	93.69
COMBUST. TURB.43	2024		43.000	9017.	9.071	26.65	100.13	8190.	331.	1124.	9645.	96.33
COMBUST. TURB.43	2027		43.000	9043.	9.071	19.87	74.63	6123.	247.	1124.	7494.	100.41
COMBUST. TURB.75	2015		88.000	11139.	9.071	13.24	101.79	10286.	336.	1757.	12379.	121.61
COMBUST. TURB.75	2015		88.000	11325.	9.071	4.20	32.31	3319.	107.	1757.	5183.	160.42
NEW DSM	2014	DHYDR	8.700	1.	0.000	3.14	2.39	0.	91.	435.	526.	220.00
GLENDIVE CT #1			42.000	12075.	9.071	1.23	4.51	494.	18.	228.	740.	164.03
MILES CITY C.T.			30.000	13854.	9.071	0.80	2.09	263.	8.	520.	791.	378.02
DSM	2015	D	12.500	1.	0.000	0.72	0.79	0.	237.	626.	862.	1092.71
DSM	2015	D	12.500	1.	0.000	0.54	0.59	0.	177.	626.	802.	1362.31
GLENDIVE DISEL			2.000	11000.	65.358	0.22	0.04	28.	0.	9.	37.	962.17

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	348.	752.	1100.	10.70
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	226.	417.	643.	9.63
MISO-On Peak			30.000	10500.	0.000	100.00	262.08	0.	13851.	0.	13851.	52.85
BIG STONE UP	2015	MUST	105.900	10542.	4.714	85.55	791.47	39332.	4054.	5007.	48394.	61.14
MISO-Off peak			30.000	10500.	0.000	84.92	222.55	0.	12590.	0.	12590.	56.57
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	341.	414.	755.	19.41
LEWIS & CLARK			52.300	12680.	1.985	80.82	369.25	9295.	1647.	4234.	15176.	41.10
COYOTE		MUST	106.800	11225.	2.548	75.98	708.86	20272.	3089.	4033.	27394.	38.64
HESKETT #2		MUST	74.600	13550.	3.163	69.83	455.10	19506.	6485.	6548.	32539.	71.50
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	411.	0.	411.	28.67
HESKETT #1			29.200	15801.	2.881	55.04	140.40	6390.	1472.	2603.	10466.	74.55
GLENDIVE CT #2			43.000	8545.	9.389	52.58	197.52	15846.	790.	412.	17049.	86.31
COMBUST. TURB.43	2021		43.000	8979.	9.389	38.24	143.66	12110.	489.	1158.	13757.	95.76
COMBUST. TURB.43	2024		43.000	9004.	9.389	30.70	115.34	9751.	393.	1158.	11302.	97.99
COMBUST. TURB.43	2027		43.000	9026.	9.389	23.58	88.57	7506.	302.	1158.	8966.	101.22
COMBUST. TURB.75	2015		88.000	11084.	9.389	16.55	127.22	13239.	433.	1810.	15481.	121.69
COMBUST. TURB.75	2015		88.000	11266.	9.389	5.76	44.29	4684.	151.	1810.	6645.	150.04
NEW DSM	2014	DHYDR	8.700	1.	0.000	3.34	2.54	0.	96.	435.	531.	209.57
GLENDIVE CT #1			42.000	12025.	9.389	1.87	6.85	774.	27.	235.	1037.	151.22
MILES CITY C.T.			30.000	13846.	9.389	1.12	2.92	380.	12.	535.	927.	317.07
DSM	2015	D	12.500	1.	0.000	1.02	1.12	0.	335.	626.	961.	859.77
DSM	2015	D	12.500	1.	0.000	0.77	0.84	0.	252.	626.	878.	1043.71
GLENDIVE DISEL			2.000	11000.	69.934	0.31	0.05	42.	0.	9.	52.	949.13

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	359.	775.	1133.	11.03
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	233.	429.	663.	9.92
MISO-On Peak			30.000	10500.	0.000	100.00	262.08	0.	13851.	0.	13851.	52.85
MISO-Off peak			30.000	10500.	0.000	84.74	222.08	0.	13192.	0.	13192.	59.40
BIG STONE UP	2015	MUST	105.900	10542.	4.926	84.14	778.44	40426.	4107.	5157.	49690.	63.83
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	346.	476.	822.	21.14
COYOTE		MUST	106.800	11225.	2.649	82.58	770.50	22916.	3459.	4154.	30528.	39.62
LEWIS & CLARK			52.300	12680.	2.030	79.17	361.71	9310.	1662.	4361.	15333.	42.39
HESKETT #2		MUST	74.600	13534.	3.282	76.42	498.01	22118.	7309.	6745.	36172.	72.63
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	423.	0.	423.	29.53
HESKETT #1			29.200	15800.	2.996	54.03	137.82	6523.	1489.	2681.	10693.	77.59
GLENDIVE CT #2			43.000	8547.	9.717	52.35	196.65	16333.	810.	425.	17568.	89.34
COMBUST. TURB.43	2021		43.000	8984.	9.717	37.29	140.08	12229.	491.	1193.	13913.	99.32
COMBUST. TURB.43	2024		43.000	9006.	9.717	29.52	110.88	9704.	389.	1193.	11286.	101.78
COMBUST. TURB.43	2027		43.000	9028.	9.717	22.68	85.21	7476.	299.	1193.	8967.	105.24
COMBUST. TURB.75	2015		88.000	11081.	9.717	15.99	122.90	13235.	431.	1864.	15530.	126.35
COMBUST. TURB.75	2015		88.000	11256.	9.717	5.64	43.39	4745.	152.	1864.	6762.	155.85
NEW DSM	2014	DHYDR	8.700	1.	0.000	3.53	2.68	0.	102.	435.	537.	200.15
GLENDIVE CT #1			42.000	12039.	9.717	1.82	6.66	779.	27.	242.	1049.	157.49
MILES CITY C.T.			30.000	13840.	9.717	1.13	2.96	398.	12.	551.	962.	324.89
DSM	2015	D	12.500	1.	0.000	1.04	1.13	0.	340.	626.	965.	852.27
DSM	2015	D	12.500	1.	0.000	0.79	0.86	0.	258.	626.	883.	1028.12
GLENDIVE DISEL			2.000	11000.	74.829	0.34	0.06	49.	1.	10.	59.	994.27

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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	39.22	102.79	0.	369.	798.	1167.	11.36
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	240.	442.	682.	10.21
MISO-On Peak			30.000	10500.	0.000	100.00	262.08	0.	13851.	0.	13851.	52.85
MISO-Off peak			30.000	10500.	0.000	88.29	231.40	0.	14433.	0.	14433.	62.37
GLEN ULLIN ORMAT		MUST	5.300	1.	0.000	84.01	38.90	0.	351.	439.	790.	20.32
COYOTE		MUST	106.800	11225.	2.755	82.58	770.50	23832.	3563.	4278.	31673.	41.11
LEWIS & CLARK			52.300	12680.	2.076	82.47	376.78	9916.	1783.	4492.	16191.	42.97
HESKETT #2		MUST	74.600	13532.	3.405	76.56	498.94	22988.	7543.	6947.	37478.	75.11
BIG STONE UP	2015	MUST	105.900	10542.	5.148	73.03	675.63	36665.	3672.	5312.	45649.	67.57
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	436.	0.	436.	30.41
HESKETT #1			29.200	15797.	3.116	57.45	146.55	7213.	1630.	2762.	11605.	79.19
GLENDIVE CT #2			43.000	8537.	10.058	55.95	210.19	18047.	892.	437.	19376.	92.18
COMBUST. TURB.43	2021		43.000	8966.	10.058	41.96	157.63	14213.	569.	1229.	16011.	101.58
COMBUST. TURB.43	2024		43.000	8989.	10.058	34.86	130.97	11841.	473.	1229.	13543.	103.40
COMBUST. TURB.43	2027		43.000	9012.	10.058	27.67	103.95	9421.	375.	1229.	11025.	106.07
COMBUST. TURB.75	2015		88.000	11021.	10.058	20.76	159.56	17687.	576.	1920.	20183.	126.49
COMBUST. TURB.75	2015		88.000	11200.	10.058	8.06	61.94	6977.	224.	1920.	9121.	147.26
NEW DSM	2014	DHYDR	8.700	1.	0.000	3.73	2.83	0.	108.	435.	543.	191.61
GLENDIVE CT #1			42.000	11947.	10.058	2.94	10.78	1295.	46.	250.	1590.	147.56
MILES CITY C.T.			30.000	13904.	10.058	1.63	4.26	596.	18.	568.	1182.	277.25
DSM	2015	D	12.500	1.	0.000	1.62	1.77	0.	531.	626.	1156.	653.51
DSM	2015	D	12.500	1.	0.000	1.23	1.35	0.	404.	626.	1029.	764.85
GLENDIVE DISEL			2.000	11000.	80.067	0.50	0.09	76.	1.	10.	87.	1003.82

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2010.

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.
2011	511.7	2747.20	545.3	6.57	701.5	31.20	0.003571	651.9	3.41	0.12
2012	527.0	2853.50	550.3	4.43	706.5	31.55	0.003612	656.9	3.81	0.13
2013	542.0	3002.09	565.3	4.30	721.5	5.44	0.000622	671.9	0.40	0.01
2014	552.3	3058.99	579.0	4.92	735.2	5.92	0.000677	685.6	0.51	0.02
2015	568.3	3157.69	636.7	12.80	791.5	8.28	0.000948	726.2	0.79	0.02
2016	577.2	3212.89	636.7	10.95	791.5	5.53	0.000632	726.2	0.56	0.02
2017	586.0	3267.29	636.7	9.18	791.5	7.67	0.000879	726.2	0.82	0.03
2018	594.9	3322.59	636.7	7.45	791.5	10.63	0.001216	726.2	1.24	0.04
2019	604.0	3378.78	636.7	5.74	791.5	10.76	0.001232	726.2	1.30	0.04
2020	613.0	3433.58	636.7	4.09	891.5	14.98	0.001715	826.2	1.67	0.05
2021	622.1	3489.38	670.1	8.16	931.4	9.25	0.001059	862.2	1.19	0.03
2022	631.4	3545.98	670.1	6.48	931.4	10.07	0.001153	862.2	1.21	0.03
2023	640.8	3603.58	670.1	4.83	931.4	8.82	0.001010	862.2	1.08	0.03
2024	650.4	3661.98	703.5	8.61	971.3	5.95	0.000681	898.2	0.81	0.02
2025	660.2	3721.48	703.5	6.91	971.3	14.73	0.001687	898.2	1.98	0.05
2026	669.9	3781.87	703.5	5.28	871.3	15.60	0.001786	798.2	1.98	0.05
2027	679.8	3843.27	736.9	8.84	911.2	10.48	0.001200	834.2	1.47	0.04
2028	689.8	3905.67	736.9	7.18	911.2	15.65	0.001792	834.2	2.22	0.06
2029	700.2	3969.27	736.9	5.51	911.2	15.93	0.001824	834.2	2.34	0.06
2030	710.8	4033.77	736.9	3.86	911.2	26.53	0.003037	834.2	3.75	0.09
EXT.	710.8	4033.77	736.9	3.86	911.2	26.53	0.003037	834.2	3.75	0.09

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

	LOADS				RESOURCES				RESERVE
YEAR	PEAK LOAD MW	PURCH./SALE CONTRACTS	DEMAND-SIDE MANAGEMENT	NET LOADS MW	CAPACITY MW	RESERVE SHARING	PURCH./SALE CONTRACTS	NET RESOURCES MW	MARGIN PCT.
2011	511.7	0.0	0.0	511.7	545.3	0.0	0.0	545.3	6.57
2012	527.0	0.0	0.0	527.0	550.3	0.0	0.0	550.3	4.43
2013	542.0	0.0	0.0	542.0	565.3	0.0	0.0	565.3	4.30
2014	552.3	0.0	-8.7	543.6	570.3	0.0	0.0	570.3	4.92
2015	568.3	0.0	-33.7	534.6	603.0	0.0	0.0	603.0	12.80
2016	577.2	0.0	-33.7	543.5	603.0	0.0	0.0	603.0	10.95
2017	586.0	0.0	-33.7	552.3	603.0	0.0	0.0	603.0	9.18
2018	594.9	0.0	-33.7	561.2	603.0	0.0	0.0	603.0	7.45
2019	604.0	0.0	-33.7	570.3	603.0	0.0	0.0	603.0	5.74
2020	613.0	0.0	-33.7	579.3	603.0	0.0	0.0	603.0	4.09
2021	622.1	0.0	-33.7	588.4	636.4	0.0	0.0	636.4	8.16
2022	631.4	0.0	-33.7	597.7	636.4	0.0	0.0	636.4	6.48
2023	640.8	0.0	-33.7	607.1	636.4	0.0	0.0	636.4	4.83
2024	650.4	0.0	-33.7	616.7	669.8	0.0	0.0	669.8	8.61
2025	660.2	0.0	-33.7	626.5	669.8	0.0	0.0	669.8	6.91
2026	669.9	0.0	-33.7	636.2	669.8	0.0	0.0	669.8	5.28
2027	679.8	0.0	-33.7	646.1	703.2	0.0	0.0	703.2	8.84
2028	689.8	0.0	-33.7	656.1	703.2	0.0	0.0	703.2	7.18
2029	700.2	0.0	-33.7	666.5	703.2	0.0	0.0	703.2	5.51
2030	710.8	0.0	-33.7	677.1	703.2	0.0	0.0	703.2	3.86
EXT.	710.8	0.0	-33.7	677.1	703.2	0.0	0.0	703.2	3.86

PLAN 1

YEAR	FIXED CHARGES	OPERATING COSTS	TOTAL SYSTEM COST	OTHER ELECTRIC REVENUES	SALES GWH	SYSTEM AVERAGE RATE $/MWH	SYSTEM AVERAGE RATE PERCENT INCREASE 1 YEAR
2011	18207.	72835.	91042.	0.	2747.20	33.140	
2012	18207.	82596.	100803.	0.	2853.50	35.326	6.597
2013	18207.	90794.	109001.	0.	3002.09	36.308	2.781
2014	18207.	99154.	117361.	0.	3058.42	38.373	5.686
2015	50328.	110224.	160552.	0.	3155.99	50.872	32.572
2016	50328.	113051.	163378.	0.	3211.30	50.876	0.007
2017	50328.	120761.	171088.	0.	3265.36	52.395	2.986
2018	50328.	130038.	180366.	0.	3320.13	54.325	3.684
2019	50328.	135977.	186304.	0.	3376.21	55.182	1.577
2020	50328.	152282.	202610.	0.	3430.48	59.062	7.032
2021	56166.	162199.	218365.	0.	3486.66	62.629	6.039
2022	56166.	170997.	227163.	0.	3543.10	64.114	2.372
2023	56166.	176077.	232243.	0.	3600.69	64.500	0.601
2024	62546.	187869.	250415.	0.	3659.20	68.435	6.101
2025	62546.	202531.	265077.	0.	3717.49	71.305	4.195
2026	62546.	212119.	274665.	0.	3777.81	72.705	1.963
2027	69517.	225499.	295017.	0.	3839.51	76.837	5.684
2028	59613.	241394.	301007.	0.	3901.18	77.158	0.417
2029	59613.	251513.	311126.	0.	3964.59	78.476	1.708
2030	53175.	269683.	322858.	0.	4027.82	80.157	2.142
TOTAL	972848.	3207592.	4180440.				
PRESENT VALUE REVENUE REQUIREMENTS (THOUSANDS OF 2010 DOLLARS)	469610.	1511812.	1981422.				

LEVELIZED SYSTEM AVERAGE RATE = 53.700 $/MWH

PERCENT INCREASE IN SYSTEM AVERAGE RATE

MINIMUM	0.007
MAXIMUM	32.572
COMPOUND AVERAGE	4.758

NOTE - ALL COSTS ARE IN THOUSANDS OF CURRENT YEAR DOLLARS EXCEPT PRESENT VALUE TOTALS.
- ** INDICATES CONSTRAINT WAS NOT SATISFIED.

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 are taken.

MONTANA-DAKOTA UTILITIES CO. INTEGRATED RESOURCE PLANNING
2010-2011 PUBLIC ADVISORY GROUP ROSTER

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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:

Andrea Stomberg	Vice President—Electric Supply
Abbie Krebsbach	Environmental Manager
JP Maddock	Electric System Engineer
Alan Welte	Generation Manager

Henry Ford	Electric Transmission Engineering Manager
Ken Callahan	Energy Services Manager
Al Jirges	Measurement Supervisor
Rick Matteson *	Director of Communications and Public Affairs, MDU Resources Group, Inc.

** Invited presenter*

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

August 24, 2010 Meeting Agenda

Overview of the IRP Process	Hoa Nguyen
Montana-Dakota's Existing Generation Mix	Andrea Stomberg
2009 Integrated Resource Plan	Brian Giggee
Pending Carbon and Other Environmental Legislations	Abbie Krebsbach
Resource Expansion Planning Process and Model	Brian Giggee Hoa Nguyen
Montana-Dakota's Outstanding Requests for Proposals	JP Maddock Darcy Neigum
Updates on Demand-Side Management (DSM) Programs	Larry Oswald
Cost Allocations for Regional Expansion Criteria Benefits (RECB)	Darcy Neigum
Workings of the IRP Public Advisory Meeting Logistics Discussion Topics for Future Meetings Meeting Schedule through 2010	Group Discussion

October 20, 2010 Meeting Agenda

North American Power Grid: How It Evolves	Hoa Nguyen
MISO 101 – Midwest ISO Operations	Darcy Neigum
Montana Energy Update, 2010	Jeff Blend
Energy Policy and Stimulus Update for North Dakota	Mike Fladeland Zac Weis
2010 Electric Load Forecast	Kayla Kaul
Supply-Side Option Review and Resource Requirements	Brian Giggee
2011 DSM Approach DSMore versus Existing Model	Larry Oswald
General Discussion Schedule Date for Next Meeting	

December 15, 2010 Meeting Agenda

Updates on Montana-Dakota Activities	Andrea Stomberg
Generation Update	Alan Welte
Transmission Projects Updates	Henry Ford
North Dakota Energy Policy & Stimulus Update	Mike Fladeland
Changes and Forecast for the Williston District	Ken Callahan
After the AMR: It's More than Meter Readings	Alan Jirges
Economic Conditions in North Central South Dakota	Christine Martin-Goldsmith
Montana Energy Overview Updates	Jeff Blend
Supply-Side Analysis and Midwest ISO Resource Adequacy Requirements	Brian Giggee

Demand-Side Management Program Updates	Larry Oswald

Wrap-up
Next Meetings: Wednesday March 16, 2011
Wednesday May 19, 2011

March 17, 2010 Meeting Agenda

Updates on Montana-Dakota's Regulatory Affairs Activities	Tami Aberle
Demand-Side Analysis and Results	Larry Oswald
Integration Analysis and Results	Brian Giggee
Current Energy Legislations in Montana, North Dakota, and South Dakota	Rick Matteson
Two-Year Action Plan	Darcy Neigum
Environmental Considerations	Abbie Krebsbach
Big Stone Air Quality Control System (AQCS)	Alan Welte
Combustion Turbine Site Study	Alan Welte
Wrap-up	Group Discussion

IRP Filing Timeline
Feedback from the PAG Members
Future PAG Membership for 2013 IRP

Attachment E

June 1, 2010 Request for Proposal for Capacity and Energy Supply

Montana-Dakota Utilities Co.

Request for Proposal for Capacity and Energy Supply

June 1, 2010

Table of Contents

1. INTRODUCTION

1.1. Purpose

Montana-Dakota Utilities Co., a Division of MDU Resources Group Inc. ("Montana-Dakota"), is a public utility with retail electric load in parts of North Dakota, South Dakota, Montana, and Wyoming. During the normal course of its business operations, Montana-Dakota routinely evaluates alternatives to fulfill its need to maintain reliable and cost-efficient capacity and energy resources for its customers.

In this Request for Proposal ("RFP"), Montana-Dakota requests competitive proposals ("Proposals") for capacity and energy totaling at least 25 megawatts (MW) and no more than 225 MW for a period of at least five years, with five-year extension options available, beginning power deliveries between June 1, 2015 and May 31, 2020. Persons or entities responding to this RFP are referred to as "Respondents."

1.2. Product Description and Requirements

For reliability purposes, Montana-Dakota is seeking Proposals involving the purchase of capacity and energy resources for a term of at least five years, with five year extension options available, beginning with deliveries to begin between June 1, 2015 and May 31, 2020. To meet Montana-Dakota's summer peak requirements, preference will be given to Proposals that have the ability to be dispatched with load-following capabilities.

All capacity and energy offered in a Proposal must be delivered to Montana-Dakota's Integrated System, which consists of its service territories in North Dakota, South Dakota, and Montana, in order to serve Montana-Dakota retail customers. Bid pricing should reflect the capacity and energy at the designated delivery point and include all costs to deliver the capacity and energy to such delivery point. Proposals must be for generating capacity of at least 25 MW and no more than 225 MW. Montana-Dakota strongly prefers unit-specific Proposals that involve a full unit at a single site for which Montana-Dakota will have full scheduling and dispatch authority. Montana-Dakota also prefers automatic generation control functionality in order to meet its load-following requirements.

Montana-Dakota encourages Respondents to provide Proposals for summer and non-summer capacity and/or energy if the Respondent believes its Proposal can provide an economic benefit to Montana-Dakota customers. For the purpose of this RFP, summer capacity months refer to the period of June through September.

Montana-Dakota will consider all Proposals that meet the aforementioned requirements. Montana-Dakota will evaluate the reliability, cost and customer rate impacts of all Proposals.

No proposed Power Purchase Agreements (PPA) of a term shorter than five years will be considered in this RFP.

If a Proposal involves a generating resource not yet fully operational, in addition to the other requirements outlined in this section, the Respondent must provide Montana-Dakota with sufficient data to establish that the proposed generating resource will achieve the commercial operation date designated in the Proposal, and at that date will be fully capable of producing the capacity and energy stated in the Proposal. The Proposal must provide an overview and detailed description of the proposed generating resource, including status of any and all necessary permits and regulatory approvals, in a separate attachment as part of the Respondent's response package.

Montana-Dakota reserves the right to require additional information not identified in this RFP in order to fully evaluate the costs and impacts of any Proposal.

1.3. Changes to RFP, Schedules, and Addenda

Montana-Dakota reserves the right to unilaterally revise or suspend the schedule, or terminate this RFP process at its sole discretion without liability to any Respondent.

2. BID SUBMITTAL

2.1. General Instructions

Montana-Dakota's Official Contact for this RFP is:

Mr. Hoa Nguyen
Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND 58501
Phone: 701-222-7656
Fax: 701-222-7872
E-mail: hoa.nguyen@mdu.com

Respondents should meet all the terms and conditions of the RFP to be eligible to compete in the RFP process. Respondents should follow all instructions contained in the RFP and submit all relevant documents. It is the Respondent's responsibility to advise the Official Contact of any conflicting requirements, omissions of information, or the need for clarification before Proposals are due. Respondents should clearly organize and identify all information submitted in their Proposals to facilitate review and evaluation. Failure to provide all the information requested in the RFP process or failure to demonstrate that the Proposal satisfies all of the Montana-Dakota requirements will be grounds for disqualification. Prior to the short-listing of Proposals, all correspondence and communications from the Respondent to Montana-Dakota must be made in writing through the Official Contact.

2.2. Respondent's Qualifications

Montana-Dakota will consider Proposals from any qualified Respondent, including electric utilities (e.g., investor-owned, municipal, cooperative, or tribal), independent power producers, qualified developers of generating resources (including renewable resources, distributed generation, and demand-side management (DSM) resources), and power marketers**.**

Each Respondent shall respond fully and accurately to the Statement of Financial Conditions and Creditworthiness Qualifications included in Exhibit A to the RFP. In addition to that information, during the Proposal review process, Montana-Dakota may require each Respondent to provide further credit and financial information in order to assist Montana-Dakota in addressing and weighing the creditworthiness of each Respondent.

Montana-Dakota invites Proposals from all potential suppliers who are capable of meeting the conditions of the RFP, and Montana-Dakota will evaluate all responsive bids.

2.3. RFP Communications

Prior to the proposal submission deadline, all communications should be directed to the Official Contact's e-mail. Based upon the nature and frequency of the questions Montana-Dakota receives, Montana-Dakota will choose to either respond to individuals directly or address the question through the bidder's conference (see Section 2.5).

2.4. Schedule

The following schedule and deadlines apply to this RFP:

ACTIVITY	DATE*
Issue RFP	June 1, 2010
Bidder's Conference	July 8, 2010
Notice of Intent to Bid Due	July 23, 2010
RFP Responses Due	August 20, 2010
Shortlist Notification	October 1, 2010
Selection Process Complete	November 15, 2010

* Dates may be advanced or delayed at Montana-Dakota's sole discretion. The Respondents will be notified if the dates are changed.

2.5. Bidder's Conference

Montana-Dakota currently plans on conducting a bidder's conference for interested Respondents:

Time: 9:00 am Central Time
Date: July 8, 2010
Location: Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND 58501

Prospective Respondents who plan on attending the conference should RSVP to the Official Contact's e-mail. Please provide names, titles, and phone numbers of the individuals who will be attending and a brief description of the Respondent's proposed project if possible. The purpose of the bidder's conference is to allow potential Respondents the opportunity to ask questions and seek clarification about the RFP process. To make the meeting as productive and informative as possible, Respondents are encouraged to submit any questions in writing prior to the conference. Attendance is not required for submitting a Proposal, but the bidder's conference will serve as a forum to clarify any preliminary issues regarding the RFP.

Teleconferencing capabilities will be available be for prospective Respondents that RSVP to the Official Contact's e-mail.

2.6. Notice of Intent to Bid (NOIB)

In order to identify persons or entities interested in submitting a Proposal, and to assure that all those having such an interest receive any subsequent information distributed in the RFP process, interested parties are requested to submit via e-mail or facsimile, a non-binding NOIB by **July 23, 2010**. The form for the NOIB is included in Exhibit B to this RFP.

2.7. Proposal Submittal Fee

A non-refundable fee of one thousand dollars ($1,000.00) per bid per Respondent will be required in order to qualify the Proposal(s) for consideration. The fee should be payable in a check made out to "Montana-Dakota Utilities Co." Proposal submittal fees must be paid by the bid submittal deadline (see Section 2.8.2).

2.8. Proposal Content and Submission Instructions

2.8.1 In addition to the information described elsewhere in this RFP, all Respondents must include as part of their Proposal all relevant information requested in the response package. Proposals that do not contain all required information or do not fully reflect the bid requirements may not be considered at Montana-Dakota's sole discretion. In addition to the required information, the Respondents should include with their Proposals any other information that may be needed for a thorough understanding and evaluation of their Proposals.

2.8.2 Complete Proposals, including all exhibits, must be received by **August 20, 2010** by Montana-Dakota's Official Contact. Montana-Dakota will accept Proposals delivered by the U.S. Postal service, express delivery services, personal hand delivery, or electronic means such as e-mail and facsimile. Electronic submittals must be immediately followed by the hard copy of the original response package. Only sealed Proposals will be accepted. On the envelope, Respondent shall indicate **"***Response to Montana-Dakota RFP re. Capacity and Energy Supply Resources***."**

2.8.3 All Proposal terms, conditions, and pricing should be valid through the completion of the selection process, currently planned for **December 31, 2010**. Any accepted Proposal will become binding in accordance with the executed definitive agreement (Section 4.3) and after the Regulatory Approval Process (Section 4.4).

2.8.4 Respondents will be notified by **October 1, 2010** if their Proposal has been selected for the short-list and subsequent negotiation. Respondents with

Proposals not selected for the short-list will be notified. None of the material received by Montana-Dakota from Respondents in response to this RFP will be returned. All Proposals and exhibits will become the property of Montana-Dakota, subject to the confidentiality provisions of Section 2.9.

2.8.5 Prices and dollar figures must be stated in U.S. Dollars of which the base year must be specified.

2.9. Confidentiality

With each Proposal, Montana-Dakota will require all parties to sign the Confidentiality Agreement, contained in Exhibit C to this RFP. Montana-Dakota will sign and execute the Confidentiality Agreement upon receipt from each Respondent. Montana-Dakota will use commercially reasonable efforts, in a manner consistent with the Confidentiality Agreement, to protect any claimed proprietary and confidential information contained in a Proposal, provided that such information is clearly identified by the Respondent as “PROPRIETARY AND CONFIDENTIAL” on the page on which proprietary and confidential material appears.

2.10. Requirements of the Proposals

2.10.1 Proposals should be provided in the format outlined in Section 2.10. Montana-Dakota requests that all exhibits, documents, schedules, etc. submitted as a part of a proposal be clearly labeled and organized in a fashion that facilitates easy location and review.

2.10.2 All proposals must conform, as applicable, to the requirements in this RFP.

2.10.3 Proposals must be for the sale to, and purchase by Montana-Dakota, of a firm, unit-contingent supply of capacity and energy, and/or system participation capacity and energy. The proposals must identify the resource and location supplying the capacity and any special regulatory status that may be claimed.

2.10.4 A single Respondent may submit more than one proposal.

2.10.5 The pricing, as set forth in Section 2.10.11.5, contained in each proposal shall reflect all present applicable state and federal environmental regulations and requirements. Montana-Dakota reserves the right to estimate the impacts of future environmental regulations on the Proposal. Montana-Dakota will not be responsible for any "stranded costs" that the Respondent may incur, but are not identified in the proposal. Any exit fees must be explicitly stated in the Proposal.

2.10.6 Proposals that rely upon supply resources located outside of the Montana-Dakota system must provide for the delivery of the full capacity amount to Montana-Dakota’s system.

2.10.7 Transmission service that the Respondent acquires for the purpose of delivering said capacity should be Firm, Point-to-Point, or Network service.

Said transmission service shall be continuously reserved for the duration of the capacity transaction. If Firm, Point-to-Point, or Network Transmission service is not obtained prior to the time the Respondent submits his proposal, the burden will be on the Respondent to identify all known fixed and variable cost for delivery to Montana-Dakota's system as well as any known transmission constraints.

2.10.8 The Respondent shall be responsible for the providing and contracting of all transmission related services for delivery to the Montana-Dakota system. At some point during the evaluation process, Montana-Dakota, in its sole discretion, will require a Respondent to demonstrate the ability to acquire transmission services if necessary. If the Respondent is unable or fails to demonstrate such ability to obtain transmission services, or if obtaining such service requires system upgrade or interconnection costs that Montana-Dakota, in its sole discretion, determines to be excessive, Montana-Dakota may terminate further consideration of the Proposal.

2.10.9 Proposals should address any contractual and operational constraints such as cycling, minimum load, minimum run time, minimum down time, start-up fees, etc., that the Respondent intends to impose in his proposal.

2.10.10 Prior to Montana-Dakota signing a power purchase agreement, the Respondent will be required to provide evidence of credit assurance as detailed in Section 2.10.11.9 of this RFP. Montana-Dakota will approve all forms of credit assurance before entering into the agreement.

2.10.11 All Proposals must include the following minimum components in the order provided:

2.10.11.1 "Executive summary" which indicates the highlights and special features of the Proposal including a description of the source for the capacity and energy.

2.10.11.2 Statement from the Respondent which indicates the time period during which the proposal will remain in effect, but no sooner than December 31, 2010.

2.10.11.3 Comprehensive listing and description, including a rationale if warranted, of all contract terms and conditions that the Respondent would seek during contract negotiations.

2.10.11.4 Listing of any economic, operational, or system conditions (including sensitivities to anticipated dispatch levels) that might affect the Respondent's ability to deliver capacity and energy, as proposed. Proposals should address any contractual and operational constraints, such as cycling, minimum load, minimum run time, minimum down time, and start-up fees, that the Respondent intends to impose in its proposal.

2.10.11.5 Information on the cost of the capacity and energy shall be provided including:

2.10.11.5.1 Designated delivery point.

2.10.11.5.2 Firm price bid. The capacity price must be fixed for the time period(s) quoted and the energy price must be either fixed or based on known and measurable indices.

2.10.11.5.3 In addition to a firm price bid, the Respondent may submit alternative non-firm price bids. However, these bids must specifically describe the risks that the Respondent is passing on to Montana-Dakota and its customers.

2.10.11.5.4 The Respondent should specify the basis (i.e., annually, quarterly, monthly, etc.) and type of all payments it expects to receive. In the case of a fully dispatchable generating resource, such payments might include start-up payments ($/start) or spinning and supplemental reserve payments ($/operating hour).

2.10.11.5.5 As applicable, the Proposal should include all formulas that will be used to calculate the full capacity and energy rate, or any other rate that the Respondent may specify, with all its respective components well defined. A sample calculation illustrating the application of each formula is also required.

2.10.11.5.6 The Respondent must provide a printed schedule projecting for each contract year, quarter, or month, as appropriate, depending upon how frequently the Respondent's rate(s) or its respective components will be updated, for the full term of the proposed contract of the following:

a. Full capacity rate and all components ($/kW-month, etc.).
b. Contract capacity amount in MW at the delivery point for which the Respondent is expected to provide its estimated Unforced Capacity (UCAP) amount according to Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO or MISO) definition.
c. Capacity payment ($/month).
d. Total energy rate and all its components ($/MWh).
e. Projected values of any independent variables (e.g., fuel price, heat rates, operating hours, and number of starts) that are to be used in the calculation of payments.

f. Sufficient information to allow Montana-Dakota to replicate this proposed contract term data.
g. Any proposed revisions to the pricing scheme if the Respondent intends to offer a contract extension option.

2.10.11.6 Information on the makeup of the Respondent's Company and its parent organization shall be provided along with the most current annual financial report, most recent audited financial report, and SEC Form 10-K.

2.10.11.7 Site locations of the proposed projects and other drawings that are helpful in describing projects shall be included.

2.10.11.8 The Respondent must certify that any identified generating resource is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.

2.10.11.9 Montana-Dakota requires secure and reliable physical delivery of the capacity and associated energy corresponding to all proposals. Security and reliability of physical delivery will be guaranteed by either (1) contractual credit assurance by a third party, (2) corporation commitment accompanied by an investment level credit rating from a major rating agency, or (3) combinations of 1 and 2. All forms of credit assurance will be approved by Montana-Dakota before entering into a power purchase agreement. (Credit Assurances shall include a letter of credit or performance bonds for an amount equal to the costs associated with one year of the contract or as mutually agreed.)

2.10.11.10 The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit. The Respondent shall provide a description of the resource's ability to comply with all presently applicable and anticipated environmental regulations and requirements and any additional environmental benefits that the resource would, or presently does, afford; a listing of expected emissions (as applicable) and the status of all permit applications; and a listing of any and all potential and known environmental liabilities that may be associated with the project or its site.

2.10.11.11 Montana-Dakota prefers Proposals offering full dispatchability of energy for all hours during the term of the contract. This would permit Montana-Dakota to schedule quantities of energy, from a minimum of zero to a maximum equal to the quantity stated in the Proposal on an hour-by-hour basis. Montana-Dakota prefers to have the option of connecting the proposed generating resources to its automatic generation control system, but dispatchability is not a requirement.

2.10.12 Montana-Dakota encourages Respondents to provide Proposals for summer and non-summer capacity and energy if the Respondent believes its Proposal can provide an economic benefit to Montana-Dakota and its customers. For the purpose of this RFP, summer capacity months refer to the period of June through September.

2.10.13 Proposals for variable capacity resources such as wind, solar, run-of-river hydro, landfill gas, and anaerobic digestion should provide, for each calendar month, a schedule of expected capacity factors, maximum capacity, and hourly capacity (for each hour of the month).

2.10.14 Proposals for DSM resources such as demand-response programs and energy efficiency programs should provide, for each calendar month, a schedule of expected capacity factors, maximum capacity, and hourly capacity (for each hour of the month).

2.10.15 Montana-Dakota will entertain Proposals which contain the provision for an asset sale or option for an asset sale from the Respondent to Montana-Dakota as part of the Respondent's bid.

3. EVALUATION PROCESS

3.1. Proposal Review

3.1.1. Price will be a major factor in Montana-Dakota's evaluation, with due consideration given to dispatchability, operational performance, reliability, deliverability, credit, environmental impacts, contract terms, and other factors. Respondents shall include sufficient detail to evaluate all costs associated with the Proposal(s). To ensure that Proposals will provide customer benefits, Montana-Dakota will compare Proposals with the benefits, including costs and reliability, of alternative resource scenarios. Proposals will also be compared and evaluated in terms of other non-price characteristics; therefore, the lowest price submittal may not necessarily be selected. The evaluation of Proposals will be based on the information provided by the Respondent and available industry information, with special emphasis on Montana-Dakota being able to provide reliable service and maximize the economic value to its customers. Montana-Dakota shall evaluate all Proposals in terms of price and non-price attributes and reject any Proposal that, at Montana-Dakota's sole discretion,

a) Does not meet the minimum requirements set forth in the RFP;

b) Is not economically competitive with other Proposals or resource alternatives;

c) Is submitted by the Respondent who is determined by Montana-Dakota to have insufficient creditworthiness, insufficient financial resources and/or insufficient technical qualifications to provide dependable or reliable service; or

d) Fails to meet the resource and reliability needs of Montana-Dakota.

In order to assess the feasibility and viability of the Proposals, the evaluation will determine the technical, physical and operational capability of the applicable generating resources to meet the operating parameters specified in the Proposal. Such technical analysis will include, but not be limited to, a review of transmission access (including existing transmission contracts), fuel access and transportation (including existing fuel contracts), environmental conditions, certification and permit conditions and/or restrictions, unit location, maintenance history and schedules, and operational flexibility and history.

3.1.2. Montana-Dakota shall evaluate responsive Proposals and select for further review and negotiation a Proposal or Proposals, if any, that Montana-Dakota believes provides the greatest value to its customers. In the event negotiations with a Respondent or Respondents do not produce a final and fully executed contract satisfactory to Montana-Dakota, Montana-Dakota reserves the right to pursue any and all other resource options available to it.

3.1.3. Montana-Dakota intends to compare system impacts of short-listed Proposals against the system impacts from new-build alternatives in determining the appropriate purchases and/or acquisitions for Montana-Dakota’s future capacity and energy needs.

3.1.4. Montana-Dakota reserves the right to accept or reject any or all Proposals for any reason at any time after submittal without explanation to the Respondent, or to make an award at any time to a Respondent who, in the sole opinion and discretion of Montana-Dakota, provides a Proposal Montana-Dakota deems favorable. Montana-Dakota also reserves the right to make an award to other than the lowest price Respondent, if Montana-Dakota determines that to do so would result in the greatest value to its customers.

3.1.5. All renewable resources, distributed generation and DSM are invited to compete in this RFP process and will be evaluated in a consistent manner with all other bids, with consideration given to projections as to their life-cycle costs, operational compatibility, reliability, and availability.

3.1.6. Those Respondents who submit Proposals do so without legal recourse against Montana-Dakota or its directors, management, employees, agents, or contractors, based on Montana-Dakota’s rejection, in whole or in part, of their

Proposal or for failure to execute any agreement tendered by Montana-Dakota. Montana-Dakota shall not be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to Montana-Dakota's acts or omissions arising out of or in connection with the RFP.

3.1.7. If a selected Proposal involves a generating resource not yet operational, the Respondent must provide Montana-Dakota with a full financial guarantee, including performance bonds and/or letters of credit, up to the level of product commitments and in an amount and at a level determined by Montana-Dakota in its sole discretion, expressly including replacement capacity and energy costs and any related penalty fees, in the event the generating resource does not become commercially operational as scheduled.

3.1.8. In reviewing and considering Proposals, Montana-Dakota will analyze potential credit and risk concerns in any comparison of Proposals. As part of its detailed evaluation phase, Montana-Dakota will specifically weigh the credit- and risk-related factors and costs underlying each of the Proposals. To conduct this review, Montana-Dakota requires that each Respondent include with its response package a detailed description of the proposed credit support. The pricing provided shall expressly include the costs of such credit support. Montana-Dakota will review and assess the sufficiency and adequacy of the proposed credit support, and if Montana-Dakota, at its sole discretion, determines such credit support is insufficient, it shall assess additional costs and/or expenses to the evaluation of such a Proposal.

3.1.9. Selection and elimination of Proposals and subsequent notification of Respondents at all stages of the evaluation will remain entirely at Montana-Dakota's discretion.

3.1.10 Montana-Dakota reserves the right to award multiple contracts if combinations of proposals provide the lowest overall cost and the highest level of reliability.

3.2. Proposal Threshold Requirements

The Respondent should provide complete and accurate information to ensure that its Proposal satisfies the Threshold Requirements listed below. Montana-Dakota, at its sole discretion, may reject a Proposal for further consideration if the Proposal fails to meet the Threshold Requirements or provides incomplete and/or inaccurate responses. Montana-Dakota may seek clarification and/or remedy of a Proposal.

3.2.1. General Threshold Requirements

a. The Proposal is received on time and complies with the submission instructions.

b. The Proposal is bona fide, and the Respondent (or its guarantor) has sufficient financial capacity to support the Proposal.

c. Complete and accurate answers are provided to all questions in the RFP.

d. The Proposal Submittal Fee is included.

e. The proposed capacity and associated energy are available and deliverable to Montana-Dakota's Integrated System no later than June 1, 2015.

f. The proposed capacity is at least 25 MW and no more than 225 MW.

g. If a PPA, the proposed term is for a minimum of five years.

3.2.2. Operating Performance Thresholds

a. The Respondent must certify that it has or will have all necessary permits in effect for the identified generating resource.

b. The Respondent must certify that any identified generating resource is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.

c. Montana-Dakota prefers the identified generating resource be fully dispatchable and has an automatic generation control that is tied into Montana-Dakota's Electric Control Center in Bismarck, North Dakota. The costs associated with this installation are the responsibility of the Respondent.

e. If a PPA, the Respondent must be willing to coordinate the generating resource's maintenance scheduling with Montana-Dakota.

3.2.3. Transmission Threshold

a. Deliverability to Montana-Dakota's Integrated System will be taken into account.

b. If the generating resource is or will be located outside of Montana-Dakota's Integrated System, the Respondent must provide a transmission plan for deliverability to wheel the generating resource's power to the Integrated System. Transmission costs to connect with the Integrated System are the responsibility of the Respondent.

c. If the generating resource is not yet in-service, but has a completed Generator Interconnection Study, a copy of this agreement must accompany the Proposal.

d. If the generating resource is not yet in-service and will be interconnected to Montana-Dakota's transmission system, the Respondent must complete an Application for Generator Interconnection Request with the Midwest ISO. A copy of this application must accompany the Proposal.

e. For an unfinished resource, the final agreement between Montana-Dakota and the Respondent will require the Interconnection Study to be completed, or will be contingent upon such a study being completed.

3.3. Screening Process

Montana-Dakota intends to select Proposals that will be included on its short-list by **October 1, 2010**. Through the short-listing process, those Proposals that are inferior to other Proposals in terms of overall cost and level of reliability, at Montana-Dakota's sole discretion, will be eliminated from further consideration. Montana-Dakota will notify all short-listed Respondents that they have been included on the short-list. Similarly, Montana-Dakota intends to notify Respondents of those Proposals that are eliminated from further consideration within a reasonable amount of time.

Montana-Dakota plans to analyze the short-listed Proposals in detail by assessing their impact on its customer electric service rates, comparing their costs to those of other resource alternatives, and examining their compatibility with Montana-Dakota's resource needs.

Montana-Dakota may elect to schedule meetings or conference calls with each short-listed Respondent to review and clarify its Proposal. After the selection of the short-listed Proposals, Montana-Dakota will begin contract negotiations with such Respondent(s).

Montana-Dakota may select a final Respondent(s) based on the detailed evaluation of the short-listed Proposals. This selection will not automatically be based on the lowest price alternatives available amongst the Proposals. The price and non-price attributes described in part in this RFP solicitation document will be considered in their totality for each Proposal. Montana-Dakota will use its sole discretion, judgment and analyses in making the final selection in the RFP process. Montana-Dakota's objective is to select resources that have the potential to offer the maximum reliability and value, based on cost and non-cost attributes.

4. CONTRACTS AND REGULATORY APPROVAL

4.1. General

The Respondent(s) whose Proposal is selected will be responsible for acquiring and verifying that they are in compliance with all necessary licenses, permits, certifications, reporting requirements, and approvals required by federal, state and local government laws, regulations and policies, including if applicable, for the design, construction and operation of the project. In addition, the Respondent shall fully support the regulatory approval process associated with any potential acquisition or power supply arrangement.

The Respondent shall be liable for all, and Montana-Dakota shall not be responsible for any, of the costs that the Respondent incurs to prepare, submit, and negotiate his Proposal, subsequent contract, and any related activity including governmental approvals.

4.2. Contract Modifications

It is anticipated that the contract format for the prospective PPA resulting from this RFP will be based on the Mid-Continent Energy Marketers Association Agreement (MEMA). A copy of the MEMA Agreement is contained in Exhibit D for reference purposes. Respondents may expressly identify and include proposed changes to the MEMA Agreement in their response packages. Such proposed revisions will allow Montana-Dakota to assess the significance and impact of the requested changes to the Proposal. Montana-Dakota reserves the right to utilize a different contract format, based on its sole discretion.

4.3. Definitive Agreement

As soon as practicable after Montana-Dakota completes negotiations, Montana-Dakota expects the selected Respondent(s) to execute a definitive agreement. Failure of the Respondent(s) to promptly execute a definitive written agreement after notification of a winning bid will result in rejection of the Proposal.

4.4. Regulatory Approval Process

At Montana-Dakota's sole discretion, any final negotiated contract may be conditioned upon regulatory actions and approvals by regulatory authorities. All consents and approvals of governmental authorities required for the consummation of the contemplated transactions shall have terms and conditions acceptable to Montana-Dakota.

4.5. Collusion

By submitting a Proposal to Montana-Dakota in response to this RFP, the Respondent certifies that the Respondent has not divulged, discussed, or compared its Proposal with any other Respondents and has not colluded whatsoever with any other Respondents with respect to its Proposals.

Exhibit A – Form of Statement of Financial Conditions and Creditworthiness

The following information shall be completed as appropriate and will be used to assess the applicant's financial conditions and creditworthiness.

1. Company Information

Type of Business

____ Corporation
____ Limited Liability Company
____ Partnership
____ Other (describe)

Applicant Organization

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

Applicant Credit Contact

Name:

Title:

Phone Number:

Email Address:

For Corporation/Limited Liability Companies

Date and State of Incorporation/Registration:

Street Address:

City, State, Zip Code:

For General Partnerships

Name of General Partner:

Address of General Partner/Registered Agent:

City, State, Zip Code:

2. Guarantor

Guarantor Company

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

3. Credit Information

The company and/or company's guarantor (if applicable) is required to submit the most recent 2 years of audited financial statements and accompanying notes. Indicate below what statements are being submitted.

____ 10K

____ 8Ks to the extent they address any information set forth in the 10Ks or 10Qs

____ 10Q

____ Other (describe)

All submitted information must be in the English language, and financial data denominated in United States currency, and conform to generally accepted accounting principles (GAAP) in the United States. If the offering entity's financial information is consolidated with other entities, then it is the offering entity's responsibility to extract and submit as separate documents all data and information related solely to the offering entity. This must include all financial information, associated notes and all other information that would comprise a full financial report conforming to GAAP.

Has the offering entity or predecessor company declared bankruptcy in the last 5 years?

____ Yes

____No

Are there any pending bankruptcies or other similar state or federal proceedings, outstanding judgments or pending claims or lawsuits that could affect the solvency of the offering entity?

____ Yes

____No

If the answer is "Yes" to either of the above questions, please provide an addendum to this application describing the situation and how it affects the offering entity's ability to meet or not meet it credit obligations.

Respondent/Guarantor Credit Rating

Standard & Poor's

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Moody's

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Fitch

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

In the event the above information is inadequate or fails to completely meet Montana-Dakota's need for financial security for a given bid, the entity must provide evidence of its capability to provide collateral instruments.

Please detail all credit related issues and concerns that Montana-Dakota should be aware of prior to negotiation of a formal power purchase agreement document:

Bank Reference Information

Bank Name:

Street Address:

City, State, Zip Code:

Contact Name:

Phone Number:

Fax Number:

Account Number:

4. Project-specific Information

For project-specific supply proposals, please provide the following information:

Owners and percentage of ownership in generation unit(s):

Amount and source(s) of equity financing:

Amount and terms of financing, including:

- Amount of loan(s)
- Term of loan(s)
- List of conditions
- Amortization schedule

5. Authorization

The Offering Entity hereby represents and warrants that all statements and representations made herein, including any supporting documents, are true to the best of Offering Entity's knowledge and belief. The undersigned authorized official of the Offering Entity warrants that the Offering Entity agrees to be bound by these representations. The Offering Entity authorizes the above listed entities to release data requested by Montana-Dakota necessary to perform a credit check in connection with Offering Entity's interest to bid on this RFP.

Offering Entity's Company Name:________________________________

Signature of Authorized Official:_________________________________

Name of Authorized Official (print):______________________________

Title of Authorized Official (print):______________________________

Date Signed:____

Exhibit B – Form of Notice of Intent to Bid

Date: ______________________________

Our organization intends to submit a proposal in response to the Montana-Dakota Utilities Co. Request for Proposals for Capacity and Energy Supply.

Contact Name: ______________________________

Name of Firm: ______________________________

Address: ______________________________

____

Phone: ______________________________

e-mail: ______________________________

Alternate Contact: ______________________________

Address: ______________________________

____

Phone: ______________________________

e-mail: ______________________________

Project Description: ______________________________

____

____

____

____

Signature: ______________________________

Exhibit C – Form of Confidentiality Agreement

MUTUAL CONFIDENTIALITY AGREEMENT

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., having its principal place of business at 400 North 4th Street, Bismarck, ND 58501 ("Montana-Dakota") and ____________________, having its principal place of business at ______________________________ ("Respondent"), are discussing details related to the Respondent's reply to a Request for Proposal ("RFP") that Montana-Dakota has issued regarding the purchases of capacity and energy dated June 1, 2010. In the course of the discussions about the RFP each party may disclose certain confidential or proprietary information ("Proprietary Information") to the other party.

For purposes of this Mutual Confidentiality Agreement, Proprietary Information shall mean all information, technical data or know-how, whether written, oral, visual, electronic or in any other form (which may include, without limitation, strategic project development plans, financial information, business plans and records, and project information and records,) disclosed, acquired, or generated as a result of or in connection with the RFP process. Proprietary Information shall also include this Mutual Confidentiality Agreement and the terms and conditions set forth herein.

A. In consideration of Montana-Dakota and Respondent agreeing to supply each other Proprietary Information relating to the RFP process and in consideration of both parties entering into the exchange of information and/or discussions relating to the RFP process, Montana-Dakota and Respondent each agree that it, its corporate affiliates, and each of their respective directors, officers, employees, lenders, and professional advisors (each individually "Representatives"):

1. Will keep secret and confidential the Proprietary Information supplied to the other party and any discussions and negotiations about the RFP process except as herein provided and in a manner no less restrictive than the manner that the receiving party protects its own confidential information;

2. Will use the Proprietary Information only for the purpose of participating in, evaluating and negotiating the RFP process;

3. Will disclose the Proprietary Information only to its Representatives who need to know the Proprietary Information for the purpose of participating in, evaluating and negotiating the RFP process;

4. Will not, whether or not the Parties enter into definitive agreements,

disclose to any third party (other than its Representatives) any of the Proprietary Information, other than the Proprietary Information which is in, or independently comes into, the public domain;

5. Will not, engage in any transactions of any kind or description whatsoever with regard to or using the Proprietary Information during the term of this Agreement without the written consent of the other party;

6. Will, if requested in writing, promptly destroy or return any of the Proprietary Information provided without keeping any copies; and

7. Will promptly notify the other party if any of the Proprietary Information conveyed to it is required to be disclosed by reason of law or legal process and will cooperate with the other party regarding any action which the other party (at the other party's sole cost and expense) may elect to take to challenge the legality or validity of such requirement.

B. Montana-Dakota and Respondent also acknowledge and agree:

1. Proprietary Information which is provided will not be considered to be Proprietary information if that information is (i) in the other party's possession prior to disclosure, (ii) is in the public domain prior to disclosure, or (iii) lawfully enters the public domain through no violation of this Mutual Confidentiality Agreement.

2. No agreement for a power purchase agreement or other transaction shall be deemed to exist unless and until a Definitive Transaction Agreement has been executed and delivered by the parties. The term "Definitive Transaction Agreement" does not include this Mutual Confidentiality Agreement, a letter of interest or any other preliminary written agreement, nor does it include any verbal agreement;

3. Neither party makes any representation or warranty regarding the completeness or accuracy of any information provided to the other; any and all such representations and warranties shall be made in a written, executed agreement and will then be subject to the provisions thereof;

4. Money damages would not be a sufficient remedy for a breach of this Mutual Confidentiality Agreement and the injured party is entitled to specific performance and injunctive or other equitable relief and remedies for any breach; such remedies shall not be the exclusive remedies but shall be in addition to all other remedies available at law or in equity;

5. Neither party will make any announcement of the status of the Respondent's reply to the RFP or of any negotiations with respect to a possible power purchase agreement without the prior written consent of the other;

6. This Mutual Confidentiality Agreement is governed by the laws of the state of North Dakota; and

7. The obligations under this Mutual Confidentiality Agreement shall be continuing and shall survive the termination of the RFP process and any discussion or negotiations between the parties, but that all obligations of the parties hereunder will expire two years from the date of this Mutual Confidentiality Agreement.

The parties have executed this Mutual Confidentiality Agreement as of ______________ ___, 2010.

______________________________	MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc.
By:___________________________	By:___________________________
Title:_________________________	Title:_________________________

Exhibit D – Mid-Continent Energy Marketers Association Agreement

MEMA

Mid-Continent Energy Marketers Association

Capacity and Energy Tariff

MID-CONTINENT ENERGY MARKETERS ASSOCIATION
CAPACITY AND ENERGY TARIFF
TABLE OF CONTENTS

ARTICLE ONE: PURPOSE, APPLICABILITY AND GOVERNANCE

1.1 Purpose. The purpose of this Tariff is to provide for sales of Product by MEMA Members.

1.2 Applicability. Services under this Tariff are applicable to MEMA Members.

1.3 Disclaimer. This Tariff was prepared by MEMA to facilitate orderly trading in and development of wholesale power markets. Neither MEMA nor any MEMA Member nor any of their agents, representatives or attorneys shall be responsible for its use, or any damages resulting therefrom. By providing this Tariff MEMA does not offer legal advice and all users are urged to consult their own legal counsel to ensure that their commercial objectives will be achieved and their legal interests are adequately protected.

GENERAL TERMS AND CONDITIONS

ARTICLE TWO: GENERAL DEFINITIONS

2.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

2.2 "Agreement" means this Tariff, including its exhibits (including but not limited to the Supplementary Agreement attached hereto as Exhibit B), schedules and any written supplements, any collateral, credit support or margin agreement or similar arrangement between the Parties to a Transaction, and all Transactions (including any Confirmations).

2.3 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

2.4 "Business Day" means any day except a Saturday, Sunday, a Federal Reserve Bank holiday, or a Canadian Banking holiday where the Buyer or Seller has its principal place of business located in Canada. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

2.5 "Buyer" means the MEMA Member to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

2.6 "Call Option" means an Option entitling, but not obligating, the Option Buyer to purchase and receive the Product from the Option Seller at a price equal to the Strike Price for the Delivery Period for which the Option may be exercised, all as specified in the Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller shall be obligated to sell and deliver the Product for the Delivery Period for which the Option has been exercised.

2.7 "Claiming Party" has the meaning set forth in Section 4.3.

2.8 "Claims" means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Tariff.

2.9 "Confirmation" has the meaning set forth in Section 3.3.

2.10 "Contract Price" means the price in $U.S. (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Transaction.

2.11 "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

2.12 "Credit Rating" means, with respect to a Party (or its Guarantor, if applicable) (i) the rating then assigned to the unsecured, senior long-term debt obligations (not supported by third party credit enhancements) of such entity, or (ii) in the case that such entity does not have a rating for its senior unsecured long-term debt, the rating then assigned as an issuer rating. In either case the rating shall refer to the rating then assigned by S&P, Moody's, or any other rating agency agreed to by the Parties as set forth in the Supplementary Agreement attached hereto as Exhibit B.

2.13 "Defaulting Party" has the meaning set forth in Section 6.1.

2.14 "Delivery Period" means the period of delivery for a Transaction, as specified in the Transaction. "Delivery Point" means the point at which the Product shall be delivered and received, as specified in the Transaction.

2.15 "Downgrade Event" means the downgrade event, if any, as agreed by the Parties in the Credit and Collateral Requirements.

2.16 "Early Termination Date" has the meaning set forth in Section 6.2.

2.17 "Electronic Confirmation" has the meaning set forth in Section 3.4.

2.18 "Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

2.19 "Event of Default" has the meaning set forth in Section 6.1.

2.20 "Federal Power Marketing Agency" means any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy.

2.21 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

2.22 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability economically to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedules P and Q.

2.23 "Gains" means, with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of a Terminated Transaction, determined in a commercially reasonable manner.

2.24 "Governmental Charges" has the meaning set forth in Section 10.2

2.25 "Guarantor" means, with respect to a Party, the guarantor, if any, acceptable to the Party as set forth in the Supplementary Agreement attached hereto as Exhibit B.

2.26 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

2.27 "Imaged Document" has the meaning set forth in Section 11.17.

2.28 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, or a Canadian Bank if the applicant for such Letter of Credit has its principal place of business located in Canada, or such other entity as agreed to by the Parties, including but not limited to CoBank, ACB or National Rural Utilities Cooperative, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

2.29 "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of a Terminated Transaction, determined in a commercially reasonable manner.

2.30 "MEMA" means the Mid-Continent Energy Marketers Association, which is a Minnesota nonprofit corporation and independent energy marketing association.

2.31 "MEMA Member" means an entity approved for membership as a voting member (or any successor designation adopted by MEMA) in MEMA pursuant to article three of the MEMA bylaws and in compliance therewith, or any successor rules adopted by MEMA governing admission to membership.

2.32 "Moody's" means Moody's Investors Service, Inc. or its successor.

2.33 "NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Corporation ("NERC") or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

2.34 "Non-Defaulting Party" has the meaning set forth in Section 6.2.

2.35 "Offsetting Transactions" mean any two or more outstanding Transactions, having the same or overlapping Delivery Period(s), Delivery Point and payment date, where under one or more of such Transactions, one Party is the Seller, and under the other such Transaction(s), the same Party is the Buyer.

2.36 "Option" means the right but not the obligation to purchase or sell a Product as specified in a Transaction.

2.37 "Option Buyer" means the Party specified in a Transaction as the purchaser of an option, as defined in Schedule P.

2.38 "Option Seller" means the Party specified in a Transaction as the seller of an option , as defined in Schedule P.

2.39 "Oral Confirmation" has the meaning set forth in Section 3.3.

2.40 "Party" means the Seller or the Buyer in a Transaction.

2.41 "Parties" means the Seller and the Buyer in a Transaction.

2.42 "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit, or other security acceptable to the Party requesting an assurance of performance.

2.43 "Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

2.44 "Product" means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to a Product listed in Schedules P or Q hereto or as otherwise specified by the Parties in the Transaction.

2.45 "Put Option" means an Option entitling, but not obligating, the Option Buyer to sell and deliver the Product to the Option Seller at a price equal to the Strike Price for the Delivery Period for which the option may be exercised, all as specified in a Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller shall be obligated to purchase and receive the Product.

2.46 "Quantity" means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

2.47 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases a replacement for any Product specified in a Transaction but not delivered by Seller, plus (i) costs reasonably incurred by Buyer in purchasing such substitute

Product and (ii) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or at Buyer's option, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party.

2.48 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

2.49 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells any Product not received by Buyer, deducting from such proceeds any (i) costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or at Seller's option, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party.

2.50 "Schedule" or "Scheduling" means the actions of Seller, Buyer and/or their designated representatives, including each Party's Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

2.51 "Seller" means the MEMA Member to a Transaction that is obligated to sell and deliver, or cause to be delivered, the Product, as specified in the Transaction.

2.52 "Settlement Amount" means, with respect to a Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such party incurs as a result of the liquidation of a Terminated Transaction pursuant to Section 6.2.

2.53 "Strike Price" means the price to be paid for the purchase of the Product pursuant to an Option.

2.54 "Tariff" means this Mid-Continent Energy Marketers Association Capacity and Energy Tariff.

2.55 "Terminated Transaction" has the meaning set forth in Section 6.2.

2.56 "Termination Payment" has the meaning set forth in Section 6.3.

2.57 "Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Tariff.

2.58 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

2.59 "Website" means the Website maintained by MEMA at http://www.memarketers.org or successor site.

2.60 "Written Confirmation" has the meaning set forth in Section 3.2.

ARTICLE THREE: TRANSACTION TERMS AND CONDITIONS

3.1 Confirmations. A Transaction shall be entered into upon the agreement of the Parties by one or more of the following methods as evidenced in paragraph 1 of the Supplementary Agreement attached hereto as Exhibit B:

i) in writing in accordance with Section 3.2;

ii) orally in accordance with Section 3.3; or

iii) by electronic means of communication in accordance with Section 3.4

(a "Confirmation").

The Supplementary Agreement may contain additional terms relating to confirmation of a Transaction as may be agreed to by the Parties. If the Parties do not enter into a Supplementary Agreement or if no method for entering transactions is selected in a Supplementary Agreement between the Parties, then the Transactions shall be entered into orally. Each Party agrees not to contest, or assert any defense to, the validity or enforceability of the Transaction entered into in accordance with this Tariff (i) based on any law requiring agreements to be in writing or to be signed by the parties, or (ii) based on any lack of authority of the Party or any lack of authority o of any employee of the Party to enter into a Transaction.

3.2 Written Confirmation. When confirming a Transaction in writing, Seller shall forward to Buyer within three (3) Business Days after the Transaction is entered into a written confirmation substantially in the form of Exhibit A or other format as mutually agreed to by the Parties ("Written Confirmation"). When evidencing a Transaction by way of Oral Confirmation or Electronic Confirmation, Seller may also confirm the Transaction by forwarding to Buyer within three (3) Business Days after the Transaction is entered into, a Written Confirmation. If Buyer objects to any term(s) of such Written Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Written Confirmation within three (3) Business Days after the Transaction is entered into, a Written Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such Written Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Written Confirmation and neither Party objects to the other Party's Written Confirmation within two (2) Business Days of receipt, Seller's Written Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Written Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Written Confirmation was sent prior to Seller's Written Confirmation, in which case Buyer's Written Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Written Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

3.3 Oral Confirmation. When confirming a Transaction orally, each Party consents to the creation of a tape or electronic recording ("Oral Confirmation") of all telephone conversations between the Parties to a proposed Transaction under this Tariff, and that any such Oral Confirmation shall be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to such proposed Transaction. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. The Oral Confirmation, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties' agreement with respect to a particular Transaction in the event a Written Confirmation or Electronic Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Written Confirmation or Electronic Confirmation, such Written Confirmation or Electronic Confirmation shall control in the event of any conflict with the terms of an Oral Confirmation, or in the event of any conflict with the terms of this Tariff.

3.4 Electronic Confirmation. When confirming a Transaction by an electronic means of communication for which a written record can be retrieved and which is mutually agreed upon by the Parties as evidenced in a Supplementary Agreement ("Electronic Confirmation"), the record of Electronic confirmation shall be retained in electronic form in confidence secured from improper access, and may, if properly authenticated, be submitted in evidence in any proceeding or action relating to such proposed Transaction. The Electronic Confirmation and the terms and conditions described therein, if admissible, shall be the controlling evidence of the Parties agreement with respect to a particular Transaction in the event a Written Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Written Confirmation, such Written Confirmation shall control in the event of any conflict with the terms of an Electronic Confirmation, or in the event of such conflict with the terms of this Tariff.

3.5 Governing Terms. Unless otherwise specifically agreed, each Transaction between the Parties shall be governed by this Tariff. This Tariff (including all exhibits, schedules and any written supplements hereto), any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmations accepted in accordance with Sections 3.2, 3.3 and 3.4) shall form a single integrated agreement between the Parties. Any inconsistency between any terms of this Tariff and any terms of the Transaction shall be resolved in favor of the terms of such Transaction.

3.6 Additional Confirmation Terms. The Parties to a Transaction may mutually agree to terms which modify or supplement the general terms and conditions of this Tariff either through, Written Confirmation or Supplementary Agreement.

ARTICLE FOUR: OBLIGATIONS AND DELIVERIES

4.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

4.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

4.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

ARTICLE FIVE: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

5.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

5.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

ARTICLE SIX: EVENTS OF DEFAULT; REMEDIES

6.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

a. the failure to make, when due, any payment required pursuant to a Transaction if such failure is not remedied within three (3) Business Days after written notice;
b. any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;
c. the failure to perform any material covenant or obligation set forth in a Transaction (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive remedy for which is provided in Article Five) if such failure is not remedied within three (3) Business Days after written notice;
d. such Party becomes Bankrupt;
e. the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to with the other Party;
f. such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under a Transaction to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;
g. with respect to such Party's Guarantor, if any:

(i) if any representation or warranty made by a Guarantor in connection with a Transaction is false or misleading in any material respect when made or when deemed made or repeated;

(ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guaranty made in connection with a Transaction and such failure shall not be remedied within three (3) Business Days after written notice;

(iii) a Guarantor becomes Bankrupt;

(iv) the failure of a Guarantor's guaranty to be in full force and effect for purposes of a Transaction (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

6.2 Declaration of an Early Termination Date and Calculation of Settlement. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party") shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under each Transaction and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

6.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party pursuant to Article Nine, plus any or all other amounts due to the Defaulting Party under this Tariff against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Tariff, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

6.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

6.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within two (2) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

6.6 Closeout Setoffs. After calculation of a Termination Payment in accordance with Section 6.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 6.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

6.7 Suspension of Performance. Notwithstanding any other provision of this Tariff, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an Early Termination Date shall have been declared and notice thereof pursuant to Section 6.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

ARTICLE SEVEN: PAYMENT AND NETTING

7.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this Tariff (other than Termination Payments, payments pursuant to Section 5.1 or 5.2, and Option premium payments pursuant to Section 7.7). As soon as practicable after the end of each month, each Party shall render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

7.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Tariff shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party shall make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

7.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Tariff or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 7.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance of a Transaction occurred, the right to payment for such performance is waived.

7.4 Netting of Payments. The Parties agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Tariff, including any related damages calculated pursuant to Article Five, interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it. Notwithstanding the previous sentence, netting shall not apply to option premiums which shall be settled in accordance with Section 7.7.

7.5 Payment Obligation Absent Netting. If Parties agree not to do netting of payment pursuant to Section 7.4 or only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Five, interest, and payments or credits, that Party shall pay such sum in full when due.

7.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Six, all amounts netted pursuant to this Article Seven shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Tariff.

7.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 7.1.

7.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

a. the Party obligated to deliver the greater amount of Energy shall deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and
b. the Party owing the greater aggregate payment shall pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

ARTICLE EIGHT: LIMITATIONS

EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS TARIFF SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR’S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED IN THIS TARIFF OR IN A TRANSACTION, THE OBLIGOR’S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR

ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE NINE: CREDIT AND COLLATERAL REQUIREMENTS

9.1 The applicable credit and collateral requirements shall be as agreed to by the Parties to a Transaction as evidenced in the Supplementary Agreement attached hereto as Exhibit B. The Parties may elect to choose one of the following options as listed below. If the Parties do not enter into a Supplementary Agreement or if no option is selected in the Supplementary Agreement between the Parties, Option 1 shall apply exclusively.

9.2 <u>Credit Assurances.</u>

<u>Option 1 - Standard Credit Assurance</u>

If a Party has reasonable grounds to believe that the other Party's creditworthiness or performance under a Transaction has become unsatisfactory, such requesting Party will provide the other Party with written notice requesting Performance Assurance in an amount determined by the requesting Party in a commercially reasonable manner. Upon receipt of such notice the Party shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to the requesting Party. In the event that a Party receives a request for a Performance Assurance but fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to the requesting Party within three (3) Business Days of receipt of notice, then an Event of Default under Article Six will be deemed to have occurred and the Party requesting such Performance Assurance will be entitled to the remedies set forth in Article Six of this Tariff.

<u>Option 2 - Enhanced Credit Assurance</u>

Should a Party's creditworthiness or performance become unsatisfactory to the other Party in such other Party's reasonably exercised discretion with regard to any Transaction (including any Confirmation) pursuant to this Tariff, the dissatisfied Party (the "First Party") may require the other Party (the "Second Party") to provide Performance Assurance in an amount determined by the First Party in a commercially reasonable manner. Events which may trigger the First Party questioning the Second Party's creditworthiness or performance include, but are not limited to, the following:

(1) The First Party has knowledge that the Second Party (or its Guarantor, if applicable) is failing to perform or defaulting under other material contracts.

(2) The Second Party has exceeded any credit or trading limit set out in any Confirmation or other agreement between the Parties.

(3) The Second Party's (or its Guarantor's, if applicable) Credit Rating falls below BBB- from S&P or Baa3 from Moody's (based on the lower of the S&P or Moody's Credit Rating).

(4) Other material adverse changes in the Second Party's (or its Guarantor, if applicable) financial condition occur.
(5) Substantial changes in market prices which materially and adversely impact the Second Party's ability to perform under this Tariff or any Confirmation occur.

If the Second Party fails to provide Performance Assurance, or a guaranty or other credit assurance acceptable to the First Party within three (3) Business Days of receipt of notice, then an Event of Default under Article Six of the Tariff shall be deemed to have occurred and the First Party will be entitled to the remedies set forth in Article Six of this Tariff. Nothing contained in the Article Nine shall affect any credit agreement or arrangement, if any, between the Parties.

Option 3 - Downgrade Event

If at any time there shall occur a Downgrade Event with respect to either Party, then the non-affected Party (the "First Party") may require the affected Party (the "Second Party") to provide Performance Assurance in an amount determined by the First Party in a commercially reasonable manner. In the event the Second Party shall fail to provide such Performance Assurance or guaranty or other credit assurance acceptable to the First Party within three (3) Business Days of receipt of notice, than an Event of Default shall be deemed to have occurred and the First Party will be entitled to exercise any of the remedies set forth in Article Six of the Tariff.

The Parties shall specify within a Supplementary Agreement the meaning of a Downgrade Event with respect to each Party.

Option 4 - Mutually Agreed to Credit Assurance

As mutually agreed in writing by both Parties and referenced in the Supplementary Agreement.

9.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, unless prohibited by applicable law, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a secured party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE TEN: GOVERNMENTAL CHARGES

10.1 Cooperation. Each Party to a Transaction shall use reasonable efforts to implement the provisions of and to administer this Tariff in accordance with the intent of the Parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

10.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any government authority ("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). In the event Seller is required by law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Governmental Charges from the sums due to Seller under Article Seven of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the law.

ARTICLE ELEVEN: MISCELLANEOUS

11.1 Term of Tariff. This Tariff shall be effective as of the effective date accepted by the FERC. This Tariff shall remain in effect until terminated by MEMA or successor organization upon sixty (60) days prior written notice; provided, however, no such termination notice shall be effective as to any ongoing Transaction hereunder until the Parties have fulfilled all Tariff obligations with respect to Transactions agreed to prior to the date of termination and until regulatory approval, if required, is granted to terminate this Tariff.

11.2 Representations and Warranties. On the date of entering into each Transaction, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to legally perform its obligations under this Tariff and each Transaction (including any Confirmation accepted in accordance with Article Three);

(iii) the execution, delivery and performance of this Tariff and each Transaction (including any Confirmation accepted in accordance with Article Three) are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Tariff, each Transaction (including any Confirmation), and each other document executed and delivered in accordance with this Tariff (including but not limited to the Supplementary Agreement) constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

(v) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vi) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Tariff and each Transaction (including any Confirmation);

(vii) no Event of Default or Potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Tariff and each Transaction (including any Confirmation);

(viii) it is acting for its own account, has made its own independent decision to enter into each Transaction (including any Confirmation) and as to whether this Tariff and each such Transaction (including any Confirmation) is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of another Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Tariff and each Transaction (including any Confirmation);

(ix) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(x) it has entered into each Transaction (including any Confirmation) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

11.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it shall deliver to Buyer the Quantity of the Product free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

11.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 11.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Ten.

11.5 Assignment. No Party shall assign a Transaction or any of its rights under a Transaction without the prior written consent of the other Party, which consent may not unreasonably be withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign a Transaction or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign a Transaction to an Affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign a Transaction to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

11.6 Governing Law. THIS TARIFF AND THE RIGHTS AND DUTIES OF PARTIES TO A TRANSACTION, TO THE EXTENT PERMITTED BY LAW, SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITH THE EXCEPTION OF UNITED STATES FEDERAL LAW OR CANADIAN LAWS WITH RESPECT TO THE SALE OF ELECTRICAL CAPACITY OR ENERGY IN CANADA. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS TARIFF.

11.7 Notices. All notices, requests, statements or payments shall be made as specified in the Supplementary Agreement or if the Parties do not enter into a Supplementary Agreement then as specified in a Transaction (including any Confirmation).. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith. Notwithstanding the foregoing, a Party is entitled to rely on the other Party's invoice regarding payment instructions.

11.8 General. This Tariff (including the exhibits, schedules, the Supplementary Agreement and any written supplements hereto), any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of a Transaction and shall be incorporated therein by reference. Each Party to a Transaction agrees if it seeks to amend any applicable wholesale power sales tariff during the term of a Transaction, such amendment shall not in any way affect such Transaction under this Tariff without the prior written consent of the other Party. Each Party to a Transaction further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Tariff. Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as “Regulatory Event”) shall not otherwise affect the remaining lawful obligations that arise under this Tariff; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform their Transaction in order to give effect to the original intention of the Parties. The term “including” when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of the applicable Transaction for twelve (12) months.

11.9 Audit. Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Tariff. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof shall be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment shall be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

11.10 Forward Contract. The Parties acknowledge and agree that all Transactions constitute “forward contracts” within the meaning of the United States Bankruptcy Code.

11.11 Confidentiality. The Parties agree that neither Party shall disclose the terms or conditions of the Transaction(s) to a third party (other than the Party’s or its Affiliate’s employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area, regional reliability council, or independent system operator rule, or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

11.12 Resolution of Disputes. Prior to the initiation of arbitration, any controversy, dispute or claim between the Parties involving or arising under this Tariff first shall be referred for resolution to a senior representative of each Party. A Party claiming that a dispute has arisen must give written notice within a reasonable period of time to the other Party describing the dispute and designating the Party's senior representative. Upon receipt of a notice describing the dispute, the other Party shall promptly designate its senior representative to the notifying Party. The senior representatives so designated shall attempt to resolve the dispute on an informal basis as promptly as practicable. If the dispute has not been resolved within thirty (30) days after the notifying Party's notice was received by the other Party, or within such other period as the Parties may jointly agree, the Parties shall submit the dispute to arbitration in accordance with the arbitration procedure set forth in Section 11.13.

11.13 Arbitration. Any controversy, dispute or claim involving or arising under this Tariff which cannot be resolved pursuant to Section 11.12 shall be submitted to binding arbitration by one arbitrator qualified by education, experience or training to render a decision upon the issues in dispute and who has not previously been employed by either Party, and does not have a direct or indirect interest in either Party or the subject matter of the arbitration. Such arbitrator shall either be mutually agreed upon by the Parties within thirty (30) days after written notice from either Party requesting arbitration, or failing agreement, the arbitration shall be conducted by a panel of three arbitrators having the qualifications set forth in the preceding sentence, one to be selected by each Party and the third arbitrator to be selected by the two arbitrators selected by the Parties. If either Party fails to notify the other Party of the arbitrator selected by it within ten (10) days after receiving notice of the other Party's arbitrator, or if the two arbitrators selected fail to select a third arbitrator within ten (10) days after notice is given of the selection of the second arbitrator, then such arbitrator shall be selected under the expedited rules of the American Arbitration Association (the "AAA"). The Parties shall divide equally the cost of the hearing, and each Party shall be responsible for its own expenses and those of its counsel or other representative. The commercial arbitration rules of the AAA shall apply to the extent not inconsistent with the rules specified above. Unless otherwise agreed to by the Parties, all arbitrations shall be held in St. Paul, Minnesota.

11.14 Laws of the United States. This Tariff shall not make any laws or regulations governing employment or production of goods and services enacted by the Congress of the United States or by any other legislative or governmental body in the United States or any state thereof applicable to any power or other service provided or used in Canada. This Tariff shall not confer or extend the authority or jurisdiction of FERC or any regulatory agency over matters pertaining to the generation, sale, purchase or transmission of electric energy in Canada.

11.15 Compliance with Applicable Laws. This Tariff shall be binding on all Parties to the maximum extent permitted by United States federal and state law or regulation, and Canadian federal and/or provincial government law or regulation, but notwithstanding any other provision of this Tariff, no Party shall be required to take any action or do any other thing with respect to rates, charges, terms or conditions of service, the resolution of disputes under this Tariff, or any other matter, that (a) it is not permitted by law to undertake or that is prohibited in whole or in part by any law or regulation applicable to such a Party, or (b) would require such a

Party to violate a provision of such law or regulation in order to comply with this Tariff. Each Party shall seek such approvals, grant such waivers, and take such other actions as may be necessary to comply with this Tariff, to the maximum extent permitted by United States federal or state law or regulation, or Canadian federal or provincial law or regulation.

11.16 Effect of Canadian Laws**.** The sale, purchase and transmission of electricity in Canada and the rates, charges, terms and conditions of service therefore are subject in all respects to Canadian Laws. This includes but is not limited to:

(i) The final authority of the Government of Canada in all matters relating to the export of electric power; and

(ii) The final authority of the government of a Canadian province in all matters relating to the installation or construction of facilities.

11.17 Imaged Documents. Any original executed document relating to this Agreement may be scanned and stored on computer tapes and disks (the "Imaged Document"). The Imaged Document if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the Imaged Document on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

SCHEDULE M

(THIS SCHEDULE IS INCLUDED IF A PARTY IS A FEDERAL POWER MARKETING AGENCY)

A. If either Party is a Federal Power Marketing Agency, the Parties agree that the following provisions apply to this Tariff and any Transaction conducted under this Tariff:

1. Participation by the United States**.** The participation by the United States through a Federal Power Marketing Agency in this Tariff is subject in all respects to acts of Congress and to regulations of the Secretary of Energy established thereunder, and to rate schedules promulgated by the Secretary of Energy or delegate. This reservation includes, but is not limited to, the statutory limitations upon the authority of the Secretary of Energy to submit disputes arising under this Tariff to arbitration. In the event of a conflict between this Schedule M and any other provision in this Tariff, this Schedule M shall have precedence with respect to the application of this Tariff to the United States.

2. Contingent Upon Appropriations. Where activities provided for in this Tariff extend beyond the current fiscal year of a Federal Power Marketing Agency, continued expenditures by the United States are contingent upon Congress making the necessary appropriations required for the continued performance of the obligations of the United States under this Tariff. In case such appropriation is not made, a Party to a Transaction with a Federal Power Marketing Agency hereby releases the United States from its contractual obligations under this Tariff and from all liability due to the failure of Congress to make such appropriation.

3. Officials Not To Benefit. No member of or delegate to Congress or Resident Commissioner shall be admitted to any share or part of this Tariff or to any benefit that may have arisen from this Tariff, but this restriction shall not be construed to extend to this Tariff if made with a corporation or company for its general benefit.

4. Covenant Against Contingent Fees. A Party to a Transaction with a Federal Power Marketing Agency warrants that no person or selling agency has been employed or retained to solicit or secure participation by a Federal Power Marketing Agency in this Tariff upon an agreement or understanding for a commission, percentage, brokerage or contingent fee, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Party for the purpose of securing business. For breach or violation of this warranty, the Party that is a Federal Power Marketing Agency shall have the right to annul its participation in this Tariff without liability or, in its

discretion, to deduct from the contract price or consideration the full amount of such commission, percentage, brokerage, or contingent fee.

5. Contractor Agreement. For the purpose of this Schedule M the term "Tariff" shall mean this Tariff and the term "Contractor" shall mean a Party having a Transaction with a Federal Power Marketing Agency. During the performance of a Transaction under this Tariff, the Contractor agrees to the following provisions. In addition, the Contractor shall include the following provisions in every subcontract or purchase order involving the Federal Power Marketing Agency unless exempted by rules, regulations or order of the Secretary of Labor.

6. Equal Opportunity Employment Practices. Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor shall not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Tariff.

7. Contract Work Hours and Safety Standards. The Tariff, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act, 40 U.S.C. § 329 (1986) (the "Act"), is subject to the provisions of the Act, 40 U.S.C. §§ 327-333 (1986), and to regulations promulgated by the Secretary of Labor pursuant to the Act.

8. Use of Convict Labor. The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the Tariff except as provided by 18 U.S.C. § 4082(c)(2) (1986) and Executive Order 11755, 39 Fed. Reg. 779 (1973).

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Environmental Attributes" means an aspect, claim, characteristic or benefit associated with the generation of a quantity of Energy by an electricity generation facility that is capable of being measured, verified or calculated, including any and all credits, benefits, emissions reductions, offsets and allowances, howsoever entitled, attributable to the generation of such quantity of Energy by an electricity generation facility and its displacement of conventional, non-renewable electricity generation together with the right(s) to report ownership of such attributes to any agency, authority, or third party. Environmental Attributes shall not include (i) any Energy, Capacity, reliability or other power attributes from the electricity generation facility; (ii) production tax credits associated with the construction or operation of the electricity generation facility and other financial incentives in the form of credits, reductions or allowances associated with the electricity generation facility that are applicable to a state, provincial or federal income taxation obligation; (iii) fuel-related subsidies, "tipping fees", or other local subsidies received by the electricity generation facility for the destruction of particular preexisting pollutants or the promotion of local environmental benefits; or (iv) emission reduction credits encumbered or used by the electricity generation facility for compliance with local, state, provincial or federal operating and/or air quality permits.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Five.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Five, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the Transmission Provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable Transmission Provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 2.22 to the contrary.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Five, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the Transmission Provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable Transmission Provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 2.22 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an amount determined pursuant to Article Five. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into ______________ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. <u>Prescheduling and Notification</u>. Subject to the provisions of Section 6 of this Schedule, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. <u>Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission</u>." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly

completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. <u>Rights of Buyer and Seller Depending Upon Availability of Timely Request for Firm Transmission</u>.

A. <u>Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer</u>. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

i If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer, and Seller shall be liable to Buyer for amounts determined pursuant to Article Five.

iv In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. <u>Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider</u>. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Five.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Five.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Five.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 2.22.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1 of this Schedule.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"Renewable Energy Credit" or "REC" has the meaning specified in the Transaction.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither Party shall be liable to the other for any damages, including any amounts determined pursuant to Article Five.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Five, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 2.22 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Five.

SCHEDULE Q: MAPP GRSP AND OTHER MAPP PRODUCTS

GENERAL TERMS AND CONDITIONS

1. General

1.1 The Products described herein are intended to facilitate the exchange of capacity and energy in the Mid-Continent Area Power Pool ("MAPP"). The Products employ market based rates for interchange of capacity and energy.

1.2 Governance. Capitalized terms used, but not defined, in Schedule Q of this Tariff shall have the meaning ascribed to them in the MAPP Restated Agreement. In the event of a conflict between the terms of this Tariff and the terms of the MAPP Restated Agreement, the terms of this Tariff shall control.

2. Accreditation

2.1 Accreditation of capacity transactions shall be determined and assigned under applicable procedures of the MAPP Generation Reserve Sharing Pool ("GRSP").

3. Transmission Loading Relief

3.1 Delivery of energy shall be subject to the applicable transmission provider's loading relief procedures.

4. Definitions

4.1 Public Utility: A public utility as defined in Section 201(e) of the Federal Power Act, as amended.[1]

4.2 MAPP means Mid-Continent Area Power Pool, which is an association of electric utilities and other electric industry participants organized for the purpose of pooling generation and transmission.

4.3 GRSP means the MAPP Generation Reserve Sharing Pool or its successor, as defined in the MAPP Restated Agreement.

5. Uncontrollable Forces

5.1 Force Majeure (Section 2.22), as defined and used in this Tariff, does not apply to any of the Products in this Schedule Q.

5.2 All Products in this Schedule Q are subject to "uncontrollable forces" or "force majeure". A Party shall not be considered to be in default in respect to any obligation under a Product in this Schedule Q if prevented from fulfilling such obligation by reason of "uncontrollable forces" or "force majeure", except that the

[1] Note that the Energy Policy Act 2005 exempted a variety of entities, including electric cooperatives that sell less than 4 million MWh of energy per year from FERC jurisdiction over the determination of their ability to sell at negotiated rates.

obligation to pay money in a timely manner is absolute and shall not be subject to "uncontrollable forces" or "force majeure". Any Party unable to fulfill any obligation by reason of "uncontrollable forces" or "force majeure" will exercise due diligence to remove such disability with reasonable dispatch, but such obligation shall not require the settlement of a labor dispute except in the sole discretion of the Party experiencing such labor dispute. For the purposes of this Section 5.2 "uncontrollable forces" and/or "force majeure" shall have the meaning ascribed to such terms in the Transmission Provider's tariff.

Product A: Participation Power Interchange Service

1. Service to be Provided

1.1 This Product provides for the sale of Participation Power by a Seller to a Buyer from a specific generating unit or units. Participation Power shall mean power and energy sold from a specific generating unit or units on a continuously available basis except when such unit or units are temporarily out of service for maintenance, during which time the delivery of energy from other sources shall be at the Seller's option.

2. Conditions of Service

2.1 This Product shall be available for a period of one or more consecutive days.

2.2 Participation Power shall be supplied through transmission facilities that have adequate capacity for transmitting such power and energy, in accordance with any applicable reliability standards and procedures.

3. Schedules of Rates

3.1 The rates and term for Participation Power shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the Federal Energy Regulatory Commission ("FERC"), or (ii) is not a Public Utility.

3.2 In the event the service cannot be supplied on the effective date of an agreement to sell Participation Power because of a delayed in-service date of the associated generating facility or facilities, the capacity payment to be paid by the Buyer shall not be effective until the date such facility or facilities are placed in commercial operation.

Product J: Firm Power Interchange Service

1. **Service to be Provided**

   1.1 This Product provides for the sale of Firm Power by a Seller to a Buyer.

2. **Conditions of Service**

   2.1 Firm Power shall be supplied through transmission facilities which have adequate capacity for transmitting such power and energy, in accordance with any applicable GRSP reliability standards and procedures.

   2.2 This Product shall be available for a period of one or more consecutive days.

   2.3 Energy available under this Product may be supplied in one of the following forms:

   i. Energy is available at all times during the period covered by the commitment; or

   ii. If energy is being supplied as peaking energy, or for other purposes which anticipate a capacity-factor limitation, the Seller and the Buyer may mutually agree on minimum or maximum limits on the energy to be delivered during the period covered by the Transaction; provided, however, service under this paragraph 2.3(ii) shall not be interruptible for reasons other than reliability of service to native load.

3. **Schedule of Rates**

   3.1 The rates and term for Firm Power shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

Product K: System Participation Power Interchange Service

1. Service to be Provided

1.1 This Product provides for the sale of System Participation Power by a Seller to a Buyer for a specified period for the purpose of obtaining a supply of power that can be depended upon with the same degree of assurance as that expected from the Buyer's own generating capacity, but which does not include reserve capacity.

2. Conditions of Service

2.1 This Product shall be available for periods of one or more consecutive days.

2.2 System Participation Power is intended to be available at all times during the period covered by the Transaction; provided, however, that if conditions arise during the period covered by the Transaction that would otherwise require curtailment of service to its native load customers, the Seller has the right to notify and require the Buyer to reduce its take of such energy to any amount specified and for any portion of the term of the Transaction; provided, however, this paragraph 2.2 shall not be used to allow interruptions for reasons other than reliability of service to native load. The Buyer shall promptly comply with such requirements of the Seller.

2.3 System Participation Power shall be supplied through transmission facilities that have adequate capacity for transmitting such power and energy, in accordance with any applicable GRSP reliability standards and procedures.

3. Schedule of Rates

3.1 The rates and term for System Participation Power shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

Product L: Interruptible Load Replacement Energy Service

1. Service to be Provided

1.1 This Product provides for the supply of Interruptible Load Replacement Energy by a Seller to a Buyer when it is economical and practical to do so under the conditions set forth hereinafter.

2. Conditions of Service

2.1 Interruptible Load Replacement Energy may be used by a Buyer to serve interruptible load when that load would otherwise be interrupted.

2.1.1 In order to be eligible for Interruptible Load Replacement Energy Service, the Buyer must report in advance monthly quantities of Certified Interruptible Demand, as specified by the GRSP.

2.1.2 The rate of delivery of energy supplied under this Product in any hour shall not exceed the Buyer's total Certified Interruptible Demand ("CID").

2.1.3 Deliveries of energy may be received under this Product only when a Buyer's maximum System Demand would otherwise be greater than such Buyer's forecast System Demand for the current season, and shall not exceed the lesser of either that required to reduce the expected System Demand to the forecast System Demand or the Buyer's Certified Interruptible Demand being served by a purchase under this Product L.

2.1.4 Interruptible Load Replacement Energy Service shall be supplied through transmission facilities which have adequate capacity for transmitting such power and energy, in accordance with any applicable GRSP reliability standards and procedures.

3. Schedules of Rates

3.1 The rates and term for Interruptible Load Replacement Energy Service shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

Product M: General Purpose Energy Service

1. Service to be Provided

1.1 This Product provides for the supply of General Purpose Energy by a Seller to a Buyer to enhance economic system operation.

2. Conditions of Service

2.1 To the extent practicable, General Purpose Energy shall be used to improve the overall economy of the systems involved in the Transaction.

2.2 General Purpose Energy shall be supplied through transmission facilities which have adequate capacity for transmitting such energy, in accordance with any applicable reliability standards and procedures.

3. Schedule of Rates

The rates and term for General Purpose Energy shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

EXHIBIT A
MID-CONTINENT ENERGY MARKETERS ASSOCIATION
CAPACITY AND ENERGY TARIFF

CONFIRMATION LETTER

This confirmation letter shall confirm the Transaction agreed to on ___________, ___ between ___________________________ (as "Seller") and ______________________ (as "Buyer") regarding the sale/purchase of the Product under the terms and conditions as follows:

Schedule P Product:

[] Into _________________, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] Non-Firm

[] System Firm

(Specify System:) ____

[] Unit Firm

(Specify Unit(s): ____

[] Other: ____

[] Transmission Contingency (If not marked, no transmission contingency)

[] FT-Contract Path Contingency [] Seller [] Buyer

[] FT-Delivery Point Contingency [] Seller [] Buyer

[] Transmission Contingent [] Seller [] Buyer

[] Other transmission contingency

(Specify: ____)

Schedule Q Product:

[] Product A – Participation Power Interchange Service

[] Product J – Firm Power Interchange Service

[] Product K – System Participation Power Interchange Service

[] Product L – Interruptible Load Replacement Energy Service

[] Product M – General Purpose Energy Service

Contract Quantity: ______________________________

Delivery Point: ______________________________

Contract Price: ______________________________

Energy Price: ______________________________

Other Charges: ______________________________

Delivery Period: ______________________________

Special Conditions: ______________________________

____

____

____

____

____

____

Scheduling: ______________________________

Option Buyer: ______________________________

Option Seller: ______________________________

Type of Option: ______________________________

Strike Price: ______________________________

Premium: ______________________________

Exercise Period: ______________________________

This confirmation letter is being provided pursuant to and in accordance with the Mid-Continent Energy Marketers Association Capacity and Energy Tariff (the "Tariff") and constitutes part of and is subject to the terms and provisions of such Tariff. Terms used but not defined herein shall have the meanings ascribed to them in the Tariff.

Seller	Buyer
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
Phone No: ______________________	Phone No: ______________________
Fax: ______________________	Fax: ______________________

EXHIBIT B
MID-CONTINENT ENERGY MARKETERS ASSOCIATION
CAPACITY AND ENERGY TARIFF

SUPPLEMENTARY AGREEMENT

Between

____

and

____

This Supplementary Agreement is made as of ___________ ("Effective Date") by ____________ ("Party A") and ___________ ("Party B") ("Supplementary Agreement").

Whereas Party A and Party B are MEMA Members and desire to transact in accordance with the terms and conditions contained in the Tariff, as amended, restated or replaced from time to time;

And Whereas, if an to the extent that Party A and Party B carry on business, transact or act pursuant to the Agreement, Party A and Party B wish to make elections with respect to certain options contained in the Tariff, as set forth in this Supplementary Agreement. Such elections shall not, however, apply as between Party A or Party B and any other MEMA Members.

Now therefore, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree that if and to the extent that Party A and Party B carry on business, transact or act pursuant to the Agreement, the Parties agree as follows:

1. **Article Three Election - Confirmations**

☐ Written Confirmation
☐ Oral Confirmation
☐ Electronic Confirmation
If Electronic Confirmation is applicable, complete the appropriate specific confirmation provisions below

<u>Specific Confirmation Provisions</u>

(i) Electronic Confirmation Method:
Electronic means of communication to be used by Party A and Party B shall be:

(ii) Other Provisions: (if required)

2. **Article Nine Election - Credit Assurance**

For the purposes of Article Nine, the Parties hereto make the following elections:

Section 9.2 Credit Assurances

☐ Option 1
☐ Option 2
☐ Option 3
If Option 3 is applicable, complete the following:
Downgrade Event for Party A shall mean:______________________________
Downgrade Event for Party B shall mean:______________________________
☐ Option 4 (see Schedule A)

3. **Guarantors**

Party A:

☐ Not Applicable
☐ Applicable
If applicable, complete the following:
Guarantor for Party A: ______________________

Party B:

☐ Not Applicable
☐ Applicable
If applicable, complete the following:
Guarantor for Party B: ______________________

4. **Amendments to Tariff**

☐ Not Applicable
☐ Pursuant to Section 3.6 of the Tariff, Party A and Party B agree to amend the Tariff as follows: ______________________________
____
____

5. **Notices**

Party A:

Address: ______________________
____
____

Attention: ______________________
Telephone No.: ______________________
Facsimile No.: ______________________

Party B:

Address: ______________________________
____
____

Attention: ______________________________
Telephone No.: ______________________________
Facsimile No.: ______________________________

6. **Effect**. This Supplementary Agreement shall be applicable to all Transactions entered into between Party A and Party B pursuant to the Agreement on or after the Effective Date without the need to reference this Supplementary Agreement in any such Transaction unless Party A and Party B mutually agree otherwise with respect to a particular Transaction. Capitalized terms used but not defined in this Supplementary Agreement shall have the meanings ascribed to them in the Tariff.

7. **Entire Agreement**. This Supplementary Agreement constitutes the entire agreement and understanding of the Parties with respect to its subject matter and supersedes all oral communication and prior writings (except as otherwise provided herein) with respect thereto.

8. **Counterparts**. This Supplementary Agreement may be executed and delivery in counterparts (including by facsimile transmission), each of which will be deemed an original.

9. **Authority to Bind**. By signing below, each individual additionally warrants that he or she is authorized to sign this Supplementary Agreement on behalf of the Party for which it was executed.

10. **Headings**, The headings used in this Supplementary Agreement are for convenience of reference only and are not to effect the construction of or to be taken into consideration in interpreting this Supplementary Agreement. In witness whereof, the Parties have executed this Supplementary Agreement with effect from the date above written.

Party A:	**Party B:**
______________________________	______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________

Attachment F

COMBUSTION TURBINE SITE STUDY

Combustion Turbine Site Study

Prepared by

Alan Welte
Manager of Generation

February 2011

Combustion Turbine Site Study
February 2011

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1.0 Executive Summary

As part of Montana-Dakota Utilities Co. (Montana-Dakota) electric supply-side resource planning, three sites were analyzed for a self-built 88 MW Simple Cycle Combustion Turbine (SCCT). This report presents the background and the results of the site analysis for a reference SCCT. Three North Dakota sites were selected with an emphasis on the availability of water, electric transmission, and natural gas supply. The sites included areas near Richardton, Linton, and Mandan. The unit capital cost and capacity estimates for each site are presented in Table 1. The Mandan site has the lowest estimated capital cost, the highest projected capacity, and the lowest potential operational costs if integrated with the Heskett Station operation. Based on the results of the analysis, the Mandan site was chosen, and the unit capital cost and capacity information was included with other resource options in the resource expansion analysis using the Electric Generation Expansion Analysis System (EGEAS) model.

Table 1. SCCT Cost Summary[1]

	Richardton, ND	**Linton, ND**	**Mandan, ND**
Capital Cost Estimate (2010$ million)	$73.47	$74.61	$71.59
Base Load (kW)	86,279	87,388	88,054
Peak Load (kW)	93,525	94,707	95,418
Peak Load ($/kW)	$786	$788	$750

[1] *Estimate for single nozzle GE 7EA Simple Cycle Combustion Turbine with water injection for NO_x control. See Appendix A - PS&I Self-Build Capital Cost Estimate (SCCT), Page A-1*

2.0 Introduction

A supply-side resource analysis is periodically conducted to identify the feasible resources to be added to Montana-Dakota's generation system. Resource expansion analysis considers use of available generation resource alternatives to expand the generation portfolio to meet Montana-Dakota's forecasted energy and capacity requirements. The capacity, capital cost, fixed operating and maintenance (O&M) costs, variable O&M costs, and fuel costs for the resource alternatives are modeled using the Electric Generation Expansion Analysis System (EGEAS) software developed by Electric Power Resource Institute (EPRI).[2] This report details the evaluation of three North Dakota sites for an 88 MW reference SCCT. Capital cost and capacity estimates were developed individually for each site.

2.1 Overview of SCCT Analysis Approach

To develop the unit capital cost and capability estimates for a SCCT, a number of assumptions must be made and criteria determined to compare alternatives. Section 3 discusses the selection of a representative combustion turbine. Electric transmission system interconnection, fuel supply, water supply, environmental permitting, and other criteria are described in Section 4. Criteria comparisons are presented in Section 5. Preliminary cost and capability estimates for a reference SCCT, along with the proposed site location, are presented in Section 6. Cost estimates and other factors were developed from site visits, manufacturer's budgetary pricing, consulting engineers, Montana-Dakota's experience and expertise, and other available sources.

3.0 Reference Combustion Turbine

Simple Cycle Combustion Turbines (SCCTs) are primarily utilized for peaking service and often supply a limited amount of energy because they are fueled by natural gas or fuel oil. The SCCT generally has lower capital costs compared to other unit types and can be installed within short time periods (two to three years from placement of equipment order). There are primarily two SCCT types. The heavy-duty (Frame) type is designed to drive stationary

[2] *See Chapter 4 – 6 of and Attachment C to this 2011 IRP report.*

generation sources and process plant equipment. The aero-derivative (Aero) type design is derived from engines used in the aircraft industry. Montana-Dakota has operating experience with four Frame units and one Aero unit. Table 2 lists several of the noteworthy differences between the two types.

Table 2. SCCT Type Comparison

SCCT Type	Costs	Emissions	Other Factors	Operating Experience
Frame Unit (GE 7EA reference), compared to Aero	Lower per kW Capital Cost	NOx control more robust due to more residence time for proper fuel-air mixing. Dry Low NOx (DLN) capable of 9 ppm	Most major maintenance can be performed on site.	More stable combustion control. Auto tune capable.
	Lower per kW fixed O&M Costs	Better turn-down capability while meeting guaranteed emissions (to 50 percent versus 70 percent for Aero).	Lower inlet natural gas pressure requirement. Pressure is 385 psi for Frame versus 675 psi for Aero.	Less impacted by cold weather.
	Lower per MWh Variable Maintenance Costs		Longer on-site construction period	Less technical complexity. Problems can be resolved more frequently by internal staff.
	Higher per MWh fuel costs at rated output		More robust due to design specific for stationary generation.	
Aero-derivative (GE LM6000 reference) compared to Frame	Higher per kW Capital Cost	NOx control less robust due to less residence time for proper fuel-air mixing. Dry Low Emissions (DLE) capable of 15 ppm	Major maintenance performed off site at repair facility.	Requires frequent combustion tuning to maintain operability and optimum emissions.
	Higher per kW fixed O&M Costs	Worse turn-down capability while meeting guaranteed emissions. (to 70 percent versus 50 percent for Frame).	Higher inlet natural gas pressure requirement. Pressure is 675 psi for Aero versus 385 psi for Frame type.	Susceptible to cold weather operations problems. Fuel heating required to avoid contamination of combustion system.
	Higher per MWh Variable Maintenance Costs		Shorter on-site construction period (more pre-packaged / shipped components)	Technical complexity requires increased training and use of external resources.
	Lower per MWh fuel costs at rated output		Less robust design due to derivation from aircraft engine (size, weight, etc.)	Additional on-site gas compression is required unless connected to a major gas pipeline.

The comparison shows that the Frame type SCCT offers lower capital and O&M costs, lower and more robust emissions control, and a larger turn down capability than an Aero Unit. A Frame type unit requires a lower natural gas inlet pressure, is less technically complex, can have major maintenance performed on-site, is less susceptible to cold weather operational problems, and is better suited to Montana-Dakota's existing operation. Based on the results of the comparison, the GE 7EA Frame unit was chosen as the reference SCCT to be used in the analysis of the potential sites. [3]

4.0 Site Evaluation Criteria

For the purpose of establishing capital cost and capability estimates for the representative SCCT, consideration was given to a number of site specific criteria including the interconnection to the transmission system, availability of a natural gas and water supply, environmental permitting, and other items. These items are described in the following sections. Comparisons for the selected sites are shown in Section 5, Tables 3 through 6.

4.1 Natural Gas Supply

Montana-Dakota's existing combustion turbines located at Miles City and Glendive, Montana are connected to the Williston Basin Interstate Pipeline Co. (WBI) natural gas pipeline system. The pipeline is used to transport purchased natural gas to Montana-Dakota's combustion turbines. The WBI FERC Tariff/Service Agreements guarantees a natural gas supply pressure of 200 psi and, under interruptible service agreements, the pipeline capacity is subject to interruption when the demand for natural gas exceeds the supply. As presented in Table 2, the pressure required to achieve full output is approximately 385 psi for a Frame type SCCT and 675 psi for the Aero type SCCT. Historical WBI pipeline pressures have often been high enough to meet the full output requirements for the Frame type SCCTs, but when the pressure drops to the tariff minimum, the output capability of the turbines can suffer. For the Aero type SCCTs, the potential of lower WBI pipeline pressures require that additional on-site gas compression equipment be installed, adding to the capital and O&M costs as well as the operational complexity for site

[3] *See Appendix B to this Attachment for SCCT Suppliers and availability information.*

personnel. Montana-Dakota has mitigated the impacts of lower than optimum pipeline pressure and potential delivery interruptions to the existing gas turbines by purchasing units that are able to burn fuel oil as a secondary fuel source and by contracting enough firm gas transportation capacity to transition between fuel oil and natural gas during start-up and shutdown of the combustion turbines. This ensures that certificated generation capacity is available at all times. However, the dual fuel capability adds to the complexity of operations and at times has resulted in operability and environmental compliance concerns.

To reduce the risks of low natural gas supply pressure and supply interruptions, sites were selected where the reference SCCT could be connected to the Northern Border pipeline system. The Northern Border pipeline system offers a consistent source of high pressure natural gas, the potential of firm natural gas supply and firm transportation contracts (eliminating the potential for interruptions), and therefore eliminates the need for additional on-site gas compression equipment and the complexity and problems inherent with dual fuel combustion.

4.2 Electric Transmission Interconnection

As a member of the Midwest Independent Transmission System Operator (MISO), Montana-Dakota evaluated sites for the representative SCCT within the MISO transmission footprint where the point of generator interconnect is to Montana-Dakota owned transmission facilities. The number of selected sites was narrowed by investigating locations within reasonable proximity to a natural gas supply as discussed in Section 4.1. Consideration was also given to locations where a new SCCT would strengthen Montana-Dakota's electric system and where future transmission upgrades are already planned. Preliminary estimates of costs to connect the representative SCCT generating facility to the transmission system and to address potential transmission network system impacts (relating to short circuit, instability, and power flow issues) were developed. Final costs for required network transmission upgrades for the SCCT will be determined through the MISO generator interconnection queue study process. For transmission facilities less than 345 kV, one hundred percent (100%) of the required network transmission upgrades are assigned to the interconnecting generator(s).

4.3 Water Supply

Combustion turbines require water of sufficient quantity and quality for evaporative inlet air cooling to maximize unit output in high ambient temperatures and for injection into the combustion zone for nitrogen oxide (NO_x) emissions control. The estimated water requirements for the reference SCCT are 40 gallons per minute (gpm) for evaporative inlet air cooling and 90 gpm for NO_x control. Options are also available to control the reference SCCT's NO_x emissions by installing dry low NO_x (DLN) combustion hardware which reduces the water requirement.

Sources of water include wells, rivers, regional pipelines, and municipal systems. Water purchase costs from regional pipelines and municipal systems are anticipated to be higher than those for water supplied directly from wells or river intakes.

4.4 Environmental Permitting and Other Factors

The Montana-Dakota Environmental Department has made a preliminary determination that there are no fatal flaws in permitting the reference SCCT at each of the selected sites. However, additional pre-construction analysis and permitting, including the Certificate of Site Compatibility, Route Permit for the natural gas pipeline, air Permit-to-Construct, air Title V permitting changes, and water discharge permitting, will be required for a SCCT project.

Synergies and cost reductions from sharing facilities, equipment, supervision, and labor can be achieved by locating a new SCCT near an existing electric generating unit. Therefore, locations near Montana-Dakota's generating stations were considered.

Topography, site access and roads, potential routing of transmission lines and pipelines, constructability and environmental factors were assessed during visits to the potential sites.

5.0 Summary of Site Evaluation

Based on the criteria presented in Section 4, a number of sites were investigated, and three North Dakota sites were ultimately selected for final evaluation. Appendix C to this Attachment shows the sites considered in preliminary screening. Tables 3 though 6 present a comparison of the selected sites located near Richardton, Linton, and Mandan (adjacent to Heskett Station). A map depicting the site locations is included in Appendix D to this Attachment.

Table 3. Natural Gas Supply Comparison

Natural Gas Supply	Richardton, ND	Linton, ND	Mandan, ND
Pipeline	Northern Border	Northern Border	Northern Border
Pipeline tap required	Yes	No (share existing)	Yes
Nominal Pipeline Diameter (inches)	8	8	8
Pipeline Length - Tap to SCCT site (miles)	1	1	24
Nominal Pipeline Pressure (psi)	1,000	1,000	1,000
Capital Cost (2010$ million)	$3.00	$1.00	$14.98

The Linton site has the lowest estimated natural gas supply capital cost due to a shorter delivery pipeline length and the potential for sharing an existing pipeline tap. The Mandan site has the highest estimated capital costs due to a 24 mile delivery pipeline and the need for a new tap on the Northern Border pipeline.

Table 4. Electric Transmission Interconnect Comparison

Electric Transmission	**Richardton, ND**	**Linton, ND**	**Mandan, ND**
Point of Interconnection	Coyote to Dickinson 115 kV line	Bismarck to Linton 115 kV line	Existing Mandan Junction or Heskett 115 kV substations
System Upgrades	Upgrade Coyote to Dickinson and Coyote to Beulah Junction 115kV lines (54 miles), and replace one transformer at Dickinson.	Upgrade Bismarck to Linton 115kV lines (45 miles), and replace one transformer at Wishek.	Minor upgrades to transmission system near Heskett Station. Enhances electric system in Bismarck-Mandan area.
Capital Cost (2010$ million)	$14.50	$17.88	$2.00

The Mandan site has a lower estimated electric transmission interconnect capital cost than the other sites due to less required system upgrades, and this site offers the potential for enhancing the Bismarck-Mandan area electric system reliability. Additionally, the Mandan site would require fewer construction-related transmission system outages.

Table 5. Water Supply Comparison

Water Supply	Richardton, ND	Linton, ND	Mandan, ND
Source of Water	River Water	Well Water	River Water
Point of Connection	Southwest Water Pipeline	Municipal System	Shared water intake with Heskett Station
Pipeline and Equipment	Pipeline and storage equipment (one mile)	Pipeline (six miles)	Pipeline (one mile)
Available Water Supply Capacity	Limited by existing capacity of Southwest Pipeline system.	Limited by existing capacity of municipal system.	Not expected to be limited (pending review of final water discharge parameters and potential new regulatory requirements)
Cost of Water	High water cost. May include costs to upgrade Southwest Water Pipeline system.	High water cost. May require costs to upgrade municipal system.	Low cost
Capital Cost (2010$ million)	$0.42	$0.31	$0.05

The Mandan site has a lower estimated water supply capital cost due to the potential for sharing the Heskett Station intake. The water available at the other two sites may be limited by the existing regional pipeline or municipal system capacity. The cost of upgrades to these systems would likely be included in the cost of water from the supplier.

Table 6. Environmental Permitting and Other Factor Comparison

Environmental Permitting & Other Factors	Richardton, ND	Linton, ND	Mandan, ND
Preliminary Environmental Fatal Flaw Determination	None	None	None
Environmental Permitting Complexity	Low	Low	High
Unit performance	Low	Low	High (Lower elevation)
Shared facilities and equipment	None	Existing Northern Border pipeline tap	Shared water intake and treatment, communications, control room, buildings, vehicles, tools, consumables with Heskett Station
Shared supervision and labor	None	None	Possible integration of supervision and labor for operations, maintenance, and engineering functions with Heskett Station.
Combustion Turbine Stack height/costs	Low	Low	High
Land costs	High	High	Low (Montana-Dakota Owned Property)

There are no identified environmental fatal flaws for the three sites. The complexity in environmental permitting is, however, anticipated to be highest at the Mandan site due to proximity to and integration with the Heskett Station.

At the Mandan site, the potential for sharing of facilities, equipment, supervision, and labor with the Heskett Station will result in reduced operating costs, and would not require the purchase of additional land.

6.0 Proposed SCCT and Site

Based on the results of the cost estimates and comparison of the site evaluation criteria, the Mandan site is recommended for the future installation of an 88 MW GE 7EA Frame type simple cycle combustion turbine.

The Frame type is recommended over an Aero type unit because it offers lower capital and O&M costs, lower and more robust emissions control, and a larger turn down capability. It requires a lower natural gas inlet pressure, is less technically complex, can have major maintenance performed on site, is less susceptible to cold weather operational problems, and is better suited to Montana-Dakota's existing operation than an Aero type unit.

The Mandan site has the lowest estimated total capital cost, the highest projected capacity, and the lowest potential operational cost if integrated with the Heskett Station. Higher natural gas pipeline costs are offset by reduced electric transmission upgrade costs. Sharing of the existing Heskett Station intake will result in lower pipeline and water costs. The Mandan site has the potential for sharing of facilities, equipment, supervision, and labor with the Heskett Station that will result in reduced operating costs, and it would not require the purchase of additional land.

The unit capital cost and capacity estimates for each site are presented in Table 7.[4] An additional conservative case is presented for the Mandan location.[5] Contingency was added in developing this case to address potential environmental permitting complexities of locating the SCCT in proximity with Heskett Station. The conservative case remained competitive with the other sites on a cost per unit of installed capacity basis. The base load capital cost and capacity estimates for the Mandan site conservative case were submitted to the System Operations Department for inclusion with other resource options in the resource expansion analysis.

[4] *Estimate for single nozzle GE 7EA Simple Cycle Combustion Turbine with water injection for NO_x control. See Appendix A - PS&I Self-Build Capital Cost Estimate (SCCT), Page A-1*

[5] *Estimate for single nozzle GE 7EA Simple Cycle Combustion Turbine with water injection for NO_x control and ~$3.8M added for environmental permitting complexity. See Appendix A - PS&I Self-Build Capital Cost Estimate (SCCT), Page A-2*

Table 7. SCCT Capital Cost and Capacity

	Richardton, ND	Linton, ND	Mandan, ND	Mandan, ND (conservative)
Capital Cost Estimate (2010$ million)	$73.47	$74.61	$71.59	$75.42
Base Load (kW)	86,279	87,388	88,054	88,054
Base Load ($ per kW)	$851	$854	$813	$857
Peak Load (kW)	93,525	94,707	95,418	95,418
Peak Load ($ per kW)	$786	$788	$750	$790

Appendix A
PS&I Self-Build Capital Cost Estimate (SCCT)

Site 3 - Normal Case

PS&I Self-Build Capital Cost Estimate (SCCT)			
	SITE 1[A]	SITE 2[B]	SITE 3[C]
BASE LOAD [$/kW @ Rated kW]	$ 851.49	$ 853.74	$ 813.07
	86,279	87,388	88,054
BASE LOAD (DLN) [$/kW @ Rated kW]	$ 921.83	$ 925.39	$ 882.29
	81,951	83,018	83,649
PEAK LOAD [$/kW @ Rated kW]	$ 785.52	$ 787.76	$ 750.32
	93,525	94,707	95,418
PEAK LOAD (DLN) [$/kW @ Rated kW]	$ 887.43	$ 890.90	$ 849.43
	85,128	86,232	86,885
	SITE 1[A]	SITE 2[B]	SITE 3[C]
CIVIL	$ 3,393,600	$ 3,393,600	$ 2,969,850
MECHANICAL	$ 36,801,000	$ 36,691,000	$ 36,167,100
NATURAL GAS PIPELINE	$ 2,996,622	$ 996,622	$ 14,981,006
ELECTRICAL	$ 4,361,020	$ 4,361,020	$ 4,361,020
TRANSMISSION LINE	$ 14,500,000	$ 17,875,000	$ 2,000,000
ENGINEERING & SUPERVISION / OTHER	$ 4,826,169	$ 4,822,869	$ 4,794,439
OWNER'S COSTS	$ 3,804,029	$ 3,694,595	$ 3,602,415
SUBTOTAL	**$ 70,682,440**	**$ 71,834,706**	**$ 68,875,830**
CONTINGENCY	$ 2,659,291	$ 2,648,154	$ 2,594,741
ES & GA	$ 123,600	$ 123,600	$ 123,600
AFUDC	$ -	$ -	$ -
CWIP	$ -	$ -	$ -
TOTAL	**$ 73,465,331**	**$ 74,606,460**	**$ 71,594,172**
TOTAL (DLN)	$ 75,545,284	$ 76,823,971	$ 73,802,938

Last Revised: August 3, 2010

[A] Site Location: Richardton, ND

[B] Site Location: Linton, ND

[C] Site Location: Mandan, ND

Site 3 - Conservative Case

PS&I Self-Build Capital Cost Estimate (SCCT)^			
	SITE 1[A]	SITE 2[B]	SITE 3[C D]
BASE LOAD [$/kW @ Rated kW]	$ 851.49	$ 853.74	$ 856.53
	86,279	87,388	88,054
BASE LOAD (DLN) [$/kW @ Rated kW]	$ 921.83	$ 925.39	$ 928.04
	81,951	83,018	83,649
PEAK LOAD [$/kW @ Rated kW]	$ 785.52	$ 787.76	$ 790.43
	93,525	94,707	95,418
PEAK LOAD (DLN) [$/kW @ Rated kW]	$ 887.43	$ 890.90	$ 893.48
	85,128	86,232	86,885
	SITE 1[A]	SITE 2[B]	SITE 3[C D]
CIVIL	$ 3,393,600	$ 3,393,600	$ 2,969,850
MECHANICAL	$ 36,801,000	$ 36,691,000	$ 36,167,100
NATURAL GAS PIPELINE	$ 2,996,622	$ 996,622	$ 14,981,006
ELECTRICAL	$ 4,361,020	$ 4,361,020	$ 4,361,020
TRANSMISSION LINE	$ 14,500,000	$ 17,875,000	$ 2,000,000
ENGINEERING & SUPERVISION / OTHER	$ 4,826,169	$ 4,822,869	$ 4,894,939
OWNER'S COSTS	$ 3,804,029	$ 3,694,595	$ 3,796,484
SUBTOTAL	**$ 70,682,440**	**$ 71,834,706**	**$ 69,170,399**
CONTINGENCY	$ 2,659,291	$ 2,648,154	$ 6,126,970
ES & GA	$ 123,600	$ 123,600	$ 123,600
AFUDC	$ -	$ -	$ -
CWIP	$ -	$ -	$ -
TOTAL	**$ 73,465,331**	**$ 74,606,460**	**$ 75,420,969**
TOTAL (DLN)	$ 75,545,284	$ 76,823,971	$ 77,629,736

Last Revised: August 3, 2010

[A] Site Location: Richardton, ND

[B] Site Location: Linton, ND

[C] Site Location: Mandan, ND

[D] ~$3.8M added for environmental permitting complexity (conservative case)

^ Sent to System Operations on September 2, 2010

^ Sent to System Operations on September 2, 2010

Appendix B
SCCT Suppliers

Simple Cycle Combustion Turbines (SCCT) Suppliers					
Manufacturer / Model	**Size (Mw)**	**Type**	**Difference from Base Cost (%)**	**Origin[2]**	**Proposal Received[4]**
General Electric					
6B PG6581	42	Frame	13%	Europe	No
LM6000 PD	43	Aero	27%	US	No
6FA PG6111	77	Frame	4%	Europe	No
7EA PG7121	85	Frame	Base[1]	US	Yes
LMS100 PA	103	Aero	13%	US	No
7FA PG7241[3]	183	Frame	-13%	US	No
Alstom					
GT11N2	115	Frame	-5%	Europe	Yes
Siemens					
SG T6-2000E	113	Frame	-	Europe	Declined
Mitsubishi Heavy Industries					
M501DA	114	Frame	-	-	No Response

1 / Combustion Turbine costs from 2010 Gas Turbine World Handbook. Base case is a GE 7EA SCCT.

2 / Turbine FOB manufacturer location. Europe origins impacted by currency exchange & shipping costs.

3/ Too large for MDU requirements.

4/ Budgetary proposals of $296/kW for GE 7EA and $376/kW for Alstom GT11N2 received (FOB manufacturer location for CT equipment only).

Appendix C
Combustion Turbine Sites / Natural Gas Sources

5-May-08

Combustion Turbine / Natural Gas Sources

Baker

- Connect to Grasslands Pipeline or WBI Baker to Glendive pipeline
- Connection to Grasslands should not need additional compression
- Baker to Glendive line would require compression
- Reduced transport limitations (curtailments) on Grasslands
- WBI tariff pricing for transportation (approx. 31 cents)
- Synergies with Diamond Willow and Glendive
- Access to Rockies Gas and Ventura based gas
- Possible land from WBI at Baker Booster or Cabin Creek

Bismarck

- Would require compression
- Less than 3,000 dk/day of firm gas available without upgrades to Glen Ullin
- Would require compression
- Fuel pricing is Ventura Based
- WBI tariff price for transport (approx. 31 cents)
- Synergies with Heskett Station
- Availability of water for combined cycle unit
- Potentially beneficial to electric grid

Linton

- Firm Transportation Available on Northern Border
- Interconnect limited to 40 MW without significant upgrades
- Fuel pricing is Ventura based
- Northern Border tariff pricing for transport (approx. 30 cents)
- Potential high pressure gas - no compression required
- Using MDU Gas Supply Tap would save interconnection charge but subject turbine to Montana-Dakota gas distribution tariff rates
- Potentially beneficial to electric grid

Mobridge

- Connect to Montana-Dakota
- High transportation cost (approx. $2.88)
- Fuel pricing is Ventura based
- Would require compression
- Firm gas available from Montana-Dakota
- Availability of water for combined cycle unit
- Potentially beneficial to electric grid

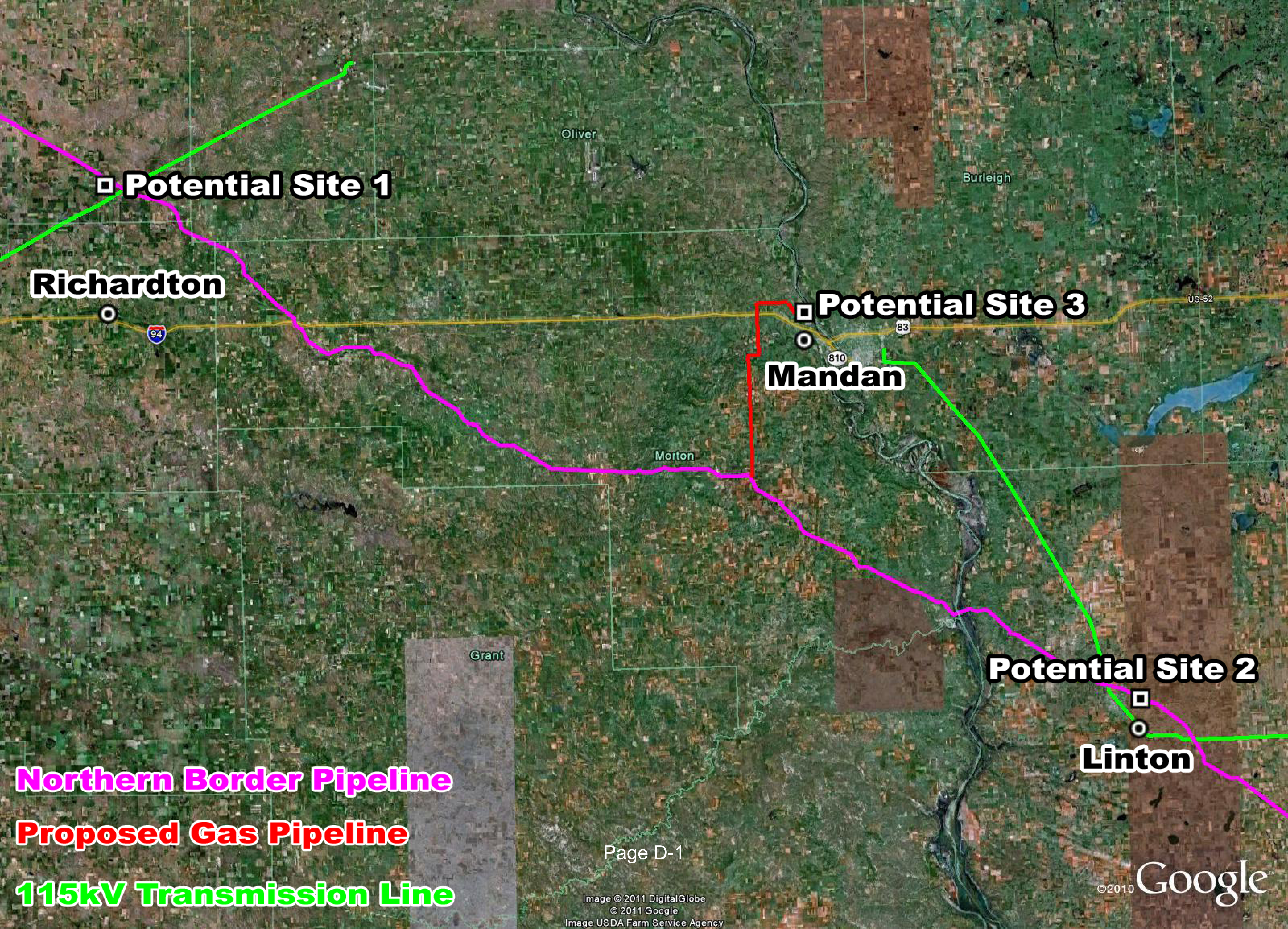
Tioga

- Connect to Amerada Hess for supply
- 10,000 to 20,000 dk/day gas supply available
- High pressure gas - no compression required
- Potentiall no transportation charge for gas from Amerada
- Fuel pricing in Ventura based
- Potential new electric customer (?)
- Questions on potential electrical interconnection size (undetermined and potentially problematic)
- Potential land available from Amerada Hess

Williston

- Access to Norther Border and WBI pipelines
- Compression may not be required
- Fuel pricing is Ventura Based
- Future electrical system upgrades are planned in area
- Power Production currently owns land in Williston area

Appendix D
Map of Sites


Potential Site 1
Oliver
Burleigh
Richardton
94
Potential Site 3
US-52
83
810
Mandan
Morton
Grant
Potential Site 2
Linton
Northern Border Pipeline
Proposed Gas Pipeline
115kV Transmission Line
Image © 2011 DigitalGlobe
© 2011 Google
Image USDA Farm Service Agency
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Attachment G

POLLUTION CONTROL PROJECTS

POLLUTION CONTROL PROJECTS

The U.S. Environmental Protection Agency (EPA) has made known that it intends to propose several significant new air emissions regulations that aim to reduce air emissions, including the greenhouse gases, at coal-fired electric generating facilities. Montana-Dakota will continue to monitor the impacts from proposed regulations and will take the regulations into consideration when planning for future resource needs.

One of these regulations is the EPA National Emission Standards for Hazardous Air Pollutants (HAP) Rule for Coal-fired Utilities which proposes to require maximum achievable control technology (MACT) pollution controls to be installed to reduce HAP emissions. The Utility MACT rule, as it is called, was proposed on March 16, 2011 and is projected to be final by November 16, 2011. Montana-Dakota has not completed review of this proposed rule, and plans to include a discussion on the potential impacts from this rule in the future IRPs.

Regional Haze Rule

The EPA promulgated the Regional Haze Rule (RHR) in 1999 to address visibility impairment in Class I areas in the United States, constituting 156 national parks and wilderness areas. This rule was developed in accordance with the Clean Air Act's (CAA) national goal of remedying existing and preventing future visibility impairment of Class I areas due to man-made air pollution. In 2005, the EPA published a revised rule that included guidelines for control technology determinations under the RHR for Best Available Retrofit Technology (BART) sources and for sources addressed for reasonable progress.

State environmental agencies like the South Dakota Department of Environment and Natural Resources (DENR) and North Dakota Department of Health (NDDH) are required to submit State Implementation Plans (SIPs) to EPA that develop and implement their strategy to reduce emissions that may contribute to regional haze, and to set reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064. Additional detail on the RHR is provided in Attachment H in conjunction with detailed discussion about the Big Stone Plant's Air Quality Control System (AQCS) Project which is proposed to be implemented to comply with the BART requirements of the RHR.

R.M. Heskett Station Unit 2

In conjunction with the North Dakota Department of Health's Reasonable Progress Goals, Montana-Dakota has committed to implement limestone injection at R.M. Heskett Station Unit 2 to reduce sulfur dioxide (SO_2) emissions for compliance with the RHR. The limestone injection project entails replacing a portion of the sand that is currently injected into the fluidized bed of Unit 2 with limestone to increase capture of SO_2 and is expected to be completed at a cost of approximately $6.5 million. According to the State of North Dakota Regional Haze (ND Haze) SIP, Unit 2 must demonstrate compliance with the SO_2 emissions reductions as expeditiously as practicable, but not later than five years from the EPA's approval of the ND Haze SIP. The ND Department of Health submitted its initial ND Haze SIP to the EPA on March 3, 2010 and submitted Supplement No. 1, which included its final determination on R.M. Heskett Unit 2, to the EPA on August 3, 2010.

The limestone injection at R.M. Heskett Station Unit 2 is also deemed to be necessary in order for the unit to comply with acid gas emissions reductions required in newly proposed EPA air emissions regulations for coal-fired facilities and in the approximate same compliance timeframe.

Coyote Station

Montana-Dakota committed to implement separated overfire air (SOFA) at the Coyote Station to reduce nitrogen oxide (NO_x) emissions for compliance with the RHR under the rule's reasonable progress goal requirements. Montana-Dakota is a 25 percent owner of Coyote and committed to this reduction with the plant's other joint owners. SOFA involves modifying the boiler to inject air at different staged zones, diverting a portion of the combustion air from the burners and injecting it through ports located at higher levels in the boiler. Staging the combustion air reduces NO_x formation by cooling the flame and limiting the amount of oxygen that reacts with the fuel. SOFA is expected to be completed at a cost of approximately $6 million. According to the ND Haze SIP, Coyote Station must demonstrate compliance with the NO_x emissions reductions by July 1, 2018.

Lewis & Clark Station

Lewis & Clark Station (L&C) must also comply with the RHR under the rule's reasonable progress goal requirements. However, the State of Montana returned administration of the RHR to EPA, requiring EPA to develop and implement the strategy for reducing emissions that may contribute to regional haze within Montana's Class I areas. The EPA will propose a Regional

Haze Federal Implementation Plan for the State of Montana in the near future that is expected to include emissions reductions from L&C. Montana-Dakota recently submitted a report to the EPA that identified potential SO_2 and NO_x pollution control technologies for further reducing visibility impairing emissions at L&C to meet the RHR requirements. Montana-Dakota does not yet know what pollution controls would be required at L&C, or the compliance timeline.

Big Stone Plant's Air Quality Control System

As shown in Chapters 4 – 6 and in detailed discussion in Attachment H of this 2011 IRP report, Montana-Dakota is studying the proposed air quality control system at the Big Stone Plant, of which Montana-Dakota is a 22.7 percent owner. The Big Stone AQCS project will also be required to comply with the RHR and the South Dakota Regional Haze State Implementation Plan ("SD Haze SIP") as well as the State of South Dakota's associated rules. The Big Stone AQCS project is estimated to cost a total of $489 million.

The SD Haze SIP and its implementing rules require that the Big Stone AQCS be installed as expeditiously as practicable, but not later than five years from the EPA's approval of the SD Haze SIP, which was filed on January 21, 2011, resulting in the Big Stone AQCS project required as early as 2016.

Attachment H

BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT

BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT

Table of Contents

Executive Summary

This attachment describes the proposed Air Quality Control System Project at the Big Stone Plant (the "Big Stone AQCS" or "AQCS Project"). Montana-Dakota Utilities Co. (Montana-Dakota) owns a 22.7 percent share of the Big Stone Plant. The Big Stone AQCS is needed to comply with the federal Clean Air Act ("CAA"), federal air quality regulations that address regional haze, and the South Dakota Regional Haze State Implementation Plan ("SD Haze SIP") as well as the State of South Dakota's associated rules. The AQCS Project will include installation of the following air pollution control equipment:

- Selective Catalytic Reduction with Separated Overfire Air (SCR/SOFA), to reduce nitrogen oxide (NOx) emissions;
- Semi-Dry Flue Gas Desulfurization (FGD), to reduce sulfur dioxide ($SO_{2)}$ emissions; and
- A Baghouse, to reduce particulate matter ("PM") emissions.

The SD Haze SIP and its implementing rules require that the Big Stone AQCS be installed as expeditiously as practicable, but not later than five years from the U.S. Environmental Protection Agency's ("EPA's") approval of the SD Haze SIP. The SD Haze SIP was filed with the EPA on January 21, 2011. Montana-Dakota and the other Big Stone co-owners project that Big Stone AQCS operation and emissions compliance may be required as early as 2016.

The AQCS Project is required for the Big Stone Plant to comply with the CAA and the SD Haze SIP and its implementing rules, Administrative Rules of South Dakota Chapter 74:36:21. According to the South Dakota Department of Environment and Natural Resources' ("DENR") Best Available Retrofit Technology ("BART") determination, the suite of control technologies to be implemented in the Big Stone AQCS will reduce emissions to a level at which the Plant would not contribute to visibility impairment in the Boundary Waters and Voyager's Class I areas in Minnesota, Isle Royale National Park in

Michigan, the Badlands National Park in South Dakota, and the Theodore Roosevelt National Park in North Dakota.

Because the BART requirement is a direct requirement individually determined for Big Stone, the only alternative to installing the AQCS Project and achieving regulatory compliance is to cease operations at the facility as it is currently configured.

The total capital cost for the Big Stone AQCS is estimated to be $489.4 million (2015$) with an accuracy of +/- 20 percent. Montana-Dakota's share of these costs is approximately $111.1 million. Additionally, the plant owners anticipate that installation of activated carbon injection (ACI) mercury control on the Plant, at an estimated cost of $5,012,700, will be required under different federal regulations. This control equipment will be installed concurrently with the AQCS.

As shown in Appendix A to this Attachment, an analysis developed by Burns & McDonnell for the Big Stone Plant co-owners, upon request by Otter Tail Power Company – the operator of the Plant, compared installation of the AQCS Project to several alternatives for providing energy from a generation resource other than the Big Stone Plant – the options for repowering or retiring and replacing the Plant with natural gas. Burns & McDonnell's analysis shows that, under multiple scenarios that consider potential changes in capital, operating and maintenance (O&M), and fuel costs, the installation of the Big Stone AQCS is the least-cost option. The Burns & McDonnell study was based on inputs provide by Otter Tail Power Company but provided an analysis for the co-owners of the alternatives available in lieu of the AQCS Project.

As shown in Chapters 4 - 6 and Attachment C, Montana-Dakota conducted a separate analysis of the Big Stone AQCS. Montana-Dakota's analysis also showed the Big Stone AQCS to be cost effective relative to retrofit or plant closure and replacement. This conclusion does not change when considering the potential for additional costs that may be imposed by anticipated environmental regulation, and does not change when considering the range of CO_2 values under realistic assumptions on when carbon costs might possibly be imposed.

Big Stone Plant Description

The Big Stone Plant ("Plant") is located in Grant County, South Dakota, 2.5 miles northwest of Big Stone City, South Dakota, which is on the Minnesota-South Dakota border. Big Stone is rated at 495 MW gross and 475 MW net electrical output. The Plant has three owners – Montana-Dakota with 22.7 percent of the Plant, Otter Tail Power Company with 53.9 percent, and NorthWestern Energy with 23.4 percent. Otter Tail Power Company is the operator of the Plant. The three utility company owners use the Plant to provide electricity to customers in their South Dakota, North Dakota, Montana, and Minnesota service areas. The Plant began commercial operation on May 1, 1975.

The Plant was constructed and operates as a baseload facility with load following capabilities. Load following is the ability for the unit to adjust its output between full load and partial load to meet the demands of the system.[1] The Plant is one of the two largest baseload generating resources for Montana-Dakota. The Plant also provides electricity, steam and water to the adjacent POET Biorefining Ethanol Plant.

The Big Stone Plant has a single generating unit and receives its fuel by rail from Wyoming. The Big Stone Plant burns low sulfur PRB fuel to limit sulfur dioxide emissions. Particulate emissions are controlled by a baghouse. An overfire air system provides nitrogen oxide control.

The Plant is a zero-liquid discharge facility, meaning that no process water used in Plant operations leaves the site other than through evaporation. Big Stone Lake is the water source for the Plant. Water can only be taken from the lake when lake levels are at or above levels prescribed in water appropriations permits issued by the South Dakota DENR. The water is stored in a cooling pond for use in the condenser for cooling. The Plant also has an evaporation pond and holding pond for maintaining water quality as well as a brine concentrator used to control water chemistry in the cooling pond.

[1] For example, during certain times of the year the Plant's output will be low at night, as demand is low. The Plant will then increase output in the morning as the system load increases. Late in the evening the Plant will decrease its output as load decreases.

The Big Stone Plant has a dry on-site ash disposal area that has been permitted by the South Dakota DENR since initial Plant operation. The ash is transported to the disposal area with conventional earthmoving equipment. The site is underlain with native clay, which serves as a barrier for the disposal area. Each portion of the designated disposal area is covered with clay and topsoil once it is filled to capacity, and groundwater monitoring has been conducted since before Plant operations began.

Requirement to Implement the Big Stone AQCS Project

The federal Clean Air Act established a national goal of remedying any existing and preventing any future impairment of visibility from man-made air pollution in specified "Class I" areas of the United States.[2] Class I areas include 156 national parks and wilderness areas. EPA promulgated the Regional Haze Rule ("RHR") in 1999 to address visibility impairment in these areas, and in 2005 published a revised rule that provided guidelines for control technology determinations under the RHR.[3] State environmental agencies like the South Dakota DENR and North Dakota Department of Health (NDDH) are required to submit State Implementation Plans ("SIPs") to EPA that develop and implement their strategy to reduce emissions that may contribute to regional haze, and to set reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064.

Of the multiple CAA requirements for state regional haze programs, among the most significant requirements is the requirement to install Best Available Retrofit Technology ("BART") on major air emission sources, including existing electric generating units, that were placed into operation between 1962 and 1977.[4] The BART requirement is designed to determine appropriate air pollution control equipment to retrofit on major air emission sources that were constructed before the applicability of the New Source Review program

[2] 42 U.S.C. § 7479 (CAA § 169A).

[3] 40 C.F.R. §§ 51.300 to 51.309 ("Protection of Visibility") & App. Y ("Guidelines for BART Determinations Under the Regional Haze Rule").

[4] *See* 42 U.S.C. § 7491(b)(2)(A) (CAA § 169A(b)(2)(A)).

in the late 1970s.[5] The Big Stone Plant became operational in 1975 and is among the newer plants subject to the BART requirement.

The South Dakota DENR is the agency responsible for developing the SD Haze SIP, which includes the determination of BART emission controls for air emission sources in the state that are subject to the BART requirement. A regional haze SIP includes extensive emission and visibility impact analysis, establishing goals for reasonable progress in improving visibility, development of a long term strategy, and determination of BART requirements for individual facilities.[6] The process of preparing the SIP also includes opportunities for public comment, consultation with Federal Land Managers, and review of proposed plans by neighboring states.

The DENR recently determined that the Big Stone Plant is both BART-eligible and subject to BART, based upon air dispersion modeling indicating that the Plant reasonably contributes to visibility impairment in certain Class I areas in South Dakota, North Dakota, Michigan, and Minnesota.[7] The DENR therefore determined that BART must be installed on the Big Stone Plant.

Since BART is a case-by-case determination for each unit that is subject to BART, the DENR evaluated available control technology for particulate matter ("PM"), sulfur dioxide ("SO_2") and nitrogen oxides ("NO_X"), based on its technical feasibility, cost, non-air impacts, remaining useful life of the source, and projected reduction of visibility

[5] While emission standards had been applied to electric generating units in other Clean Air Act programs before the late 1970s, the New Source Review program was not yet in place. The New Source Review program initiated the requirement that new major sources of air emissions install Best Available Control technology as part of their construction permit requirements. *See* 42 U.S.C. § 7475(a)(4) (CAA § 165(a)(4)).

[6] South Dakota's full SIP contains these elements, and can be found online at: http://denr.sd.gov/des/aq/publicnotices/RegionalHazeSIPDraft.pdf.

[7] The South Dakota DENR determined that, based on air dispersion modeling results, the Big Stone Plant would be reasonably anticipated to contribute to an impairment of visibility at the following Class I Areas: Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, Isle Royale National Park in Michigan, and Voyagers National Park and the Boundary Waters Canoe Area in Minnesota. The detailed technical analysis and associated modeling results are fully set forth in the SD Haze SIP, §§ 6.1.3, Otter Tail Power Company-Big Stone I, and 6.2, Otter Tail Power Company's Modeling Results. Otter Tail Power Company is the operator of the Plant.

impacts.[8] After considering information on the available control technology options, the DENR assessed the visibility improvement to be expected from the installation of air pollution control technology on the Big Stone Plant, in eight different configurations.[9]

Based on its extensive technical analysis, the South Dakota DENR made a final determination that the following control technology constitutes BART for the Big Stone Plant:

- Selective Catalytic Reduction with Separated Overfire Air ("SCR," "SOFA," and collectively, "SCR/SOFA"), for NO_X, which provides the highest level of control of the control equipment found to be feasible;
- Semi-Dry Flue Gas Desulfurization (FGD), for SO_2,[10] which provides slightly less than the highest level of SO_2 control of the control equipment found to be feasible, but which SD DENR found to have less visibility impact than the top-ranked option for SO_2, when modeled in combination with the selected NO_X and PM BART controls;[11] and
- A Baghouse, for PM, which provides the highest level of control of the control equipment found to be feasible.[12]

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[8] *Id*. at §§ 6.3.1, Particulate BART Review, 6.3.2, Sulfur Dioxide BART Review, and 6.3.3, Nitrogen Oxide BART Review.

[9] *Id*. at § 6.3.4, Visibility Impact Evaluations.

[10] The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a baghouse for downstream particulate collection. This Attachment addresses the spray dryer FGD process. Two other variations, the Novel Integrated Desulfurization (NIDTM) and Circulating Dry Scrubber are similar technologies that achieve similar levels of control effectiveness. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Due to the similar nature of the different semi-dry technologies and the similar levels of control efficiency achieved by all the technologies, semi-dry technologies are grouped together for purposes of this Attachment.

[11] South Dakota noted that the Big Stone Plant had already switched from lignite coal to sub-bituminous coal from the Powder River Basin. This coal has one of the lowest sulfur contents available. SD Haze SIP, § 6.3.2.2, Technically Feasible Sulfur Dioxide Control Technologies.

[12] Note that while its current baghouse represents BART, the baghouse will have to be replaced to accommodate the additional flue gas draft requirements that will be caused by the upstream installation of the semi-dry FGD and SCR/SOFA systems.

The emission limitations represented by installation of these control technologies on the Big Stone Plant were determined to constitute BART, and the equipment required by the SD Haze SIP must be installed and operational as expeditiously as practicable but not later than five years from EPA's approval of the SD Haze SIP. As part of the SD Haze SIP, South Dakota implemented its BART determination by placing the related emission limitations into its state rules.[13] Administrative Rules of South Dakota Chapter 74:36:21 requires these controls to be installed on existing coal-fired power plants that are subject to BART by establishing the related emission limitations for SO_2, NO_X and PM that reflect the installation of the BART control technology.[14] For Montana-Dakota's electric generating facilities, the Big Stone Plant is the only plant to which BART applies.

The EPA could require changes in aspects of the SD Haze SIP as part of its review. EPA reviewed and provided comments to the South Dakota DENR throughout the development of the SD Haze SIP. EPA's latest comments to the DENR related to the form of the final emission limitations and their associated compliance monitoring requirements, and other parts of the SD Haze SIP not related to the Big Stone AQCS. The EPA did not disagree with the control technology chosen as BART for the Big Stone Plant, and adjustments to the form of final emission limits and compliance monitoring requirements would be unlikely to change the determination of the control equipment required by the DENR under BART, particularly as the DENR chose the combination of controls predicted by air dispersion modeling to provide the greatest degree of visibility improvement.

[13] *See* SD Haze SIP, § 6.4, BART Requirements.

[14] S.D. Admin. R. 74:36:21:06, BART Determination for a BART-eligible Coal-fired Power Plant, establishes the emission limitations for particulate, sulfur dioxide and nitrogen oxides. The rules were approved by the South Dakota Board of Minerals and Environment on September 15, 2010, and by the South Dakota Interim Rules Review Committee on November 17, 2010. The rules were filed with the South Dakota Secretary of State on November 17, 2010, and became effective twenty (20) days later, on December 7, 2010. Upon filing with the South Dakota Secretary of State, the adoption of the rules is complete. S. D. Codified Laws § 1-26-6. The rules are then "provisionally effective" on the 20th day after filing with the Secretary of State. The "provisionally effective" period allows the Interim Rules Committee to act to suspend the rule, but provides that "[u]nless suspended, a provisionally effective rule *shall be enforced by the agency and the courts as if it were not so conditioned*." *Id.* (emphasis added).

The comparison of emission limitations in the Big Stone Plant's current South Dakota DENR air quality permit with the emission limitations that represent the DENR's BART determination are shown in Table 1.

Table 1 – Big Stone Emission Limits

	Current Permit	**BART Rule**
SO_2	3.0 lb/MMBtu	0.09 lb/MMBtu
PM10	0.26 lb/MMBtu	0.012 lb/MMBtu
NO_X	0.86 lb/MMBtu	0.10 lb/MMBtu

According to South Dakota DENR's BART determination, the suite of control technologies to be implemented in the Big Stone AQCS reduce emissions to a level at which the Plant would not reasonably contribute to visibility impairment in the Boundary Waters and Voyager's Class I areas in Minnesota, Isle Royale National Park in Michigan, the Badlands National Park in South Dakota, and the Theodore Roosevelt National Park in North Dakota.[15]

Detailed Description of the Big Stone AQCS Project

The Big Stone AQCS Project consists of a semi-dry FGD system with a new baghouse, anhydrous-based SCR, SOFA, Activated Carbon Injection ("ACI"), and the associated ancillary balance-of-plant systems. The Big Stone co-owners have included in the AQCS the design and installation of an ACI for control of mercury emissions in anticipation that such requirements will be imposed by the EPA within the timeframe of the AQCS Project construction schedule.

At the Big Stone co-owners' request, Sargent & Lundy conducted a conceptual design study and prepared estimated costs for the AQCS needed to comply with the South Dakota DENR BART determination.

[15] *See* SD Haze SIP, § 6.3.4, Visibility Impact Evaluations.

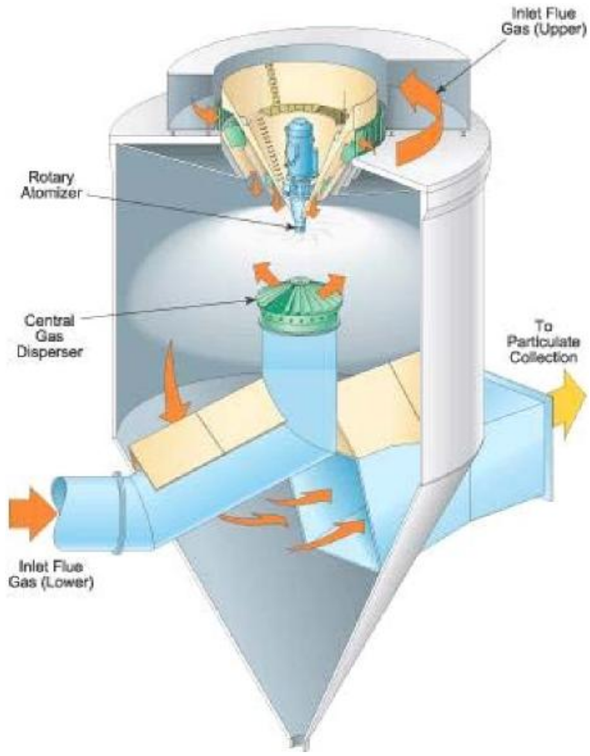
This section describes the AQCS in detail, while the implementation schedule and cost of the AQCS Project are discussed in the sections that follow.

Semi-Dry Flue Gas Desulfurization

The semi-dry FGD system is focused on the control of SO_2 emissions, and includes spray dryer absorbers, a baghouse, lime and recycle preparation, and solid waste handling. The spray dryer absorbers and baghouse are installed on the Plant downstream of the air heater. In a semi-dry FGD system, flue gas is brought into contact with lime slurry in a spray dryer absorber ("SDA") vessel. This process uses pebble quicklime (CaO) that must be hydrated before use. Pebble lime will be delivered to the Plant site via truck and stored in a silo. Lime will then transfer to a slaker where the hydration (water mixed with lime) occurs. SO_2 absorption takes place in the SDA. Additional SO_2 removal takes place in the baghouse, downstream of the SDA. Calcium reacts with the SO_2 to form two waste solids, sulfate ($CaSO_4$) and sulfite ($CaSO_3$).

The dried solids are entrained in the flue gas, exit the SDA along with the fly ash from the boiler, and will be collected in a baghouse. Waste collected in the baghouse is pneumatically transported to either a waste storage silo or a recycle silo. The recycle silo is located above the waste slurry preparation area. From the recycle silo, the dry waste flows to a premix tank where it is combined with water. The slurry overflows to a recycle holding tank, which then overflows into a recycle slurry storage tank. This recycle system allows the lime to be passed through the SDA several times, mainly to reduce lime consumption. Semi-dry FGD waste not utilized in the recycle silo will be sent to a waste storage silo then loaded into trucks and sent to a landfill for disposal.

Illustration of "Semi-Dry Flue Gas Desulfurization" Unit

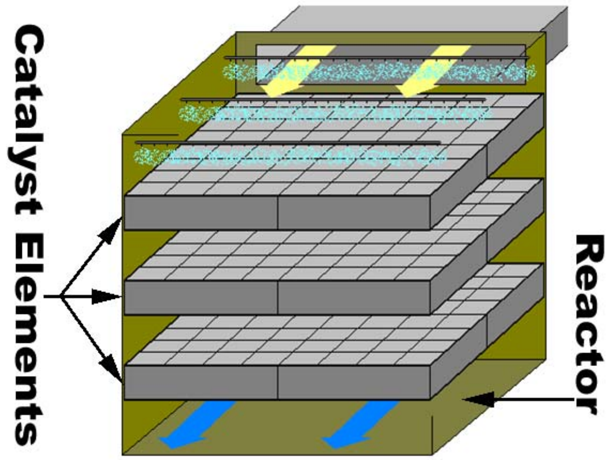


Selective Catalytic Reduction with Separated Overfire Air

SCR/SOFA technology is focused on the control of NO_X emissions. SCR is a post-combustion technology that uses catalyst elements, which are housed in a reactor that is installed in the flue gas stream upstream of the air heater. The process utilizes ammonia, which reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water.

In this process, ammonia is injected into the flue gas stream well ahead of the catalyst, so the ammonia and NO_X are uniformly distributed as they reach the catalyst. The target temperature window for the flue gas is 625°F ± 25°F to 750°F ± 25°F. Flue gas exiting the SCR reactor will contain low concentrations of unreacted ammonia (called ammonia slip). Ammonia slip is limited to 2 ppmvd (parts per million, volumetric, dry) (at 3 percent O_2) at the SCR outlet. A higher slip value usually indicates that catalyst is beyond its life and is losing effectiveness at reducing NO_X.

Illustration of "Selective Catalytic Reduction" Unit



The SOFA system is designed to provide optimum mixing of the balance of combustion air with the main combustion zone flue gas during the second stage of combustion within the furnace region of the Plant's cyclone boiler.

Activated Carbon Injection

ACI technology is focused on the control of mercury emissions. ACI uses powdered-activated carbon ("PAC"), which is pneumatically injected into the flue gas stream prior to the particulate collection equipment, to capture both elemental and ionic mercury ("Hg"). PAC will be delivered to the Plant site by truck and pneumatically unloaded into a silo by a blower located on the truck. PAC is then blown into the top of the silo and then settles to fill the vessel. Fluidized PAC is then transferred from the silo cone through a rotary airlock feeder into a gravimetric feeder. After the gravimetric feeder, the PAC falls into an eductor and is blown through a piping system and distributed to an array of injection lances that disperse the PAC into the cross-section of the flue gas ductwork upstream of the particulate control device. In the ductwork, PAC mixes with flue gas and the vapor-phase Hg is adsorbed on the surface of the PAC particle. The Hg laden PAC particles then are captured in the particulate collection device.

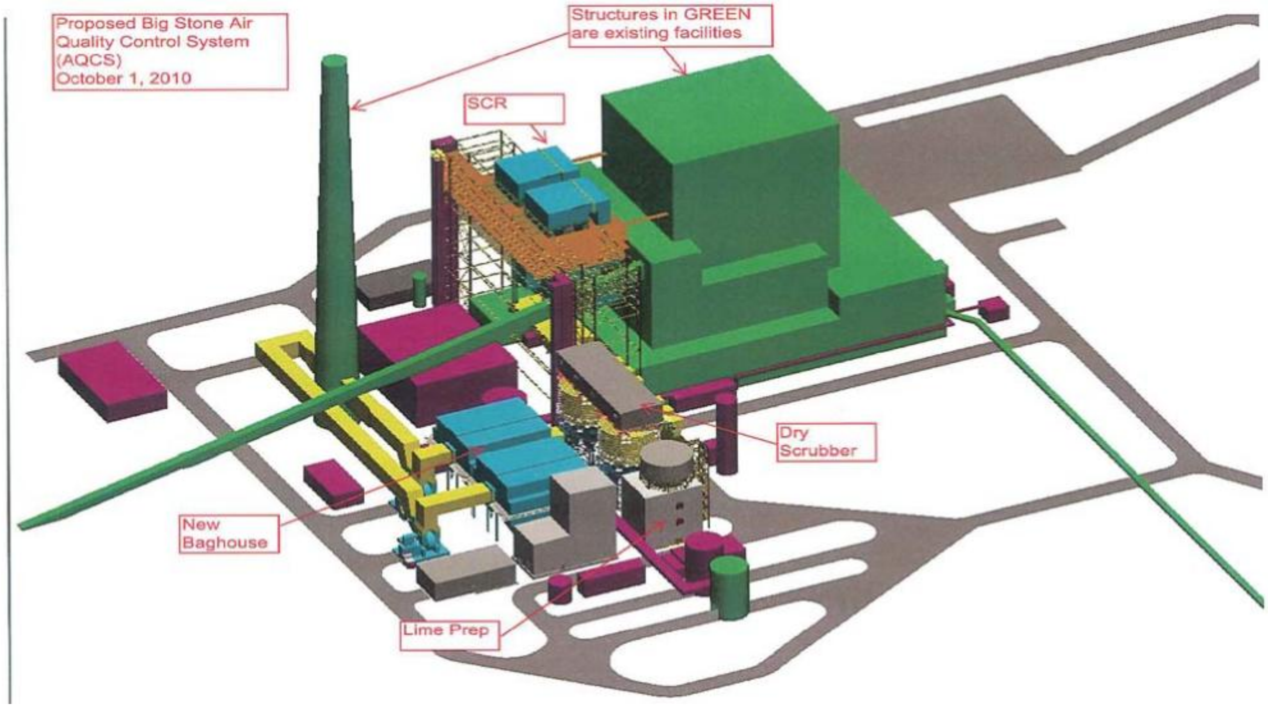
Balance of Plant Modifications

In order to install and successfully operate the control technologies that are part of the AQCS Project, the Big Stone co-owners also must make the following balance of plant modifications at the Big Stone Plant:

- Modify boiler to deliver flue gas at the required temperature for operation of the SCR and to maintain or improve boiler efficiency;
- Replace existing baghouse;
- Replace ID fans;
- Reinforce the boiler and duct work; and
- Modify plant electrical infrastructure.

The following schematic depicts the AQCS system as it will be installed at the Plant.

Illustration of Big Stone Plant with Proposed AQCS Project



Implementation Schedule

The SD Haze SIP and its implementing rules require that the Big Stone AQCS be installed, operated, and shown to comply as expeditiously as practicable, but not later than five years from the EPA's approval of the SD Haze SIP.[16] As a result, if EPA approves the SD Haze SIP in 2011, the Big Stone AQCS will be required to be operational as early as 2016.

The final deadline for BART compliance will be set by the EPA's approval date, and EPA has eighteen months to review a SIP submission. In addition, EPA has the discretion to partially approve a SIP submittal, so there is also the possibility that EPA could decide to approve the Big Stone BART determination in advance of other elements of the SD Haze SIP. This leaves the Big Stone co-owners under the obligation to proceed with the AQCS Project as expeditiously as practicable, and within the timeframe needed to meet a five year compliance deadline that could end as early as 2016.[17]

The exact compliance deadline is not now known, and is not in the Big Stone co-owners' control to determine. The Big Stone AQCS is a large undertaking that will take several years to complete. The main implementation steps include detailed engineering work in 2011, with procurement of major components of the AQCS starting in 2012. The construction phase would continue into 2015. Once constructed, the AQCS will need to be tied in to the Plant, which has to be done during a scheduled outage of the Plant in 2015. Because a scheduled outage is required, slippage of the project schedule could ultimately cause significant delay until there is another opportunity to schedule an outage for the Plant. Testing to demonstrate the compliance of the AQCS with the BART emission limits will need to occur within six months of the tie in of the AQCS, and in time to start compliant operation before the final compliance deadline.

[16] S.D. Admin. R. 74:36:21:07, Installation of Controls based on Visibility Impact Analysis or BART Determination; SD Haze SIP § 6.4, BART Requirements. The SD DENR plans to submit the SD Haze SIP to EPA prior to January 15, 2011.

[17] *See* 74 Fed. Reg. 2392 (Jan. 15, 2009). In general, the CAA requires EPA to act on a SIP submission within 14 to 18 months of its submission, and allows EPA to approve parts of a SIP that meet applicable requirements. 42 U.S.C. § 110(k) (CAA § 110(k)).

Cost Estimate

The estimate of the capital costs to install the AQCS Project at the Big Stone Plant, including the semi-dry FGD scrubber, SCR/SOFA, new baghouse and balance of plant changes, escalated to an in-service date of late 2015, is $489,397,400, with an accuracy of +/-20 percent. Installation of ACI mercury control on the Plant is estimated to cost an additional $5,012,700.

The capital cost estimate was prepared for the Plant's co-owners by Sargent & Lundy, which was selected as the engineering firm for the AQCS Project as part of a request for proposal process that considered cost, experience, and expertise. Sargent & Lundy was both the lowest cost firm and the firm that has performed the engineering on more projects like the AQCS Project than any other firm in the country. In particular, Sargent & Lundy has been involved with 57 percent of the dry FGD projects, 46 percent of the wet FGD projects, and 30 percent of the SCR projects in the industry.

Sargent & Lundy's detailed explanation of the basis for the capital cost estimate was based on a conceptual design of the project and Sargent & Lundy's experience with similar projects. As the Big Stone AQCS Project is still at the early stages of the engineering process, the estimate includes a contingency range of +/-20 percent.

The cost estimate has been compared against similar projects that Sargent & Lundy have completed, and then adjusted for plant size and year in-service. The results on an equalized basis show that the cost estimate is consistent with other comparable projects. Large retrofit projects such as the AQCS Project at the Big Stone Plant typically contain very unique features that result from physical or operating constraints present at the existing plants. These unique conditions often make comparing one project to the other difficult. For example, some plants have considerable space available for new equipment while others are limited in space, and some plants have design margin in their auxiliary power systems, draft systems, etc., while other plants have no or limited available design margin in their existing systems. Consequently, the cost data from projects completed by Sargent & Lundy, as well as publicly available data from semi-dry FGD and SCR projects completed in the years 2006 to 2010, fall within a fairly wide range of values from

$525/kW$_g$ to $850/kW$_g$ in 2010$. Using this cost range as a benchmark, the AQCS Project at the Big Stone Plant is consistent with other comparable projects in that the AQCS Project falls near the midpoint of the range of historical costs at a value of approximately $617/kW$_g$. In addition to the capital cost, there will be an additional ongoing cost to operate and maintain the AQCS Project equipment. It is estimated that in 2016, the expected first full year of operation, the additional cost to operate the equipment would be approximately $11 million (including escalation). The additional operating and maintenance cost would add approximately $3.50 to the cost to produce a MWh of energy, or $.0035 per kWh, based on the Plant's net dispatchable energy generation of 3,120,750 MWh. The total operating and maintenance cost for the Plant in 2016 with an AQCS Project will be $27.3 million. The biggest operational cost increase (approximately two-thirds of the operational cost increase) is caused by the lime and ammonia necessary to operate the SCR and semi-dry FGD, as well as the addition of employees at the Plant. The addition of ACI mercury control would add an operating and maintenance cost of approximately $2 million per year. This would translate to approximately $0.65 increase to the cost to produce a MWh of energy, or $0.00065 per kWh.

Efforts to Ensure Lowest Reasonable Costs

To ensure lowest reasonable cost, the Big Stone co-owners will (1) use a request for proposal to select the lowest evaluated cost; (2) use a single erection contractor to manage installation to ensure coordinated site work; (3) use separate requests for proposal for each major portion of the AQCS Project to allow for competition in the bidding process; and (4) aggressively manage the project to assure lowest reasonable cost.

Alternatives to Big Stone AQCS Project

The Big Stone co-owners are proposing to undertake the Big Stone AQCS Project in order to comply with the SD Haze SIP and its associated implementing rules. The SD Haze SIP specifies the control technology that represents BART for the Big Stone Plant and establishes emission limitations to reflect installation of the BART technology. The emission limitations reflect the emissions expected from installation and proper operation of an AQCS at the Big Stone Plant consisting of a semidry FGD, SCR/SOFA and baghouse. Because the BART requirement is a direct requirement that has been individually determined for the Big Stone Plant, the only alternative to installing the AQCS and achieving regulatory compliance is to cease operations at the facility.

Reasonableness of Big Stone AQCS Project

The South Dakota DENR is the state agency responsible for implementing federal CAA requirements to reduce emissions that may contribute to regional haze from emitting facilities located in South Dakota, including the Big Stone Plant. After conducting a thorough analysis of pollution control options, the DENR determined that the control technologies in the AQCS Project must be required. As a result, the Big Stone co-owners must design, construct, install and operate the AQCS by the compliance deadline established by the DENR, or the Plant will not be able to continue operation as currently configured.

The Big Stone co-owners also completed an assessment of anticipated state and federal environmental regulations and the costs that could be expected to be imposed to achieve compliance. The analysis shows that the AQCS Project would consist of the most effective feasible air emission controls on the Big Stone Plant for several regulated pollutants. In addition to the AQCS Project required by the SD Haze SIP and South Dakota regulations, compliance costs that could reasonably be expected to materialize concern EPA regulations to reduce mercury emissions and regulations that may impose additional costs to dispose of coal waste.

Burns & McDonnell was retained by Otter Tail Power Company on behalf of the Big Stone co-owners to perform a pro forma economic analysis of the Big Stone AQCS Project. The Burns & McDonnell analysis, included as Appendix A to this Attachment, provides a pro forma economic model for each of the following scenarios:

- Implementing the Big Stone AQCS Project, as the Big Stone co-owners have proposed;
- Repowering the Big Stone boiler with natural gas;

- Retiring/Replacing the Big Stone Plant with CCGT Plant; and
- Retiring/Replacing the Big Stone Plant with a CCGT Plant and purchased wind power.

The analysis compared installation of the AQCS Project to several alternatives for providing energy from a generation resource other than the Big Stone Plant – the options for repowering or retiring and replacing the Plant with natural gas. The analysis shows that, under multiple scenarios that consider potential changes in capital, O&M, and fuel costs, the Big Stone AQCS Project is the most cost-effective option. The Burns & McDonnell study was based on inputs provide by Otter Tail Power Company but provided an analysis for the co-owners of the alternatives available in lieu of the AQCS Project.

As shown in Chapters 4 - 6 and Attachment C, Montana-Dakota also conducted a separate analysis of the Big Stone AQCS. Montana-Dakota's analysis also showed the Big Stone AQCS Project to be cost effective relative to retrofit or plant closure and replacement. This conclusion does not change when considering the potential for additional costs that may be imposed by anticipated environmental regulation, and does not change when considering the range of CO_2 values under realistic assumptions on when carbon costs might possibly be imposed.

The Big Stone co-owners' analysis of the operational impacts of the above scenarios demonstrates that the AQCS Project can be implemented to assure that the current function of the Big Stone Plant in the Big Stone co-owners' systems is maintained, including dispatchable baseload and load following capability. In contrast, the scenarios without the AQSC Project would dramatically increase the exposure of the customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant.

PUBLIC DOCUMENT –

TRADE SECRET DATA HAS BEEN EXCISED

Appendix A

BIG STONE PRO FORMA ECONOMIC ANALYSIS – MODELING RESULTS

March 29, 2011

Mr. Mark Rolfes
Manager, Generation Development
Otter Tail Power Corporation
215 South Cascade Street
Fergus Falls, MN 56538

Re: Big Stone Plant Pro Forma Economic Analysis – Modeling Results
BMcD Project No. 57975

Dear Mr. Rolfes:

Burns & McDonnell (BMcD) has been retained by Otter Tail Electric Power Company (Otter Tail) to perform a pro forma economic analysis (Analysis) of the air quality control system (AQCS) proposed to be installed on the existing Big Stone Plant (BSP). The AQCS option will be compared to several alternatives for providing energy from a generation resource other than BSP. The Analysis includes preparing a pro forma economic model for each of the following cases.

- BSP with AQCS
- BSP Retrofitted to Burn Natural Gas (BSP on NG)
- A Combined Cycle Plant to Replace BSP (CCGT)
- A Combined Cycle Plant Combined with Wind Energy Purchases to Match the BSP Energy Production (CCGT + Wind)

Screening level pro forma economic models were prepared to determine the levelized cost of power for each alternative over a 20 year planning period. These levelized energy costs can be compared to one another to determine the relative economic attractiveness of each of the options under consideration.

Modeling Inputs

The following inputs were provided to BMcD from Otter Tail's recently filed Integrated Resource Plan (IRP).

- O&M Inflation 3.0% per annum
- Capital Cost Inflation 4.0% per annum

[TRADE SECRET DATA BEGINS...

- Interest Rate
- Return on Equity
- Discount Rate

...TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS...

- Market Price of Wind Power (2009 $, excluding PTC)

...TRADE SECRET DATA ENDS]

- Fuel Cost Forecast Table 1

[TRADE SECRET DATA BEGINS...

...TRADE SECRET DATA ENDS]

The following inputs were provided to BMcD based on Otter Tail's internal estimates for the BSP options.

- BSP with AQCS
  - Net Plant Output 475 MW
  - Net Plant Heat Rate 10,715 Btu/kW
  - Net Plant Capacity Factor 75%
  - Capital Cost of AQCS (2016 $) $490 million

- Annual O&M Cost (Fixed & Variable 2016 $) — $27.3 million

- BSP on NG
  - Net Plant Output — 475 MW
  - Net Plant Heat Rate — 10,023 Btu/kW
  - Net Plant Capacity Factor — 75%
  - Conversion Capital Cost (2016 $) — $147 million
  - Annual O&M Cost (Fixed & Variable 2016 $) — $13.0 million

- CCGT and CCGT + Wind
  - BSP Decommissioning Cost (2016 $) — $21.3 million

- All Natural Gas Fired Options
  - Linear Facility Capital Cost (2016 $) — $120 million

The following inputs were developed by BMcD from recent project experience.

- CCGT
  - Net Plant Output — 475 MW
  - Net Plant Heat Rate — 6,680 Btu/kW
  - Net Plant Capacity Factor — 75%
  - Capital Cost (2010 $) — $402 million
  - Annual Fixed O&M Cost (2010 $) — $8.50/kW-year
  - Annual Variable O&M Cost (2010 $) — $4.30/MWh

- CCGT + Wind
  - Combined Cycle Net Plant Output — 475 MW
  - Combined Cycle Net Plant Heat Rate — 6,680 Btu/kW

- Combined Cycle Net Plant Capacity Factor 35%
- Combined Cycle Capital Cost (2010 $) $402 million
- Combined Cycle Annual Fixed O&M Cost (2010 $) $8.50/kW-year
- Combined Cycle Annual Variable O&M Cost (2010 $) $4.30/MWh
- Capacity Factor of Wind Purchases 40%
- Levelized Value of Production Tax Credit (PTC) (2009$) $20/MWh

The combined cycle cost estimates and performance values presented above for the CCGT and CCGT + Wind options are based on recent project experience. These values are based on a typical cost for an unfired 2 on 1 GE FA.05 combined cycle plant. Although a plant of this type will have an output in the range of approximately 600 MW, only the first 475 MW of capacity was considered in this Analysis, in order to compare the options on a consistent basis. The total capital cost presented above was calculated based on the dollar per kilowatt installed cost of an unfired 2 on 1 GE FA.05 combined cycle plant, multiplied by 475 MW. The heat rate values presented above are based on typical unfired 2 on 1 GE FA.05 combined cycle plant performance. The annual fixed O&M and variable O&M values are also based on typical unfired 2 on 1 GE FA.05 combined cycle plant costs and the variable O&M values included major maintenance costs.

The capacity factor for wind purchases considered in the Analysis is based on an assumed capacity factor for a typical wind farm in this region of the country. The levelized value of the PTC used in the analysis is based on the current legislation and the impact to the levelized cost of power for a typical wind farm, based on recent project experience.

Base Case Results

Each of the alternatives listed above was evaluated in a pro forma economic model to determine a screening level energy cost. These costs can be compared to determine the relative economic attractiveness of each of the alternatives considered.

The capital and O&M costs for BSP with AQCS and BSP on NG were provided to BMcD by Otter Tail in 2016 dollars. These values were input directly into the model without additional escalation applied, other than annual O&M escalation for year to year operations. The year to year escalation rate of three percent was used consistent with Otter Tail's IRP filing.

Capital and O&M costs for the CCGT option were taken from recent BMcD experience. These values were developed in 2010 dollars, and were escalated four percent per year for capital and three percent per year for O&M to 2016 dollars, consistent with Otter Tail's IRP modeling assumptions.

In the CCGT + Wind case, BMcD estimated that a 40% capacity factor could be provided by market wind energy purchases. The $71/MWh cost of market wind energy purchases in 2009 dollar provided by Otter Tail was used as a starting point to determine the price of market wind energy to use in this Analysis. The CCGT + Wind option evaluated in the base case included the value of the PTC. No option was considered in the base case without the PTC. A value of the PTC of $20/MWh in 2009 dollars was deducted from the market wind energy purchases price to arrive at a 2009 cost of wind power of $51/MWh including the value of the PTC. This value was escalated by four percent per year to 2016 dollars resulting in a levelized market price of wind energy of $67.11 to use in the economic modeling. The remaining energy would be produced by a combined cycle plant. For purposes of this Analysis, a 475 MW combined cycle plant was utilized, equivalent to BSP. This facility would operate at a 35 percent capacity factor to achieve an annual energy production equivalent to BSP. Current combustion turbine technology results in combined cycle plant net capacities in the range of 615 MW. The capital cost in this Analysis was based on the dollar per kilowatt estimates from for a 615 MW facility, assuming that Otter Tail would own a 475 MW share in a facility of this size.

For each of the alternatives to BSP with AQCS, $120 million was added to cover the costs of linear facilities required to support the project. This would cover the costs to run a new natural gas line to the BSP plant to convert the units to burn natural gas or construct a new combined cycle plant at that site. Alternatively, if a new combined cycle facility were to be constructed at another site, linear infrastructure would need to be constructed for natural gas, transmission service, and possibly water and discharge pipelines.

For the CCGT and CCGT + Wind options a cost of $21.3 million was also added to the capital costs to cover the decommissioning costs for BSP.

In addition to the decommissioning costs, Otter Tail estimated that an $82 million cost should be assigned to the CCGT and CCGT + Wind options to cover stranded asset costs if BSP would cease to operate. This cost represents the current book value of BSP. However, the economic modeling for the BSP with AQCS and BSP on NG options does not account for this remaining book value to be depreciated going forward. The BSP with AQCS and BSP on NG options only account for the capital cost to add the new AQCS equipment or to convert to fire with natural gas. The stranded asset cost was not included in the base case values, however this cost was modeled as an additional scenario to determine the impact it would have on the energy cost. It was determined that this scenario would add $3.81/MWh to the levelized energy cost for the CCGT and CCGT + Wind options.

Otter Tail also requested that BMcD consider the impact of a high environmental cost scenario. This scenario consists of the inclusion of mercury emissions control requirements and potential ash regulations. Otter Tail provided a $5 million additional capital cost and $2 million per year additional O&M cost to be included for mercury removal on the BSP with AQCS option. Also, $6.66 million in additional O&M was provided for handing ash if it is categorized as a hazardous waste. These three additional costs resulted in a $3.66/MWh increase in the levelized cost of energy for the BSP with AQCS option.

The results of the modeling using the base case assumptions are provided in Table 2 below.

Table 2 – Economic Modeling Base Case Results

20-YEAR LEVELIZED BUSBAR COSTS		BSP + AQCS	CCGT + Wind with PTC	CCGT	BSP on NG
Operations Summary					
Net Dispatchable Capacity (MW)		475	475	475	475
Net Dispatchable Generation Capacity Factor		75%	35%	75%	75%
Net Dispatchable Energy Generation (MWh)		3,120,750	1,456,350	3,120,750	3,120,750
Net Wind Capacity Factor		-	40%	-	-
Net Wind Energy Market Purchases (MWh)		-	1,664,400	-	-
Capital Cost (2016 $)		$ 490,000,000	$ 621,289,115	$ 621,289,115	$ 267,000,000
Depreciation & Interest Basis Energy Costs					
Fuel	(2016$ / MWh)	$ 40.68	$ 66.44	$ 66.44	$ 99.70
O&M	(2016$ / MWh)	$ 12.09	$ 13.37	$ 9.55	$ 5.78
Depreciation	(2016$ / MWh)	$ 8.56	$ 23.25	$ 10.85	$ 4.66
Return	(2016$ / MWh)	$ 6.10	$ 16.58	$ 7.74	$ 3.32
Interest	(2016$ / MWh)	$ 4.91	$ 13.34	$ 6.22	$ 2.68
Income Taxes	(2016$ / MWh)	$ 2.03	$ 5.53	$ 2.58	$ 1.11
Levelized Revenue Requirement	**(2016$ / MWh)**	**$ 74.38**	**$ 138.50**	**$ 103.38**	**$ 117.25**
Cost of Wind Energy	**(2016$ / MWh)**	**$ -**	**$ 67.11**	**$ -**	**$ -**
Combined Levelized Energy Cost	**(2016$ / MWh)**	**$ 74.38**	**$ 100.43**	**$ 103.38**	**$ 117.25**
Stranded Asset Cost Scenario Adder	**(2016$ / MWh)**	**$ -**	**$ 3.81**	**$ 3.81**	**$ -**
Total Energy Cost Including Stranded Asset Cost	**(2016$ / MWh)**	**$ 74.38**	**$ 104.24**	**$ 107.19**	**$ 117.25**
High Environmental Cost Scenario Adder	**(2016$ / MWh)**	**$ 3.66**	**$ -**	**$ -**	**$ -**
Total Energy Cost Including High Environmental Cost	**(2016$ / MWh)**	**$ 78.04**	**$ 100.43**	**$ 103.38**	**$ 117.25**

Based on the results of the base case Analysis presented above, BSP with AQCS is the most economically attractive alternative under the base case assumptions. The second most attractive alternative is the CCGT + Wind option, however, this option results in a 35 percent higher cost of energy than BSP with AQCS. Adding in the stranded asset costs to the CCGT + Wind option increases the differential in cost of energy between these two options to 40 percent. Adding in the high environmental cost scenario adder reduces these differentials in levelized energy costs to 29 percent and 34 percent respectively.

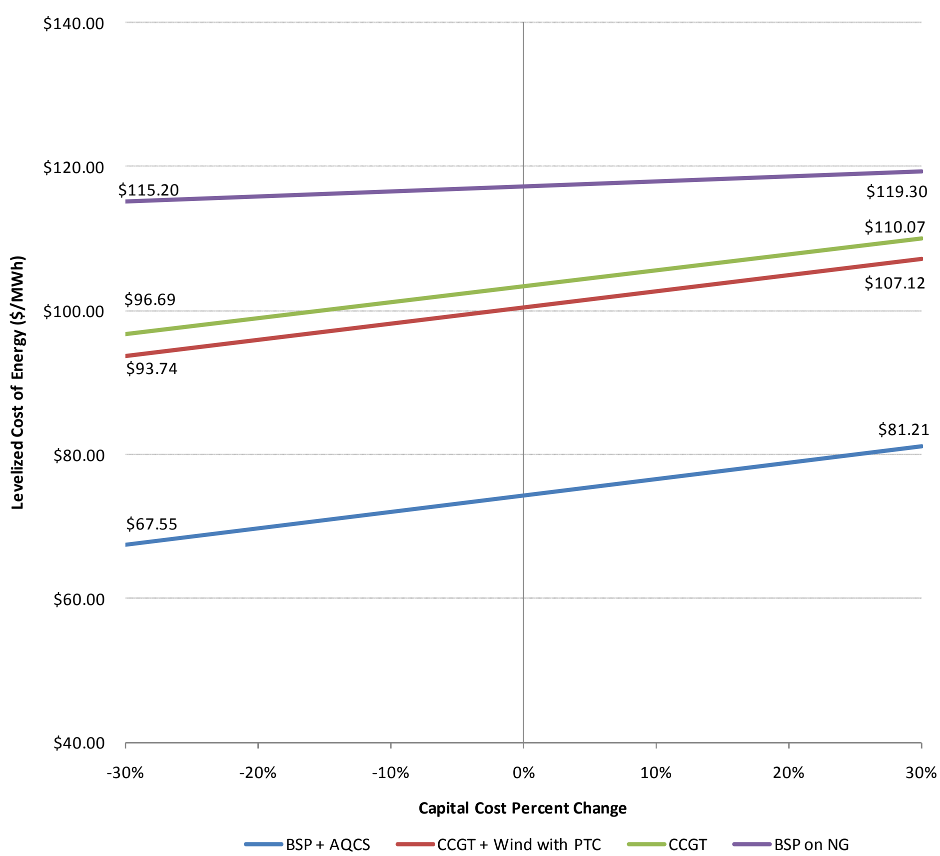
Sensitivity Analysis

A sensitivity analysis was prepared for each of the alternatives evaluated in the Analysis under the following cases:

- Capital Cost (plus or minus 30%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 20%)

A sensitivity analysis was performed to determine the impact of changes to the capital costs of each option. The results of the capital cost sensitivity analysis are presented in Figure 1 below.

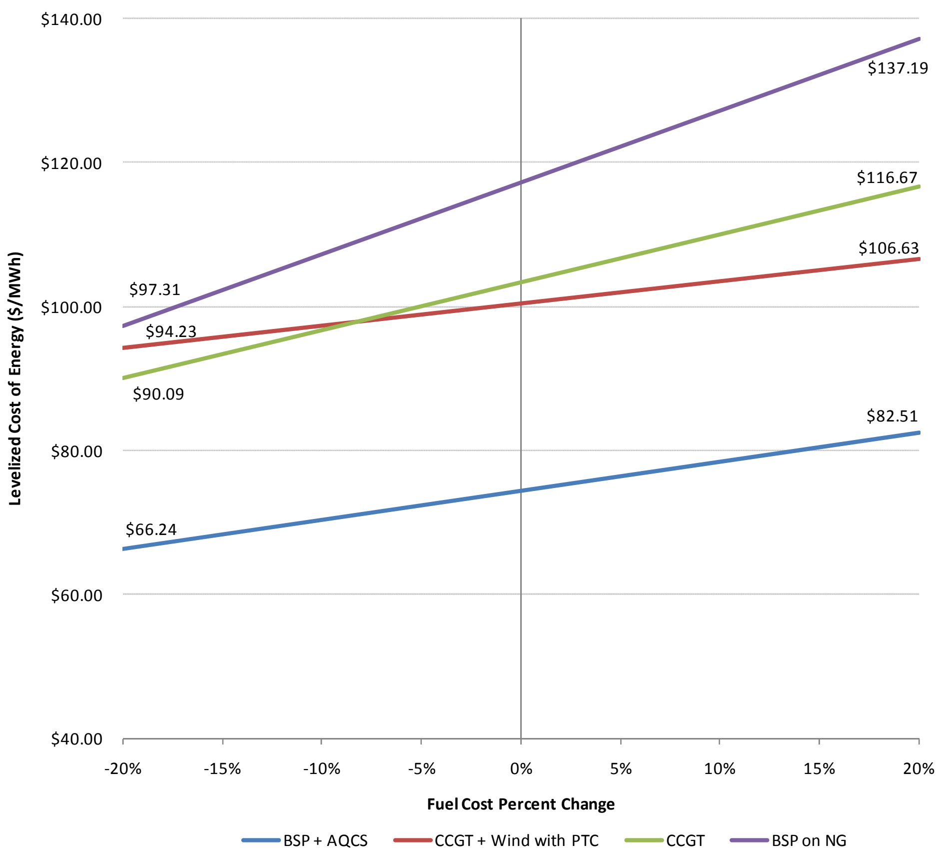
Figure 1 – Capital Cost Sensitivity Levelized Energy Costs



Over the range of capital costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Capital cost changes have a similar impact on BSP with AQCS, CCGT and CCGT + Wind options, since they all have relatively similar capital costs. Capital cost changes have the least impact on the BSP on NG option, since it requires the least capital cost investment.

A sensitivity analysis was performed to determine the impact of changes to the fuel costs for each option. The results of the fuel cost sensitivity analysis are presented in Figure 2 below.

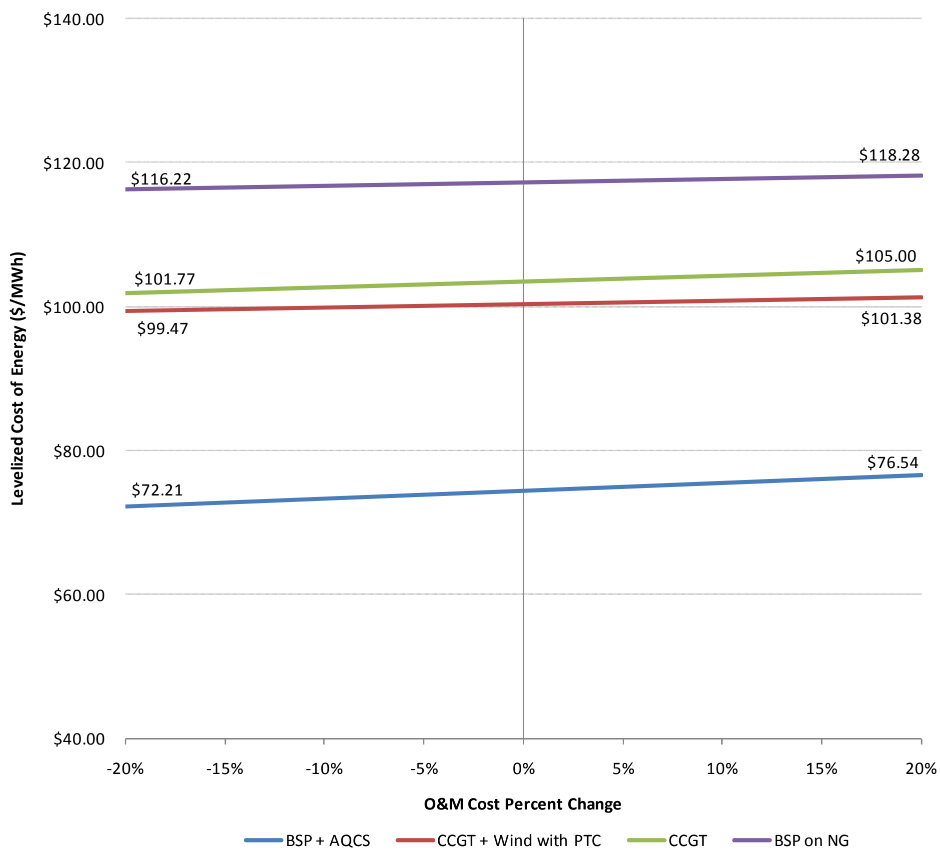
Figure 2 – Fuel Cost Sensitivity Levelized Energy Costs



Over the range of fuel costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Fuel cost changes have the largest impact on the natural gas-fired options, since natural gas has a much higher base case cost than coal. The impact or fuel cost changes is reduced on the CCGT + Wind case, since more than half of the energy in that case is provided from wind power generation, which is unaffected by changes in fuel prices.

A sensitivity analysis was performed to determine the impact of changes in O&M costs for each of the options. The results of the O&M cost sensitivity analysis are presented in Figure 3 below.

Figure 3 – O&M Cost Sensitivity Levelized Energy Costs



Over the range of O&M costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. O&M cost changes have relatively insignificant impacts on all of the options considered.

Conclusions

Based on the results of this Analysis, the BSP with AQCS is the most economically attractive alternative of the options considered for BSP under the potential future scenarios evaluated. The BSP with AQCS option results in a significantly lower levelized cost of energy than the other options evaluated under the base case assumptions. BSP with AQCS option remains economically attractive relative to the other options considered over the range of sensitivities evaluated in this Analysis.

The impact on other Otter Tail resources and Otter Tail's integrated resource plan (IRP) was not evaluated in this Analysis. Otter Tail will need to determine how a change of resource type at the BSP site would impact other resources in Otter Tail's generation portfolio, as well as how a new resource would fit into Otter Tail's IRP.

If you have any questions regarding the results of this Analysis, please call Jeff Greig at 816-822-3392 or Jeff Kopp at 816-822-4239 to discuss.

Sincerely,

Jeff Greig
General Manager, Business & Technology Services

Jeffrey T Kopp
Jeff Kopp, PE
Development Engineer

JTK

cc: Mark Rolfes