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

Before the Public Service Commission of North Dakota

Case No. PU-06-482

Direct Testimony of James A. Heidell

Q. Please state your name, title, and business address.

A. My name is James A. Heidell. I am a Managing Consultant at PA Consulting Group, Inc. ("PA"), a global management and technology consulting firm. My business address is PA Consulting Group, 390 Interlocken Crescent, Suite 410, Broomfield, CO 80021.

Q. Please summarize your professional qualifications and educational background.

A. I have been employed by PA since 2000 and have specialized in the analysis of U.S. wholesale energy markets, financial modeling of electric generation assets, and analysis of retail rates. Prior to joining PA I worked for ten years at Puget Sound Energy (PSE), an integrated natural gas and electric utility serving retail customers in western Washington. At PSE I held multiple positions including Director of Financial Planning and Director of Federal and State Regulation. I received a BS in Civil Engineering from Tufts University, a MS in Engineering Economics from Stanford University, and a MBA from the University of Washington. I am also a CFA. My full CV is attached as Exhibit No.___(JAH-1).

Q. Please describe your background and experience in the electricity industry.

A. I have worked in the electricity industry for over twenty years and my areas of expertise include: electricity market modeling, financial modeling, and analysis of both demand and supply side resource expansion.

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Direct Testimony of James A. Heidell
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

Q. Whom do you represent in this proceeding?

A. I am presenting testimony on behalf of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present the base case resource expansion analysis for the Montana-Dakota electric system. The purpose of my study was to determine the least cost expansion option based upon the base case load forecast provided by Montana-Dakota in conjunction with PA base case assumptions about resource expansion options and future fuel costs. I performed this study using the Strategist optimization model licensed from NewEnergy Associates.

Q. What are your conclusions?

A. Based upon the results of my analysis, I have concluded:

- Under the base case assumptions, the selection of Big Stone II for the next resource addition in 2011 results in the lowest long term utility costs.

- Based upon the data provided about Big Stone II, this option is the optimal next resource addition, based upon the alternatives of lignite coal, IGCC, natural gas fired combined cycle and simple cycle plants, wind resources, and demand side management resources.

- An additional capacity resource is likely to be needed in 2014. Based upon current data, that resource is likely to be a combustion turbine. However, given the relatively short lead time required to construct new combustion turbines, no decision on that resource is necessary at this time.

Q. What methodology did you use to identify the lowest cost resource addition

A. I used a third-party integrated strategic planning model called Strategist. This model, licensed from NewEnergy Associates, is used by a number of retail utilities to evaluate resource expansion options to serve retail load customers. Strategist is a dynamic programming model that identifies the least cost resource expansion option based upon a number of variables including system loads, currently available generation resources, cost of new resources (both supply and demand side), and fuel costs.

Q. What was the time frame for the study?

A. PA's analysis was based upon a twenty year time horizon (2006 – 2025). The analysis considered "end-effects". End-effects account for the value of resources past the end of the study-period and are used to ensure that the answer is not biased away from long-lived assets that retain significant value past the end of the study period.

Q. What economic test was used in the cost minimization study?

A. The study was based upon minimizing utility costs whereby the fixed and variable costs of existing resource options were considered, along with the fixed costs, variable costs and levelized cost of new resource options.

Q. What data did you rely upon to reach your conclusions?

A. The base case analysis utilized a combination of data provided by Montana-Dakota and assumptions used by PA in its analysis of wholesale energy markets. PA reviewed the Montana-Dakota supplied data and concluded that both sources of data when combined created an integrated and reasonable set of assumptions for the purposes of developing the least cost expansion study.

Q. What data were provided by Montana-Dakota?

A. Montana-Dakota provided data regarding its load shape and hourly load forecast. These data were used to generate typical week load patterns for the Strategist software. Montana-Dakota also provided the attributes of its existing generation resources and contracts including: capacity and energy limitations, expected end of contract / asset retirement, heat rates, contract terms, and coal costs. Montana-Dakota also provided information about the costs of the proposed Big Stone Unit II. PA and Montana-Dakota jointly developed assumptions about demand side management options based upon information in the 2005 North Dakota Integrated Resource Plan.

Q. What data were developed by PA for the resource expansion study?

A. The study is based upon PA's forecast of natural gas costs and the cost of new generation resource options.

Q. What did your study conclude?

A. The PA study concluded that the lowest cost system expansion option, given existing commitments, is to add Big Stone Unit II in 2011 and add combustion turbines in 2014 and 2021. PA also developed two alternative expansion plans where 1) additional demand side resources are forced in to the utility system in 2011, and 2) additional wind is forced in 2015. Both of these alternative plans result in minimal increases in total utility costs over the study period.

Q. Have you prepared a summary report of your analysis?

A. Yes. The report is provided as Exhibit No.___(JAH-2).

Q. Does this conclude your testimony?

A. Yes.

Personal Profile

Name	**James A. Heidell**
Present Position	Member of PA's Management Group
Present Position	Managing Consultant – Global Energy Practice

Mr. Heidell has over 24 years experience in the energy and utility business. His area of specialization at PA includes: litigation support for retail utilities, the analysis of generation resource acquisitions, valuation of electric generation assets, and the analysis of wholesale energy markets in the United States. Mr. Heidell has extensive experience in financial analysis of major generation investments to support restructuring, financing and investment decisions. He is also experienced in regulatory policy, cost-of-service, pricing, performance based regulatory mechanisms, and service quality. Mr. Heidell has prepared expert reports for civil litigation and provided testimony in regulatory proceedings.

PA Experience

A BUSINESS VALUATION OF MERCHANT ENERGY COMPANIES

Mr. Heidell led a PA team that valued the worldwide generation portfolio of NRG a major merchant energy company that went into bankruptcy. The work on behalf of the creditors, valued the company, developed an analysis of cash flows, and advised the creditors on the viability of the debtor's plan of reorganization. Mr. Heidell advised creditors on the strategic plan with regards to which assets and markets the Company should shed and which ones should be retained.

Mr. Heidell provided asset valuations to creditors for a number of different merchant generation projects in the U.S. that were either in bankruptcy, or in the process of consensual transfer to the creditors. These projects included Brazos Valley, Granite Ridge, Lake Road, Audrain, and Kendall. The valuation work incorporated market modeling to develop short and long-term forecasts of gross margins and cash flows, evaluation of contracts, and due diligence on all aspects of the generation company's financials.

Mr. Heidell led the market analysis and valuation of the Wolf Hollow generation project to support the financing of the merchant power plant as well as obtaining credit ratings from Moody's and Standard & Poor's.

Mr. Heidell provides ongoing advisory services to equity and debt funds with regards to valuation of generation assets to support equity and distressed debt acquisition and sales.

Mr. Heidell has valued multiple wholesale generation companies to support billions of dollars of corporate credit agreements. Valuation work involved development of cash flows as a going concern and from a third party basis at the enterprise level. The analysis involved forecasting energy markets, analysis of fuel contracts and off-take agreements, and review of non-fuel O&M and capital expenditures.

B ANALYSIS OF WHOLESALE ENERGY MARKETS

Mr. Heidell has worked on modeling energy prices using PROSYM and PA proprietary volatility models to support the financing of generation assets and identification of new generation markets for a number of clients including Edison Mission Energy and KeySpan. He has also developed SAS models to analyze the market value of power contracts for Exelon. The work for Exelon was used to support a bond financing. In a separate transaction involving bond reinsurance, Mr. Heidell modeled distributions of prices to identify 95% and 97.5% probabilities of repayment.

Mr. Heidell has worked with numerous retail electric utilities to develop least cost generation resource acquisition strategies. This area of work involved analysis of wholesale markets and identification of least cost alternative between build versus buy decisions. Mr. Heidell has developed probabilistic distributions of future market electric prices to identify how resource acquisition strategies are impacted by uncertainty.

Mr. Heidell has developed valuations of generation assets to support development of bids for the acquisition of major generation portfolios. In two separate transactions the valuation of assets involved developing distributions of asset values as well as valuing POLR load and merchant generation contracts.

Mr. Heidell led an evaluation of wholesale markets for MDU to support an investigation into the feasibility of building a new lignite coal plant to be included in utility rate base.

Mr. Heidell performed an analysis the Alberta Energy Markets to develop benchmark prices for evaluation of bids as part of the sale of the rights to generation assets.

C NATURAL GAS LDC DUE DILIGENCE

Mr. Heidell conducted due diligence of the Mountaineer Gas local distribution company to support bank financing of the acquisition.

D RISK AND OTHER MODELING

Mr. Heidell developed a model to analyze quarterly earnings risk associated with weather variation for a U.S. retail utility. The model incorporated correlations between weather, load, and wholesale energy prices to identify changes in retail revenue and associated changes in cost based upon historic temperature distributions.

Mr. Heidell developed a value at risk model for a U.S. retail utility to guide risk management decisions about the level of surplus power sales to target for long-term versus short-term positions. The model develops target long-term positions based upon risk preferences, earnings targets, and a combination of historical and simulated distributions of wholesale gas and electric prices.

Mr. Heidell was part of a team to develop the market value of gas in the German markets. The modeling determined the value of gas based upon the cost of the use of alternative fuels. The analysis was used as part of contract negotiations to determine the price of natural gas.

Mr. Heidell reviewed the Alberta Electric System Operator load forecasting methodology. The review examined the analytic approach; bench marked forecasting techniques, and made recommendations for enhancements.

E LITIGATION SUPPORT

Mr. Heidell developed avoided costs and an economic analysis to support a utility litigating with a wind developer seeking to obtain a long-term power contract under PURPA.

Mr. Heidell reviewed the prudence of actions of a public power entity regarding the appropriateness of financial and ratemaking polices as part of litigation related to a power sales contract.

Mr. Heidell benchmarked management performance of a major utility to support management in a shareholder lawsuit.

Mr. Heidell filed testimony on behalf of Hydro One addressing the issue of rate mitigation as part of the transition from the vertically integrated market structure in Ontario.

Mr. Heidell prepared cost-of-service and rate design testimony for PSE's 2001 and 2004 electric and natural gas rate cases. Mr. Heidell developed a gas and electric cost-of-service model used to support regulatory filings.

Mr. Heidell provided complex financial modeling support in a federal tax case to identify levels of losses associated with utility power contracts that were not fungible.

Mr. Heidell has supported NRG in litigation pertaining to breach of contract claims. The analysis involves examining the value of certain merchant power opportunities in New York state through the development of market assessments and development of a financial analysis.

Mr. Heidell supported Firestone in the preparation of insurance claims for recovery of losses related to major injury claims associated with recalled tires. The work involved development of databases and analysis of claim rates.

Mr. Heidell was part of a team analyzing emissions from coal plants over the past two decades to defend a client against Federal prosecution in New Source Review litigation.

F FINANCIAL MANAGEMENT & ANALYSIS

Mr. Heidell served as the interim Finance Manager for a New England gas fired combined cycle plant. Responsibilities included financial reporting, developing an annual budget, and preparing long run financial projections for a project to be turned back to the creditors.

Mr. Heidell developed an analysis of the economics of the Dallas Fort Worth airport pursing an option to purchase the natural gas and electric distribution systems used to deliver energy to the airport facilities. The analysis considered the economics with regards to the airport pursuing different organizational structures under Texas law for delivering and selling electricity.

Pre PA Experience

Mr. Heidell worked in the energy business for eighteen years prior to joining PA. Prior to joining PA he worked at Puget Sound Energy, an investor-owned electric / natural gas utility in Washington state. He held multiple positions including Director of Financial Planning and Director of Federal & State Regulation. Prior to working at Puget Sound Energy, he was an energy consultant providing services to government agencies, investor owned utilities, and public utilities. Mr. Heidell has conducted numerous financial studies related to the purchase and sale of power plants, NUG contracts, and natural gas generation supply contracts. He has also worked on the valuation of utility distribution companies and determined the profitability associated with adding and disposing of electric and natural gas distribution service areas. Mr. Heidell has performed embedded and marginal cost-of-service studies and developed pricing for regulated and market-based electric services. Mr. Heidell has presented expert testimony on cost-of-service and pricing.

	Mr. Heidell was the Manager of Energy Economics at a SRC, a utility consulting firm. Mr. Heidell prepared assessments of energy and water conservation potential, modeled energy use in commercial buildings, performed statistical analysis associated with large utility customer data sets, and analyzed electro-technologies for industrial applications.
Education	CFA - Chartered Financial Analyst, 1997
	University of Washington, MBA, Finance and Accounting, 1989
	Stanford University, MS, Engineering Economic Systems, 1982.
	Tufts University, BSE, Civil Engineering, 1979
Societies	Association of Investment Management Research

Case No. PU-06-482
Exhibit No.___(JAH-2)

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.

Generation Expansion Plan Analysis

October 2, 2006

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FOREWORD

PA Consulting Group (PA) prepared a base case analysis to identify the least cost expansion plan for Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (Montana-Dakota) to serve its retail load growth. The generation expansion plan was developed using the Strategist software and considered a range of options including wind, natural gas-fired combined cycle and combustion turbine plants, conventional and IGCC coal-fired generation, and DSM resources. The results of this analysis are presented in this report. The analysis does not consider all the risk factors related to both supply and demand.

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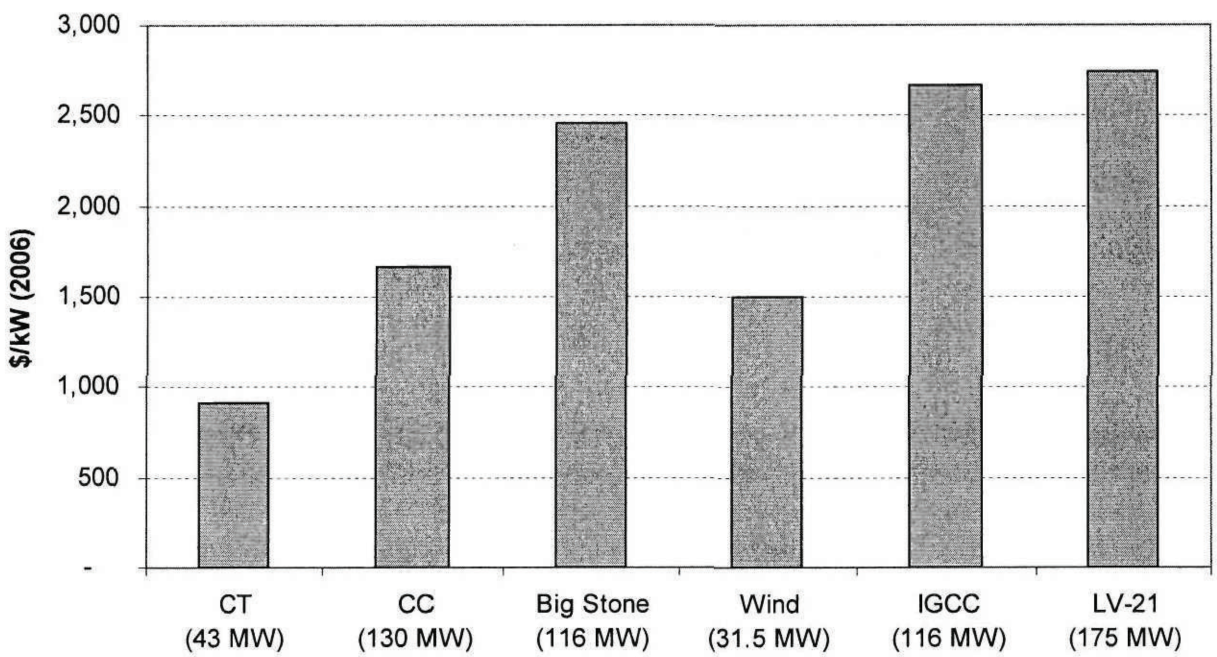
1. *EXECUTIVE SUMMARY*

PA Consulting Group (PA) was requested to perform a base case generation expansion plan for Montana-Dakota. The analysis was initially conducted in May and June of 2006 and then updated in September of 2006. The update reflected revised assumptions regarding the cost of thermal resources as well as the associated cost to integrate those resources into the Montana-Dakota system. The purpose of the study was for PA to independently identify the least cost resource addition for the Montana-Dakota system. This analysis was completed using the Strategist software developed by NewEnergy Associates. PA performed a base case analysis to examine the economics of multiple expansion options including demand side management, wind resources, natural gas fired resources, and coal-fired resources. The result of the analysis is that Montana-Dakota's participation in 116 MW of the proposed Big Stone II coal plant yielded the lowest cost expansion option.

1.1 OPTIONS EXAMINED

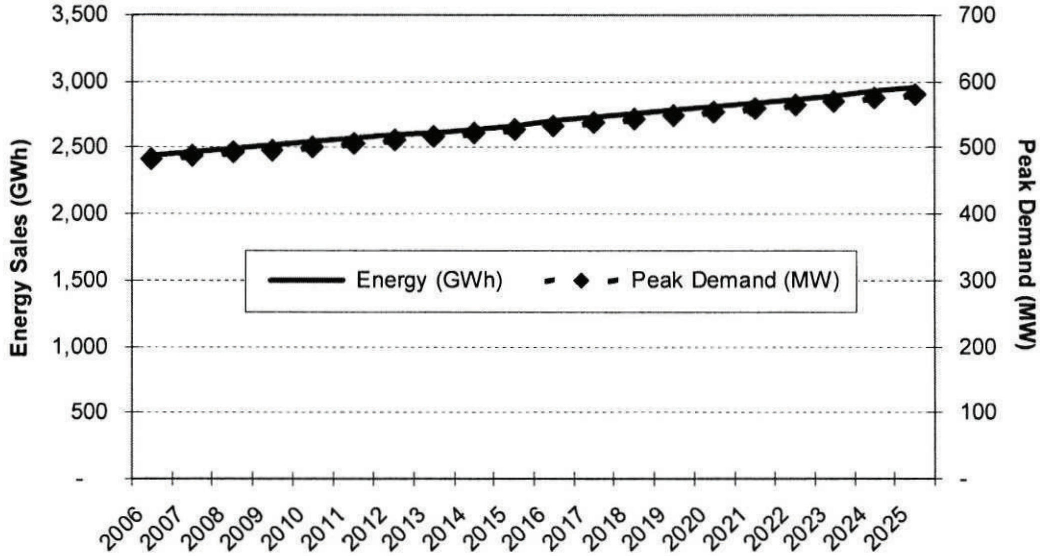
PA considered a number of supply side options including wind, natural gas fired generation and coal generation. A summary of the initial cost of the options is shown in Figure 1-1 – the base year for dollars in the study was 2006. (The options for the thermal resources include estimates of transmission costs.) In addition, PA also included conservation options in the study.

Figure 1-1: Generation Options



These options were examined in conjunction with the load growth assumptions shown in Figure 1-2, described in Chapter 3, and other generation and fuel cost assumptions described in Chapter 4.

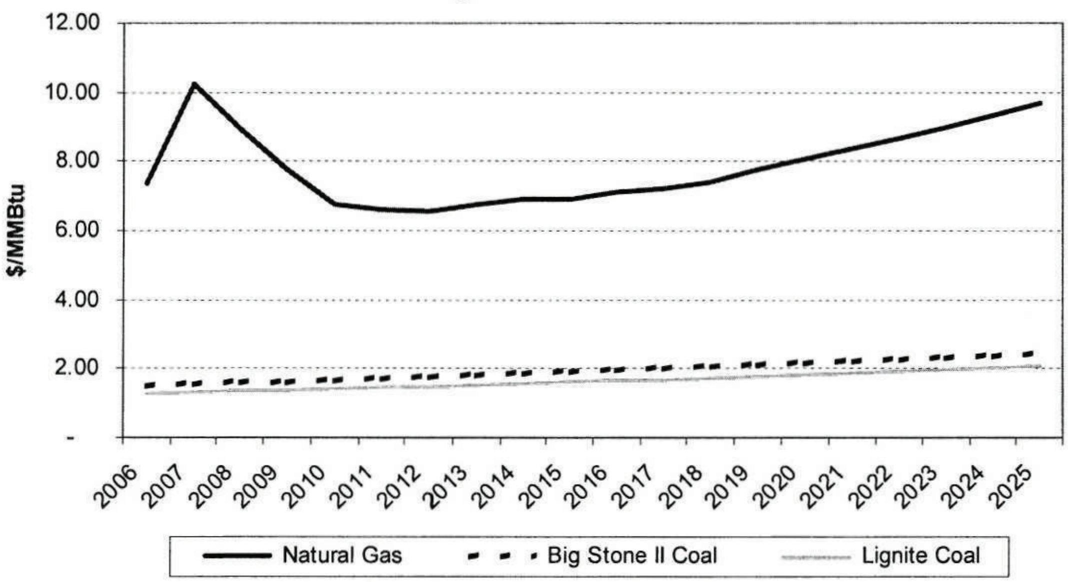
Figure 1-2: Montana-Dakota Load Assumptions



1.2 FUEL COST ASSUMPTIONS

The coal forecast for Big Stone II and LV-21 along with the natural gas price forecast is shown below in Figure 1-3.

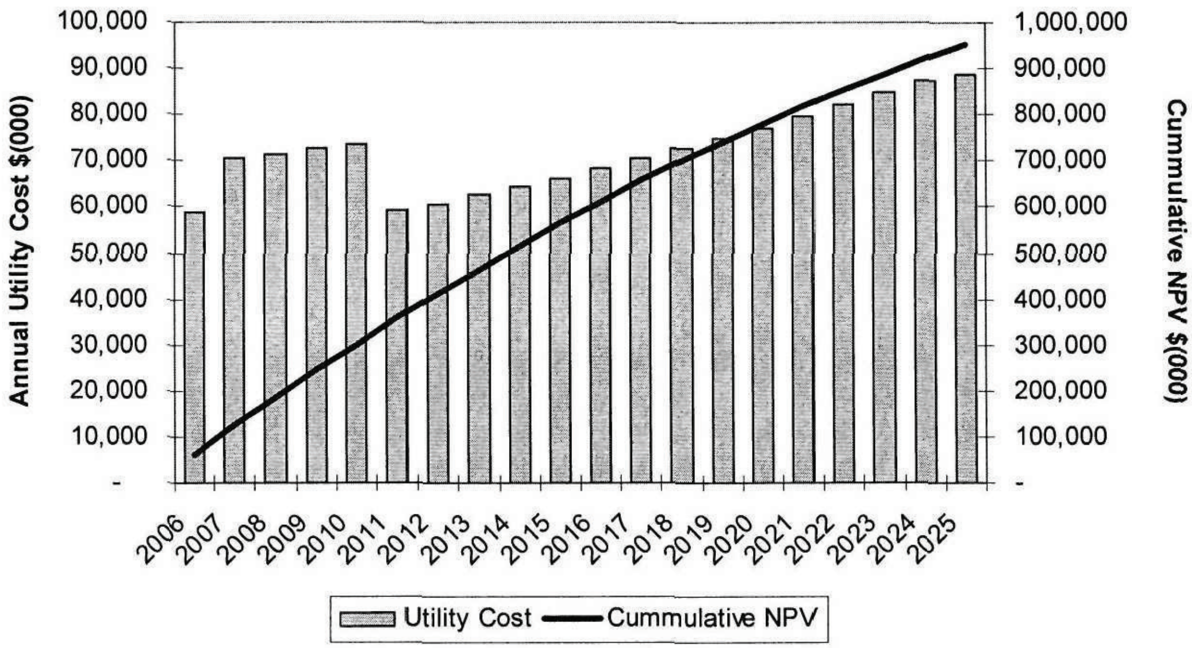
Figure 1-3: Fuel Forecast



1.3 RESULTS

The results of the analysis of the least cost expansion plan are based upon current generation plus the planned and committed additions. The committed additions include the short term capacity contract with Xcel Energy (85-100 MW), the South Dakota Wind project (31.5 MW), and an assumed wind project in Montana. The least cost additions selected by the Strategist model are the planned Big Stone II project in 2012, a combustion turbine in 2015, additional wind resources in 2023 and 2024, DSM in 2014 and 2015, and a contract extension. A summary of the cost associated with the preferred plan is shown in Figure 1-4.

Figure 1-4: Forecast of Utility System Costs



2. *METHODOLOGY*

PA developed the generation expansion plan analysis with the Strategist software licensed from NewEnergy Associates. The software includes an optimization module that selects the least cost resource using dynamic programming techniques. The optimization was set up to minimize utility system costs based upon existing generation and loads, projected load growth, fuel cost forecasts, and generation expansion options. PA performed the study using a twenty year planning horizon (2006 – 2025) and allowed the optimization to incorporate end effects (accounting for the cost of generation resources that have economic life beyond the end of the study period.)

2.1 DATA SOURCES

PA utilized data provided by Montana-Dakota with regards to existing loads, the load forecast, and the costs associated with existing generation. PA also relied upon information provided by Montana-Dakota to determine the cost of the Big Stone II coal plant in South Dakota and the LV-21 unit in North Dakota. PA reviewed the data provided and concur they represent reasonable assumptions.

PA used its own data to develop the long-term forecast of natural gas prices as well as the wind and Integrated Gasification Combined Cycle (IGCC) units. The costs of combined cycle and simple cycle gas turbines were based upon the Black & Veatch Supply-Side Technology Study.

2.2 SYSTEM CHARACTERIZATION

The Montana-Dakota retail load was modeled as a single system. The analysis did not consider exports or imports to the Montana-Dakota system beyond what was necessary to serve emergency power needs or to assign a value for excess energy as a result of must-run units (dump power). The analysis did not consider optimization of utility system costs by including any benefits from off-system sales.

2.3 SCENARIO/RISK ANALYSIS

PA's analysis was limited to base case scenarios using a combination of existing unit costs provided by Montana-Dakota, and PA generic unit cost assumptions. Risks related to fuel prices, load deviations from the forecast, environmental regulations, MISO market design, and a range of other factors were not included in this study.

3. LOAD AND EXISTING SYSTEM ASSUMPTIONS

Key inputs to the optimization model are the load forecast and the characteristics of the existing system. These assumptions drive both the need and timing for new demand or supply side resources. Upon the request of PA, these data were provided by Montana-Dakota.

3.1 LOAD ASSUMPTIONS

PA treated Montana-Dakota's retail electric load obligations in South Dakota, North Dakota, and Montana as a single system. The system load assumptions are shown in Table 3-1. The average annual energy and load growth during the study period is 0.96% and 0.94% respectively. These assumptions include implementation of existing DSM programs that provide a reduction of approximately 6.5 MW of peak demand and 38,000 MWh of energy.

Table 3.1: Load Assumptions

Year	Energy (GWH)	Peak Demand (MW)	Load Factor (%)
2006	2,441	481.8	57.8%
2007	2,496	487.8	58.4%
2008	2,540	492.4	58.9%
2009	2,581	497.0	59.2%
2010	2,624	502.4	59.6%
2011	2,647	507.7	59.5%
2012	2,669	512.9	59.4%
2013	2,689	518.1	59.2%
2014	2,706	523.3	59.0%
2015	2,723	528.6	58.8%
2016	2,740	533.6	58.6%
2017	2,758	538.9	58.4%
2018	2,775	544.1	58.2%
2019	2,793	549.3	58.0%
2020	2,811	554.5	57.8%
2021	2,829	559.8	57.7%
2022	2,847	564.8	57.5%
2023	2,866	570.1	57.4%
2024	2,884	575.3	57.2%
2025	2,903	580.5	57.1%

3.2 EXISTING RESOURCES

PA's base case assumes that the existing Montana-Dakota thermal resources are available through out the study period. A summary of these resources and associated characteristics is provided in Table 3-2. In addition to the thermal resources, PA also included existing contracts with the current expiration dates. A summary of the contracts is provided in Tables 3-3 and 3-4.

Table 3.2: Existing Montana-Dakota Resources Modeled

Generating Unit Name	Year Installed	Rated Capacity (MW)	Full Load Heat Rate ($/MMBtu)	2006 Fuel Price ($/MMBtu)	2006 Variable O&M Cost ($/MWh)	2006 Fixed O&M Cost ($/kW-Year)	Average Planned Maintenance (Weeks/Year)	Forced Outage Rate (Percent)
Big Stone I	1975	107.0					2.6	5.93%
Coyote	1981	106.8					3.0	5.93%
Heskett #1	1954	29.4					3.1	4.04%
Heskett #2	1963	73.5					3.6	4.04%
Lewis & Clark	1958	52.3		Redacted			3.3	4.04%
Glendive CT #1	1979	42.6					2.0	12.06%
Glendive CT #2	2003	42.6					2.0	12.06%
Miles City CT	1972	28.9					2.0	12.06%
Williston CT	1953	10.6					1.0	12.06%

Capital costs associated with continued operation of these resources were not included in the analysis and those costs are therefore not reflected in the summary results of total system costs.

Table 3.3: Existing Contracts Modeled

Contract	Starting Date	Expiration Date	Capacity (MW)	First Year Annual Energy (MWh)	2006 Demand Charge ($/kW-Year)	2006 Energy Cost ($/MWh)
AVS II	1996	2006	66.4	456.5		
South Dakota Wind	2008	2038	31.5	110.4		
NorthPoint	2005	2006	15.0 - 25.0	36.5	Redacted	
WAPA	2001	2031	2.8	14.3		
Xcel Peaking[1]	2007	2010	85 - 100	215.9		

(1) The Xcel contract increase to 100 MW in 2010 and has an option to be extended 1 year

Table 3.4: Potential Contracts Modeled

Contract	Starting Date	Expiration Date	Capacity (MW)	First Year Annual Energy (MWh)	2006 Demand Charge ($/kW-Year)	2006 Energy Cost ($/MWh)
Xcel Peaking	2011	2011	105	226.7		
MT Wind[1]	2008	2038	39020	110.4	Redacted	

(1) The MT wind contract is assumed to start at 10 MW in 2008, 20 MW in 2010, & 30 MW starting in 2015

4. *RESOURCE OPTIONS*

The Strategist Model determines the least cost generation expansion plan based upon the identified options. PA's analysis included the natural gas, coal, and wind generation options and DSM that was modeled as a contract. The parameters associated with these options are identified in this section.

4.1 GENERATION

The characteristics of the generation expansion options are shown below in Table 4-1. The capital costs of the units reflect the likely available options to Montana-Dakota. For example, both the LV-21 and combined cycle costs are relatively high on a dollar per kW basis as a result of not having economies of scale. The variable cost of wind includes wind integration costs. Wind resources were assumed to have a 22% capacity credit for summer months. The Wind option was modeled with a capital cost of $1,500/kW in 2006, declining to a cost of $1,200/kW in 2011.

Table 4-1: New Generation Resource Options

Unit	Fuel	Years Available	Capacity (MW)	Capital Cost $/kW (2006)	Full Load Heat Rate (Bt/kWh)	Fuel Price ($/MMBtu)	Variable Cost $/MWH	Fixed Cost $/kW (2006)	Planned Maint. Wks/Yr	FOR (%)
Combustion Turbine[1]	Natural Gas	2008 - 2025	43	916	9,000	7.37	4	32.22	2	3
Combined Cycle[1]	Natural Gas	2009 - 2025	130	1,668	7,550	7.37	4	18.85	2	3
Bigstone II[1]	Coal	2012 - 2025	116	2,461	9,600	1.52	2	27.70	4	5
Wind	Wind	2008 - 2025	50	1,500			5	25.00		
IGCC[1]	Coal	2015 - 2025	116	2,668	9,612	1.07	6	24.15	4	5
Lignite Coal[1]	Coal	2112 - 2025	116	2,745	10,440	1.28	3	46.72	4	5

(1) Includes estimates of transmission integration costs

In addition to the generation options, PA included three DSM options as contracts based upon extrapolation of data from Montana-Dakota's 2005 Integrated Resource Plan. One was based upon Montana-Dakota's 2005 Integrated Resource Plan and the other two were the result of discussions with Montana-Dakota. The three DSM options are 7.36 MW of residential and commercial air conditioning peak control measures available at a cost of $373/kW and an additional 5 and 10 MW of conservation available at $470/kW and $560/kW, respectively. The DSM options are summarized in Table 4-2.

Table 4-2: DSM Options

Contract	Years Available	2006 Capital Cost ($/kW)	Capacity (MW)	First Year Annual Energy (MWh)	2006 Demand Charge ($/kW-Year)	2006 Energy Cost ($/MWh)
DSM Option 1	2011-2025	373	7.36	2,550	0	0.00
DSM Option 2	2009-2025	470	10	1,275	0	0.00
DSM Option 3	2009-2025	560	10	2,550	0	0.00

4.2 FUEL

PA relied upon the coal cost estimates developed by Montana-Dakota for the coal resources and used PA's long-term consensus natural gas forecast for the combined cycle and combustion turbine options.

Table 4-3: Fuel Forecast ($/MMBtu)

Year	Natural Gas	Big Stone II & Generic Steam Turbine Coal	LV-21 Coal
2006	7.37	1.52	1.31
2007	10.26	1.56	1.35
2008	8.92	1.60	1.38
2009	7.78	1.64	1.41
2010	6.78	1.68	1.45
2011	6.58	1.72	1.49
2012	6.53	1.76	1.52
2013	6.77	1.81	1.56
2014	6.90	1.85	1.60
2015	6.92	1.90	1.64
2016	7.10	1.95	1.68
2017	7.21	1.99	1.73
2018	7.39	2.04	1.77
2019	7.77	2.10	1.81
2020	8.06	2.15	1.86
2021	8.38	2.20	1.91
2022	8.69	2.26	1.95
2023	9.00	2.31	2.00
2024	9.34	2.37	2.05
2025	9.70	2.43	2.10

4.3 OTHER ASSUMPTIONS

Table 4-4 shows the economic assumptions related to the generation alternatives.

Table 4-4: Economic Parameters

	Combustion Turbine	Combined Cycle	Bigstone II	Wind	IGCC	LV-21
Book Life (Years)	25	25	40	20	40	40
Operating Life (Years)	25	25	40	20	40	40
Cost of Money (%)	7.65	7.65	7.65	7.65	7.65	7.65
Insurance and Property Taxes (%)	2%	2%	1%	2%	2%	2%
Levelized Fixed Charge Rates (%)	10.67	10.67	9.34	11.69	9.34	9.34

5. RESULTS

The optimal plan selects Big Stone II in 2012, a gas-fired combustion turbines in 2015, and additional DSM and wind resources. The optimal plan also assumes an extension of the Xcel Peaking contract for one year, 2011. This plan also assumes that in addition to the South Dakota wind project, MDU also acquires 30 MW of wind to serve Montana load. The net present value of the utility system cost is $1,780,543,800. (Note the system cost does not include capital expenditures associated with extending the life of plants.)

Table 5-1: Expansion Plan Summary

	Least Cost
NPV Utility System Cost ($000)	1,780,543
Resource in Least Cost Plan	
2006	
2007	Xcel Peaking
2008	South Dakota Wind, Montana Wind
2009	
2010	
2011	Extension of Xcel Peaking
2012	Big Stone II
2013	
2014	DSM
2015	CT, DSM
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	Wind
2024	Wind
2025	

APPENDIX A: MODEL RESULTS

Table A-1 shows the forecasted operations for each unit, including expansion resources. Table A-2 shows the annual estimated total system costs associated with the selected plan.

Table A-1. Unit Operations Forecast

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Big Stone I	Capacity factor	%	69	79	78	79	79	79	81	81	82	81
	Capacity	MW	107	107	107	107	107	107	107	107	107	107
	Avg heat rate	MBtu/MWh	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85
	Var O&M cost	$000	728	853	858	886	908	926	972	991	1,014	1,030
	Fixed cost	$000	1,784	1,820	1,856	1,893	1,931	1,969	2,009	2,049	2,090	2,132
	Fuel cost	$000	9,173	10,665	10,652	10,912	11,100	11,240	11,709	11,854	12,045	12,141
	Av var cost	$/MWh	15.36	15.57	15.77	15.97	16.18	16.39	16.61	16.83	17.05	17.27
	Generation	GWh	644	740	730	739	742	742	764	763	766	763
	Fuel burn	GBtu	6,345	7,286	7,187	7,271	7,306	7,306	7,517	7,516	7,543	7,509
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Big Stone I	Capacity factor	%	82	82	82	82	83	83	83	82	79	80
	Capacity	MW	107	107	107	107	107	107	107	107	107	107
	Avg heat rate	MBtu/MWh	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85
	Var O&M cost	$000	1,058	1,080	1,106	1,129	1,159	1,184	1,211	1,212	1,205	1,240
	Fixed cost	$000	2,174	2,218	2,262	2,308	2,354	2,401	2,449	2,498	2,548	2,599
	Fuel cost	$000	12,385	12,544	12,747	12,923	13,169	13,354	13,556	13,463	13,290	13,581
	Avg var cost	$/MWh	17.5	17.72	17.96	18.19	18.43	18.67	18.92	19.16	19.42	19.67
	Generation	GWh	768	769	772	773	778	779	781	766	747	754
	Fuel burn	GBtu	7,566	7,568	7,596	7,606	7,655	7,666	7,686	7,539	7,350	7,419

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Coyote	Capacity factor	%	89	90	86	87	87	87	87	87	87	87
	Capacity	MW	107	107	107	107	107	107	107	107	107	107
	Avg heat rate	MBtu/MWh	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24
	Var O&M cost	$000	1,729	1,771	1,745	1,780	1,818	1,854	1,896	1,928	1,967	2,006
	Fixed cost	$000	1,998	2,038	2,079	2,120	2,163	2,206	2,250	2,295	2,341	2,388
	Fuel cost	$000	8,505	8,756	8,668	8,887	9,123	9,352	9,610	9,825	10,073	10,325
	Avg var cost	$/MWh	12.25	12.55	12.85	13.17	13.49	13.81	14.15	14.49	14.85	15.21
	Generation	GWh	835	839	810	810	811	811	813	811	811	811
	Fuel burn	GBtu	9,391	9,431	9,107	9,108	9,120	9,120	9,141	9,117	9,118	9,116
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Coyote	Capacity factor	%	87	87	87	87	87	87	87	87	87	87
	Capacity	MW	107	107	107	107	107	107	107	107	107	107
	Avg heat rate	MBtu/MWh	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	10.33
	Var O&M cost	$000	2,052	2,088	2,129	2,172	2,222	2,260	2,305	2,351	2,401	2,443
	Fixed cost	$000	2,436	2,484	2,534	2,585	2,636	2,689	2,743	2,798	2,854	2,911
	Fuel cost	$000	10,615	10,854	11,127	11,407	11,728	11,989	12,291	12,597	12,932	12,145
	Avg var cost	$/MWh	15.58	15.96	16.34	16.74	17.15	17.57	17.99	18.43	18.88	18.01
	Generation	GWh	813	811	811	811	814	811	811	811	812	810
	Fuel burn	GBtu	9,143	9,118	9,119	9,119	9,145	9,119	9,120	9,117	9,130	8,364

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Glendive 2	Capacity factor	%	4	5	4	4	5	5	2	2	2	1
	Capacity	MW	43	43	43	43	43	43	43	43	43	43
	Avg heat rate	MBtu/MWh	11.42	11.85	11.85	11.85	11.85	11.85	11.85	11.85	11.85	11.85
	Var O&M cost	$000	83	93	78	90	93	100	46	50	52	13
	Fixed cost	$000	159	163	166	169	173	176	180	183	187	191
	Fuel cost	$000	1,258	2,010	1,440	1,414	1,255	1,286	546	597	621	150
	Avg var cost	$/MWh	82.73	117.38	102.81	90.51	79.77	77.81	73.2	75.72	77.36	78.01
	Generation	GWh	16	18	15	17	17	18	8	9	9	2
	Fuel burn	GBtu	185	212	175	197	200	211	96	101	103	25
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Glendive 2	Capacity factor	%	1	1	1	1	1	1	1	1	1	1
	Capacity	MW	43	43	43	43	43	43	43	43	43	43
	Avg heat rate	MBtu/MWh	11.85	11.85	11.85	11.85	11.85	11.85	11.85	11.85	11.85	11.85
	Var O&M cost	$000	14	16	17	19	20	22	24	23	23	22
	Fixed cost	$000	194	198	202	206	210	215	219	223	228	232
	Fuel cost	$000	162	187	203	233	254	285	316	305	304	294
	Avg var cost	$/MWh	80.02	81.17	83.19	87.58	90.67	94.09	97.59	100.36	103.4	106.27
	Generation	GWh	2	3	3	3	3	3	4	3	3	3
	Fuel burn	GBtu	26	30	31	34	36	39	41	39	38	35

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Glendive I	Capacity factor	%	6	13	10	11	12	12	4	4	4	1
	Capacity	MW	43	43	43	43	43	43	43	43	43	43
	Avg heat rate	MBtu/MWh	11.61	11.61	11.61	11.61	11.61	11.61	11.61	11.61	11.61	11.61
	Var O&M cost	$000	105	247	205	232	239	254	76	82	86	27
	Fixed cost	$000	150	153	156	159	162	165	169	172	175	179
	Fuel cost	$000	1,606	5,195	3,688	3,557	3,140	3,170	890	977	1,021	317
	Avg var cost	$/MWh	83.26	114.53	100.66	88.51	77.99	75.99	73.02	75.54	77.16	77.4
	Generation	GWh	21	48	39	43	43	45	13	14	14	4
	Fuel burn	GBtu	239	552	449	497	503	523	154	163	167	52
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Glendive I	Capacity factor	%	1	2	2	2	2	2	3	2	2	2
	Capacity	MW	43	43	43	43	43	43	43	43	43	43
	Avg heat rate	MBtu/MWh	11.61	11.61	11.61	11.61	11.61	11.61	11.61	11.61	11.61	11.61
	Var O&M cost	$000	29	39	41	44	52	61	65	58	54	57
	Fixed cost	$000	182	186	190	194	197	201	205	210	214	218
	Fuel cost	$000	338	448	478	527	641	770	837	751	711	756
	Avg var cost	$/MWh	79.3	80	82.03	86.15	88.99	93.09	96.61	99.61	102.49	105.13
	Generation	GWh	5	6	6	7	8	9	9	8	8	8
	Fuel burn	GBtu	54	71	73	77	91	104	108	94	87	90

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Heskett 1	Capacity factor	%	23	22	19	21	21	22	8	9	9	8
	Capacity	MW	29	29	29	29	29	29	29	29	29	29
	Avg heat rate	MBtu/MWh	9.54	11.86	11.86	11.86	11.86	11.86	11.86	11.86	11.86	11.86
	Var O&M cost	$000	342	335	304	337	346	360	143	162	151	141
	Fixed cost	$000	1,273	1,299	1,325	1,351	1,378	1,406	1,434	1,462	1,492	1,522
	Fuel cost	$000	708	868	791	881	908	949	378	431	405	381
	Avg var cost	$/MWh	17.9	21.34	21.84	22.36	22.89	23.43	23.99	24.56	25.14	25.74
	Generation	GWh	59	56	50	55	55	56	22	24	22	20
	Fuel burn	GBtu	559	669	595	646	650	662	258	286	262	241
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heskett 1	Capacity factor	%	8	13	14	14	15	15	16	14	12	12
	Capacity	MW	29	29	29	29	29	29	29	29	29	29
	Avg heat rate	MBtu/MWh	11.86	11.86	11.86	11.86	11.86	11.86	11.86	11.86	11.86	11.86
	Var O&M cost	$000	148	242	266	280	290	306	320	286	262	272
	Fixed cost	$000	1,552	1,583	1,615	1,647	1,680	1,714	1,748	1,783	1,818	1,855
	Fuel cost	$000	400	659	729	771	801	850	894	802	739	770
	Avg var cost	$/MWh	26.35	26.98	27.62	28.28	28.95	29.64	30.34	31.07	31.8	32.56
	Generation	GWh	21	33	36	37	38	39	40	35	32	32
	Fuel burn	GBtu	247	396	427	441	447	463	475	416	374	379

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Heskett 2	Capacity factor	%	27	40	37	38	39	39	25	26	26	26
	Capacity	MW	74	76	76	76	76	76	76	76	76	76
	Avg heat rate	MBtu/MWh	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59
	Var O&M cost	$000	773	1,202	1,137	1,213	1,245	1,291	851	876	897	915
	Fixed cost	$000	2,455	2,504	2,554	2,606	2,658	2,711	2,765	2,820	2,877	2,934
	Fuel cost	$000	2,556	3,994	3,796	4,071	4,200	4,378	2,900	3,000	3,086	3,164
	Avg var cost	$/MWh	19.33	19.8	20.27	20.76	21.25	21.76	22.28	22.82	23.37	23.93
	Generation	GWh	172	263	243	255	256	261	168	170	171	171
	Fuel burn	GBtu	1,997	3,043	2,821	2,951	2,970	3,020	1,951	1,969	1,976	1,976
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heskett 2	Capacity factor	%	26	26	26	27	27	27	27	26	25	25
	Capacity	MW	76	76	76	76	76	76	76	76	76	76
	Avg heat rate	MBtu/MWh	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59
	Var O&M cost	$000	940	966	993	1,022	1,043	1,070	1,101	1,089	1,075	1,092
	Fixed cost	$000	2,993	3,053	3,114	3,176	3,240	3,304	3,371	3,438	3,507	3,577
	Fuel cost	$000	3,268	3,376	3,488	3,606	3,702	3,815	3,947	3,922	3,890	3,973
	Avg var cost	$/MWh	24.5	25.09	25.69	26.31	26.94	27.59	28.25	28.93	29.63	30.34
	Generation	GWh	172	173	174	176	176	177	179	173	168	167
	Fuel burn	GBtu	1,991	2,006	2,022	2,039	2,042	2,053	2,072	2,008	1,943	1,935

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
L&C	Capacity factor	%	36	55	52	53	53	54	29	30	31	29
	Capacity	MW	52	52	52	52	52	52	52	52	52	52
	Avg heat rate	MBtu/MWh	13.09	13.09	13.10	13.10	13.10	13.09	13.10	13.10	13.09	13.09
	Var O&M cost	$000	330	526	502	526	538	553	307	322	334	320
	Fixed cost	$000	2,148	2,191	2,235	2,280	2,325	2,372	2,419	2,467	2,517	2,567
	Fuel cost	$000	2,281	3,632	3,466	3,635	3,719	3,822	2,121	2,224	2,309	2,212
	Avg var cost	$/MWh	16.05	16.37	16.7	17.03	17.38	17.72	18.08	18.44	18.81	19.18
	Generation	GWh	163	254	238	244	245	247	134	138	141	132
	Fuel burn	GBtu	2,130	3,325	3,111	3,199	3,209	3,233	1,759	1,808	1,840	1,729
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
L&C	Capacity factor	%	29	56	57	58	58	59	60	55	50	53
	Capacity	MW	52	52	52	52	52	52	52	52	52	52
	Avg heat rate	MBtu/MWh	13.09	13.10	13.10	13.09	13.10	13.10	13.09	13.09	13.09	13.09
	Var O&M cost	$000	333	645	669	694	716	740	765	713	662	722
	Fixed cost	$000	2,619	2,671	2,724	2,779	2,834	2,891	2,949	3,008	3,068	3,129
	Fuel cost	$000	2,299	4,458	4,620	4,796	4,948	5,111	5,283	4,927	4,571	4,990
	Avg var cost	$/MWh	19.57	19.96	20.36	20.76	21.18	21.6	22.04	22.48	22.93	23.38
	Generation	GWh	135	256	260	264	267	271	275	251	228	244
	Fuel burn	GBtu	1,761	3,348	3,402	3,463	3,502	3,547	3,594	3,286	2,989	3,199

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Miles City	Capacity factor	%	9	17	14	16	16	16	5	5	5	3
	Capacity	MW	29	29	29	29	29	29	29	29	29	29
	Avg heat rate	MBtu/MWh	9.68	11.27	11.27	11.27	11.27	11.27	11.27	11.27	11.27	11.27
	Var O&M cost	$000	112	229	191	214	220	232	73	79	81	50
	Fixed cost	$000	378	385	393	401	409	417	426	434	443	452
	Fuel cost	$000	1,441	4,653	3,328	3,177	2,798	2,806	830	911	931	565
	Avg var cost	$/MWh	70.55	110.95	97.58	85.81	75.64	73.7	70.84	73.27	74.96	75.58
	Generation	GWh	22	44	36	40	40	41	13	14	14	8
	Fuel burn	GBtu	213	496	406	445	450	465	144	152	152	92
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Miles City	Capacity factor	%	3	4	4	4	4	4	4	4	3	3
	Capacity	MW	29	29	29	29	29	29	29	29	29	29
	Avg heat rate	MBtu/MWh	11.27	11.27	11.27	11.27	11.27	11.27	11.27	11.27	11.27	11.27
	Var O&M cost	$000	52	56	60	63	66	71	76	66	58	62
	Fixed cost	$000	461	470	479	489	499	509	519	529	540	551
	Fuel cost	$000	592	644	685	751	797	874	947	834	743	793
	Avg var cost	$/MWh	77.43	78.66	80.64	84.65	87.66	90.97	94.38	97.41	100.56	103.16
	Generation	GWh	8	9	9	10	10	10	11	9	8	8
	Fuel burn	GBtu	94	100	104	108	111	117	122	104	90	93

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Williston	Capacity factor	%	0.6	1.1	0.9	1.0	1.1	1.2	0.4	0.5	0.5	0.1
	Capacity	MW	11	11	11	11	11	11	11	11	11	11
	Avg heat rate	MBtu/MWh	23.35	23.02	23.24	23.21	23.21	23.31	23.91	23.88	23.84	23.93
	Var O&M cost	$000	3	5	4	5	5	6	2	3	2	1
	Fixed cost	$000	14	14	15	15	15	15	16	16	16	17
	Fuel cost	$000	82	214	162	162	144	156	55	61	60	18
	Avg var cost	$/MWh	163.34	223.04	197.28	172.61	151.39	148.44	142.38	147.16	150.45	151.84
	Generation	GWh	0.5	1.0	0.8	1.0	1.0	1.1	0.4	0.4	0.4	0.1
	Fuel burn	GBtu	12	23	20	22	23	25	10	10	10	3
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Williston	Capacity factor	%	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Capacity	MW	11	11	11	11	11	11	11	11	11	11
	Avg heat rate	MBtu/MWh	23.96	23.95	23.94	23.91	23.93	23.91	23.88	23.97	24.07	24.20
	Var O&M cost	$000	1	1	1	1	1	1	1	1	1	1
	Fixed cost	$000	17	17	18	18	19	19	19	20	20	20
	Fuel cost	$000	19	22	24	27	30	34	38	34	33	34
	Avg var cost	$/MWh	155.87	158.17	162	170.2	176.21	182.77	189.47	196.02	202.81	209.25
	Generation	GWh	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Fuel burn	GBtu	3	3	4	4	4	5	5	4	4	4

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Generic CT I	Capacity factor	%	0	0	0	0	0	0	0	0	0	5
	Capacity	MW	0	0	0	0	0	0	0	0	0	44
	Avg heat rate	MBtu/MWh	0	0	0	0	0	0	0	0	0	9.00
	Var O&M cost	$000	0	0	0	0	0	0	0	0	0	91
	Fixed cost	$000	0	0	0	0	0	0	0	0	0	2,531
	Fuel cost	$000	0	0	0	0	0	0	0	0	0	1,046
	Avg var cost	$/MWh	0	0	0	0	0	0	0	0	0	60.23
	Generation	GWh	0	0	0	0	0	0	0	0	0	19
	Fuel burn	GBtu	0	0	0	0	0	0	0	0	0	170
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Generic CT I	Capacity factor	%	5	5	7	7	7	7	8	7	8	10
	Capacity	MW	44	44	44	44	44	44	44	44	44	44
	Avg heat rate	MBtu/MWh	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
	Var O&M cost	$000	96	105	134	143	150	162	188	170	189	235
	Fixed cost	$000	2,572	2,613	2,655	2,699	2,742	2,787	2,833	2,879	2,927	2,975
	Fuel cost	$000	1,097	1,188	1,539	1,672	1,767	1,917	2,227	2,025	2,238	2,820
	Avg var cost	$/MWh	61.76	62.82	65.49	68.77	71.26	73.92	76.31	78.97	80.97	84.18
	Generation	GWh	19	21	26	26	27	28	32	28	30	36
	Fuel burn	GBtu	174	185	230	238	242	253	285	250	270	327

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Big Stone II	Capacity factor	%	0	0	0	0	0	0	53	54	55	55
	Capacity	MW	0	0	0	0	0	0	116	116	116	116
	Avg heat rate	MBtu/MWh	0	0	0	0	0	0	9.60	9.60	9.60	9.60
	Var O&M cost	$000	0	0	0	0	0	0	458	483	507	520
	Fixed cost	$000	0	0	0	0	0	0	5,333	5,416	5,500	5,586
	Fuel cost	$000	0	0	0	0	0	0	9,100	9,554	9,979	10,189
	Avg var cost	$/MWh	0	0	0	0	0	0	17.79	18.24	18.71	19.18
	Generation	GWh	0	0	0	0	0	0	537	550	561	558
	Fuel burn	GBtu	0	0	0	0	0	0	5,158	5,282	5,381	5,360
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Big Stone II	Capacity factor	%	55	44	44	44	45	46	46	43	39	38
	Capacity	MW	116	116	116	116	116	116	116	116	116	116
	Avg heat rate	MBtu/MWh	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60
	Var O&M cost	$000	540	453	469	491	512	538	562	536	503	506
	Fixed cost	$000	5,674	5,763	5,854	5,947	6,042	6,138	6,236	6,336	6,438	6,542
	Fuel cost	$000	10,516	8,489	8,720	9,091	9,412	9,866	10,230	9,695	9,044	9,136
	Avg var cost	$/MWh	19.67	20.2	20.72	21.25	21.79	22.34	22.91	23.49	24.09	24.69
	Generation	GWh	562	443	444	451	456	466	471	436	396	391
	Fuel burn	GBtu	5,396	4,249	4,258	4,330	4,373	4,471	4,522	4,180	3,804	3,749

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Generic WT I	Capacity factor	%	0	0	0	0	0	0	0	0	0	0
	Capacity	MW	0	0	0	0	0	0	0	0	0	0
	Energy Cost	$000	0	0	0	0	0	0	0	0	0	0
	Capacity cost	$000	0	0	0	0	0	0	0	0	0	0
	Avg energy cost	$/MWh	0	0	0	0	0	0	0	0	0	0
	Generation	GWh	0	0	0	0	0	0	0	0	0	0
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Generic WT I	Capacity factor	%	0	0	0	0	0	0	0	40	40	40
	Capacity	MW	0	0	0	0	0	0	0	31.5	31.5	31.5
	Energy Cost	$000	0	0	0	0	0	0	0	508	508	508
	Capacity Cost	$000	0	0	0	0	0	0	0	1,176	1,203	1,223
	Avg energy cost	$/MWh	0	0	0	0	0	0	0	4.6	4.6	4.6
	Generation	GWh	0	0	0	0	0	0	0	110.4	110.4	110.4

Unit Name	Data Item	Data Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Generic WT II	Capacity factor	%	0	0	0	0	0	0	0	0	0	0
	Capacity	MW	0	0	0	0	0	0	0	0	0	0
	Energy Cost	$000	0	0	0	0	0	0	0	0	0	0
	Capacity cost	$000	0	0	0	0	0	0	0	0	0	0
	Avg energy cost	$/MWh	0	0	0	0	0	0	0	0	0	0
	Generation	GWh	0	0	0	0	0	0	0	0	0	0
			2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Generic WT II	Capacity factor	%	0	0	0	0	0	0	0	0	40	40
	Capacity	MW	0	0	0	0	0	0	0	0	31.5	31.5
	Energy Cost	$000	0	0	0	0	0	0	0	0	508	508
	Capacity Cost	$000	0	0	0	0	0	0	0	0	1,203	1,223
	Avg energy cost	$/MWh	0	0	0	0	0	0	0	0	4.6	4.6
	Generation	GWh	0	0	0	0	0	0	0	0	110.4	110.4

Table A-2. Selected Plan System Report

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy required	GWh	2,441	2,496	2,540	2,581	2,624	2,647	2,669	2,689	2,706	2,723	2,740	2,758	2,775	2,793	2,811	2,829	2,847	2,866	2,884	2,903
Therm generation	GWh	1,933	2,262	2,161	2,202	2,210	2,222	2,473	2,493	2,508	2,488	2,505	2,523	2,540	2,558	2,575	2,593	2,612	2,520	2,431	2,453
Emergency energy	GWh	2.0	4.0	3.0	3.0	3.0	4.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	0.0
Net transactions	GWh	507	230	376	376	411	421	195	195	197	235	235	235	235	235	235	235	235	345	453	450
Peak Load	MW	482	488	492	497	502	508	513	518	523	529	534	539	544	549	554	560	565	570	575	580
Installed capacity	MW	563	558	572	577	585	590	601	601	602	650	650	650	650	650	650	650	650	657	662	685
Reserve margin	MW	81	70	80	80	82	82	88	82	79	121	116	111	106	101	96	90	85	87	87	105
Reserve margin	%	16.76	14.43	16.23	16.16	16.34	16.11	17.08	15.9	15.06	22.97	21.82	20.62	19.47	18.34	17.23	16.12	15.09	15.23	15.12	18.04
Fuel burned	GBtu	21,070	25,037	23,871	24,337	24,430	24,566	26,187	26,405	26,552	26,271	26,453	27,076	27,266	27,458	27,647	27,836	28,030	27,038	26,078	25,595
Total fuel cost	$000	27,609	39,988	35,990	36,696	36,387	37,160	38,139	39,434	40,530	40,507	41,692	42,869	44,360	45,804	47,248	48,865	50,565	49,355	48,496	49,294
Var. O&M cost	$000	4,205	5,262	5,025	5,282	5,413	5,576	4,824	4,976	5,091	5,113	5,261	5,691	5,885	6,059	6,233	6,417	6,619	6,505	6,433	6,652
Fixed O&M cost	$000	10,359	10,567	10,779	10,994	11,214	11,437	17,001	17,314	17,638	20,500	20,874	21,257	21,648	22,048	22,453	22,868	23,291	23,722	24,162	24,609
Total therm cost	$000	42,173	55,817	51,794	52,972	53,014	54,173	59,964	61,723	63,260	66,120	67,827	69,817	71,893	73,911	75,934	78,150	80,476	79,582	79,091	80,555
Net trans cost	$000	17,592	16,613	22,113	22,202	23,594	24,426	6,954	6,954	6,954	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	9,941	11,675	11,716
Total sys. cost	$000	59,886	72,689	74,103	75,404	76,842	78,851	66,999	68,767	70,301	74,397	76,107	78,102	80,180	82,201	84,227	86,447	88,777	89,561	90,801	92,299
System cost	$/MWh	24.53	29.12	29.18	29.22	29.28	29.79	25.11	25.57	25.98	27.32	27.77	28.32	28.89	29.43	29.97	30.56	31.18	31.25	31.48	31.79