BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY ON BEHALF OF BIG STONE II CO-OWNERS FOR AN ENERGY CONVERSION FACILITY PERMIT FOR THE CONSTRUCTION OF THE BIG STONE II PROJECT	))))))	**FINAL DECISION AND ORDER; NOTICE OF ENTRY** **EL05-022**

PROCEDURAL HISTORY

On November 8, 2004, Otter Tail Corporation d/b/a Otter Tail Power Company ("OTP"), on behalf of Central Minnesota Municipal Power Agency ("CMMPA"), Great River Energy ("GRE"), Heartland Consumers Power District ("HCPD"), Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("MDU"), Southern Minnesota Municipal Power Agency ("SMMPA"), and Western Minnesota Municipal Power Agency ("WMMPA") through Missouri River Energy Services ("MRES") (collectively, "Applicants") submitted to the South Dakota Public Utilities Commission ("Commission") a notice of intent to submit an application for permit to construct an energy conversion facility pursuant to SDCL 49-41B-5. The proposed energy conversion facility is a nominal 600 MW coal-fired electric generating facility and associated facilities, which the Project co-owners have named Big Stone II, to be located adjacent to the existing Big Stone Plant Unit I in Grant County, South Dakota ("Big Stone II" or the "Project"). The proposed site is located East of Milbank and Northwest of Big Stone City, in Grant County, South Dakota. On December 10, 2004, the Commission entered an Order Designating Affected Area and Local Review Committee in Docket EL04-034. On July 21, 2005, Applicants submitted to the Commission an application for a permit to construct an energy conversion facility for Big Stone Unit II.

On July 28, 2005, the Commission electronically transmitted notice of the filing to interested individuals and entities. The notice, however, inadvertently omitted mentioning the intervention date. On August 5, 2005, the Commission electronically transmitted an amended notice which included an intervention deadline of September 18, 2005. On August 18, 2005, the Commission electronically transmitted and posted to its web page an Errata Notice for Amended Weekly Filings setting forth the correct intervention deadline of September 19, 2005 in accordance with ARSD 20:10:22:40. On August 18, 2005, the Commission issued an Order Assessing Filing Fee establishing a fee amount pursuant to SDCL 49-41B-12 of not to exceed $700,000 with an initial deposit of $8,000, and issued a Notice of Application; Order for and Notice of Public Input Hearing; Notice of Opportunity to Apply for Party Status giving notice of a public input hearing to be held on the Project on September 13, 2005, in Milbank. Notice of the Public Input Hearing was published in the Milbank Valley Shopper, Sisseton Courier and Watertown Public Opinion. On September 13, 2005, the Public Input Hearing was held as scheduled in Milbank, South Dakota, and was attended by approximately 50 people.

On August 25, 2005, the Commission received a Petition to Intervene from Clean Water Action ("Clean Water"). On September 16, 2005, the Commission received Applications for Party Status from South Dakota Chapter Sierra Club ("Sierra Club") and the Union of Concerned Scientists ("UCS"). On September 19, 2005, the Commission received Applications for Party Status from Mary Jo Stueve ("Stueve"), Minnesotans for an Energy-Efficient Economy ("MEEE"), Izaak Walton League of America - Midwest Office ("Izaak Walton") and Minnesota Center for Environmental Advocacy ("MCEA") (MEEE, Izaak Walton, UCS and MCEA are referred to collectively as "Joint Intervenors"). At its September 27, 2005, meeting, the Commission granted intervention to Clean Water, Sierra Club, UCS, Stueve, MEEE, Izaak Walton and MCEA. On February 16, 2006, the Commission received a letter from Clean Water requesting that its Petition to Intervene be withdrawn. On March 16, 2006, the Commission granted an Order Granting Withdrawal of Intervention to Clean Water. On May 19, 2006, the Commission received a Stipulation requesting withdrawal of intervention from Sierra Club. On June 5, 2006, the Commission issued an Order Granting Stipulation for Withdrawal of Intervention to Sierra Club.

On September 20, 2005, the Commission received a letter and proposal from the Local Review Committee requesting funds to employ consultants to assist the Local Review Committee in carrying out the Committee's responsibilities, and on October 4, 2005, at its regularly scheduled meeting, the Commission voted unanimously to grant the Local Review Committee's request to hire consultants and to provide $47,950 for this purpose.

On November 28, 2005, the Commission received a Motion for Pre-Hearing Conference from Applicants. On December 2, 2005, a telephonic pre-hearing conference was held among counsel for the parties and the Commission's Counsel. On January 18, 2006, the Commission issued a Scheduling and Procedural Order. On February 23, 2006, Applicants filed a Motion to Clarify Scheduling and Procedural Order. On March 1, 2006, a second pre-hearing conference was held telephonically among counsel for the parties and Commission Counsel. On March 22, 2006, Applicants filed a letter suggesting changes to certain scheduling and procedural stipulations reached by the parties at the pre-hearing conference. On March 31, 2006, the Commission issued its Second Scheduling and Procedural Order, canceling the original procedural schedule, establishing a revised procedural schedule and making certain additional procedural rulings. On May 8, 2006, Joint Intervenors filed a Motion to Compel Discovery and to Extend Deadline for Intervenor Testimony. On May 12, 2006, Applicants and Joint Intervenors filed a Joint Motion and Stipulation to Amend Second Scheduling and Procedural Order, in which Joint Intervenors agreed to withdraw their Motion to Compel, Applicants agreed to respond to Joint Intervenors' discovery request IR 17, and Applicants and Joint Intervenors agreed to certain modifications of the procedural schedule in the Second Scheduling and Procedural Order to provide additional time for the filing of certain Joint Intervenor testimony responsive to the information provided by Applicants' response to IR 17. On May 19, 2006, the Commission issued a Third Scheduling and Procedural Order incorporating these stipulations.

In response to requests from the public, the Commission scheduled a second public comment hearing pursuant to ARSD 20:10:01:15.06 in conjunction with the formal evidentiary hearing and issued a Fourth Scheduling and Procedural Order on June 22, 2006, giving notice of the time, place and purpose of the public input hearing. The public comment hearing was held as scheduled on the evening of June 29, 2006, at the Capitol Building in Pierre and was attended by approximately 20 people.

In accordance with the Scheduling and Procedural Orders in this case, all parties filed pre-filed testimony. The formal evidentiary hearing was held as scheduled on June 26- 29, 2006, in Room 412 of the Capitol Building. On July 8, 2006, Stueve filed a Petition for Dismissal and accompanying Notice. Briefs were submitted by all parties on July 9, 2006, Proposed Findings of Fact, Conclusions of Law and Decision were submitted by Applicants and Joint Intervenors on July 9, 2006, and a Request for Specific Findings was submitted by Stueve on July 9, 2006. On July 10, 2006, Applicants submitted Amended Proposed Findings of Fact, Conclusions of Law and Decision. Oral argument was heard by the Commission on July 11, 2006.

On July 10, 2006, the Commission issued a Fifth Scheduling and Procedural Order to accommodate a Commissioner scheduling conflict, changing the time for Commission action on July 14, 2006, from 10:30 A.M. to 11:30 A.M.

The Commission rulings on Applicants' Amended Proposed Findings of Fact, Joint Intervenors Proposed Findings of Fact and Stueve's Proposed Findings of Fact are set forth on Attachment A, which is incorporated herein by reference.

Having considered the evidence of record and applicable law, the Commission makes the following Findings of Fact, Conclusions of Law and Decision:

FINDINGS OF FACT

1.0 APPLICANTS

1. The application is made by Otter Tail Corporation, d/b/a Otter Tail Power Company ("OTP") for itself and on behalf of the following: Central Minnesota Municipal Power Agency ("CMMPA"); Great River Energy ("GRE"); Heartland Consumers Power District ("HCPD"); Montana-Dakota Utilities Co, a Division of Montana-Dakota Resources Group, Inc. ("Montana-Dakota"); Southern Minnesota Municipal Power Agency ("SMMPA"); and Western Minnesota Municipal Power Agency ("WMMPA") through Missouri River Energy Services ("MRES"). (See Application, App. Ex 54; App. Ex. 8, pp. 3-4). (Hereinafter collectively referred to as the "Applicants"). The Applicants' proposed ownership and operation of the Big Stone Unit II is governed by participation and operating agreements. App. Ex. 8, p. 4.

2. CMMPA is a joint action agency that was created and incorporated as a municipal corporation and a political subdivision of the State of Minnesota. It is a municipal power agency that supplies wholesale electric service to its municipal utility members who are responsible for serving the retail needs of its customers. There are fourteen municipal members of CMMPA. App. Ex. 6, pp. 2-3; HTr 223-24. CMMPA has a five percent ownership interest in Big Stone Unit II. App. Ex. 6, p. 10; App. Ex. 8, pp. 3-4.

3. GRE is a non-profit generation and transmission cooperative which provides wholesale electric service to its 28 owner-members, serving approximately 666,000 retail member customers located primarily in Minnesota. App. Ex. 2, pp. 2-3. GRE has a 19.3% ownership interest in Big Stone Unit II. App. Ex. 8, pp. 3-4.

4. HCPD is a political subdivision and public corporation of South Dakota serving as a wholesale power supplier. App. Ex. 4, p. 2; App. Ex. 15, p. 6; HTr 237. HCPD is a consumer power district regulated by the statutory and administrative rules of the State of South Dakota. Id. HCPD has a statutory obligation to provide electric power and energy to the people of South Dakota, economically and reliably. SDCL 49-37-3.1. HCPD is required to forecast its needs and determine the best way to meet those needs. Id. HCPD serves municipalities in South Dakota, Minnesota, and Iowa, including three South Dakota state agencies, the University of South Dakota, South Dakota State University, and one South Dakota rural electric cooperative. HTr 171-172. HCPD has a 4.2% ownership interest in Big Stone Unit II. App. Ex. 8, pp. 3-4.

5. Montana-Dakota is an investor-owned electric utility company that operates an integrated electric system in portions of Montana, North Dakota and South Dakota. It is a division of Montana-Dakota Resources Group, Inc., a publicly traded corporation. App. Ex. 11, p. 11; App. Ex. 7, pp. 1, 3). Montana-Dakota has a 19.3% ownership interest in Big Stone Unit II. App. Ex. 7, p. 6; App. Ex. 8, pp. 3-4.

6. OTP is an investor-owned electric utility providing electric and energy services to more than 128,000 retail customers in Minnesota, North Dakota and South Dakota. Half of OTP's customers live in rural communities with populations of less than 200. App. Ex. 1, pp. 4, 7. OTP serves 423 communities, ranging in size from 200 to approximately 10,000 residents. HTr 29. It has a 19.33% ownership interest in Big Stone Unit II. App. Ex. 1, p. 10; App. Ex. 8, pp. 3-4.

7. SMMPA is a non-profit municipal corporation and political subdivision of the State of Minnesota. It provides wholesale electric service to its 18-member municipal utilities, and serves indirectly approximately 215,000 persons. App. Ex. 5, pp. 2-3. It has a 7.833% ownership interest in Big Stone Unit II. App. Ex. 5, p. 9; App. Ex. 8, pp. 3-4.

8. WMMPA is a municipal corporation and political subdivision of the State of Minnesota providing acquisition and ownership of power supply and transmission projects to 23 member municipal utilities, 22 of which are also members of MRES. App. Ex. 3, pp. 2-4. MRES is a not-for-profit joint action agency providing wholesale supplemental power service to its 60 member municipal electric utilities in South Dakota, Minnesota, North Dakota and Iowa. App. Ex. 3, pp. 4-5; App. Ex. 14, p. 12. The average population

of member communities is 4,100 persons. Id. The total number of members served is approximately 120,000. Id. WMMPA, through MRES, has a 25% ownership interest in Big Stone Unit II. App. Ex. 5, p. 9; App. Ex. 3, p. 11; App. Ex. 8, pp. 3-4.

9. The Commission has jurisdiction to regulate the retail rates of only two of the Applicants: OTP and Montana-Dakota. HTr 759. The remaining Applicants are not subject to rate regulation in any state. Instead, as a cooperative utility (GRE), or as municipal utilities (MRES, SMMPA, CMMPA and HCPD), each is self-regulating – i.e., each establishes its own rates. App. Ex. 29, pp. 4-6; App. Ex. 41, p. 8; App. Ex. 39, p. 2, HTr 760.

2.0 INTERVENORS/PARTICIPANTS

10. On October 4, 2005, the Commission granted the following parties intervenor status: MEEE; Isaak Walton; UCS; MCEA; Sierra Club; Clean Water, and Stueve.

11. The Commission's Staff ("Staff") is also a full-party participant in the case.

12. Clean Water withdrew as a party pursuant to a letter submitted to the Commission dated February 14, 2006. On May 18, 2006, Intervenor Sierra Club and the Applicants executed a written stipulation providing for the withdrawal of Intervenor Sierra Club in this matter. Notice of the Stipulation and Withdrawal was given to all the parties on May 19, 2006. The stipulation was approved at the Commission meeting held May 23, 2006, and the Order granting Sierra Club's request to withdraw was entered June 5, 2006.

3.0 PROCEDURAL FINDINGS

13. The Western Area Power Administration held Federal EIS scoping hearings in Milbank, South Dakota, and Morris, Granite Falls, and Benson, Minnesota, on June 13, 14, 15, and 16, 2005, respectively.

14. On July 21, 2005, Mark Rolfes of OTP, on behalf of the Applicants, signed and filed the Application with the Commission.

15. Pursuant to SDCL 49-41B-6, the Commission formed the Local Review Committee ("LRC"). LRC convened meetings during the fall of 2005. The LRC drafted a Report, which was filed with the Commission on or about December 20, 2005. Following a review of the LRC Report, the Applicants commissioned additional studies and hired a consultant pursuant to the Commission Order. The Report of the LRC was admitted into the record at the Hearing as App. Ex. 68.

16. A public input hearing was held on September 13, 2005, in Milbank, South Dakota. Fifteen persons provided testimony. Approximately fifty members of the public were in attendance. App. Ex. 73.

17. Substantial written discovery was exchanged. Applicants answered more than 500 discovery requests and made available more than 47,000 pages of documents. Applicants submitted more than 2,000 pages of testimony and exhibits. HTr 555.

18. The following testimony was pre-filed:

A. Applicants' March 15, 2006 Direct Testimony:

Larry Anderson, SMMPA, Senior Planner/Economist, App. Ex. 13
Dick Edenstrom, First District, Executive Director, App. Ex. 27
David Gaige, Burns & McDonnell, Senior Project Manager Environmental Studies and Permitting, App. Ex. 22
David Geschwind, SMMPA, Senior Planner/Economist, Director of Operations and Chief Operating Officer, App. Ex. 5

Stephen Gosoroski, Burns & McDonnell, Project Manager, App. Ex. 24
Terry Graumann, OTP, Manager of Environmental Services, App. Ex. 16
Jeffrey Greig, Burns & McDonnell, General Manager of the Business & Technology Services Division (corrected filing on June 16, 2006), App. Ex. 23
Kiah Harris, Burns & McDonnell, Project Manager Business & Technology Services Division, App. Ex. 25
Janelle Johnson, OTP, Senior Financial Planner, App. Ex. 28
Daniel Jones, Barr Engineering, App. Ex. 17
Anne Ketz, 106 Group, President and Technical Director, App. Ex. 21
John Knofczynski, HCPD, Manager of Engineering, App. Ex. 15
Peter Koegel, MAPPCOR, Project Manager, App. Ex. 9
Richard Lancaster, GRE, Vice President Generation, App. Ex. 2
John Lee, Barr Engineering, Vice President, App. Ex. 18
Mike McDowell, HCPD, General Manager and Chief Executive Officer, App. Ex. 4
Bryan Morlock, OTP, Manager of Resource Planning, App. Ex. 10
Hoa Nguyen, Montana-Dakota, Power Supply Coordinator, App. Ex. 11
Tina Pint, Barr Engineering, Geologist/Hydrogeologist, App. Ex. 19
Mark Rolfes, OTP, Project Manager for Big Stone Unit II, App. Ex. 8
Andrew J. Skoglund, Barr Engineering, Acoustical Engineer, App. Ex. 20
Andrea L. Stomberg, Montana-Dakota, Vice President Electric Supply, App. Ex. 7
Randall Stuefen, University of South Dakota, Professor Emeritus, App. Ex. 26
Stephen Thompson, Central Minnesota Municipal Company, Chief Operating Officer, App. Ex. 6
Gerald Tielke, MRES, Operations Manager, App. Ex. 14
Ward Uggerud, OTP, Senior Vice President, App. Ex. 1
Raymond Wahle, MRES, Director Power Supply and Operations, App. Ex. 3

B. Commission Staff's May 19, 2006 Direct Testimony:

Olesya Denney, Staff Ex. 1
Michael K. Madden, Staff Ex. 2

C. Joint Intervenors' May 19, 2006 Direct Testimony:

Marshall R. Goldberg, MRG & Associates, Joint Intervenors' Ex. 3
Eric Hausman, Synapse Energy Economics, Inc., Joint Intervenors' Ex. 2
David Schlissel and Anna Sommer, Synapse Energy Economics, Inc., Joint Intervenors' Ex. 1, (corrected testimony filed on May 26, 2006), Joint Intervenors' Ex. 4

D. May 19, 2006 Prefiled Testimony of Mary Jo Stueve:

Mary Jo Stueve, pro se, Intervenor Stueve Ex. 1

E. Applicants' June 9, 2006 Rebuttal Testimony:

Robert Brautovich, App. Ex. 35
Terry Graumann, App. Ex. 34
Thomas Hewson, Jr., App. Ex. 30
Daniel Jones, App. Ex. 37
Daniel E. Klein (corrected filing on June 19, 2006), App. Ex. 31
Richard R. Lancaster, App. Ex. 39
John Lee, App. Ex. 36
Bryan Morlock, App. Ex. 32
Mark Rolfes, App. Ex. 33
Andrew Skoglund, App. Ex. 38

Randall Stuefen, App. Ex. 40
Ward Uggerud, App. Ex. 29
Raymond Wahle, App. Ex. 41

F. Joint Intervenors' June 9, 2006 Rebuttal Testimony:

David Schlissel and Anna Sommer, Joint Intervenors' Ex. 5

G. Applicants' June 16, 2006 Rebuttal Testimony:

Robert Davis, App. Ex. 47
Jeffrey Greig, App. Ex. 51
Thomas Hewson, App. Ex. 52
Bryan Morlock, App. Ex. 42

H. Commission Staff's June 19, 2006 Surrebuttal Testimony:

Olesya Denney, Staff Ex. 3

I. Joint Intervenors' Sur-rebuttal Testimony:

Ezra Hausman (June 20, 2006), Joint Intervenors' Ex. 7
David Schlissel and Anna Sommer (June 22, 2006), Joint Intervenors' Ex. 6

19. Testimony at the June 26-30, 2006 hearing was given by the following individuals:

Ward Uggerud	Randall Stuefen	Hoa Nguyen
Mark Rolfes	Robert Brautovich	Robert Davis
Terry Graumann	Jeffrey Greig	Daniel Klein
Raymond Wahle	Stephen Gosoroski	Thomas Hewson
Michael McDowell	Kiah Harris	Mary Jo Stueve
Jerry Tielke	Peter Koegel	Michael Madden
Steve Thompson	Bryan Morlock	Olyesa Denney
John Knofczynski	Stan Selander	Marshall Goldberg
John Lee	Larry Anderson	David Schlissel
Andrew Skoglund	David Gaige	Anna Sommer

20. Pursuant to agreement of the parties, the testimony for the following witnesses was received into the record without cross-examination: Richard Lancaster, Andrea Stomberg, David Geschwind, Tina Pint, K. Anne Ketz, Janelle Johnson, Dick Edenstrom, Daniel Jones and Ezra Hausman.

21. Public input and comments were also heard by the Commission on Thursday, June 29, 2006, in Pierre, South Dakota, with approximately 20 members of the public in attendance and 12 persons appearing to personally provide comments. HTr 558.

4.0 APPLICABLE REGULATIONS AND STATUTES

22. The following Administrative Rules of South Dakota ("ARSD") are applicable: ARSD 20:10:22:01 through ARSD 20:10:22:33, ARSD 20:10:22:36, ARSD 20:10:22:39 and ARSD 20:10:22:40.

23. The following South Dakota Codified Laws ("SDCL") are applicable: SDCL 49-41B-1, 49-41B-2, 49-41B-4 through 49-41B-17, 49-41B-17.1, 49-41B-19 through 49-41B-22, and 49-41B-24.

5.0 NAME OF OWNER AND MANAGER

24. CMMPA, GRE, HCPD, Montana-Dakota, OTP, SMMPA, and WMMPA will own Big Stone Unit II as tenants-in-common. App. Ex. 8, pp. 3-4. Management of the facility will be by OTP. App. Ex. 8, p. 4.

25. Each of the Applicants will be responsible for financing its respective ownership interest in the unit in a manner unique to each owner. App. Ex. 1-7.

6.0 PURPOSE OF FACILITY

26. Big Stone Unit II is a proposed coal-fired electric generating facility and associated facilities intended to provide approximately 600 MW of baseload energy for the seven participating owners in a low-cost, environmentally responsible manner. App. Ex. 8, p. 4. The energy from the facility is intended to serve the Applicants' retail and wholesale native load customers. App. Ex. 8, p. 4. The majority of the consumers live in South Dakota, North Dakota, Minnesota, Iowa, Montana, and Wisconsin. App. Ex. 5, p. 2; App. Ex. 15, pp. 7, 12; App. Ex. 9, pp. 2-3; App. Ex. 2, pp. 2, 18; App. Ex. 4, pp. 6, 16; App. Ex. 6, pp. 3-4; App. Ex. 1, pp. 4, 7. The facility is expected to produce 4.6 million MW hrs of electricity per year. App. Ex. 8, p. 11.

27. As a baseload plant, Big Stone Unit II is expected to be dispatchable, available for generation 24 hours a day, seven days a week. As a dispatchable resource, Big Stone Unit II can be controlled to match the Applicants' customers' energy needs. App. Ex. 8, p. 8.

7.0 ESTIMATED COST

28. The estimated construction cost for Big Stone Unit II is in excess of $1 billion in 2011 dollars. As Applicants approach a more defined design stage, refined cost estimates will be prepared. App. Ex. 8, p. 6. It is anticipated that construction costs for Big Stone Unit II will be subject to overall trends for steel, concrete, and other construction commodities. HTr. p. 89.

8.0 DEMAND FOR FACILITY

Regional Needs

29. MAPP is a voluntary association of electric utilities and other electric industry participants in the Upper Midwest and others that was organized in 1972 for the purpose of pooling generation and transmission to promote efficiency and reliability. App. Ex. 9, pp. 2-3. MAPP can meet its Reserve Capability Obligation for the next five years. However, by the summer of 2011, the MAPP-US region is projected to have a capacity deficit of approximately 219 MW even if Big Stone Unit II is constructed. Without Big Stone Unit II, the MAPP-US region will have a capacity deficit of approximately 819 MW by 2011, and 2400 MW by 2014. In order to meet its forecasted Reserve Capacity Obligation, MAPP members will need to build generation, purchase additional capacity, and/or reduce their demand growth. App. Ex. 9, p. 5.

30. MAPP-US has 7,900 MW of generation fueled by oil and natural gas. Such units have relatively high production costs, and are among the last in the power pool to be called upon to run. App. Ex. 50, p. 2.

31. MAPP-US had significant installed capacity margins during the 1980s. These margins have been declining since then, due to ongoing load growth in the region. Reserve margins were maintained at adequate levels during the 1990s, primarily through the addition of new, natural gas-fired capacity. Continuing load growth will result in inadequate generation capacity by 2011, unless additional resources are added. App. Ex. 50, p. 3.

32. MAPP-Canada projects a 1,383 MW surplus in the summer season of 2011. Of that amount, Manitoba Hydro Electric Board (MHEB) represents the lion's share at 1,350 MW. Saskatchewan Power (SP) represents the balance of 33 MW. App. Ex. 50, p. 4.

33. MAPP-Canada projects a 1,200 MW surplus in the 2011/2012 winter season. Of that amount, MHEB represents 1380 MW. SP represents the balance: a net capacity deficit of 180 MW in that season. App. Ex. 50, p. 4.

34. Similar to the situation of MAPP-US, a portion of the capacity surpluses in MAPP-Canada is fired by high-cost oil and natural gas generation resources. The availability of such surpluses is limited by transmission constraints, the energy-based rather than capacity-based makeup of the MHEB system, and the unwillingness or inability of utilities in Canada to sell any surpluses to utilities in the United States. App. Ex. 50, p. 5.

Applicants' Needs

35. Each of the Applicants presented evidence of a forecasted need for the additional baseload capacity and energy that Big Stone Unit II is designed to provide. Each Applicant has performed detailed resource planning studies that demonstrate such need. Based on these studies, the Applicants have projected that they need the following baseload energy and capacity by the 2011 timeframe:

Applicant	**Baseload Need in 2001 (MW)**	**Proposed Share in Big Stone II (MW)**
CMMPA	60	30
GRE	150	116
HCPD	30	25
Montana-Dakota	126	116
MRES[1]	200	150
OTP	120	116
SMMPA	100	47
Totals	**786**	**600**

Note:
[1] Includes Hutchinson, Minnesota.

OTP

36. OTP's energy requirements are forecast to steadily increase from the present through 2014 and beyond. Over the 10-year period shown from 2005-2014, OTP's energy needs are projected to grow at an average annual rate of 1.6%. OTP experiences summer season capacity deficits beginning in 2006 with the expiration of a 50 MW capacity and energy contract coupled with the expiration of a seasonal "diversity" agreement under which OTP was providing 75 MW of summer capacity to another regional utility. The net effect of these two transactions ending is a deficit of 5 MW in 2006. This deficit increases each year due to system load growth, and then takes another increase in 2010 to 116 MW with the expiration of a second 50 MW contract. Continued forecast load growth results in a projected capacity deficit of 173 MW by 2014. App. Ex. 10, p. 7; App. Ex. 54.

37. OTP conducts extensive integrated resource planning. OTP uses capacity expansion software to develop a series of optimized resource plans. The utility's entire system (i.e., Minnesota, North Dakota, and South Dakota) is modeled within the program, including the load forecast, existing generating and capacity transaction resources, all existing assets of the utility, and its financial structure. The model contains a detailed financial sub-model that calculates all financial parameters, tracks cash flow, and can issue new financings based on the need for capital to finance operations and construction. Available supply-side

(including renewables) and demand-side alternatives are input to the model and the model is executed to select the optimized resource plan for the given scenario. App. Ex. 10, p. 4.

38. Based on OTP's resource planning, Big Stone Unit II is shown to be a least cost baseload resource for the OTP system. OTP's planning efforts also identified optimal levels of conservation (e.g., specific demand-side management programs) and renewable generation resources that should also be added to the OTP resource portfolio, in addition to its proposed share of Big Stone Unit II. App. Ex. 10, p. 11.

MRES

39. The 2006 summer peak demand for the MRES member cities is forecasted at 818 MW, of which MRES will be responsible for 418 MW plus 15% planning reserves, or 480 MW. The MRES forecasts estimate that member total demand will grow annually by an average of 1.8% between 2006 and 2010, and by an average of 1.5% between 2010 and 2020. By 2011, MRES will have an expected shortfall of 8 MW of generation capacity, increasing to 230 MW by 2020. App. Ex. 44, p. 3.

40. MRES has a Power Purchase Agreement with its municipal utility member Hutchinson, Minnesota (HUC) under which MRES has an obligation to sell, and HUC to purchase, 40 MW of capacity and related energy from the Big Stone Unit II. App. Ex. 44, p. 2.

41. MRES performs integrated resource planning, including the use of a sophisticated capacity expansion software tool which performs a combined analysis of forecasted energy requirements, demand-side management programs, and supply-side generation capability (including renewables) to determine how projected energy requirements are going to be best met in the future. The results of MRES' capacity expansion integrated resource planning confirms that 150 MW of the Big Stone Unit II project is a least-cost alternative for MRES, including the 40 MW needed to serve the HUC PPA. App. Ex. 44, pp. 10-12.

GRE

42. GRE forecasts that from 2004-2023 its demand will increase an average of approximately 96 MW per year. During the same period, GRE forecasts its energy requirements will increase by an average of approximately 337,500 MWh per year. App. Ex. 2, p. 12-13, including App. Ex. 2-D and 2-E; App. Ex. 54, Tables 3-3 and 3-4.

43. Based on GRE's continued strong load growth and the expiration of several purchase contracts, GRE will experience a capacity deficit of approximately 680 MW in 2011. App. Ex. 2, p. 11.

44. GRE conducts extensive integrated resource planning, including the use of sophisticated computer models to determine the correct, cost-effective combinations of DSM, renewables and other resources to be used to meet its customers' needs. Those resource-planning techniques have recently been expanded to include a capacity expansion optimization model as another planning tool used to confirm the need for Big Stone Unit II. The results of that analyses determined that a baseload resource such as Big Stone Unit II is projected to be needed in 2011 and to be least cost. App. Ex. 14, p. 13; App. Ex. 44.

MDU

45. Montana-Dakota's forecasts show that its energy use is growing at an average annual rate of 1.3% over the next ten years. Montana-Dakota's energy requirements are forecast to be approximately 2,440 gigawatt hours (GWh) in 2006, 2,650 GWh in 2011 and 2,744 GWh in 2016. The compounded average rate for energy requirements is 1.0 percent per year. Montana-Dakota's most recent forecast shows capacity deficits beginning in 2011 (101 MW) and increasing steadily through 2021 (164 MW). App. Ex. 11, p. 8; App. Ex. 11-C.

46. Montana-Dakota experiences a capacity deficit in 2011 of 101 MW, and the capacity deficits increase to 134 MW in 2016 and 164 MW by the summer of 2021. The deficits are largely caused by the 2006 expiration of a 66.4 MW baseload purchase agreement with Basin Electric Power Cooperative and increases in annual peak demand that grows at a rate of 1.1% per year. App. Ex. 11, p. 9.

47. Montana-Dakota undertakes extensive integrated resource planning efforts, including the use of sophisticated capacity expansion analysis that compares supply-side resources (including renewable resources) on a comparative basis with demand-side resources. The result of this analysis, along with Montana-Dakota's exercise of prudent management decisions regarding the high cost of natural gas, shows that Montana-Dakota's proposed share in Big Stone Unit II is projected to be its least-cost alternative. App. Ex. 11, pp. 10-11.

48. While Montana-Dakota's resource planning shows that its proposed 116 MW share of Big Stone Unit II in 2011 meets its needs, the evidence also shows that Montana-Dakota could justify another 10 MW. First, additional capacity would provide an incremental level of risk management to cover load forecast uncertainty, future resource uncertainty, and the potential for extreme weather conditions, thereby improving system reliability. In addition, ten additional megawatts would satisfy its customers' demand for capacity and energy requirements through 2015, thereby delaying the need for its next resource addition for another two years. App. Ex. 48, p.7.

SMMPA

49. SMMPA forecasts energy growth of 2.4% of its members over the next decade. The evidence shows that energy use in 2004 was 2,943,972 MWhr, and increases to 3,637,903 MWhr by 2014 and 4,037,580 MWhr by 2020. SMMPA forecasts annual demand growth of approximately 1.2% over the next decade. SMMPA's forecasted demand was 536 MW in 2005 and increases steadily to 640 MW by 2020. App. Ex. 13, p. 4.

50. SMMPA engages in sophisticated integrated resource planning, including the use of capacity expansion software modeling tools to forecast and plan the future power and energy resources necessary to meet its members' obligations. The modeling tools used by SMMPA are designed to evaluate integrated resource plans, independent power producers, avoided costs, and plant life management programs. These tools also have modules developed to specifically accommodate the integration of demand-side-management options and to facilitate the development of environmental compliance plans. App. Ex. 13, p. 3.

51. Because natural gas prices continue to climb, SMMPA's most recent analyses showed that a 100 MW share of a pulverized coal plant in 2011 is its least-cost alternative. A 50 MW share of a pulverized coal plant would be its second-best plan followed by a 50 MW, gas-fired alternative. Thus, SMMPA's proposed 47 MW participation in Big Stone Unit II is a least-cost option for its customers, combined with its plans for certain defined amounts of conservation and renewables. App. Ex. 45, p. 8.

CMMPA

52. Net energy for load and peak demands for CMMPA members participating in the project are projected to grow at annual growth rates of approximately 1.5 percent over the twenty year period from 2006 through 2025. Primarily following the forecast trends for major economic indicators used to develop the forecast, load growth rates for the CMMPA members are projected to decline over time, with growth rates of approximately 1.6 percent over the first decade of the forecast period (2006 through 2015), declining to approximately 1.4 percent over the second decade of the forecast period (2016 through 2025). The annual coincident peak demand of the CMMPA members is projected to be 177 MW by the summer of 2011 (the summer immediately following the anticipated commercial operating date for the Big Stone Unit II). App. Ex. 47, p. 4.

53. Assuming a 15 percent MAPP planning reserve margin is applied to the forecast of coincident peak demands for the CMMPA members, CMMPA is first in need of capacity additions in 2008. Capacity deficiencies in 2008 are projected to be rather small (less than 2 MW), and capacity needs are projected to increase only slightly in 2009 as certain purchase power contracts are set to expire and other planned resources are scheduled to come online. However by 2011, without the addition of the CMMPA members' share of Big Stone Unit II, the reserve margin for CMMPA is projected to fall below 10 percent. Capacity needs are projected to grow by an average of 3.5 MW per year thereafter. By 2025, if no capacity other than currently planned amounts are added, CMMPA would need approximately 58 MW of capacity additions.

54. CMMPA employed a sophisticated capacity expansion analysis as part of its resource planning efforts. The resource expansion analysis was performed using a generation and demand-side planning optimization analysis software package, which employs a dynamic programming optimization technique combined with a convolution generation dispatch process to approximate the operation of generating resources and power purchases and sales for electric utilities. Through this dynamic optimization process, the software tool explores all potential generation expansion plans that can be produced from a given set of resource alternatives and identifies the best candidate plans based on the planning objectives identified by CMMPA. Based on that analysis, a resource expansion plan consisting of the planned 30 MW of the Big Stone Unit II in 2011, plus an additional 10 MW of installed wind capacity in 2011, followed by 10 MW of supercritical pulverized coal capacity installed every two to three years beginning in 2019, was found to be the least-cost potential resource expansion plan. App. Ex. 47, p. 7-8.

HCPD

55. HCPD is projecting peak demand in 2006 of 118 MW. This forecast grows to 157 MW in 2008 (or 39 MW higher than as originally indicated in the Application), and 152 MW by 2021 (45 MW higher than as originally indicated in the Application). HCPD forecasts energy growth of 725,443 MWhr in 2006, growing to 876,257 MWhr by 2021. App. Ex. 49, p. 8; App. Ex. 49-B.

56. HCPD's proposed 25 MW share of Big Stone Unit II in 2011 is a least cost option for HCPD. The evidence also shows that HCPD's needs could justify another five MW. First, the additional capacity would provide an additional, incremental level of risk management to cover forecast uncertainty, future resource uncertainty, and the potential for extreme weather conditions. Second, HCPD revised forecast shows total growth at approximately four to five 5 MW per year in the 2001-to-2013 time period. As a result, a larger share in Big Stone Unit II would satisfy its customers' demand for baseload capacity and energy requirements for an additional one or two years, and thereby help HCPD delay the need for its next baseload resource addition. App. Ex. 15, p. 6; App. 49, p. 11.

Conservation/Demand-Side Management

57. The Applicants have extensive plans for conservation and demand-side management (DSM) programs and renewables, in addition to the resource additions related to their respective shares of the Big Stone Unit II. Each has performed detailed, system-level studies of these resources, and as a result each is proposing a combination of DSM and renewables and Big Stone Unit II to round out its resource portfolios. App. Ex. 42, p. 2.

58. The Applicants have enacted significant DSM measures. Their plans include accomplishment of significantly more DSM in future years, in addition to Big Stone Unit II. Taken together, as of 2005 the Applicants have collectively reduced peak demand by approximately 560 MW, or the equivalent of a large-size generating plant, and reduced energy consumption by about 370 GWh per year. Together, over the next few years, the Applicants plan to reduce peak demand by an additional 240 MW, and reduce energy consumption by an additional 780 GWh per year, compared to 2005 levels. App. Ex. 42, p. 12.

OTP

59. OTP is committed to DSM and conservation. Approximately 13% or more of its capacity needs are expected to come from conservation and DSM measures. App. Ex. 10, p. 10. The projected incremental annual DSM energy savings in OTP's preferred resource plan over the 2006-2019 planning period, which also includes its share of Big Stone Unit II, are typically in the 8,000,000 kWh to 9,000,000 kWh range. As a comparison, OTP expects to receive approximately 900,000,000 kWh annually from its 116 MW share of Big Stone Unit II. Achieving the level of energy and demand savings necessary to replace the annual energy and capacity the company expects to receive from Big Stone Unit II is not practical or economically viable. App. Ex. 10, pp. 10-11.

MRES

60. MRES and its members have enacted significant DSM measures. The MRES resource plan includes the accomplishment of a significant amount of new DSM in future years, in addition to Big Stone Unit II. DSM and conservation efforts among MRES members have reduced generation capacity requirements by approximately 57 MW as of 2005. App. Ex. 44, p. 4.

61. MRES has modeled potential DSM additions to allow the capacity expansion software to analyze the direct impact of various levels of additional DSM on supply-side choices, in order to allow DSM to compete directly against supply-side (including renewables) resources in developing the optimal resource mix. According to the results of recent DSM studies undertaken by MRES, up to 82 MW of additional cost-effective DSM appears to be least cost, in addition to its participation in Big Stone Unit II. MRES' analysis also shows that HUC will benefit from additional DSM programs, though it does not offset its need for its share of Big Stone Unit II through its PPA with MRES. App. Ex. 44, pp. 10-13.

GRE

62. Conservation is an active part of GRE's planning efforts. Taken together, GRE's DSM efforts have reduced peak demand by approximately 369 MW, and reduced energy consumption by 169 GWh as of 2005. App. Ex. 43, p. 2. GRE plans to reduce demand by an additional 35 MW and to reduce energy consumption by an additional 59 GWh by 2007. App. Ex. 43, p. 3. GRE's DSM effort, along with its members, while significant, does not offset its need for its share of Big Stone Unit II.

MDU

63. As a tool to evaluate and determine the available and most cost-effective demand-side management programs applicable to MDU's system, demand-side analysis is an integral part of MDU's integrated resource planning process. Using the ratepayer impact and societal tests, DSM evaluation is performed for MDU's residential and commercial sectors. App. Ex. 48, p. 3.

64. MDU has implemented additional DSM measures that will result in 8.1 MW of demand savings by 2010, resulting in energy savings of 0.13% of energy requirements. MDU plans to implement an additional 6.5 MW of demand-side management and conservation measures during the 2006-2010 time period. These programs will result in approximately 38,000 MWh savings. Despite these demand and energy reduction goals, MDU's resource planning analysis nevertheless indicates that its share of Big Stone Unit II is reasonable. App. Ex. 48, p. 2, 8-9.

SMMPA

65. SMMPA and its members have made significant investment in load management and conservation programs. The DSM program budget for SMMPA and its members is typically between $3 million and $3.5 million annually, which represents 2% of its members' aggregate gross operating revenue. The total DSM savings achieved from SMMPA's members in 2003, and 2004 alone was approximately 28 MW

and 13,416 MWhr, and 32 MW and 19,407 MWhr, respectively. SMMPA continues to look for, evaluate and add new conservation initiatives. Such DSM efforts will be effective in reducing the size and/or delaying the timing of additional SMMPA resources. SMMPA's DSM resources are important in deferring the investment in new generation facilities, including Big Stone Unit II, but they are not a replacement. App. Ex. 13, pp. 7-8.

CMMPA

66. In the past, CMMPA has had no direct control over the development and implementation of the DSM and energy conservation programs of its members as the members are individually responsible for demand-side management and conservation programs. Nonetheless, CMMPA has assisted and encouraged its members to establish the reporting of the effects of the various DSM and conservation programs. CMMPA is currently developing an integrated load management system for its members. App. Ex. 46, p. 3.

67. CMMPA did evaluate incremental demand-side programs against the lowest cost of the generating resource expansion cases (the addition of 30 MW of Big Stone Unit II capacity in 2011 along with 10 MW of wind capacity 2011 and future additions of coal capacity). The results of this analysis reveal, however, that the average cost per demand and energy reduction resulting from the CMMPA member DSM programs is higher than the marginal avoided costs of generation production and capacity. These results indicate that the existing demand-side programs of the CMMPA members cause higher total and average operating costs for the members than would otherwise occur if the members implemented no demand-side programs and that any increase in funding and implementation of the current demand-side programs of the members would not be cost-effective. App. Ex. 47, pp. 10-11.

HCPD

68. HCPD, as a supplemental wholesale power supplier, works with its wholesale customers to promote demand-side management programs and conservation. It assists its municipal customers in the evaluation and development of many conservation and load management programs. Each of HCPD's municipal customers is responsible for monitoring the effectiveness and accomplishments of its individual energy conservation efficiency programs and reporting those efforts to HCPD. App. Ex. 15, p. 6. In 2005, HCPD estimates that it reduced its peak demand by 7 MW, and reduced its energy consumption by 90 MWh. HCPD will continue to work with its customers to encourage more efficient use of their electric supply through load management efforts. App. Ex. 49, p. 3.

Renewables

69. Collectively, the Applicants are pursuing a significant amount of renewable energy projects in addition to the Big Stone Unit II Project. Taken together, as of 2005 the Applicants are already producing or purchasing more than 740 GWh per year from a variety of renewable resources. In addition, the Applicants plan to install or purchase an additional 2,170 GWh per year of renewable energy over the next few years. Putting the total 2,910 GWh per year of existing and planned renewables efforts of the Applicants in perspective, although it will come from a variety of renewable sources, it is equivalent to more than 950 MW of wind machines operating at a 35% annual capacity factor. App. Ex. 42, p. 20. The Applicants have shown, however, that additional renewable generation is not a replacement for the baseload need to be provided by Big Stone Unit II. The Applicants will be pursuing Big Stone Unit II and additional renewable generation projects. E.g. App. Ex. 42, Ex. 48, p. 4 Ex. 41, p. 7.

OTP

70. Over the past few years, Otter Tail's resource mix has varied from 9% to 11% renewable resources on an energy basis. On March 31, 2006, OTP issued a Request-for-Proposals (RFP) for 75 MW of additional renewable resources. OTP's resource plan calls for adding the equivalent of 110.5 MW of new wind generation by 2015. App. Ex. 42, p. 21.

MRES

71. MRES has existing renewable energy resources, and is planning significant renewable resource additions, including approximately 40 MW of new wind energy by 2020. App. Ex. 14, p. 10, 13-17.

GRE

72. GRE has made a significant commitment to renewable energy, particularly wind energy. GRE's 2005 renewable energy generation was 248,816 MWh, more than two times its Minnesota Renewable Energy Obligation goal for 2005. GRE expects to have approximately 1.6 million MWh of renewable energy in its portfolio by 2020. App. Ex. 2, pp. 8, 14-15; App. Ex. 43, p. 4.

SMMPA

73. SMMPA already has under commitment approximately 8.5 MW of wind energy that is used to serve its customers. App. Ex. 13, p. 5. It has plans to add approximately 60 MW of wind energy by 2015. App. Ex. 45, p. 5.

CMMPA

74. CMMPA also is pursuing renewable energy projects. In 2005, CMMPA entered into three wind energy purchase agreements, which provide for the purchase of 6 MW beginning in 2005 and 16.25 MW beginning in 2006, for a total of 22.25 MW. In addition, the City of Blue Earth, a CMMPA member, has recently entered into an agreement for the purchase of 2.5 MW of wind energy from a project developed by a local farmer. CMMPA is also active in the research of the potential use of landfill methane gas in the generation of electrical energy. It has been investigating a possible project at an operating landfill site. The project involves harnessing the potential energy benefits from the methane gas at the site, currently being flared to the atmosphere. The total output of the project would be between 2500 kW and 3000 kW. App. Ex. 46, p. 5.

HCPD

75. In 2005, the wind turbines at various customer sites produced 1,616 MWhr. HCPD is currently investigating the potential for additional wind energy developments. HCPD is negotiating for the output of a proposed wind development in central South Dakota in the minimum amount of 5MW. HCPD is also evaluating, in conjunction with several of its customers, the addition of wind turbines adjacent to the customers' communities. HCPD is also evaluating a landfill gas generator with one of its customers. App. Ex. 49, p. 4.

Consequences of Delay

76. Any delay in construction of Big Stone Unit II could have significant negative consequences for the Applicants, the region, and ultimately the consuming public. App. Ex. 5, p. 8; App. Ex. 25, p. 2; App. Ex. 15, p. 7; App. Ex. 2, p. 18; App. Ex. 4, p. 8; App. Ex. 10, p. 17; App. Ex. 11, pp. 9, 11; App. Ex. 3, p. 13. It increases the probability of inadequate regional generation capability and causes a reduction in the reliability of the Applicants' systems and the regional electrical supply system. Id.

77. If Big Stone Unit II does not become operational, the owners have scarce alternative resources from which to obtain energy, they are faced with increased risk and cost, and there is no single next best resource alternative or other baseload project from which to obtain the needed energy. App. Ex. 5, p. 8; App. Ex. 25, p. 2; App. Ex. 15, p. 7; App. Ex. 2, p. 18; App. Ex. 4, p. 8; App. Ex. 10, p. 17; App. Ex. 11, pp. 9, 11; App. Ex. 3, p. 13. Intervenors have not proposed an alternative to provide baseload capacity through natural gas or oil instead of coal. HTr 534. Intervenors have not suggested any specific alternative to Big

Stone Unit II, and are not specifically recommending any wind/gas combination as an alternative to Big Stone Unit II. HTr 747-48.

78. If Big Stone Unit II is not built, and a higher-cost alternative power source used instead, there would be higher costs for electricity to the consumers, and this in turn would lead to less disposable income for those consumers to meet other household needs and cause adverse impacts on South Dakota residents in terms of health, safety, welfare, and employment. App. Ex. 31, pp. 34-36. Applicants have a demand for Big Stone Unit II, despite current reserves, conservation and DSM programs and renewables.

9.0 GENERAL SITE DESCRIPTION

79. Big Stone Unit II will be constructed adjacent to the existing Big Stone Unit I, on approximately 3,200 acres located in Grant County, South Dakota, east of Milbank, South Dakota, approximately two miles west-northwest of Big Stone City, South Dakota, and two miles from the Minnesota border. MR 6. The facility will be accessible from U.S. Highway 12 at Big Stone City via State Highway 109 and County Road 34 (144th Street) and from U.S. Highway 12 via County Road 4 and 484th Avenue. App. Ex. 54, p. 2 and Ex. 1-3; App. Ex. 8, p. 6.

80. The site is situated in a relatively flat to gently rolling landscape comprising agricultural fields interspersed with small emergent wetlands. App. Ex. 17, p. 11. There are no large metropolitan areas nearby. App. Ex. 53, Table ES-4, p. ES-21.

81. Big Stone I sits on 2,200 acres. App. Ex. 8, p. 9. 1,200 acres are available for Big Stone Unit II, with an existing option to purchase an additional 625 acres. App. Ex. 27, p. 20. For Big Stone Unit II, an additional 530 acres of land will be taken permanently, with an additional 90 acres to be taken out for the construction phase; the land to be taken is primarily agricultural land. Current and future agricultural land use issues arising from the proposed construction and operation of Big Stone Unit II is remote. App. Ex. 29, p. 20.

10.0 ALTERNATIVE SITES

82. Criteria used for site selection included location (e.g., presence in North Dakota, South Dakota or Minnesota, away from residents, recreation and parks, etc.); available infrastructure (e.g., rail, transmission lines, water); and environmental impact. App. Ex. 8, pp. 6 -7.

83. Thirty-eight (38) initial alternative sites were considered; these sites were located in South Dakota, North Dakota and Minnesota, which is consistent with the Applicants' service territories. App. Ex. 8, pp. 6-7; HTr 86. Thirty of these sites were eliminated due to lack of available water supply or nearby residential development, leaving eight sites that were evaluated in more detail. Id. Of these eight sites, two were further eliminated due to nearby residences and development. App. Ex. 8, p. 7.

84. Weighted criteria were used to rank the remaining six sites. App. Ex. 8, p. 8. The criteria included air impacts, water supply, environmental considerations, fuel supply, transmission availability, highway access, land availability and staff. App. Ex. 8, p. 8; App. Ex. 54, Application, Table 3-5. Generally, water supply, fuel lines, and transmission were each given a weight of 20%; environmental issues and air quality specifically were each given 15%; and other factors, such as highway access were given 10%. App. Ex. 8, p. 8.

85. The Big Stone site ranked highest. App. Ex. 8, p. 8. The Big Stone site received the highest weighted score, due primarily to the availability of existing infrastructure, such as water structures, rail spur, staff and waste disposal. App. Ex. 2, pp. 6-7; App. Ex. 7, pp. 8-9; App. Ex. 26, p. 8. In addition, area residents are already familiar with the construction and operation of a power plant, having lived with Big Stone Unit I for more than 30 years. App. Ex. 8, p. 8. Location at this site allows for a common wet scrubber to be used by Big Stone Units I and II. App. Ex. 8, pp. 8, 11.

86. The other five sites were rejected due to considerations, such as location to wildlife refuges, insufficient existing transmission lines or water supply, higher population density and location to lignite fields. App. Ex. 54, Application, pp. 63-65.

87. The process by which the site was selected was reasonable, and Applicants' determination that the Big Stone site is the best site for them on which to locate the proposed facility is reasonable.

11.0 ENVIRONMENTAL INFORMATION

88. The Applicants have described the existing environment and the potential environmental effects of Big Stone Unit II in detail in the Application and in their testimony. The Applicants hired Barr Engineering to assist in the preparation of the Application. Barr conducted site surveys and reviewed available information and work product of other consultants hired by the Applicants. App. Exs. 17, 18, 19, 20, 21, 26, 27 and 54. In addition, the potential environmental effects have been identified and considered in an Environmental Impact Statement being prepared by the Western Area Power Administration for the federal government, which was required due to the request to interconnect to two Western Area Power Administration substations which thereby involves a major federal action significantly affecting the quality of human environment. App. Ex. 16, pp. 4-5; App. Ex. 53. The U.S. Department of Agriculture, Rural Utilities Service ("RUS") and the U.S. Department of Defense, Army Corps of Engineers ("USACE") are both cooperating agencies for preparation of the EIS. On May 27, 2005, notice of intent to develop an EIS was published. Id. On May 6, 2006, the draft EIS was sent to the parties. App. Ex. 34, pp. 6-7. The draft EIS was published and made available to the public beginning on May 6, 2006. Id. Notices of the hearing were published in 12 papers two times, and 6,000 mailings regarding notices were sent. Id. The draft federal EIS is a part of this administrative record, App. Ex. 53. Public hearings were held on the draft EIS on June 13-16, 2006, in Big Stone City, South Dakota, and Morris, Minnesota, Granite Falls, Minnesota, and Benson, Minnesota, respectively. A Record of Decision is expected from the Western Area Power Administration in December 2006. App. Ex. 34, p. 6.

89. The Applicants calculated through a narrative description the potential environmental effects from Big Stone Unit II consistent with past Commission practice. ARSD 20:10:22:13; App. Ex. 54, Section 4; App. Ex. 16-22, 27, 30, 34, 36-38, 52.

90. Assuming the Applicants comply with the environmental conditions of this decision and permit and the air quality, water quality, solid waste and water appropriation permits which Applicants must obtain in order to construct and operate the facility, no serious long-term effects to the environment or to health have been demonstrated as probable of occurrence from operation of Big Stone Unit II.

12.0 EFFECT ON PHYSICAL ENVIRONMENT

91. The Big Stone II Project area is situated in a relatively flat to gently rolling landscape comprising agricultural fields interspersed with small emergent wetlands. The existing Big Stone Plant Unit I is situated on an area developed for industrial use, and includes one large artificial cooling pond, an evaporation pond, a holding pond, and several smaller impoundments. Southeast of the plant, the Whetstone River meanders eastward to the Minnesota River. Immediately adjacent to the Whetstone River, the topography changes abruptly to steep 50 to 60-foot embankments. App. Ex. 54, at Section 4.1.1.

92. The Applicants provided a topographical map of the local area at 1.0 foot contours. App. Ex. 54.

93. Construction of the Big Stone II facility will result in the conversion of additional land into active industrial use. Approximately 500 acres, mostly in existing cropland, will be converted to an open makeup storage pond. Another 30 acres will be converted to a cooling tower blowdown pond. Grading for the new plant structure and cooling tower within the existing Big Stone Plant Unit I site will not appreciably alter the existing topography. App. Ex. 54, at Section 4.1.1.

94. The overall indirect or cumulative geological characteristics do not require any constraints on the construction and operation of Big Stone Unit II. App. Ex. 19, p. 4. Big Stone Unit II will not have an adverse impact relating to the geology in the region. App. Ex. 19, p. 2.

95. There are no economically valuable mineral deposits within the project boundaries. App. Ex. 54, p. 82.

96. Sixteen land use types exist in the project area. Crop and grassland consist of over 80% of the area. The remaining uses include industrial, woodland and wetlands. Construction of the plant will take place primarily on grassland. Ponds and the construction laydown area and parking will be constructed mainly in row crop and pasture lands. Some of the soils on the project site are classified as farmland soil; excavation will occur in areas that are primarily farmland soil. Big Stone Unit II will not have a detrimental effect on the soil. App. Ex. 22, p. 13.

97. An erosion and sedimentation analysis regarding construction and operation was done. A moderate-to-low erosion factor was determined. After construction, stabilization methods will be employed to prevent erosion from wind and water. App. Ex. 17, p. 7.

98. No seismic risks, subsidence potential, or slope instability exists in the siting area. Some grading will be done, but it will not appreciably alter the existing topography or create instability. App. Ex. 54, p. 83.

13.0 HYDROLOGY

99. Water for Big Stone Unit II will come from Big Stone Lake. App. Ex. 18, p. 8. Pumps will deliver water through an existing underground pipeline to ponds on the Big Stone property. Storage ponds will be created that have sufficient capacity to operate both Big Stone Units I and II during most drought conditions without recharging onsite storage from Big Stone Lake. Over a 70-year period, Big Stone Lake is expected to be impacted, on average, 2.5 inches. App. Ex. 18, pp. 8-9; App. Ex. 36, pp. 3-7; HTr 286-87.

100. Changes in drainage patterns due to the project will primarily be related to the construction of the makeup storage pond. The makeup storage pond will alter local surface water drainage patterns because of its size and configuration. However, this alteration is not expected to have deleterious impacts on local surface drainage. The makeup storage pond simply alters the route of the drainage. App. Ex. 17, p. 3.

101. Makeup water will be withdrawn from Big Stone Lake in compliance with permits and when the lake is at acceptable levels. App. Ex. 16, p. 14; App. Ex. 18, pp. 8-9. The additional makeup water will come from extended operation time of the existing pumps with no increase in the withdrawal rate. The impact on Big Stone Lake will be infrequent, and adverse affects on the lake are not expected to be significant. App. Ex. 18, pp. 10-11. The Applicants may rely on the use of groundwater during construction of Big Stone Unit II and may consider groundwater sources for water supply during periods of extended drought. HTr 273. In the absence of an alternative water supply in periods of extended drought, it is possible the plant could not be operated. HTr 273.

102. Three wetlands will be directly impacted during project construction. App. Ex. 17, p. 11. Alternatives to completely avoiding the wetlands are not feasible. App. Ex. 17, p. 11. The proposed construction reflects the most practicable alternative to minimize the impacts to wetlands. App. Ex. 17, p. 11. Indirect impacts to wetlands will also occur, however, the risk of harm is low, cumulative impacts on wetlands is minimal, and management and monitoring will be undertaken. Mitigation efforts as directed by governmental agencies will be complied with. App. Ex. 17, p. 11-12. In addition, measures to contribute to mitigation will be undertaken such as restoration and/or enhancement of unaffected wetlands, establishment of new wetlands, and enhancement of existing wetlands. App. Ex. 17, p. 12.

103. Big Stone Unit II will be required to comply with all hydrologic governmental standards. App. Ex. 17, p. 5.

104. On or about March 16, 2006, the Applicants filed a permit with the South Dakota Water Management Board to increase the appropriation of water under the existing permit. App. Ex. 36, p. 4. A hearing will be held on such application before the Water Board on or about July 12 and 13, 2006. App. Ex. 34, pp. 7-8; Ex. 34-B; HTr 100, 118.

14.0 LAND USE

105. The existing Big Stone II Project area comprises sixteen land use types. The Application contains a map showing the various land use types, Application, Exhibit 4-1-1, and lists the types in Table 4-7. Existing land use is dominated by row crops, which account for over half of the total Project area. Grass-dominated land uses, including industrial grasslands, pastured areas and hayfields account for another third of the Project area.

106. The Application also contains maps showing the cities, lakes, rivers, water supplies, cemeteries, historical places, housing, transportation/public, noise sensitive land use, adjacent facilities, major industries, surface water drainage, pastureland/rangeland/hayland, crops, grassland, and nonrenewable resources.

107. The construction of Big Stone II will take place primarily in existing industrial grassland areas. The cooling tower blowdown pond and the makeup storage pond will be constructed mainly in row crops and pasture lands, as will the construction laydown area and parking. App. Ex. 54, at Section 4.5.1.

108. There are no significant impacts to land use associated with the Big Stone Unit II Project.

15.0 EFFECT ON TERRESTRIAL ECOSYSTEMS

109. Big Stone Unit II will not have a detrimental effect on wildlife. App. Ex. 22, p. 13. Wildlife in the area consists primarily of game animals, songbirds, waterfowl and fur-bearers. App. Ex. 37, pp. 1-3. Three federally listed species that may occur in the project area include the Bald eagle, the Topeka shiner, and the western prairie fringed-orchid. App. Ex. 37, pp. 1-3. No adverse impact to these species is expected. App. Ex. 37, pp. 1-3.

110. On the Big Stone Unit II property, 24 vegetation cover types comprising 120 plant communities exist. 87% of the total vegetative cover is rated as low ecological quality. Most of the direct impacts to vegetation will affect the low ecological quality vegetation. Indirect impacts to vegetation may occur due to alteration of surface water drainage patterns and introduction of non-native invasive plant species to the area. Mitigation efforts will be undertaken to minimize vegetative impacts. App. Ex. 17, pp. 14-15. Construction and operation of Big Stone Unit II will have a minimal cumulative impact on vegetation in the area. App. Ex. 22, p. 13; App. Ex. 18, p. 11.

16.0 EFFECT ON AQUATIC ECOSYSTEMS

111. Big Stone Unit II will not result in either direct or indirect significant impacts to fish populations. App. Ex. 22, p. 13; App. Ex. 17, p. 12; App. Ex. 18, p. 15. Some impingement and entrainment may occur associated with water intake for cooling, however, a water intake structure and systems will be in place to reduce these occurrences to a minimum. App. Ex. 17, p. 12.

112. In part because Big Stone Lake is now regulated and will after Big Stone Unit II goes on line continue to be regulated at a fixed elevation, no significant adverse effects on water bodies are expected due to the water needs for the operation of the Big Stone Plant. App. Ex. 18, p. 10.

17.0 LOCAL LAND USE CONTROLS

113. A portion of the plant site in the vicinity of the makeup water storage pond will require rezoning from agricultural to industrial use. The Grant County Planning and Zoning Board and the Grant County Commission will review and consider the request for rezoning. The project will need a building permit from Grant County. App. Ex. 16, p. 21.

114. Other than the one rezoning issue described above, Big Stone Unit II will be required to comply with existing zoning, building rules, regulations, and ordinances pursuant to the conditions of this order.

18.0 WATER QUALITY

115. The facility will be a zero liquid discharge facility so that no process water will discharge to the surface drainage network. Consequently, plant operations will have minor impact on the existing water quality of watersheds and/or streams. App. Ex. 17, p. 7.

116. Big Stone Unit II includes a wet cooling system that involves a closed-loop circulating water system. Circulating water is used to condense steam, and the condensate is collected and returned to the boiler feed-water system. The warm water is then circulated through a cooling tower, which dissipates heat through evaporation. App. Ex. 16, p. 11. Small droplets of circulating water (drift) will be entrained within the cooling tower plume. App. Ex. 16, p. 11. Once cooled, the circulating water is returned to the condenser to complete the cooling circuit. Water for the cooling system will be supplied from the existing Big Stone I cooling pond. Makeup water for the cooling pond will be supplied from Big Stone Lake and the Minnesota River. App. Ex. 18, p. 9. To conserve fresh water, cooling pond water will be reused as makeup to the facility-cooling tower. App. Ex. 54, p. 30.

117. Construction-related water quality impact will be limited and controlled by the implementation of best management practices ("BMPs") for soil erosion. The specific BMPs for the Big Stone II project will be detailed in the Stormwater Pollution Prevention Plan that is part of the National Pollutant Discharge Elimination System Permit that is required prior to beginning construction. App. Ex. 18, p. 7.

118. All applicable water quality standards and regulations will be complied with, and necessary permits obtained. App. Ex. 17, pp. 5, 10; App. Ex. 18, p. 9. No significant adverse environmental impacts are expected relating to water, wetlands, aquifers or reservoirs. App. Ex. 17, pp. 3, 7, 8; App. Ex. 17, p. 9.

19.0 AIR QUALITY

119. The pollutants of concern that will be emitted by Big Stone Unit II include the following: sulfur dioxide (SO2), nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM10), sulfuric acid mist (SAM), fluorides, mercury (Hg), volatile organic compounds (VOCs), lead, and carbon dioxide (CO_2). See, e.g., App. Ex. 16.

120. SO2, NOx, and PM10 are criteria pollutants, for which national ambient air quality standards have been established by the U.S. Environmental Protection Agency. There will be no violations of any national ambient air quality standards resulting from operation of Big Stone Unit II. See e.g. App. Ex. 22.

121. The Applicants are required to obtain a permit from the South Dakota Department of Environmental and Natural Resources ("DENR") for operation of Big Stone Unit II. On or about July 21, 2005, the Applicants filed an application for a Prevention of Significant Deterioration ("PSD") air quality construction permit. As part of that process, the DENR will ensure that Big Stone Unit II will comply with all applicable requirements, including Best Available Control Technology ("BACT"), New Source Performance Standards ("NSPS"), acid rain, mercury, and Prevention of Significant Deterioration ("PSD") requirements. The DENR issued a draft permit on April 26, 2006, and the public comment period ended on June 26, 2006. HTr 118.

The Applicants have committed to comply with all applicable requirements established by the DENR, including the emission limits established for the various pollutants that will be emitted and all record keeping and reporting requirements. App. Ex. 16, 22, 34.

122. The Applicants intend to install highly effective pollution control equipment to control emissions of pollutants into the atmosphere. One piece of control equipment is a wet flue gas desulfurization system (wet scrubber) that will capture sulfur dioxide emissions from both Unit I and Unit II. In addition, a pulse-jet fabric filter will be installed to control particulate matter, including small particles less than 10 microns in size. The wet scrubber and the fabric filter will also remove some of the mercury in the exhaust gases. The Applicants will use fabric filters or passive dust control methods to control emissions of fugitive dust from material handling processes. App. Ex. 16, p. 10.

123. The supercritical boiler that is planned for Unit II will use burners that produce low levels of nitrogen oxides and will employ a selective catalytic reduction ("SCR") emission control technology to further control emissions of nitrogen oxides from Unit II. App. Ex. 16, pp. 10-11.

Sulfur Dioxide and Nitrogen Oxides

124. The emissions of sulfur dioxide from Unit I and Unit II will be only 1/7 of what they are presently from Unit I because of the installation of the wet scrubber to control emissions from both units and the use of the SCR system on Unit II. HTr p. 118.

125. Nitrogen oxide emissions from Unit I will be reduced through more aggressive operation of Unit I's over-fire air system so that the sum total of nitrogen oxide emissions from Unit I and Unit II will be equal to or less than Unit I's historical emissions. App. Ex. 16, p. 11.

126. Due to the control equipment and technology that will be installed to control sulfur dioxide and nitrogen oxides, the net change in emission of these pollutants is below the level required for PSD review. App. Ex. 22, p. 4.

Mercury

127. Because mercury is a trace element in coal, there will be emissions of mercury from combustion of the coal. Elemental mercury that is emitted out the stack will travel great distances before being deposited. Mercury accumulates in fish, and various state governments have issued advisories regarding the eating of fish from lakes where mercury has been found. App. Ex. 53, EIS, pp. 4-8-4-10, 4-26.

128. The U.S. Environmental Protection Agency promulgated the Clean Air Mercury Rule in May 2005. EPA established a New Source Performance Standard of 42 x 10-6 pounds of mercury per megawatt hour for new sub-bituminous coal-fired power plants. That standard was changed to 66 x 10-6 pounds per megawatt hour in June 2006. This standard would allow Big Stone Unit II to emit 330 pounds per year at its anticipated capacity. App. Ex. 16, p. 12 and 22, p. 14.

129. In the year 2004, Big Stone Unit I emitted 189 pounds of mercury into the atmosphere. In May 2006, the Applicants made a commitment to hold mercury emissions from both Unit I and Unit II combined to no more than 189 pounds per year, beginning three years after commercial operation of Unit II. Three years is a reasonable period of time to allow the Applicants to test and implement commercially available, technically feasible mercury control equipment. Even though electrical output from the Plant will increase by 130% over its current capacity, mercury emissions will not increase beyond the amount emitted during 2004 after the three-year testing and implementation period. App. Ex. 34, pp. 1-4 and Ex. 34A.

130. The Clean Air Mercury Rule ("CAMR") also establishes an allocation of mercury emissions for each state in the country for the years 2010 and 2018. South Dakota's allocation is 144 pounds of mercury per year beginning in the year 2010. Utilities may comply with the allocation requirements by reducing

emissions or by purchasing allowances. The Big Stone Applicants may be able to comply with the CAMR allowance limitation for South Dakota through installation of controls but, if necessary, it is expected that the Applicants will comply by purchasing allowances. The cost of obtaining these allowances cannot be determined at this time but will likely be in the millions of dollars per year. App. Ex. 34, pp. 1-4.

131. The Applicants have a financial incentive to select the most environmentally economical Hg emission control in existence. Possible future technology will be created to further reduce Hg emissions; such technology is anticipated to have a low cost. HTr 108, 582-83.

132. After the three year testing and implementation period, no additional impacts on the environment are expected from mercury emissions as a result of operation of Unit II because emissions of mercury will not exceed what is presently emitted from Unit I.

Carbon Dioxide

133. The combustion of fossil fuels including coal results in the formation of carbon dioxide. Carbon dioxide is a greenhouse gas. Big Stone Unit II is projected to emit 4.7 million tons of CO_2 per year. App. Ex. 53, p. 4-10- 4-11. Assuming an operating lifetime for Big Stone II of 50 years and no installation of CO_2 capture system, the plant will emit over 225 million tons of CO_2 before it closes. Ex. JI-2 at 26.

134. The Energy Information Administration reports that anthropogenic carbon dioxide emissions in 2010 are project to be 6,365 million metric tons in the United States alone. Worldwide, the projected 2010 CO_2 emissions figure is 30,005 million metric tons. App. Ex. 29, p. 6.

135. Based on projected annual emissions of 4.7 million tons, Big Stone Unit II would increase U.S. emissions of carbon dioxide by approximately 0.0007, or seven-hundredths of one percent. As a result, the proposed Big Stone Unit II plant will not contribute materially to increases in the production of anthropogenic carbon dioxide. App. Ex. 29, p. 6.

136. Big Stone Unit II will produce about 18% less CO_2 than other existing coal-fired plants because the super-critical boiler proposed here is more efficient than other forms of coal-fired technologies. App. Ex. 2, p. 7.

20.0 RISK OF REGULATION/ENVIRONMENTAL COSTS

137. Issues arose at the hearing as to whether costs should be imputed to the project for possible future regulation of CO_2 emissions. Neither federal government regulations nor South Dakota regulations have been established for CO_2 emissions. Minnesota has established environmental cost values for CO_2 emissions from electric generation, but these values do not apply to generation located outside of Minnesota. App. Ex. 30, p. 7, 5; App. Ex. 34, p. 2; HTr 737-39. It is speculative whether Congress or South Dakota will regulate CO_2, and, if either does so, what the timing and stringency of those regulations will be. App. Ex. 30, p. 9; 19-20; HTr 89-90, 523, 737-43. Quantifying the cost of future CO_2 regulations is therefore a speculative undertaking, and the evidence shows that only a small minority of states utilize quantified values to approximate the cost of future regulation. App. Ex. 30, p. 12.

138. Evidence adduced at the hearing shows that only a few states have required CO_2 emission reductions from electric generators. A group of Northeastern states is currently examining such regulations; however, the cost of the program (projected CO_2 allowance prices of $1-$3) is expected to be relatively modest. States either implementing or considering CO_2 reduction programs generally utilize far less coal generation than South Dakota (and the United States) as a percentage of their total electric generation portfolios. Such states also have higher electric rates than South Dakota. Hence, these states do not furnish a model for South Dakota for purposes of examining the CO_2 issue. App. Ex. 30, pp. 10-28.

139. Evidence was also adduced at the hearing concerning various bills introduced in Congress that would regulate CO_2 emissions. These bills do not furnish support for Intervenors' contention that there should be a cost imputed to Big Stone Unit II for future CO_2 regulation in an amount equal to $7.80-$30.50, with a mid-case range of $19.10 per ton. None of these bills passed either branch of Congress. One proposal that appeared to have the best chance of passing the Senate last year, but was never voted on, had a maximum "safety valve" allowance price cap of less than $6.36 per ton. Various planning numbers were discussed at the hearing in the $5-$6 range, and Minnesota has a CO_2 environmental cost value for use in electric generation resource planning of between $.35 and $3.64 for in-state generation. In any event, all reasonable planning numbers for possible future CO_2 regulation were substantially less than the Intervenors' $19.10 mid-case number, and none appeared to affect the cost-effectiveness of the Big Stone Unit II project as compared to alternatives. App. Ex. 30, pp. 4-28.

21.0 TIME SCHEDULE

140. At the present time, construction is scheduled to begin in the spring of 2007 after all necessary permits and approvals are obtained, with commercial operation targeted for the spring of 2011. In mid-spring 2007, mobilization is scheduled to begin with support equipment being moved to the site. During the summer of 2007, site preparation and foundation installment will occur. Steel work will commence in early 2008, followed by erection of the boiler and turbine in late 2008. In early 2009, construction of the balance of the plant equipment will commence. Installation of the boiler and turbine will be completed by early 2010. Checkout procedures will next occur, with the unit being operated first in mid-2010. Commission and checkout will be complete in late 2010, for commercial operation in spring 2011. App. Ex. 8, pp. 9-10.

22.0 COMMUNITY IMPACT

141. No material adverse effects on cultural resources will occur from the construction and operation of Big Stone Unit II. App. Ex. 29, pp. 8, 18; HTr 268. Big Stone Unit II will not impact areas of high archeological potential nor materially impact the adjacent area in terms of historical purposes. App. Ex. 21, pp. 9-10. While two nearby properties have architectural significance, no adverse effect as to these properties exists with the construction and operation of Big Stone Unit II. App. Ex. 21, pp. 14-15. Two nearby residences may be affected, but one resident is retiring and moving and the Applicants are in discussion with the other resident to purchase the land for a storage pond. HTr 101.

142. No material adverse effect in terms of noise from Big Stone Unit II will occur. App. Ex. 21, p. 14; App. Ex. 20, p. 3; App. Ex. 38, p. 2; HTr 293-94. Big Stone Unit II is not expected to create a discernable increase in noise. App. Ex. 38, p. 2. Moreover, due to the construction of Big Stone Unit II, noise from operation of snow machines that have been the subject of complaints related to Big Stone I will be eliminated. App. Ex. 20, p. 3.

143. The construction, operation and maintenance of Big Stone Unit II is not anticipated to have a significant adverse impact on land use or the community. App. Ex. 27, pp. 3, 9-21; App. Ex. 21, pp. 14, 14. It will not detract from the energy needs in the area nor on sanitary sewer systems. App. Ex. 27, p. 17; App. Ex. 18, p. 15. Solid waste disposal will be managed during the construction and operation phase to not adversely affect the community or existing landfills. App. Ex. 27, p. 20. An increase in roadway and rail traffic will occur, which can be accommodated without adverse impact. App. Ex. 27, pp. 11-12; App. Ex. 18, p. 16. Parking needs are not a significant concern. Sufficient health and educational services and facilities exist to accommodate such needs during the construction and operation phases of Big Stone Unit II. App. Ex. 27, pp. 10-11; App. Ex. 18, pp. 17-18. Neither phase will create a drain on cultural or public safety resources. App. Ex. 27, pp. 14-16; JL 18. The influx of employees required can be absorbed by the surrounding communities. App. Ex. 17, p. 16. Housing needs can be met. App. Ex. 18, pp. 14-15. No significant adverse effect for any cultural resource, recreation, population or income of the primary communities will occur. App. Ex. 27, p. 20; App. Ex. 18, p. 18. The existing railway system is sufficient to mitigate any railway transportation concerns. App. Ex. 18, p. 17.

144. The community and social impacts of Big Stone Unit II are expected to be positive and potential adverse effects to the community will be ameliorated through planned measures. App. Ex. 27, pp. 3, 21; App. Ex. 18, p. 18.

145. The Big Stone Unit II project has strong community support. App. Ex. 27, p. 21. Resolutions of Support have been passed by the City of Big Stone, County of Grant, City of Milbank, Milbank School District School Board, and the Upper Minnesota River Watershed District. App. Ex. 27, p. 21.

146. Assuming the contingency construction housing plan is implemented as required in this decision, no significant adverse economic impacts are expected related to Big Stone Unit II. Taxes assessed on Big Stone Unit II will significantly increase the tax revenue base of the State of South Dakota and the communities surrounding the facility, both during the construction phase and the operational phase of Big Stone Unit II. App. Ex. 21, p. 19; App. Ex. 28, p. 6. It is anticipated an additional $11 million in sales tax, use tax and contractor's excise tax will be realized by the State of South Dakota during the construction of Big Stone Unit II. App. Ex. 28, pp. 5, 6. The local economic impact is estimated, in 2008 dollars, at $672.8 million during construction; the State level is at $745.1 million. Long-term local economic impact is $3.6 million per year of new income in the four county area not including on-going contractor support for plant activities. App. Ex. 26, p. 8. Once operational, Big Stone Unit II will be paying around $4.7 million in annual property taxes, App. Ex. 28, p. 3, which may reduce the state aid required by the Milbank school district by about $1.4 million. $300 million of assessed value to the mill levy calculation is anticipated once Big Stone Unit II is operational. Local property taxes should decrease as a result of Big Stone Unit II. App. Ex. 28, p. 6.

147. No adverse impact on agriculture land use is expected, and any impact on such land is expected to be insignificant. App. Ex. 27, p. 20. The construction and operation are not expected to have material adverse effects on construction and operations of other industries. App. Ex. 22, p. 12.

148. There are no other major industrial facilities under regulation that may have an adverse affect on the environment as a result of the facility construction or operation.

23.0 EMPLOYMENT ESTIMATES

149. During peak construction in 2008, the project is projected to employ 1,400 workers; this peak could last up to, but probably not exceed, one year. App. Ex. 27, pp. 9, 16; App. Ex. 26, pp. 5, 10; HTr 301. Anticipated construction labor hours approximate to 5.1 million hours, at a $211 million value. Local job growth is estimated at 2,550 positions for the construction phase, and 1,844 jobs in the surrounding communities; the average for each of the four construction years is 1,098. Id. The State benefit for job growth is estimated at 2,550 jobs during construction and 2,291 jobs in the communities, with the average being 1,210. Id. Job classifications include unskilled labor, skilled labor, technical and advanced technical. App. Ex. 27, p. 16. Numerous sectors will benefit from the construction, such as food, service, real estate, auto repair, and motor vehicle. App. Ex. 26, p. 11. It is expected that the local labor pool would supply a portion of the semi-skilled and skilled project labor personnel, utilizing unemployed, underemployed, and farmers in need of additional seasonal income. Big Stone Unit II will share operational staff with existing staff from Big Stone I. App. Ex. 8, pp. 8-9. Once operational, it is anticipated that an additional 35 full time employees will be added. App. Ex. 26, p. 10; App. Ex. 18, pp. 14-15. The added 35 employees are at a cost of $2.5 million per year, at 2004 wage levels. App. Ex. 54, p. 115-116.

24.0 FUTURE ADDITIONS AND MODIFICATIONS

150. There are no future expansion plans for the proposed Big Stone Unit II or for construction of additional facilities. In the design of Big Stone Unit II, consideration is being given to allow for enough space between Unit I and Unit II to accommodate any future modifications that may be required because of changing regulations. At this time, there is no plan to make any modifications to Big Stone Unit I, other than to re-route exhaust gases from Unit I to the common scrubber. App. Ex. 8, p. 10; App. Ex. 33.

25.0 NATURE OF PROPOSED ENERGY CONVERSION SYSTEM

151. The Big Stone Unit II project involves construction of a single pulverized coal-fired steam generator (boiler) with balanced-draft combustion and a single, reheat steam turbine. App. Ex. 54, p. 2. The unit will burn Powder River Basin sub-bituminous coal, the type of fuel currently used at Big Stone Unit I. App. Ex. 8, p. 5; App. Ex. 8, p. 2. Number two fuel oil will be used for igniting the fuel on initial startup and for flame stabilization. "Opportunity fuels" such as wood or agricultural waste may also be burned, though in relatively small percentages to the overall fuel mix. App. Ex. 8, p. 12. The steam boiler will provide steam to a single steam turbine generator that converts mechanical energy of the steam turbine to electrical energy. A water-cooled steam condenser will accept the steam exhausted from the turbine. A circulating water system will supply cooling water from a wet cooling tower to the water-cooled steam condenser to dissipate the energy in the condensing steam. App. Ex. 54, p. 9.

152. Electricity produced by the generator will be supplied to the 230 kV transmission system through a new generator step-up transformer and switching equipment. App. Ex. 54, p. 9. To accommodate power and energy from Big Stone Unit II, the Applicants are proposing to construct and operate two new high voltage transmission lines and associated facilities: a line from the Big Stone Plant to Morris, Minnesota, to be designed and operated at 230 kV; and a line from the Big Stone Plant to Granite Falls, Minnesota, to be designed at 345 kV, but initially operated at 230 kV. When connected with other planned upgrades to the bulk transmission system, the Big Stone – Granite Falls line will increase transfer capability by approximately 1000 MW beyond what is required for Big Stone Unit II, which will facilitate wind and other generation resources. TR p. 32; App. Ex. 1, p. 14; App. Ex. 2, p. 7; App. Ex. 53, pp. 2-44 through 2-53.

153. Maintenance will consist of routine periodic, unscheduled and scheduled maintenance, primarily to occur on site. Annual outages for inspection of major equipment as well as major maintenance (i.e., every five years) is also expected. Onsite maintenance support will be supplied. App. Ex. 54, p. 38-39.

26.0 PRODUCTS TO BE PRODUCED

154. The burning of solid fuel will produce ash, a combustion by-product. The unit is being designed and the fuel is being selected with the expectation that the fly ash produced will be sold into the cement replacement market, thus yielding a valuable by-product. The waste from the wet scrubber will be a gypsum material. If a market can be found, this product may be sold into the wallboard manufacturing area. The remaining ash is expected to be land filled. App. Ex. 8, p. 11.

27.0 FUEL TYPE USED

155. The proposed fuel for Big Stone Unit II is sub-bituminous coal from the Powder River Basin in Wyoming and Montana. It is the same coal that is burned in Unit I. Analysis of the Unit I coal over the last five years shows a heat content of a minimum of 7,980 BTU per pound and a maximum of 9,500 BTU per pound. The Applicants have provided in the Application the expected chemical analysis of the coal. App. Ex. 8, p. 11; App. Ex. 54, pp. 16-17.

28.0 PROPOSED PRIMARY AND SECONDARY FUEL SOURCES AND TRANSPORTATION

156. Coal will be transported from the Powder River Basin to the site by unit trains by the Burlington Northern Santa Fe Railway ("BNSF"), which is the delivery system for Big Stone I. App. Ex. 8, pp. 2, 8. Combined, the two units will require six-to-eight train deliveries weekly (approximately 115 coal cars per delivery). App. Ex. 18, p. 17.

157. The existing Big Stone I rail spur provides site access. App. Ex. 18, p. 17. The existing access spur begins at a turnout ¾ mile southwest of Big Stone City; an overpass exists where the spur crosses 484th Avenue. No changes are anticipated to the rail spur. Construction to the loop on plant site will

occur to provide space for the Big Stone Unit II turbine building and to accommodate deliveries and car storage. App. Ex. 8, p. 8; App. Ex. 18, p. 17; App. Ex. 54, pp. 17-19.

158. BNSF recently experienced a shortage in railroad delivery service capability for coal transportation to Big Stone I and other plants in the Midwest. This was the first shortage because of fuel shortages experienced since Big Stone I became operational. App. Ex. 29, pp. 1-2; App. Ex. 35, p. 6. The BNSF has undertaken a significant capital expansion program to increase coal deliveries and improve reliability. App. Ex. 35, pp. 4-5; HTr 43, 314-15. HTr 316-17. In addition, the Big Stone I co-owners have leased a third train, which will increase reliability for the existing plant by 50%, and has increased stockpiling for the summer months. HTr 76-77, 96. No future coal delivery shortages are likely. Id.

159. Changing the site location because of the recent coal delivery shortage would not create any significant benefit in terms of reliability of future coal delivery. App. Ex. 29, p. 3.

160. No significant impact on the surrounding communities is anticipated on account of rail traffic. App. Ex. 18, p. 17; App. Ex. 54, p. 125.

29.0 ALTERNATE ENERGY RESOURCES

161. The decision to pursue construction of a 600 MW coal-fired second unit at the Big Stone plant is one that resulted from extensive analysis by the Applicants. Each of the Applicants, through their individual resource planning efforts, considered various different types of generation, both fossil fuel-fired and renewable energy sources, before selecting Big Stone Unit II to meet their baseload needs. App. Ex. 8, p. 8.

162. In considering all the different ways in which electricity can be generated, the Applicants made a qualitative assessment of each alternative's capability to meet the underlying objective of providing approximately 600 megawatts of baseload capacity by 2011, at a reasonable cost to their customers. The Applicants also took into account potential environmental and community impacts associated with any project. App. Ex. 8, p. 13.

163. The Applicants conducted an initial screening of various alternatives to determine whether any of the alternatives have the potential to address the need to be served by the proposed project, and then examined in more detail only those options that appeared feasible. The Applicants wanted to make sure that any generation alternative be able to satisfy three basic objectives for a baseload generation unit – the technology must be applicable; the facility must be available for service when needed; and the facility should enhance the overall reliability of the bulk electric system. While costs, economic effects, and environmental impacts are legitimate project objectives, if an alternative is not feasible, these other factors are of little significance. App. Ex. 8, p. 14.

164. Applicants' review and analysis showed that there are no renewable generation options available to address the need for 600 MW of baseload power within the timeframe required, and that other fossil fuel sources are more expensive and less desirable. App. Ex. 8, p. 14.

165. As a part of its overall analytic process, the Applicants retained the Burns & McDonnell Engineering Co. to examine alternative baseload generation technologies that could be developed at the Big Stone site. Burns & McDonnell completed this report, termed the "Phase I Report," in July 2005. App. Ex. 24-A.

166. The Phase I Report examined the following generation technologies: (1) 600 MW supercritical PC unit; (2) 450 MW supercritical PC unit; (3) 300 MW subcritical PC unit; (4) 600 MW subcritical circulating fluidized bed (CFB) unit; (5) 450 MW subcritical CFB unit; (6) 300 MW subcritical CFB unit; and (7) 500 MW Combined Cycle Gas Turbine (CCGT) unit. The Phase I Report concluded that a 600 MW supercritical pulverized coal plant represented the lowest cost generation alternative of the technologies evaluated for the

Big Stone station site on a life-cycle basis considering capital and operating costs. App. Ex. 24-A; App. Ex. 8, p. 14.

167. The Applicants further asked Burns & McDonnell to examine alternative generation technologies regardless of where these technologies might be constructed. That analysis is contained in the September 2005 Report entitled "Analysis of Baseload Generation Alternatives." App. Ex. 23-A. The report shows that a super-critical pulverized coal plant is the least-cost most appropriate way of meeting the base load power needs of the Applicants. App. Ex. 23-A.

168. The Applicants considered the following technologies:

Wind

169. While wind will continue to play a significant part in meeting the regional energy needs of the Applicants in the future, there are several reasons why wind energy cannot replace the Big Stone Unit II project. The major reason is that wind cannot be relied on to satisfy a baseload demand for 600 MW. Electricity produced from wind is an intermittent resource. Wind turbines typically are only capable of achieving capacity factors in the range of 30-to-40 percent if properly sited in an area with adequate wind resources. This means that wind turbines only generate 30-to-40 percent of the megawatt hours that would have been generated if the units had run at full load continuously for the year. Baseload generation is typically required to achieve capacity factors closer to 90%, and provide reliable energy on an around the clock basis. As a result, wind generation is not suitable to meet baseload capacity and energy needs. Baseload resources are also required to be dispatchable, meaning that they can be scheduled to run at a specified load for a given duration. Since wind power is intermittent based on wind velocities, it is not dispatchable and not suitable as a baseload capacity and energy resource. App. Ex. 8, pp. 15-17.

170. Before considering wind for baseload power, a backup source of firm generation to rely on when the wind is not blowing at the necessary speed is required. The Burns & McDonnell's Analysis of Baseload Generation Alternatives Report, App. Ex. 23-A, evaluated a combination of 600 MW of wind, backed-up by a 600 MW combined cycle gas turbine (CCGT). Under this scenario, wind energy would be utilized when it was available and the combined cycle unit would operate as necessary to back-up the wind's intermittency. Based on the report, the Applicants found that the busbar cost (the cost of electricity at the point of delivery from the generation source without any transmission or distribution costs) for wind plus CCGT of $72.89/MWh for investor owned utilities (such as OTP and Montana-Dakota) and $70.57/MWh for public power companies (such as MRES, CMMPA, SMMPA, HCPD, and GRE). This is significantly more expensive than Big Stone Unit II. App. Ex. 23, p. 10-11; App. Ex. 23-A; App. Ex. 8, p. 21.

Biomass

171. The Burns & McDonnell Analysis of Baseload Generation Alternatives Report, App. Ex. 23-A, demonstrated that biomass is not a feasible alternative. It also demonstrated that it would take approximately 600,000 acres of land to support such a plant if it were to burn whole trees, a land size nearly double the size of Big Stone County, Minnesota. The report found that biomass is not economically viable for base load energy production compared to Big Stone Unit II. App. Ex. 23-A.

Hydropower

172. Hydropower was another generation option that was considered and rejected by the Applicants because there was not enough hydropower to satisfy the projected need. App. Ex. 8, p. 17.

173. Recent analysis showed that neither Minnesota (with undeveloped capacity of 137 MW of hydropower) nor North Dakota (with only 50 MW of availability) would be able to satisfy the Applicants' need. The analysis also showed that South Dakota had the potential for 695 MW of hydropower at 33 different sites, three of which are on the Missouri River that had a potential capacity greater than 50 MW. It would take nearly

every watt of hydropower potential in South Dakota to satisfy the 600 MW demand and the Missouri River Basin is presently suffering through a long-term drought. Id. As a result, hydropower is not a realistic option. App. Ex. 8, p. 18.

Solar

174. Solar power is not a viable option to the proposed Big Stone Unit II. The Applicants need base load energy – which means electricity that is capable of running at very high capacity factors – e.g., better than 90%. Solar has been recognized not to be an option in this region because it is an intermittent resource that customers cannot count on to be dispatched. App. Ex. 8, p. 18.

Landfill gas

175. Landfill gas is not a viable option because no sources are available that would satisfy the need for additional base load generation. App. Ex. 8, p. 18.

Geothermal energy

176. Geothermal energy is also not a viable option because there are no such resources available to meet the demand in the Applicants' service areas. App. Ex. 8, p. 18.

Distributed Generation

177. Fuel cells and microturbines are two methods of distributed or dispersed generation. Neither option passed the screening analysis because the technology is not compatible with baseload energy. App. Ex. 8, p. 18.

Atmospheric Circulating Fluidized Bed ("ACFB")

178. A fluidized bed unit uses a different type of technology to burn the coal. The combustion process occurs in a suspended bed of solid particles in the lower section of the boiler. Combustion occurs at a slower rate and at lower temperatures than a conventional pulverized coal boiler. This technology allows a wide variation in fuel size and type and heat content. The coal normally burns cleaner than in a pulverized boiler but state-of-the-art control equipment is still required. A fluidized bed unit costs about 5% more than a pulverized coal unit. Also, the largest atmospheric fluidized bed boilers in operation are approximately 300 MW in size, and all ACFB boilers built to date are of sub-critical design; thus their efficiency is considerably less than the super-critical pulverized coal design of Big Stone Unit II. App. Ex. 8, p. 19.

Combined Cycle Natural Gas Turbine

179. The basic principle of the combined cycle gas turbine is to utilize gaseous fuels, such as natural gas, to produce power in a gas turbine, which is used to generate electricity, and to use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator to produce more electricity from the steam. Combined cycle operations can obtain efficiencies in the 50 to 58% range. A natural gas combined cycle plant is less expensive to construct than a pulverized coal plant. However, the busbar cost of the electricity is significantly higher. The Burns & McDonnell Analysis of Baseload Generation Alternatives Report, Exhibit 23-A, confirms this. That report shows a busbar cost of $77.94/MWh for investor owned utilities and $75.61/MWh for public power companies. In addition, the availability and price volatility of natural gas is a concern to the Applicants and the Commission. A combined cycle natural gas plant is not a good alternative for a 600 MW baseload unit. App. Ex. 8, p. 19-20.

Integrated Coal Gasification Combined Cycle

180. Integrated Gasification Combined Cycle ("IGCC") technology is a system that produces a syngas from a fossil fuel such as coal and utilizes the gas to generate electricity in a conventional combined cycle plant. The Applicants asked Burns & McDonnell in its Analysis of Baseload Generation Alternatives Report to determine the performance and costs and other features of an IGCC system. The proposal as examined called for a 535 MW IGCC generating station comprised of two coal gasifiers, two "F" class gas turbines, each coupled with a heat recovery steam generator and a single, reheat steam turbine. Because there are no IGCC facilities in the United States that have ever used sub-bituminous western coal, as proposed for Big Stone Unit II, Burns & McDonnell assumed that bituminous Illinois coal would be used. Also, because an IGCC unit would require natural gas as backup, Burns & McDonnell assumed that an IGCC facility would not be located at the Big Stone Plant, because there is no natural gas supply at that location. The Burns & McDonnell report found that an IGCC plant had higher construction costs than a coal plant. Burns & McDonnell calculated a busbar cost (the cost of electricity at the point of delivery from the generation source without any transmission or distribution costs) of $58.81/MWh for a super-critical pulverized coal plant and $83.84/MWh for an IGCC facility for investor owned utilities, and $47.37/MWh and $71.05/MWh respectively, for public utilities. An IGCC plant would cost 43% and 50% more than a coal plant for the two types of utilities. In addition, historically, IGCC plants have not achieved high capacity factor operations. App. Ex. 8, pp. 21-22; App. Ex. 23-A.

30.0 SOLID OR RADIOACTIVE WASTE

181. By-products produced from coal combustion primarily consist of bottom ash, fly ash and gypsum. App. Ex. 16, p. 14; App. Ex. 8, p. 11. Additional wastes include construction debris, plastic, cardboard, wood, metal, food and office and laboratory waste. App. Ex. 16, p. 16; App. Ex. 8, p. 11. The applicable standards and regulations will be complied with for the treatment and storage of the by-products and waste. Ash by-product is environmentally safe. HTr 95.

182. Bottom ash and gypsum will be removed by conveyor, and transferred to a temporary storage area for loading, transport and disposal in the onsite landfill. App. Ex. 16, p. 3. The gypsum may be sold and shipped for use in sheetrock or wallboard manufacturing. App. Ex. 16, p. 16.

183. Fly ash will be conveyed to the fly ash storage silo with controls of vent filters, and from there it will be unloaded onto trucks for potential sale and shipment offsite for use in concrete, soil stabilization or fill. App. Ex. 16, p. 16. Excess fly ash will be disposed of in the onsite landfill. App. Ex. 16, p. 16. Exposed (uncontained) ash will be wetted prior to open handling. Fly ash from the economizer and selective catalytic reduction section will be conveyed to the bottom ash hopper and mixed with bottom ash. App. Ex. 54, pp. 22-23.

184. At the landfill, the by-products will be distributed in layers and compacted. Water will be applied to assist in compaction and dust control. App. Ex. 33, p. 19. The existing Big Stone I landfill will accommodate approximately 10 years of disposal before it will need to be expanded. App. Ex. 33, p. 19. When the site is exhausted, the necessary permit will be obtained and regulations complied with. App. Ex. 33, p. 19.

185. Construction debris will be transported offsite to an approved solid waste landfill. App. Ex. 16, p. 16. Normal operation waste will be properly disposed of at a landfill or treatment facility. App. Ex. 16, p. 3. Combustion by-products will be disposed of at the Big Stone I landfill. App. Ex. 16, p. 17.

186. All wastes generated during construction and operation of Big Stone Unit II will be evaluated to determine whether any are classified as hazardous wastes. Small quantities of hazardous wastes may be generated. App. Ex. 16, p. 19. All hazardous wastes generated will be reported to the proper authorities and properly disposed of in accordance with all requirements. App. Ex. 33, p. 19.

187. It is likely that Big Stone Unit II will use sealed radioactive sources to monitor certain process conditions such as coal flow and the wet scrubber slurry density. Existing power plants have used these types of devices for years. They were included in the original design of the Big Stone Plant. The U. S. Nuclear Regulatory Commission regulates the installation and operation of such sources. No radioactive wastes will be disposed of on site, but will be monitored and disposal will be to an approved facility. App. Ex. 16, p. 3, 20; App. Ex. 33, p. 20.

31.0 ESTIMATE OF EXPECTED EFFICIENCY

188. The exact efficiency of Big Stone Unit II depends on final design determinations that are yet to be made. However, the super-critical steam cycle that is to be used here delivers a higher efficiency than a sub-critical unit. Assuming that it will take 9,392 BTUs of energy to produce one kilowatt hour of electricity translates into an overall efficiency of greater than 36%. App. Ex. 8, p. 23.

32.0 DECOMMISSIONING

189. Because the life of Big Stone Unit II is expected to be quite long, it is difficult to predict what decommissioning requirements will be at the time necessary to decommission the Unit. However, the Applicants intend to fully comply with all applicable laws and rules and intend to set aside an appropriate amount of reserve funds to cover decommissioning costs. App. Ex. 8, p. 23.

33.0 GENERAL

190. Pursuant to SDCL 49-41B-12, on August 9, 2005, the Commission voted to assess Applicants a filing fee not to exceed $700,000.00 with an initial deposit of $8,000.00, the minimum amount of the fee. Receipt of the deposit of $8,000.00 from OTP on behalf of Applicants was acknowledged. Applicants have paid all fees and additional deposits required by the Commission in this matter. App. Ex. 55.

191. Dr. Olesya Denney is an economist with a PhD from Oregon State University. She was retained by the Commission Staff to assists its evaluation of the Application, testimony, discovery and all other facts submitted in support of and in opposition to the permit Application. Dr. Denney recommended approval of the Application for an Energy Conversion Facility Permit, subject to certain conditions. Among other conditions, Dr. Denney recommended – to which the Applicants agreed – the following: (1) that the Applicants shall submit quarterly progress reports to the Commission that summarize the status of the construction, the status of the land acquisition, the status of environmental control activities, and the overall percent of physical completion of the project and design changes of a substantive nature. Each report shall include a summary of consultations with DENR (the South Dakota Department of Environment and Natural Resources), and other agencies concerning the issuance of permits. The reports shall list dates, names, and the results of each contact and the company's progress implementing prescribed environmental protection or control standards. The first report shall be due for the quarter ending September 30, 2006. The reports shall be filed within 31 days after the end of each quarter and shall continue until the project is fully operational; (2) that Applicants prepare a contingency housing plan for construction housing; (3) that Applicants fund an additional officer to the Grant County Sheriff's office for three years, have drug testing on potential workers, and advise law enforcement of peak employment months; (4) that Applicants purchase a high angle rescue kit and provide training in its use to a number of members of the local fire department; and (5) that Applicants provide a public affairs employee, implement a web site, and schedule periodic meetings to update the public. App. Ex. 68; Ex. 8, p. 116.

192. In addition to the above conditions recommended by Dr. Denney, the Commission finds that the evidence justifies the imposition of certain other conditions as set forth below in findings 193 through 199.

193. Applicants have applied for various federal, state and local permits in connection with Big Stone Unit II and will require additional zoning and other permits as the project progresses. These permits include but are not limited to the Water Appropriation Permit, PSD Air Quality Construction Permit, Solid

Waste Permit and Section 404 Permit. The Commission finds that in order to comply with SDCL 49-41B-22(1), the permit must be conditioned on the receipt of and compliance with all applicable federal, state and local permits.

194. Applicants have made commitments to both this Commission and DENR regarding meeting or exceeding a mercury emissions limit equal to the mercury emissions from Big Stone Unit I in 2004 of 189 pounds. See Finding 129. A condition reflecting this commitment is appropriate.

195. As discussed in finding 101, under extended drought conditions, it is possible that operation of Big Stone II might have to be diminished or shut down. Although Applicants discussed the potential for use of groundwater or other alternative water source in that contingency, no evidence relative to the specifics of such alternative supply was produced. The Commission believes that Applicants should undertake an evaluation of alternatives during the development phase of the project to enable timely response to this contingency should it occur.

196. Applicants also committed at the hearing to complying with all mitigation measures recommended as part of the Final EIS Record of Decision. A condition reflecting this commitment is appropriate.

197. Applicants OTP and MDU are subject to rate regulation by the Commission. Both of these utilities have made statements of commitment in this proceeding about increasing the contribution of DSM and renewables to their portfolio mix. The Commission accordingly finds that to keep the Commission informed concerning these efforts, beginning on July 1, 2007, OTP and MDU shall file annually a detailed report of their ongoing DSM and renewable programs and a forecast of their near- and long-term initiatives to optimize benefits related to demand-side management and renewable energy programs.

198. In her evidence, comments and argument presented to the Commission, Mary Jo Stueve expressed concern with mercury emissions despite tightened regulation of mercury under EPA's new mercury rule and Applicants' commitments in this proceeding. Although the Commission does not find that evidence peculiar to Big Stone Unit II was presented in this case that would justify denial of the permit or imposition of permanent mercury standards that are more stringent than those imposed by EPA and DENR in its air quality permitting process, the Commission does share Stueve's concern that mercury emissions be brought down to the control level as rapidly as practicable. To advise the Commission and the public of Applicants' efforts in this regard, the Commission finds that the permit shall be subject to the condition that on or before the date Big Stone Unit II starts operation and every six months thereafter, the operating partner shall provide the Commission with an update on the mercury control efforts being undertaken by the partners, until such time as the combined plants meet the agreed level of mercury emissions set forth in Findings 129 and 194.

199. Because there does not yet exist any federal or state regulation of CO_2 emissions, and because we do not yet know what effect such regulation may have on ratepayers in the future, the Commission finds that it is important for Applicants to keep the Commission informed of developments relative to the project involving CO_2 and that a condition so requiring is appropriate. The Applicants shall submit an annual report to the Commission on CO_2 with the first such report to be filed on or before July 1, 2008. Such report shall review any federal or state action taken to regulate carbon dioxide, how the operator plans to act to come into compliance with those regulations, the expected costs of those compliance efforts and the estimated effect of such compliance on rate-payers. The report should also evaluate operational techniques and commercially-available equipment being used to control CO_2 emissions at pulverized coal plants, the cost of those techniques or equipment, and whether or not the operator has evaluated the prudence of implementing those techniques or equipment.

200. Applicants have provided all information required by ARSD 20:10:22 and SDCL 49-41B.

201. SDCL Chapter 49-41B is not a certificate of convenience and necessity proceeding, and the Findings of Fact that the Commission has made in this proceeding regarding Applicants' description of need

for the baseload generation to be provided by Big Stone Unit II pursuant to ARSD 20:10:22:08 are not intended to be nor have the effect of prospective findings of prudency that may arise in any future rate proceeding involving such investments.

202. On July 8, 2006, Stueve filed and served a Petition to Dismiss Application and Notice. The Commission finds that Stueve's Petition to Dismiss should be denied. The Petition was filed less than a week before the scheduled Commission decision date and involved the type of factual determinations that consumed 52 pre-filed testimony exhibits and four full days of testimony. The Commission considered the arguments made by Stueve in her Petition in connection with its decision on the merits as it did the evidence and arguments of all parties and commenters in this proceeding and finds that the evidentiary deficiencies cited by Stueve are not material and do not warrant dismissal of the Application.

203. To the extent that any of the below conclusions are more appropriately a finding of fact, that conclusion of law is incorporated by reference as a finding of fact.

Based on the above Findings of Fact, the Commission hereby makes the following:

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the subject matter and parties to this proceeding pursuant to SDCL Chapter 49-41B and ARSD 20:10:22. Subject to the findings made on the four elements of proof under SDCL 49-41B-22, the Commission has authority to grant, deny or grant upon reasonable terms, conditions or modifications, a permit for the construction, operation and maintenance of Big Stone Unit II.

2. The Big Stone Unit II Project is an energy conversion facility as defined in SDCL 49-41B-2.1(2).

3. The Applicants' Permit Application, as amended, complies with the applicable requirements of SDL Chapter 49-41B and ARSD 20:10:22.

4. The Big Stone Unit II Project as defined herein will comply with all applicable laws and rules, including all requirements of SDCL Chapter 49-41B and ARSD 20:10:22.

5. The Big Stone Unit II Project, if constructed in accordance with the terms and conditions of this Decision, will not pose a threat of serious injury to the environment or to the social and economic conditions of inhabitants or expected inhabitants in the siting area.

6. The Big Stone Unit II Project, if constructed in accordance with the terms and conditions of this Decision, will not substantially impair the health, safety or welfare of the inhabitants of the siting area.

7. The Big Stone Unit II Project, if constructed in accordance with the terms and conditions of this Decision, will not unduly interfere with the orderly development of the region with due consideration having been given the views of governing bodies of affected local units of government.

8. The Commission has the authority to revoke or suspend any permit granted under the South Dakota Energy Facility Permit Act for failure to comply with the terms and conditions of the permit pursuant to SDCL 49-41B-33.

9. To the extent that any of the above made findings of fact are determined to be conclusions of law or mixed findings of fact and conclusions of law the same are incorporated herein by this reference as a conclusion as if set forth in full.

10. Administrative rules have the force of law and are presumed valid. Feltrop v. Department of Social Svcs,. 559 NW2d 883, 884 (SD 1997). An administrative agency is bound by its own rules. Mulder v. Department of Social Svcs., 675 NW2d 212, 216 (SD 2004).

11. The Applicants have met their burden of proof pursuant to SDCL 49-41B-22 and are entitled to a permit as provided in SDCL 49-41B-25.

12. Because a federal EIS is required in this project and because the federal EIS complies with the requirements of SDCL Ch. 34A-9, neither the Commission nor any other agency of the State of South Dakota is required to prepare a separate environmental impact statement. SDCL 34A-9-11. It is appropriate for the Commission to use the federal EIS. The requirements of SDCL 49-41B-21 have been met.

13. The burden of proof on the parties on which they have the burden is by the preponderance of the evidence.

14. The Commission concludes that it needs no other information to assess the impact of the proposed facility or to determine if Applicants or any Intervenor has met its burden of proof.

15. The Commission concludes that the Application and all required filings have been filed with the Commission in conformity with South Dakota law. All procedural requirements required under South Dakota law have been met. All data, exhibits, and related testimony have been filed.

16. The Commission concludes that the Application is supported by the testimony of the witnesses and documentary evidence.

17. The Commission concludes that the Application is legally and procedurally appropriate and complete. All formatting and timing requirements have been complied with. All public hearing requirements have been met.

18. A full and fair opportunity to litigate the issues involved in the Application was given to all parties and those in privity with the parties prior to the Commission's decision.

19. The Commission concludes that Stueve's Petition to Dismiss should be denied.

20. The Commission concludes that the conditions referenced in Findings 191 through 199 are appropriate and necessary.

21. The Commission concludes based on the evidence and findings of fact that all applicable fees and deposits have been paid; the Applicant has sustained its burden of proving the proposed facility will comply with all applicable laws and rules; the facility will not pose a threat of serious injury to the environment nor to the social and economic condition of inhabitants or expected inhabitants in the siting area; the facility will not substantially impair the health, safety or welfare of the inhabitants; and the facility will not unduly interfere with the orderly development of the region with due consideration having been given the views of governing bodies of affected local units of government.

22. The Commission concludes that the permit to construct Big Stone Unit II should be granted subject to the conditions set forth in Findings 191 through 199.

DECISION AND ORDER

Based on the above Findings of Fact and Conclusions of Law, it is therefore:

ORDERED, that Stueve's Petition to Dismiss is denied; and it is further

ORDERED, that an Energy Conversion Facility Siting Permit is issued to OTP, for itself and on behalf of the Applicants, and construction of the Big Stone Unit II Project is authorized, subject to the following conditions:

1. The Applicants shall comply with the recommendations made by the Local Review Committee in its report dated December 14, 2005, as modified by the Commission in these conditions, including but not limited to the following:

A. Applicants shall prepare a contingency housing plan for construction housing;

B. Applicants shall fund an additional officer to the Grant County Sheriff's office for three years, implement a program of drug testing of potential workers and advise law enforcement of peak employment months;

C. Applicants shall purchase for the Big Stone City Fire Department a high angle rescue kit and provide for the training of several of the Big Stone City Fire Department members in the use of the equipment; and

D. Applicants shall provide a public liaison officer to facilitate the exchange of information between the project owners, contractors and the local communities and residents and to promptly resolve problems that may develop for local communities and residents as a result of the project. Applicants shall also implement a web site and conduct periodic meetings to update the public. The public liaison officer shall be afforded immediate access to the Applicants' project manager and to contractors' on-site managers.

2. The Applicants shall comply with the following conditions recommended by Staff:

A. The Applicants shall obtain and shall thereafter comply with all applicable federal, state and local permits, including but not limited to the Water Appropriation Permit, PSD Air Quality Construction Permit, Solid Waste Permit and Section 404 Permit.

B. In the PSD Air Quality Construction Permit proceeding and at the hearing in this case, Applicants have agreed to limit mercury emissions from the combined Big Stone Unit I and Big Stone Unit II plants to no more than the emissions from Big Stone Unit I in 2004 which is 189 pounds per year, beginning three years after commercial operation commences of Unit 2. Applicants shall meet or exceed this standard.

C. The Applicants shall submit semi-annual progress reports to the Commission that summarize the status of the construction, the status of the land acquisition, the status of environmental control activities, the implementation of the other measures required by these conditions, and the overall percent of physical completion of the project and design changes of a substantive nature. Each report shall include a summary of consultations with DENR (the South Dakota Department of Environment and Natural Resources), and other agencies concerning the issuance of permits. The reports shall list dates, names, and the results of each contact and the company's progress implementing prescribed environmental protection or control standards. The first report shall be due for the period ending December 31, 2006. The reports shall be filed within 31 days after the end of each semi-annual period and shall continue until the project is fully operational;

D. The Applicants shall comply with all mitigation measures recommended as part of the Final EIS Record of Decision.

3. Applicants shall conduct an evaluation of alternative water supply options to provide water to the plant in the event that withdrawals from Big Stone Lake are curtailed for an extended period of time. Applicants shall file a report with the Commission detailing the findings of such study on or before September

1, 2007. Such study shall include (i) identification of particular potential source options, (ii) an assessment of the facilities which would be required to effectuate water delivery to the plant from such alternative sources, institutional and other impediments to contingent development of one or more of these options and the timing and logistics of implementing such options, (iii) a preliminary cost analysis of alternative supply options and (iv) a comparison of financial effects of development of one or more alternative supply options with the no-run option.

4. Beginning on July 1, 2007, Otter Tail Power and Montana-Dakota Utilities shall file annually a detailed report of their ongoing DSM and renewable programs and a forecast of their near- and long-term initiatives to optimize benefits related to demand-side management and renewable energy programs.

5. On or before the date Big Stone Unit II starts operation and every six months thereafter, the operating partner shall provide the Commission with an update on the mercury control efforts being undertaken by the partners, until such time as the combined plants meet the agreed level of mercury emissions set forth in Condition 2.B.

6. Because there does not yet exist any federal or state regulation of CO_2 emissions, and because we do not yet know what effect such regulation may have on ratepayers in the future, the Applicants shall submit an annual report to the Commission on CO_2 with the first such report to be filed on or before July 1, 2008. Such report shall review any federal or state action taken to regulate carbon dioxide, how the operator plans to act to come into compliance with those regulations, the expected costs of those compliance efforts and the estimated effect of such compliance on rate-payers. The report should also evaluate operational techniques and commercially-available equipment being used to control CO_2 emissions at pulverized coal plants, the cost of those techniques or equipment, and whether or not the operator has evaluated the prudence of implementing those techniques or equipment.

NOTICE OF ENTRY AND OF RIGHT TO APPEAL

PLEASE TAKE NOTICE that this Final Decision and Order was duly entered on the 21st day of July, 2006. Pursuant to SDCL 1-26-32, this Final Decision and Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties. Pursuant to ARSD 20:10:01:30.01, an application for a rehearing or reconsideration may be made by filing a written petition therefor and ten copies with the Commission within 30 days from the date of issuance of this Final Decision and Order. Pursuant to SDCL 1-26-31, the parties have the right to appeal this Final Decision and Order to the appropriate Circuit Court by serving notice of appeal of this decision to the circuit court within thirty (30) days after the date of service of this Notice of Decision.

Dated at Pierre, South Dakota, this 21st day of July, 2006.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 7/21/06

BY ORDER OF THE COMMISSION:

Robert K. Sahr

ROBERT K. SAHR, Chairman

Dustin M. Johnson

DUSTIN M. JOHNSON, Commissioner

Gary Hanson

GARY HANSON, Commissioner

ATTACHMENT A

RULINGS ON PROPOSED FINDINGS OF FACT

Rulings on Applicants' Amended Proposed Findings of Fact

Applicants' Amended Proposed Findings of Fact are accepted essentially as proposed and incorporated in the Decision's Findings of Fact with the exception of Finding 117, which appeared to be an inadvertent and misplaced repetition of Finding 76. Applicants' Amended Proposed Findings 118 – 192 have been renumbered as Findings 117 – 191. Applicants' Amended Proposed Findings 193 and 194 have been renumbered as Findings 200 and 203. Certain of Applicants' Amended Proposed Findings of Fact have been modified to some extent to reflect the Commission's understanding of the record and to add citations to the record where these were omitted.

Rulings on Joint Intervenors Proposed Findings of Fact

Proposed Findings 1 and 2 - Accepted and incorporated in substance in Decision Findings 1-9.

Proposed Finding 5 (Findings 3 and 4 were omitted from Joint Intervenors Proposed Findings) – Accepted and incorporated in Finding 133 with a modification to the second sentence to reflect a further necessary assumption that no CO_2 capture system is installed.

Proposed Findings 6 through 16 – Rejected. In Finding 135, the Commission finds that even though the emissions of CO_2 seem significant on a tonnage basis, they will represent only a minute fraction of total U.S. anthropogenic emissions and a much more minute fraction of global emissions. The Commission is only called upon to determine whether this particular facility will have a serious adverse impact on the environment, and there is insufficient evidence in this record on which to base a finding that Big Stone Unit II will have any appreciable effect on the global climate. It is clear from this record that if a consensus is ever reached at the national level concerning global warming and the contribution of CO_2 to the problem, regulation of carbon emissions will have to occur in a national or even global context. In Findings 139 and 199, the Commission notes that there is no federal or state regulation of CO_2, and thus far the debate at the Federal level over such regulation has yet to result in a bill that passed either house. EPA at the Federal level and DENR at the state level are charged with regulation of air pollutants, and neither agency has yet seen fit to implement regulations. The Commission acknowledges the concerns about CO_2 in Finding 199, and believes that the approach it has taken in that Finding and in Condition 6 is a proper approach given the current record and absence of regulations or standards.

Proposed Findings 17 and 18 – Rejected. Finding 123 acknowledges that the agreed mercury emissions limit of 189 pounds per year will not take effect until three years after the plant goes on line. The evidence in the record demonstrated that this period of time will be needed by plant operators to test and adjust their mercury control systems. Further, mercury emissions standards are regulated by DENR through its permitting process, and the Commission has subjected the permit to Conditions 2.A. and B. To the extent DENR determines that the emissions during the three-year shake down period or other mercury emissions from the plant will not meet state air quality standards, Applicants will be required to adjust their implementation time table and operations accordingly. Finally, the Commission has acknowledged the concerns with mercury during the three-year shakedown period in Finding 198 and has subjected the permit to Condition 5 in order to encourage the Applicants to bring mercury levels down to the agreed level as soon as practicable.

Proposed Findings 19 through 21 – Rejected. While the Commission agrees that South Dakota has an excellent wind resource and has itself been active in encouraging wind generation development in South Dakota, the Commission is called upon in this proceeding to consider whether to approve the construction of a particular coal fired base load generation facility. The evidence in the record demonstrated both a projected probable need for a true base load facility such as Big Stone Unit II and the plans by Applicants to bring significant amounts of wind energy into their resource mixes. Furthermore, the record demonstrates that the transmission constructed to accommodate Big Stone Unit II will provide surplus transmission capacity for up to

1000 MW of wind generation. The record demonstrated that the project may actually encourage wind development, not impede it.

Stueve's Proposed Findings of Fact

Proposed Finding 1 – Rejected. In Conclusion of Law 12, the Commission concluded that because a federal EIS has been prepared in this case and was entered into the record as evidence, any requirement that may exist regarding the preparation of an EIS has been substantially satisfied. SDCL 34A-9-11. The Commission is required to act on the Application within one year, and the Commission does not believe that it is justifiable to deny the permit and subject the Applicants and the other parties to the very substantial cost of another proceeding merely on the basis that the federal EIS process has not yet resulted in adoption of the final EIS document. The Commission expects changes to the Draft EIS to be minimal. Furthermore, the permit issued by this Decision is subject to Condition 2.D. which will require Applicants to comply with any mitigation measures which are included in the Final EIS.

Proposed Finding 2 – Rejected. The evidence introduced by Applicants, including the federal Draft EIS, thoroughly addressed the environmental impacts of the Big Stone Unit II facility, and the Decision contains numerous Findings of Fact reflecting the evidence regarding environmental impacts.

Proposed Finding 3 – Rejected. The Decision includes Findings of Fact on mercury emissions and required conditions in Findings 127-132 and 198 and Conditions 2.A., 2.B. and 5. requiring compliance with the mercury emissions standards and the required emissions limit and reporting on progress toward attainment of the mercury emissions limit during the three year implementations period.